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RAILROAD COMMISSION OF TEXAS
OIL AND GAS DIVISION

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

Bayou Bend CCS LLC (P5 # 100489)
1500 Louisiana Street, 11th Floor
Houston, TX 77002

Class VI Permit Number: 58339
Project/Facility Name: Bayou Bend East SL20220050 Phase 1 (BBE-P1)
County: Jefferson County (Offshore Texas State Waters), District 03

Effective Date: XXXXXX, 20XX
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, 20XX.

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 September 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 Tonnes)	Duration of Injection (Years)	Top Confining Zone	Injection Zone Formation Name
Industrial Sources (Beaumont/Port Arthur Areas)	121.5	20	Upper Lagarto (Amphistegina B Shale)	Oakville (LM1) & Lagarto (LM2) (T5-T12 sands)

TABLE 2: INJECTION WELL IDENTIFICATION AND PERMIT PARAMETERS

Well Name & No.	Latitude (NAD83)	Longitude (NAD83)	Top Inj. Interval, TVD (Feet)	Bottom Inj. Interval, TVD (Feet)	Max. Injection Mass Rate (Metric tonnes per day per well)	Max. Surface Injection Pressure (psig)	Max. Bottom Hole Injection Pressure (psig)
SL20220050 #W 1	29.5920225°	-93.89526008°	6,240	9,118	5,479	2,725	5,526
SL20220050 #W 2	29.59201108°	-93.89528519°	6,152	8,835			5,407
SL20220050 #W 4	29.5920358°	-93.89528395°	6,241	9,027			5,501
SL20220050 #W 5	29.59203393°	-93.89523497°	6,313	9,077			5,569
SL20220050 #W 6	29.59200921°	-93.89523621°	6,347	9,257			5,629

TABLE 3: MONITOR WELL IDENTIFICATION

Well Name & No.	API No.	Purpose	Total Depth, TVD (Feet)	Date Drilled
SL20220050 #M 1	708-30390	Monitoring P/T and sampling fluid above the confining zone (Goliad Formation)	8,408 PB to 8,189	04/08/2024

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 and anchor/seal stem assembly.

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.

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.

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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. The collected acoustic monitoring data must be shared with a public 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.

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.

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SPECIAL CONDITIONS:

1. The Director has granted the permittee a well-construction variance for construction of each of the five (5) injection wells. This well construction variance allows for a modified completion using a 6 5/8" seal stem adapter stabbed into a 7" Polished Bore Receptacle on top of a 7" liner instead of the traditional tubing and packer completion. The 6 5/8" tubing will be anchored by a tubing anchor above the 7" liner effectively providing an annular seal between the 6 5/8" tubing and 9 5/8" long string. The 7" liner will be hung on a hanger and cemented approximately 300' above the injection interval and 200' above the 9 5/8" casing shoe. The 9 5/8" casing string will be cemented with CO2 resistant cement across the premium casing material and cemented to the surface with Ordinary Portland Cement. These completions will contain a deep set shut-off valve anchored inside the premium casing and above the Tieback Receptacle providing an effective seal against pressurized fluids backflowing from the injection zone.

2. The following well was drilled in April 2024 as a stratigraphic characterization well. It will be converted to and repurposed as the Above Confining Zone Monitoring Well prior to commencing injection:

    - **SL20220050 #M 1 (API 42-708-30390)**

3. The following well will require corrective action **prior** to encroachment of the CO2 pressure front.:

    - **ST TR 00011-L NE/4 # 1 (API 42-708-30229)**

    The AoR time lapse evaluation estimates the CO2 saturation will reach this well after approximately 14 years of injection. Operator will actively monitor this well relative to the expanding AoR for the first five (5) years of injection leveraging the proposed monitoring plan due to proximity from injection. Operator will communicate the timing of phased corrective action after Year 5 of injection, to the RRC Director. When AoR re-evaluation provides a high certainty of CO2 saturation-front arrival, corrective action will be conducted to prevent CO2 movement vertically to the seafloor. In the event corrective action cannot be conducted due to new information or after actual attempts of well intervention work, the Director will be notified of the situation to make a decision regarding either continuing with permitted CO2 injection operations or cessation of injection.

4. Injection cannot begin until a letter of credit (LOC) in an amount of **$121,044,409** has been filed. The LOC must be renewed and continued in effect until the conditions of the LOC 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.

APPROVED AND ISSUED ON **XXXXXXX, 202X**

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Rob Castillo, Manager
Special Injection Permits Unit

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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), surface water 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,

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the application of such provision to other circumstances and the remainder of this permit shall not be affected thereby.

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/surface 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/Surface Water –** 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/surface water. If any water quality monitoring of a USDW/surface water indicates the movement of any contaminant into the USDW/surface water, 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

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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.

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

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(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.

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 (in this case Surface Water at the sea floor) 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. 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.

3. 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.

4. 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.

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.

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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.

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)**.

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(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/surface water 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 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)**.

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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/surface water 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 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/surface water located above the injection zone. These sections are incorporated by reference into this permit. USDW/surface water, 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

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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)**.

(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)**.

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(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/surface water and the well bore is prohibited.

2. **Injection Fluids/Carbon Dioxide Sources –** The carbon dioxide to be sequestered comes from industrial sources in the Beaumont/Port Arthur areas. 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/surface water. The maximum injection pressure limit is listed in Attachment E of this permit.

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.

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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/surface water.

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 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:

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(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.

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.

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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)**.

    (b) Prior to receiving authorization to inject, the permittee shall perform 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).**

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(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.

(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

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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/surface water 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).

(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

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USDW/surface water 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

1. Seismic Monitoring –

(a) Prior to commencing injection, the permittee must deploy and maintain a seismic monitoring system (Distributed Acoustic Sensing downhole fiber-optic sensors installed on the offshore injector wells). The collected acoustic monitoring data must be shared with a public seismic monitoring network to allow long-term monitoring by seismologists, and which may allow them 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 permittee shall analyze the DAS 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 these data, the permittee determines that there is 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 protocol:

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 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 the overlying water column above the seafloor, 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. **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 is required to conduct this monitoring in order to detect and locate the carbon dioxide pressure front and the dissolved carbon dioxide plume and use the data to calibrate the AoR model to determine whether modifications to the AoR is necessary. 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.

5. **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)**.

6. **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)**.

7. **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)**.

8. **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**.

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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)(8) 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:

        (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.

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(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/surface water, or any monitoring or other information which indicates that any contaminant may cause endangerment to a USDW/surface water;

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

(iii) Any triggering of the shut-off system required in Section (K)(8) 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 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:

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(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 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.

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(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.

(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.

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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:

      (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

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such deviation. If the Director determines that a deviation from the plan incorporated in this permit may endanger USDWs/surface water, 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/surface water 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/surface water 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/surface water and that no additional monitoring is needed to ensure that the project does not pose an endangerment to USDWs/surface water, as required in **16 TAC §5.206(k)(3)**. The Director reserves the right to amend the post-injection site

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monitoring requirements (including an extension of the monitoring period) if there is a concern that USDWs/surface water 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/surface water. 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/surface water 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/surface water, 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;

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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 L(3) of this permit;

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(8) 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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A. Area of Review and Corrective Action Plan

AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

Bayou Bend East SL20220050 (BBE)

PBI CROSSWALK FOR BAYOU BEND EAST CLASS VI APPLICATION

Plan Number	Plan Document Title	Contains PBI
03	Area of Review (AOR) and Corrective Action	Yes
	Appendix 3-1: Model Comparison Outputs	Yes
	Appendix 3-2: Artificial Penetrations – Wellbore Diagrams and Well Records	Yes
	Appendix 3-3: Copies of references used in support of the AOR and Corrective Action Plan	Yes
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3 AREA OF REVIEW AND CORRECTIVE ACTION PLAN
40 CFR 146.84(b)

BAYOU BEND EAST SL20220050 (BBE)

3.1 Facility Information

Facility Name: BAYOU BEND EAST SL20220050 – PHASE 1 (BBE-P1)
SL20220050 W1, SL20220050 W2, SL20220050 W4, SL20220050 W5, SL20220050 W6

Facility Contact: Claimed as PBI
1500 LOUISIANA STREET, 11TH FLOOR
HOUSTON, TEXAS 77002
Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

3.2 Computational Modeling Approach

3.2.1 Model Background

The full field static geologic model was constructed using Petrel©, a trademark of Schlumberger (SLB). The model integrated petrophysical, stratigraphic and structural inputs based on offset well data and 3D seismic interpretation. The geo-cellular model domain was built with a hybrid approach, integrating both a regional-scale and site-scale model. The size of the static model represents the Area of Interest (AOI) while providing higher resolution at the BBE-P1 site for detailed reservoir characterization and simulation.

INTERSECT© (IX©) was used for carbon dioxide (CO_2) sequestration simulation to understand CO_2 saturation and pressure front migration through time, delineate the Area of Review (AOR), and optimize development scenarios. IX©, a trademark of Schlumberger (SLB), allows for robust simulation forecasts that account for the following processes:

- Multiphase fluid flow, including supercritical, gaseous, and dissolved phase CO_2.
- Relative permeability hysteresis trapping (non-wetting phase trapping)
- Structural and stratigraphic trapping
- Capillarity effects
- Fault seal analysis to model baffling capacity of faults
- Pore volume compressibility (dilation and compaction)

Dynamic carbon transport and sequestration (CCS) modeling outputs from IX® have been compared to those from ECLIPSE, a well-known widely used simulator (developed by SLB). The comparison indicated extremely similar results presented in **Appendix 3-1**. IX® will continue as the dynamic modeling tool of choice for subsequent AOR reevaluations.

3.2.2 Model Description

IX© was used to model the Bayou Bend East SL20220050 (BBE-P1) CO_2 sequestration project. This software was built for traditional oil and gas modeling and upgraded to provide 3D CCS modeling capabilities including dissolution, residual trapping, adsorption, and diffusion with geomechanics coupling capabilities. Claimed as PBI [redacted]

Aqueous, gaseous and supercritical phases of CO_2 are modeled in IX©. A detailed compositional fluid model was developed outside of IX© using Chevron's internal PVT (Pressure, Volume, Temperature) Claimed as PBI [redacted]

The IX© model considers temperature, pressure and salinity dependent fluid properties and solubility of CO_2 in brine. Carbon dioxide solubility table and subsequent mixture property changes due to dissolution, were also modeled through Chevron's in-house proprietary tool and imported to IX©. In these models, CO_2 solubility in brine is presented by Ziabakhsh-Ganji and Kooi (2012). Claimed as PBI [redacted]

Hysteresis effects are included in the model. The term hysteresis refers to irreversibility, or path dependence. In multiphase flow, hysteresis manifests itself through the dependence of the relative Claimed as PBI [redacted]

The BBE-P1 model was developed by the Operator for the purposes of testing the storage capacity of the Claimed as PBI [redacted] lateral and vertical extents of the CO_2 saturation and pressure front during the operation phase and post-injection period, and to model injection operations throughout the life of the project. The geocellular model characterizes the geology, structure, faults, and properties pertinent to modeling fluid flow through porous media (e.g., porosity and permeability). Unless otherwise stated, the geocellular model presented is the best technical case (most likely scenario) Claimed as PBI [redacted] The 3D model includes lateral and vertical variations to facies and petrophysical properties.

3.2.3 Site Geology and Hydrology

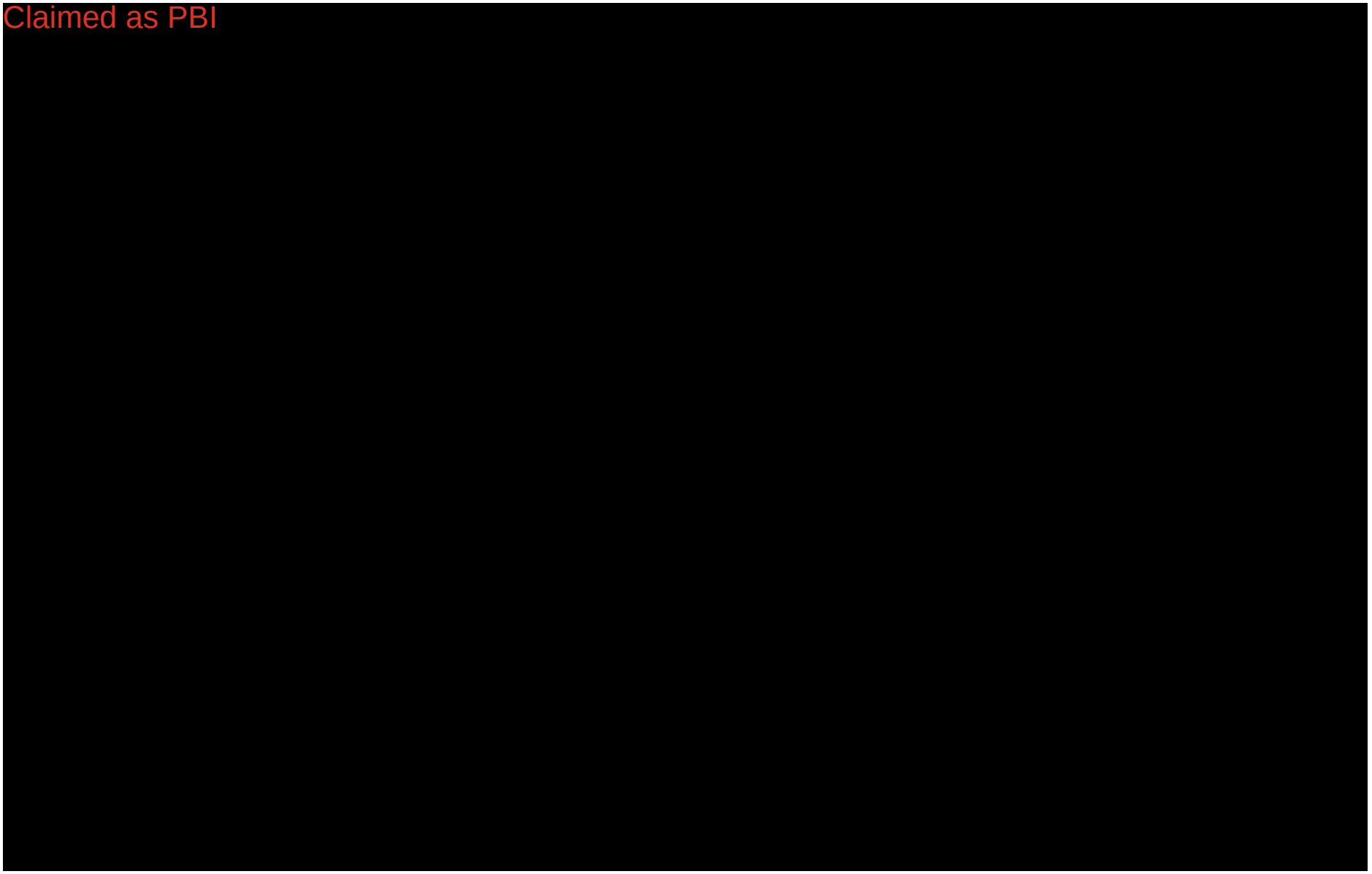
Claimed as PBI

[redacted]

The Gulf Coast aquifer system has a groundwater flow towards the southeast and is divided into five hydrostratigraphic units: Catahoula Aquitard; Jasper Aquifer; Burkeville Aquitard; and the Evangeline and Chicot Aquifers (Baker, 1978; Williamson and Grubb, 2001; and Young et al., 2012). The Lower Miocene aquifers include Jasper Aquifer and Burkeville Aquitard respectively within the Oakville and Lagarto Formations. Salt domes may locally increase groundwater salinity. Faults may act as lateral baffles or vertical conduits for groundwater flow.

The onshore Gulf Coast aquifer system of eastern Texas is located updip from BBE-P1. Offshore equivalents of these formations are observed at deeper depths with increased salinity concentrations [Narrative, Section 2.1.4]. Within Texas State Waters, there is no underground source of drinking water (USDW) and no offshore formation containing formation fluid suitable for public water supply within or with proximity to the project site has been observed [Narrative, Section 2.7.1]. Additionally, petrophysical salinity calculations indicate values of 13,000 mg/L or higher at shallow depths near BBE-P1. Therefore, an USDW was not identified for BBE as defined by 40 CFR §146.3 [Narrative, Section 2.7].

Claimed as PBI



3.2.4 Model Domain

Claimed as PBI



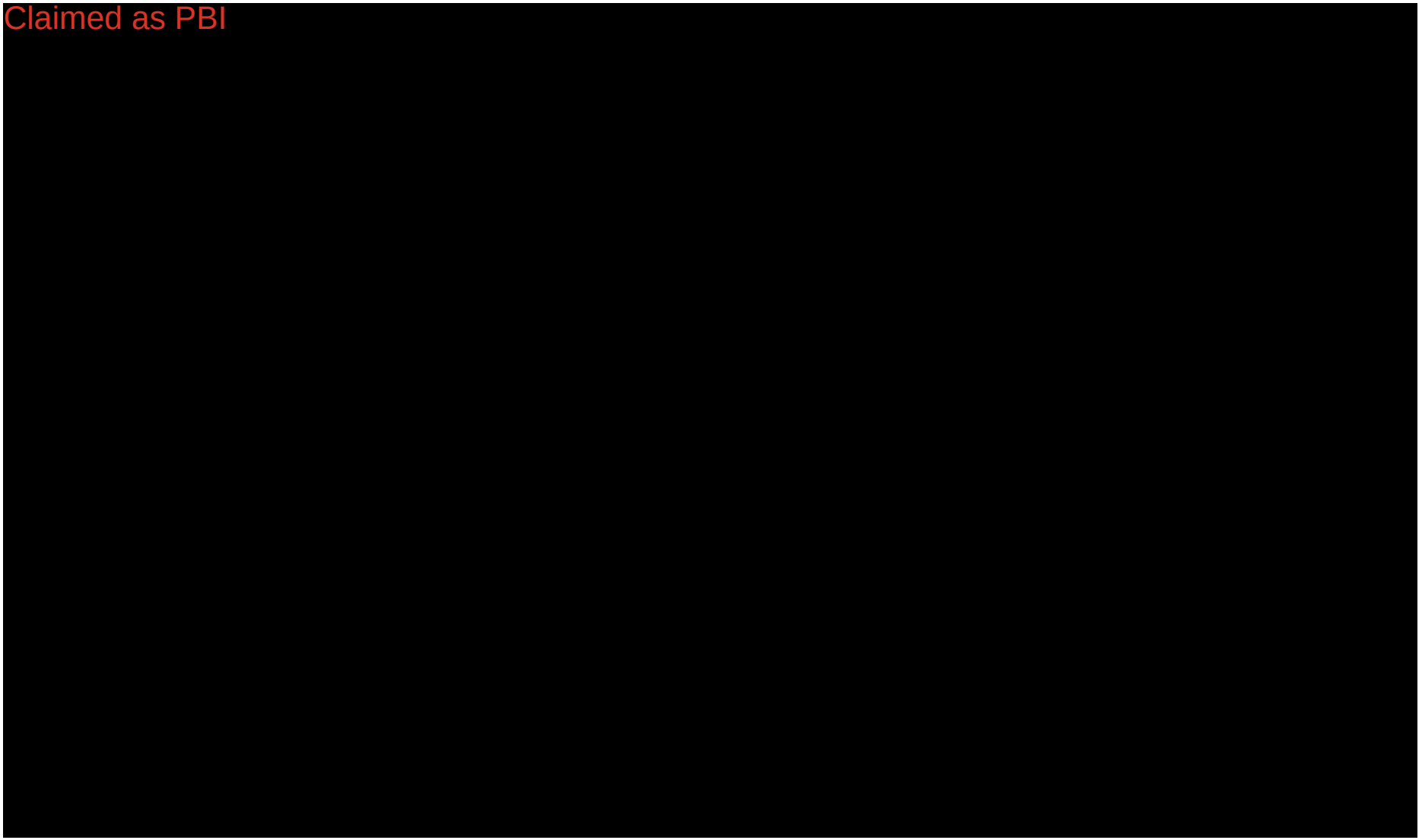
Table 3-2: Model domain information.

Coordinate System	USA NAD27 TM BLM15 CM 93W		
Horizontal Datum	North American Datum, 1927		
Coordinate System Units	Feet		
Zone	TX State Plane Zone 4		
FIPSZONE	4204	**ADSZONE**	Zone 5401
Coordinate of X min	1,295,711	**Coordinate of X max**	1,409,588
Coordinate of Y min	10,684,962	**Coordinate of Y max**	10,805,656
Elevation of bottom of domain	-3,829.44	**Elevation of bottom of domain**	-12,297.73

Claimed as PBI



Claimed as PBI



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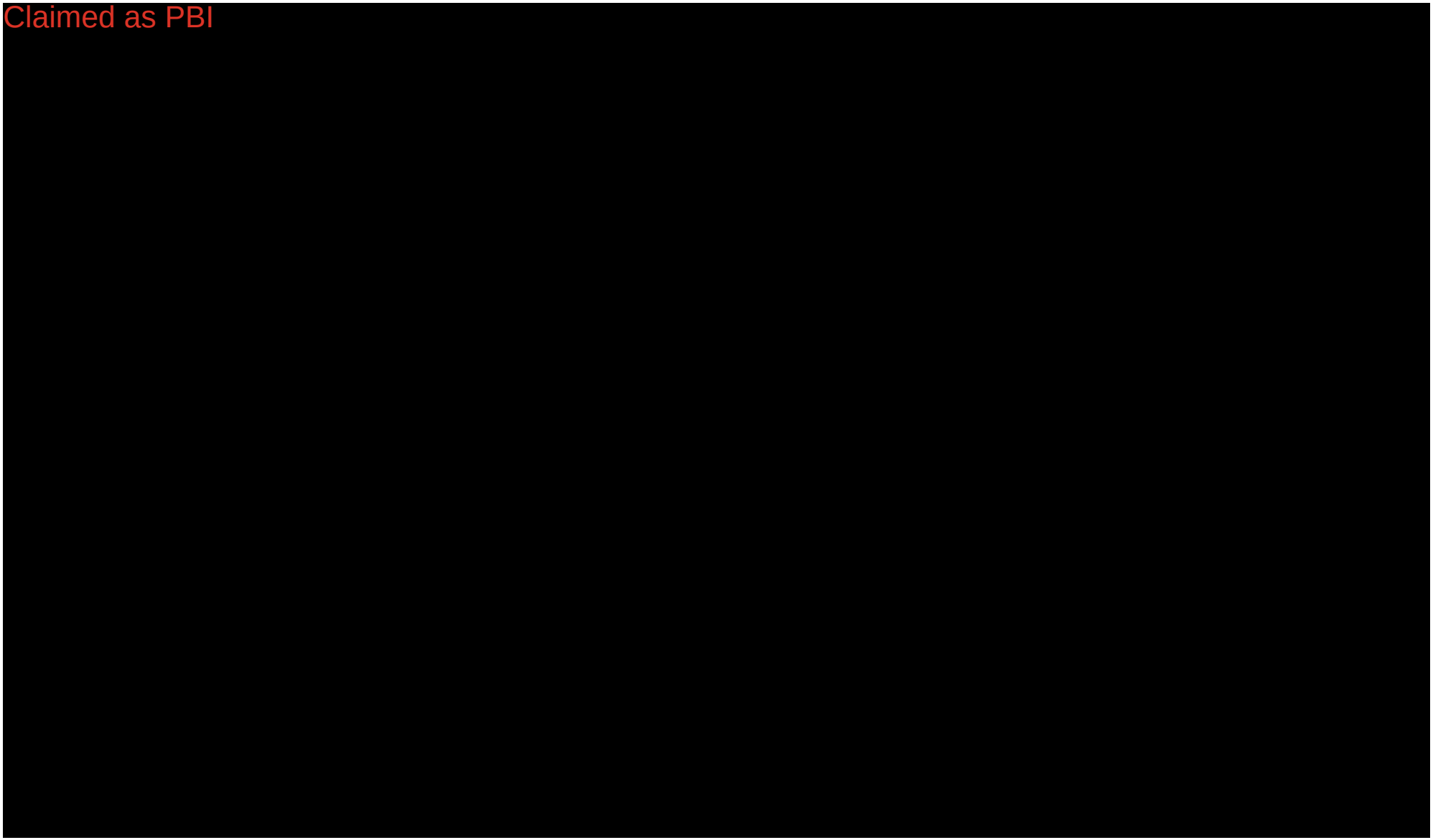


Claimed as PBI



3.2.5 Porosity and Permeability

Methodology

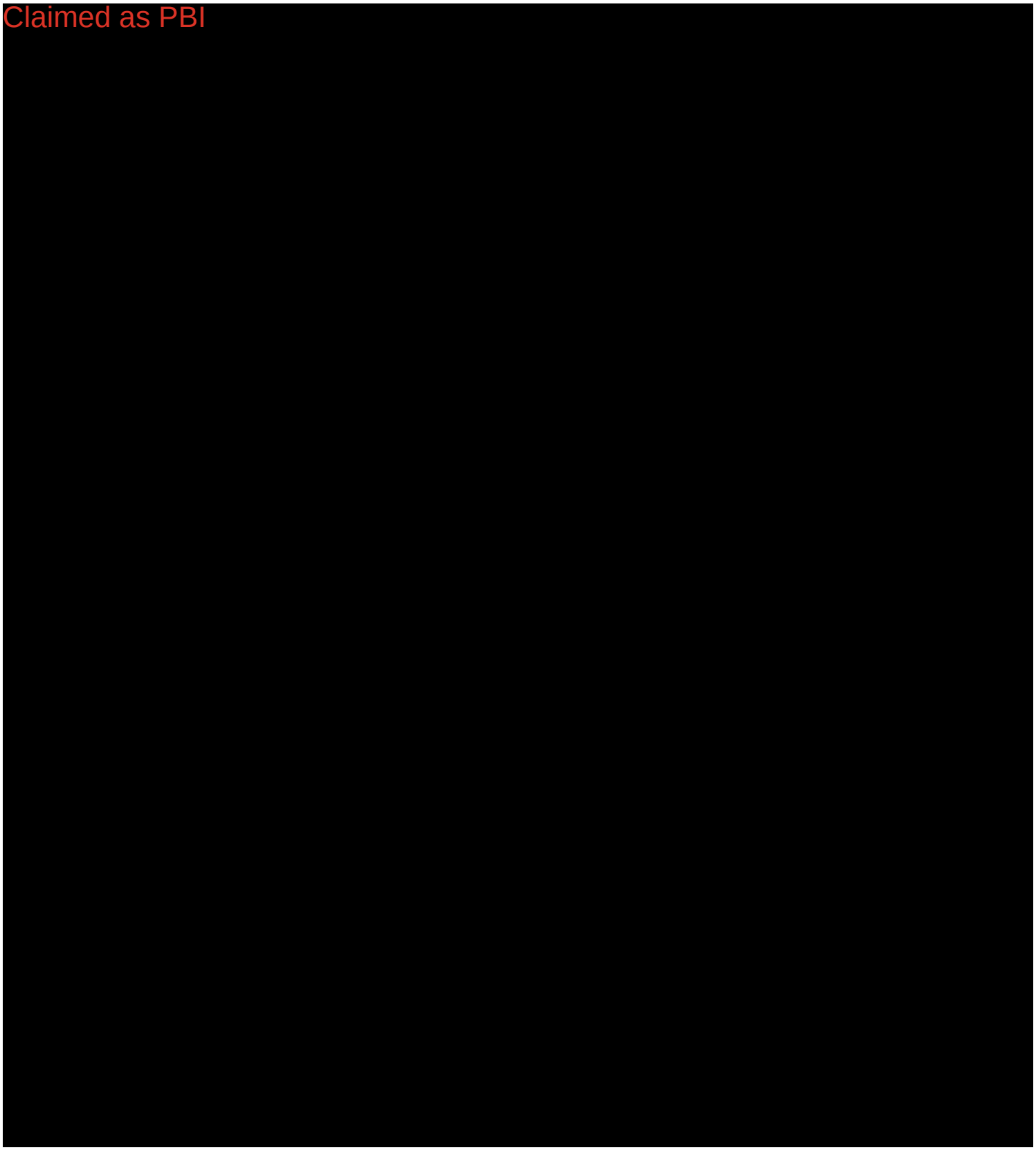
Claimed as PBI



Claimed as PBI



Claimed as PBI



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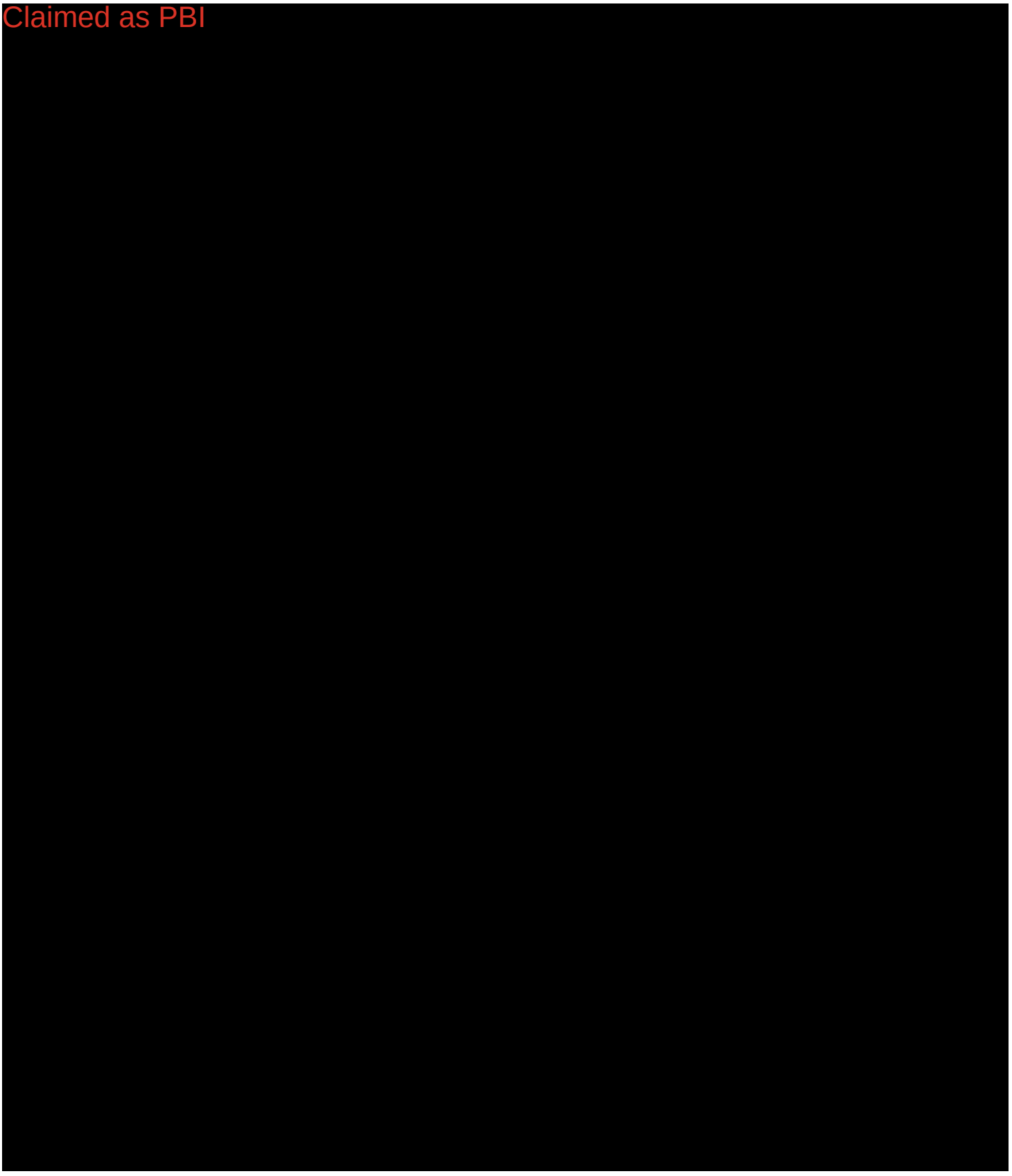

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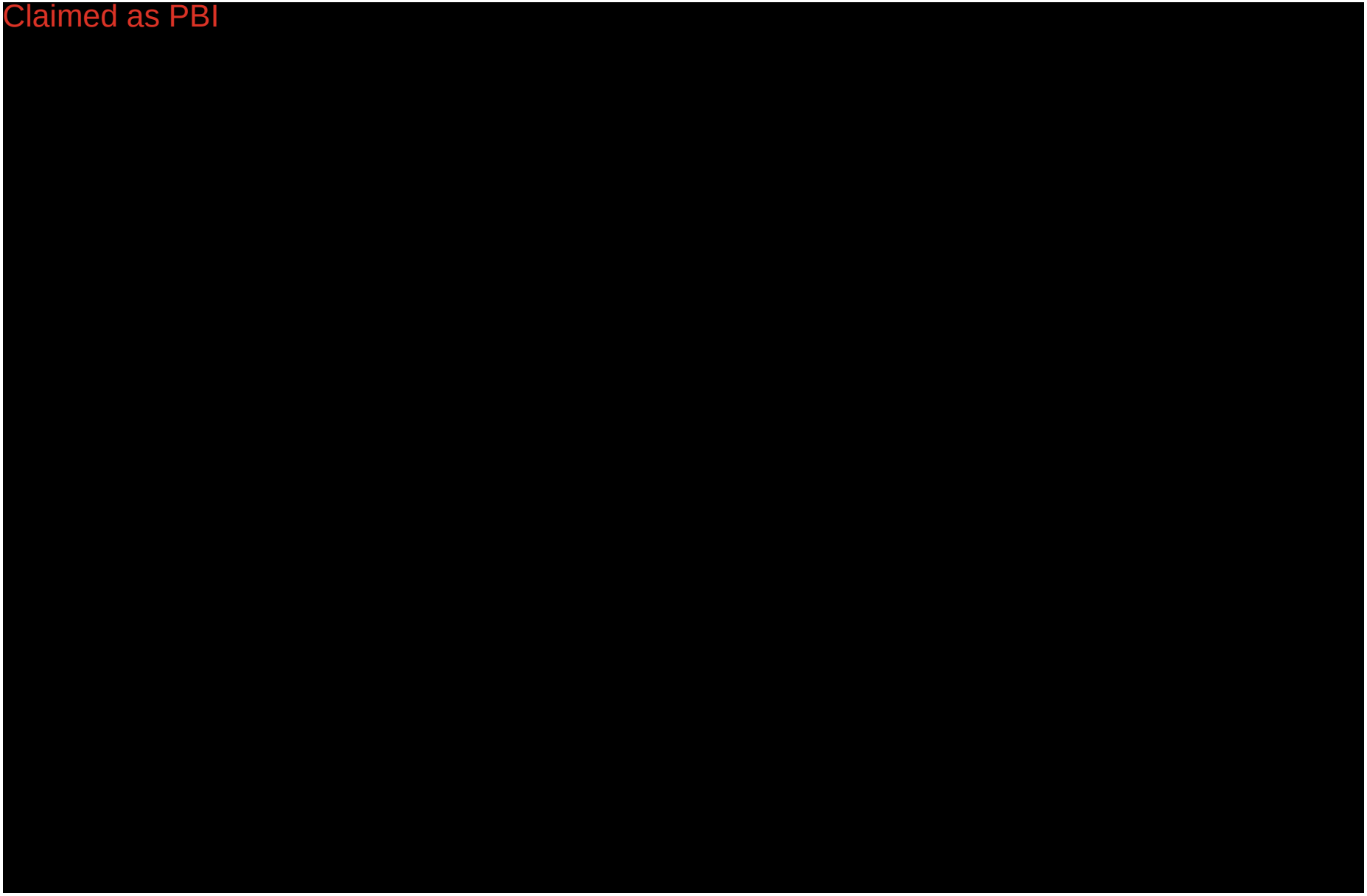

Claimed as PBI



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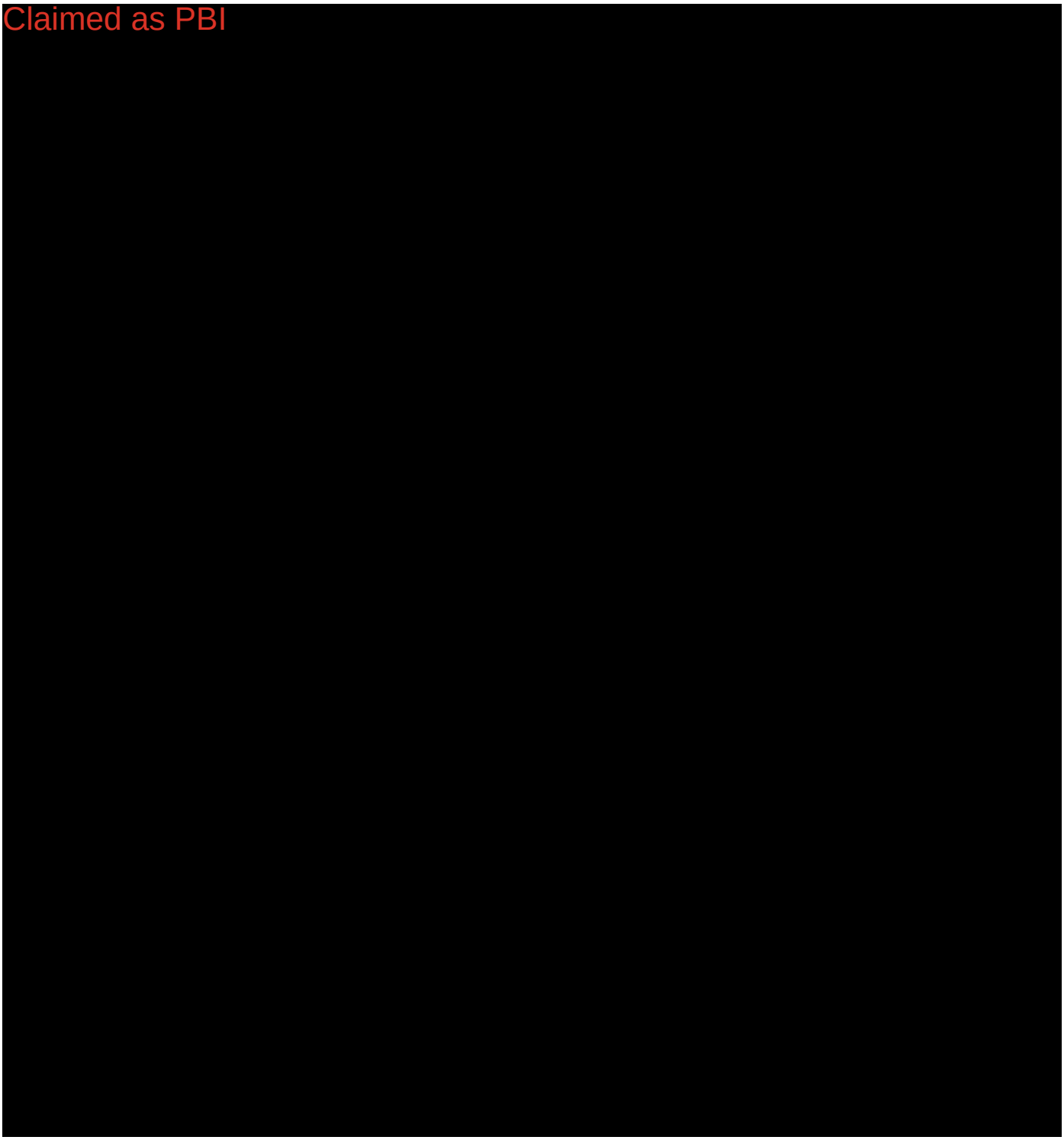

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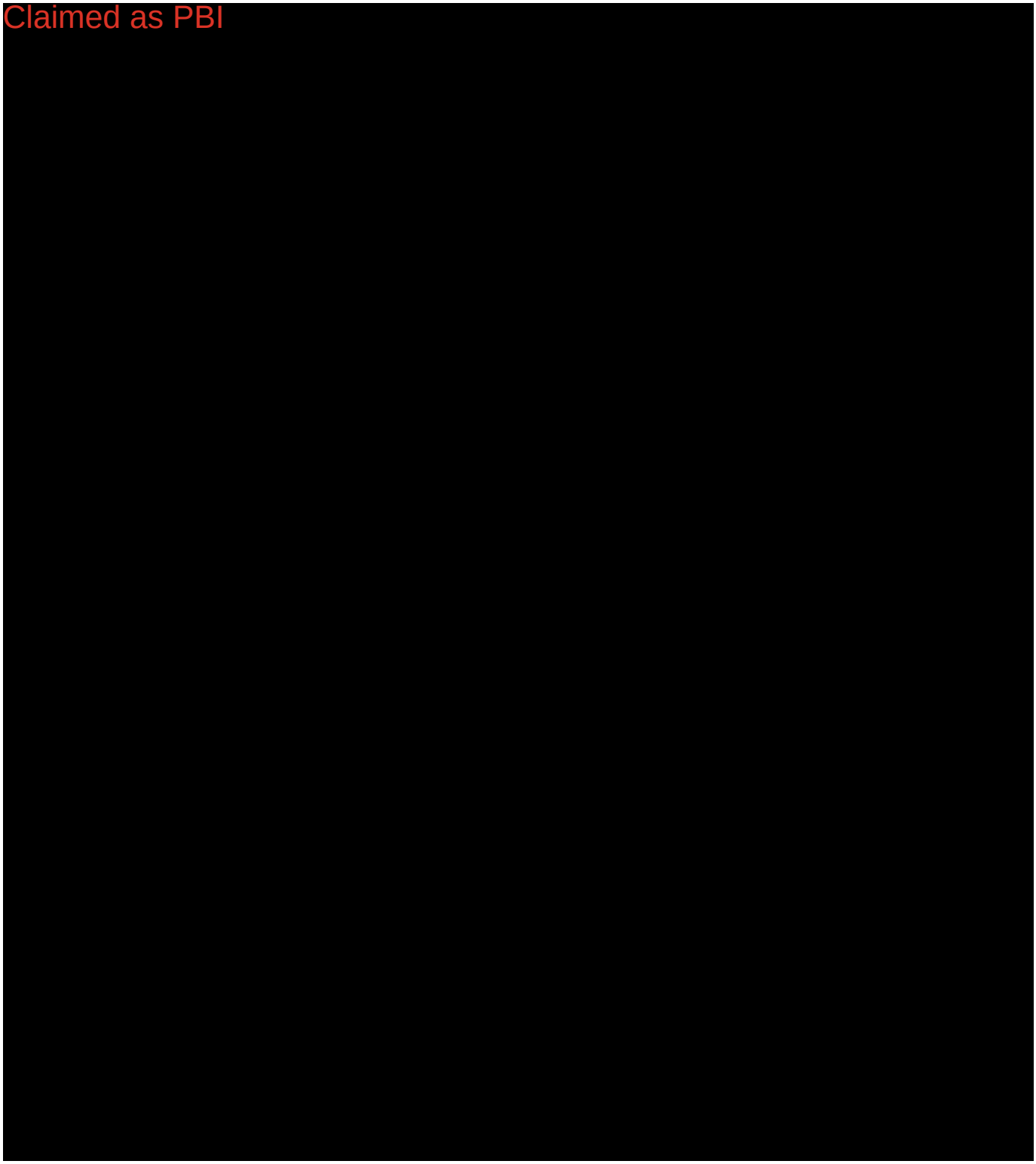

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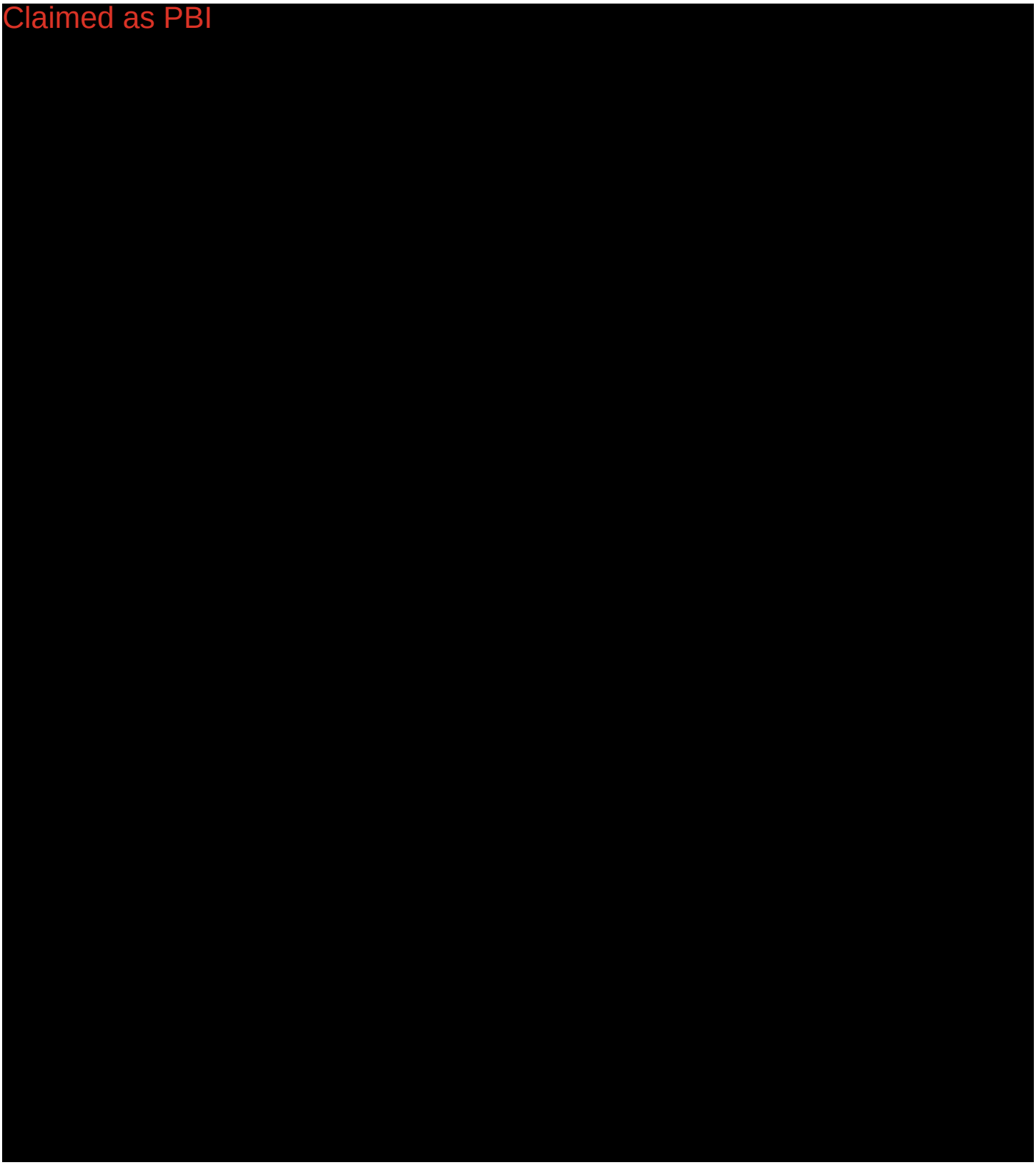

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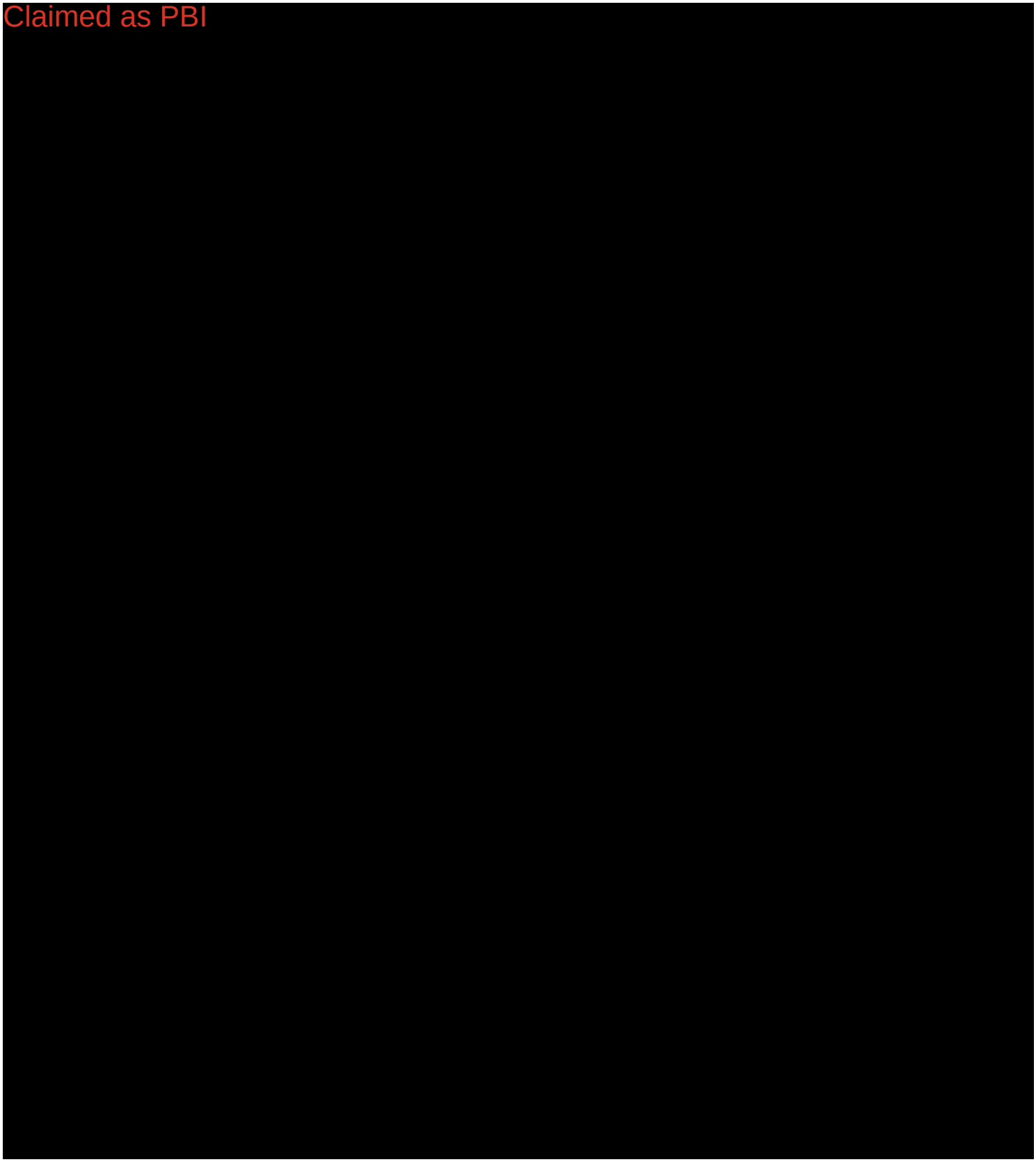

Claimed as PBI



Claimed as PBI



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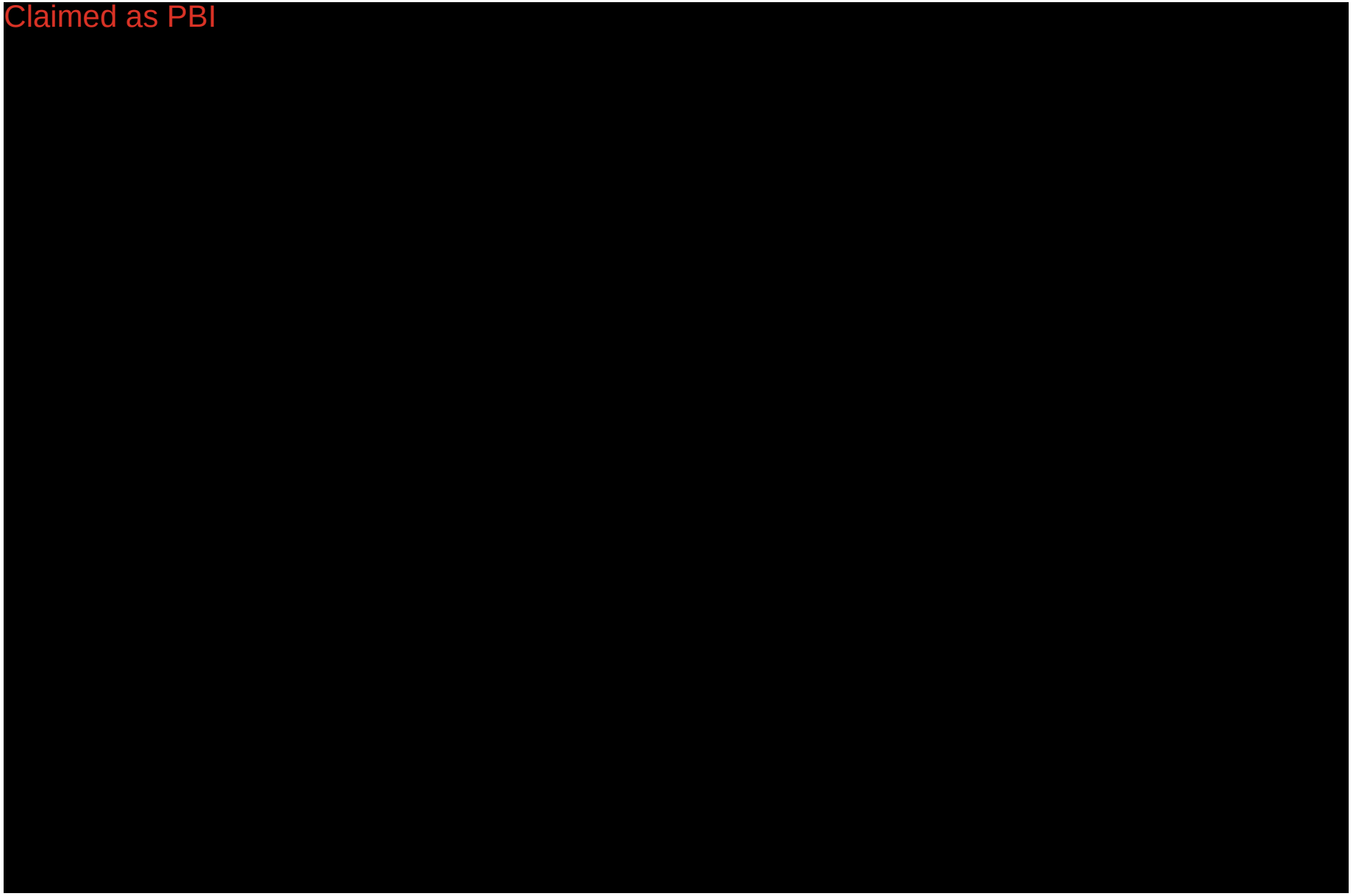

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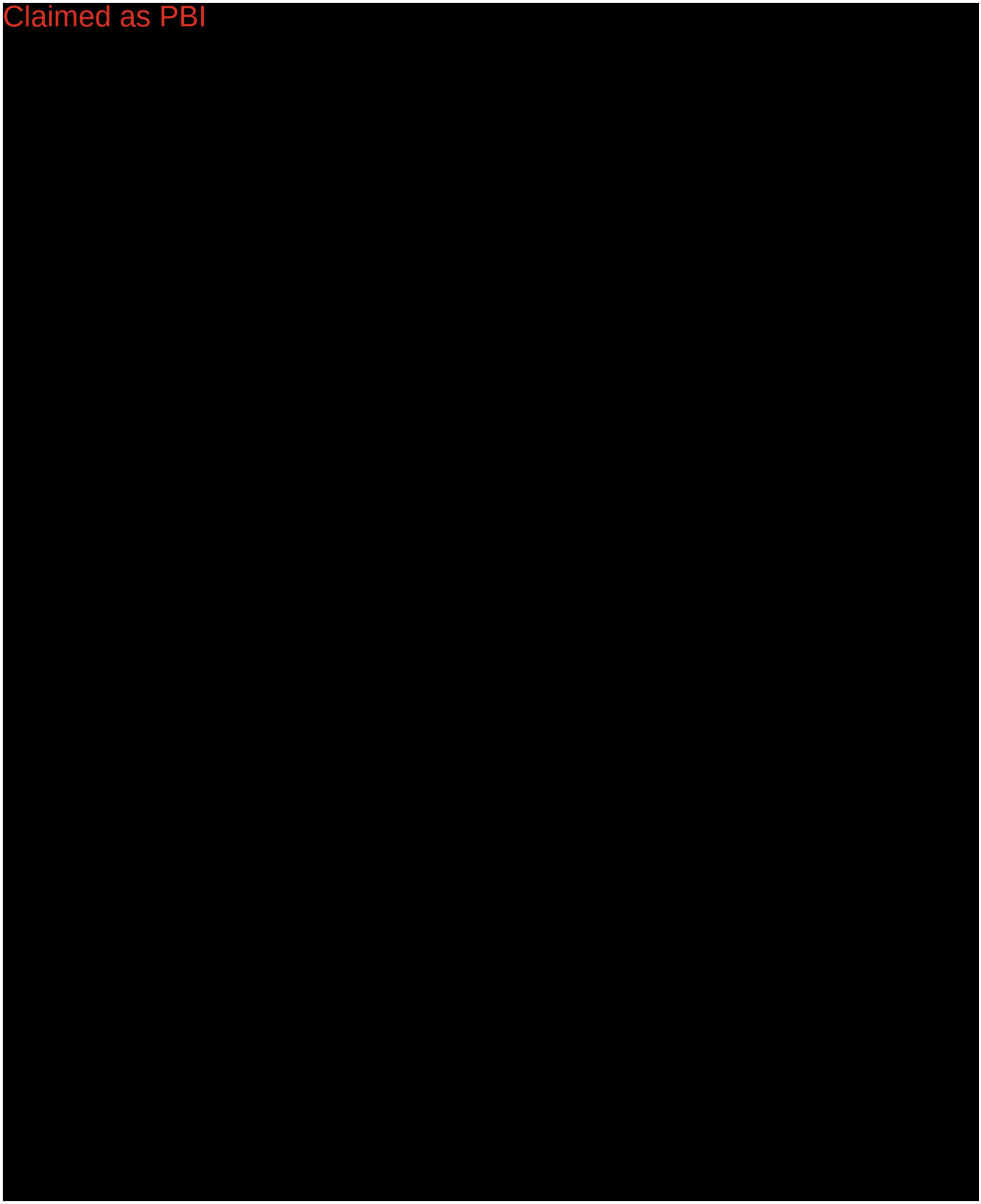


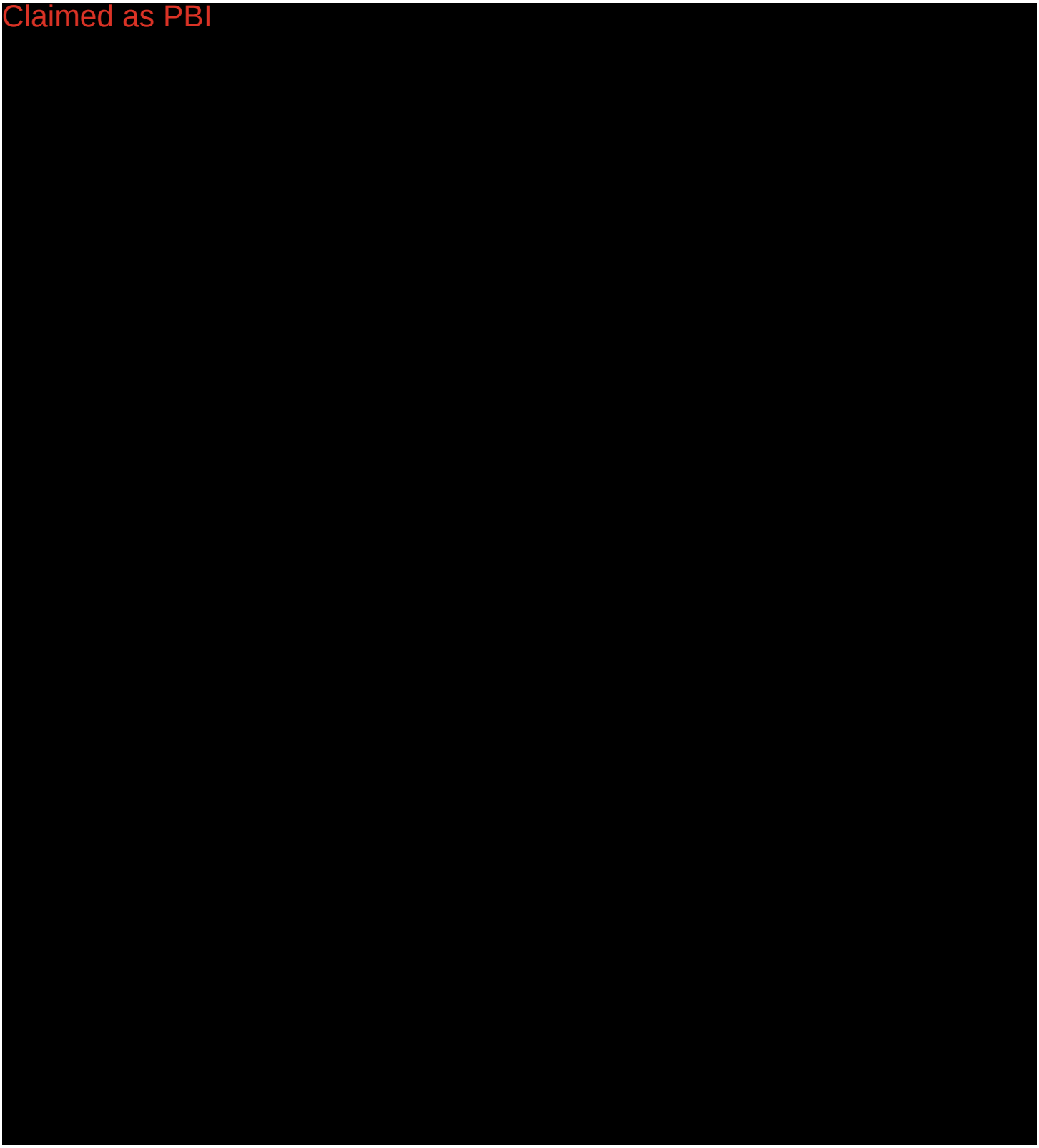
3.2.6 Constitutive Relationships and other Rock Properties

Constitutive relationships that have been implemented in the model include CO_2 density versus reservoir pressure, CO_2 viscosity versus reservoir pressure, and irreducible water saturation (S_{WIR}) versus analog-core permeability. Aqueous and gas relative permeability as function of permeability with respective drainage and imbibition relative permeability curves are also included.

Claimed as PBI



Claimed as PBI



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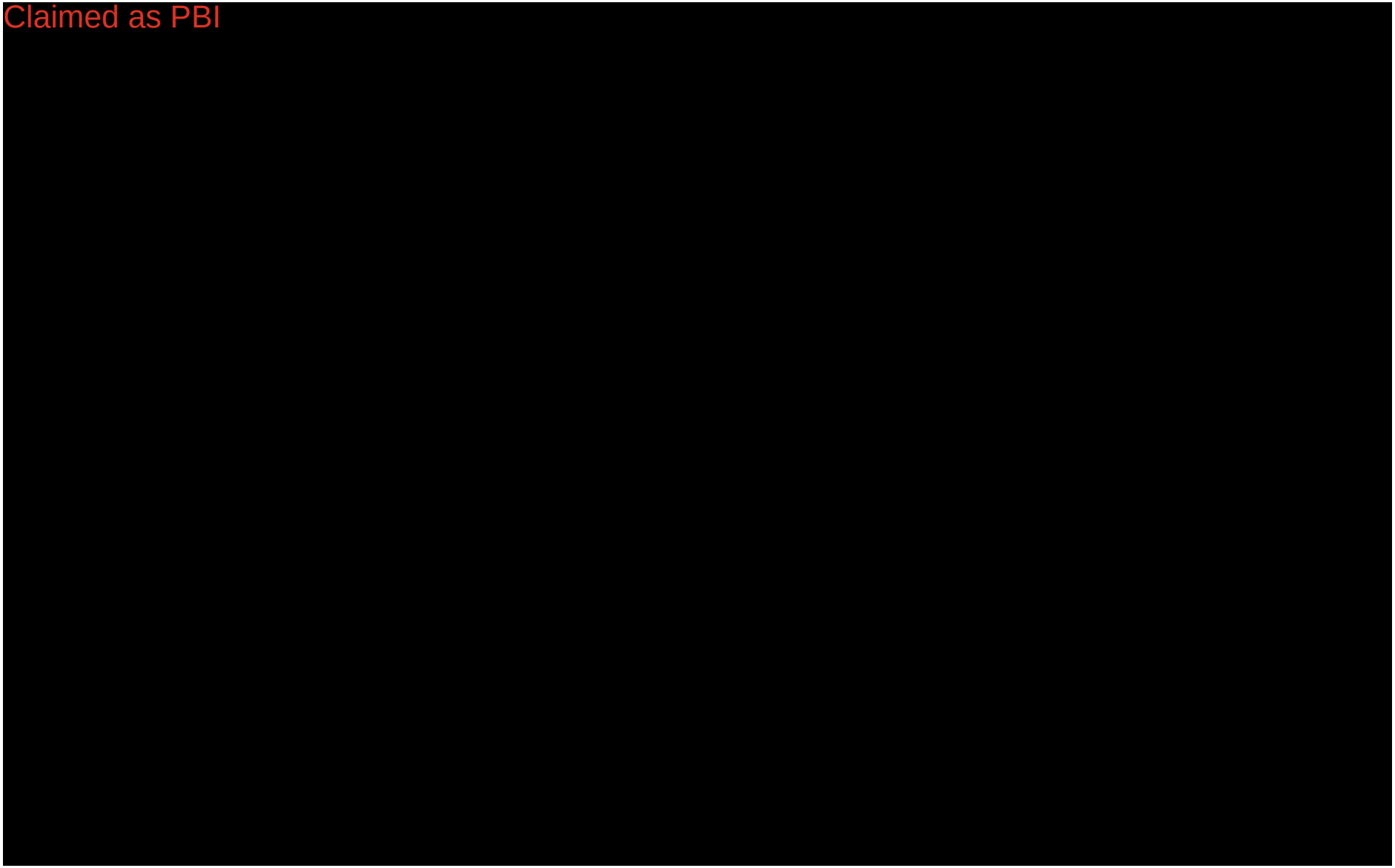

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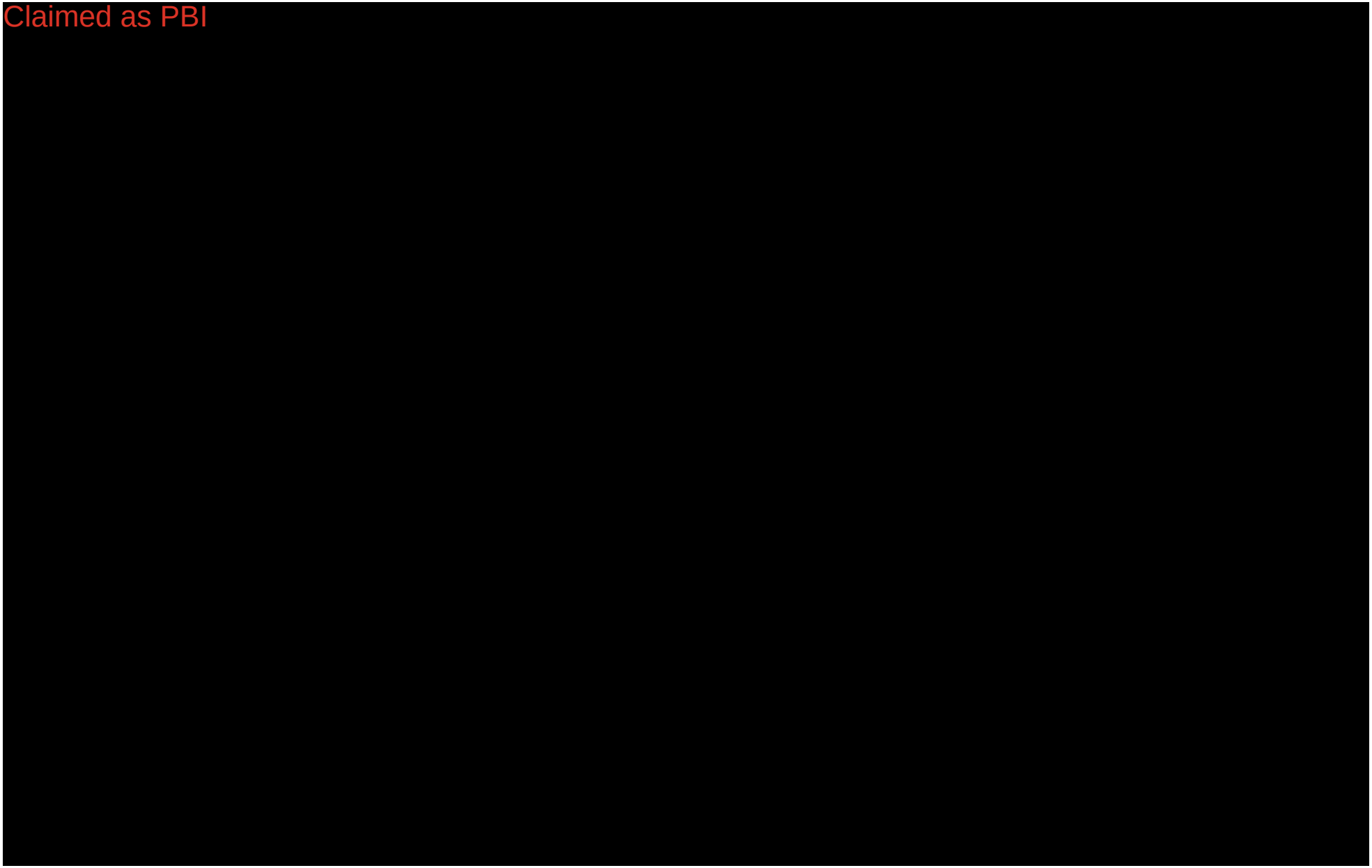

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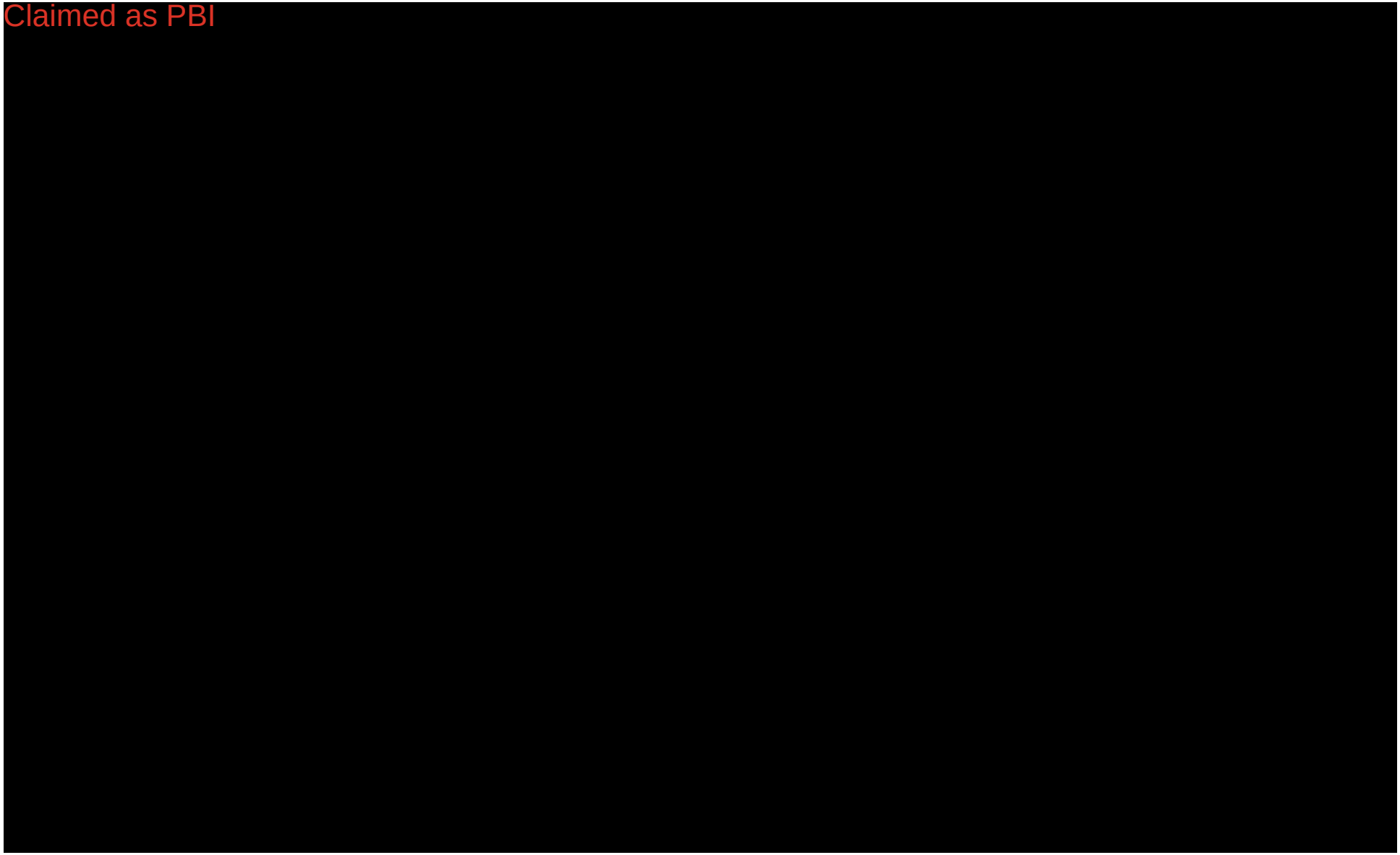

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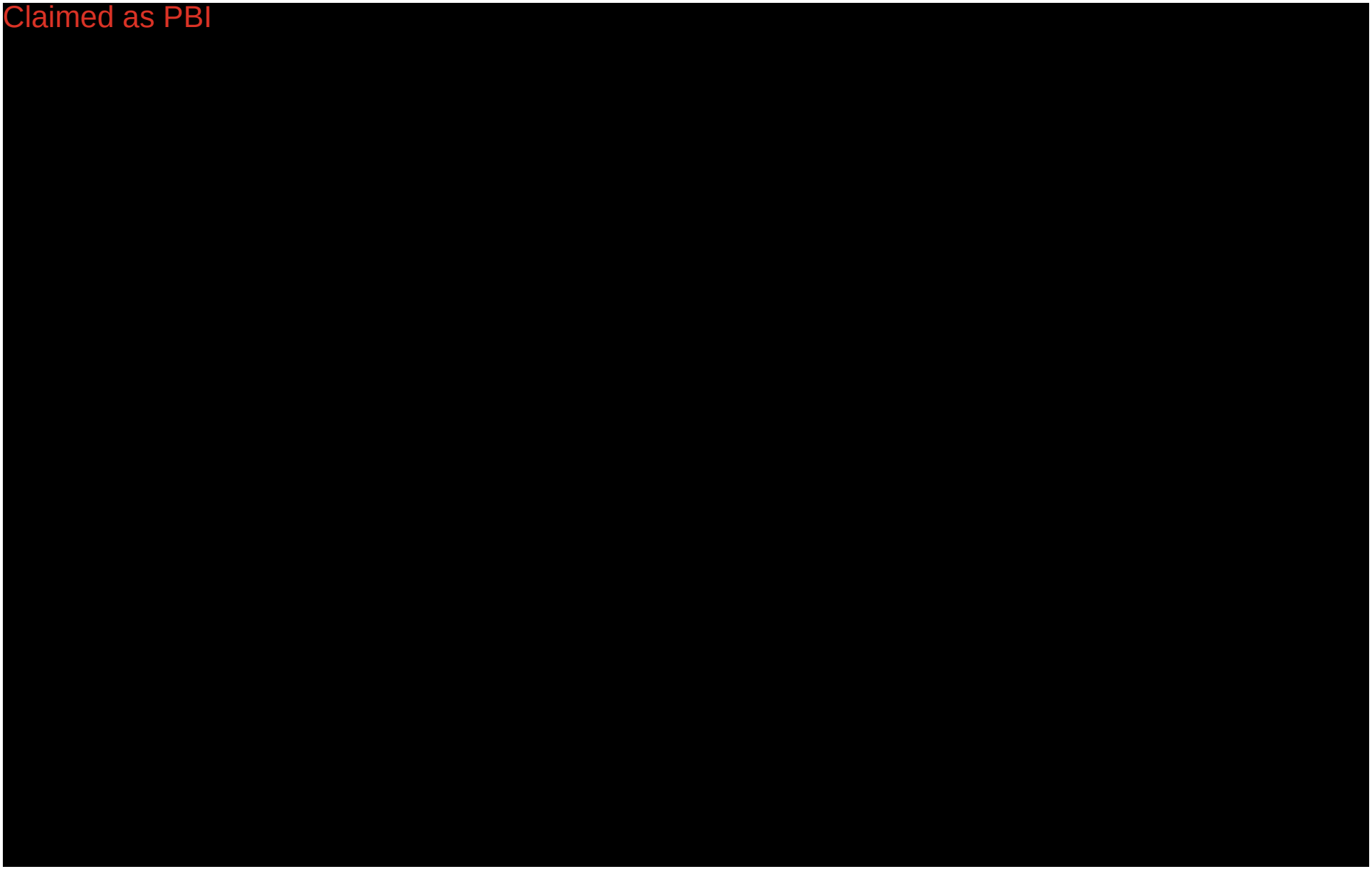


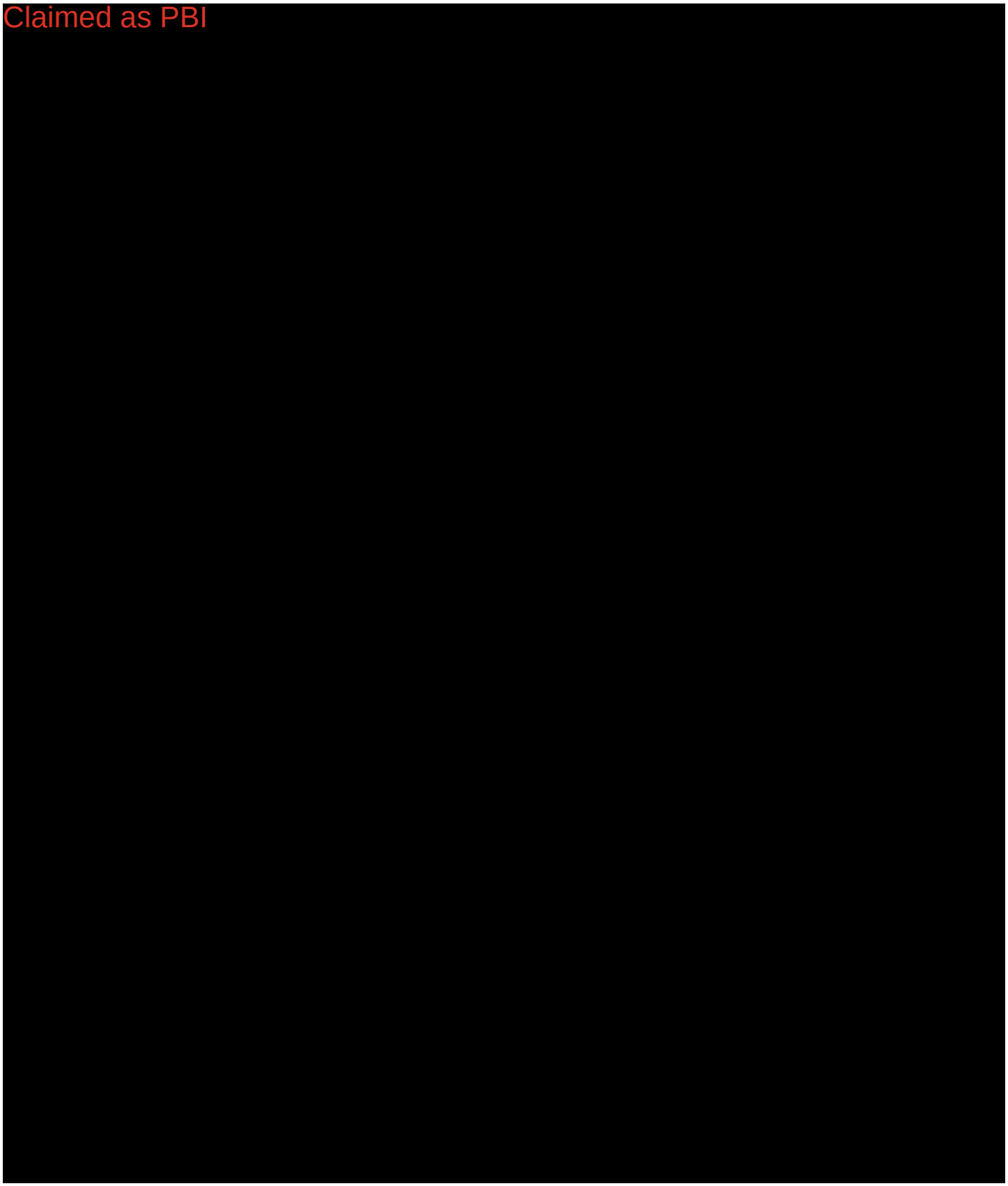
3.2.7 Compositional PVT Model

CPCP is used to generate compositional EoS for the project. The PVT model is used to calculate properties of injected gas with Claimed as PBI CO_2 has some unique properties with liquid-like density and gas-like viscosity in the super critical region. The Peng-Robinson EoS model parameters were tuned to match the CO_2 density and viscosity at 150°F temperature and the pressure range from 2,000 to 4,500 pounds per square inch (psi). The data from National Institute of Standards and Technology's (NIST) chemistry webbook is used as the reference for thermophysical properties of pure CO_2. Claimed as PBI

Claimed as PBI

tuned to match the brine density and viscosity. **Figure 3-19** compares the brine density and viscosity calculated in IX© to the benchmark data. The impact of dissolved CO_2 on the density and viscosity of brine was ignored in the current simulation model. Claimed as PBI The calculated gas-water ratio table is used as the input in IX© to calculate CO_2 solubility in brine, as shown in **Table 3-12**.

Claimed as PBI



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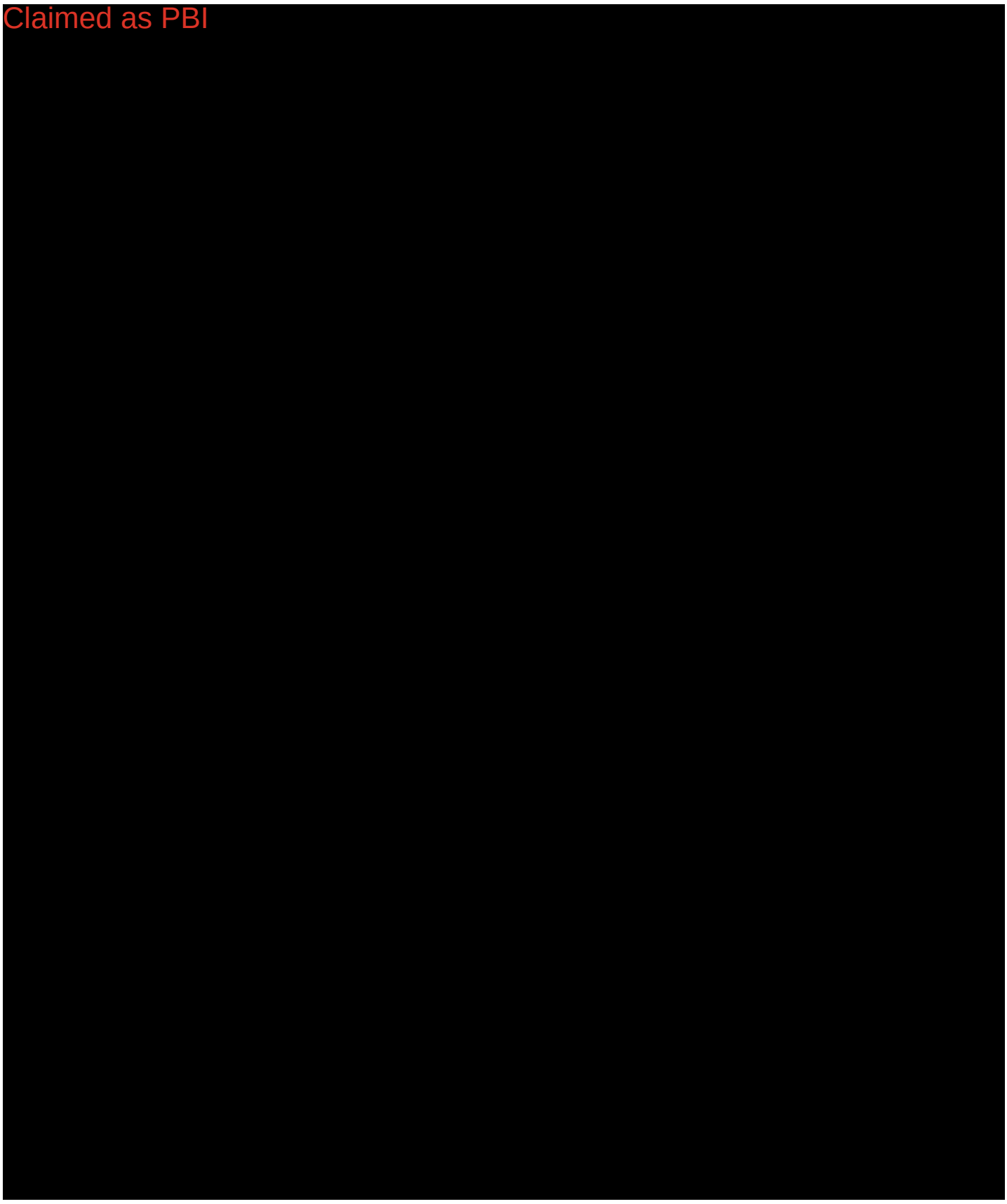

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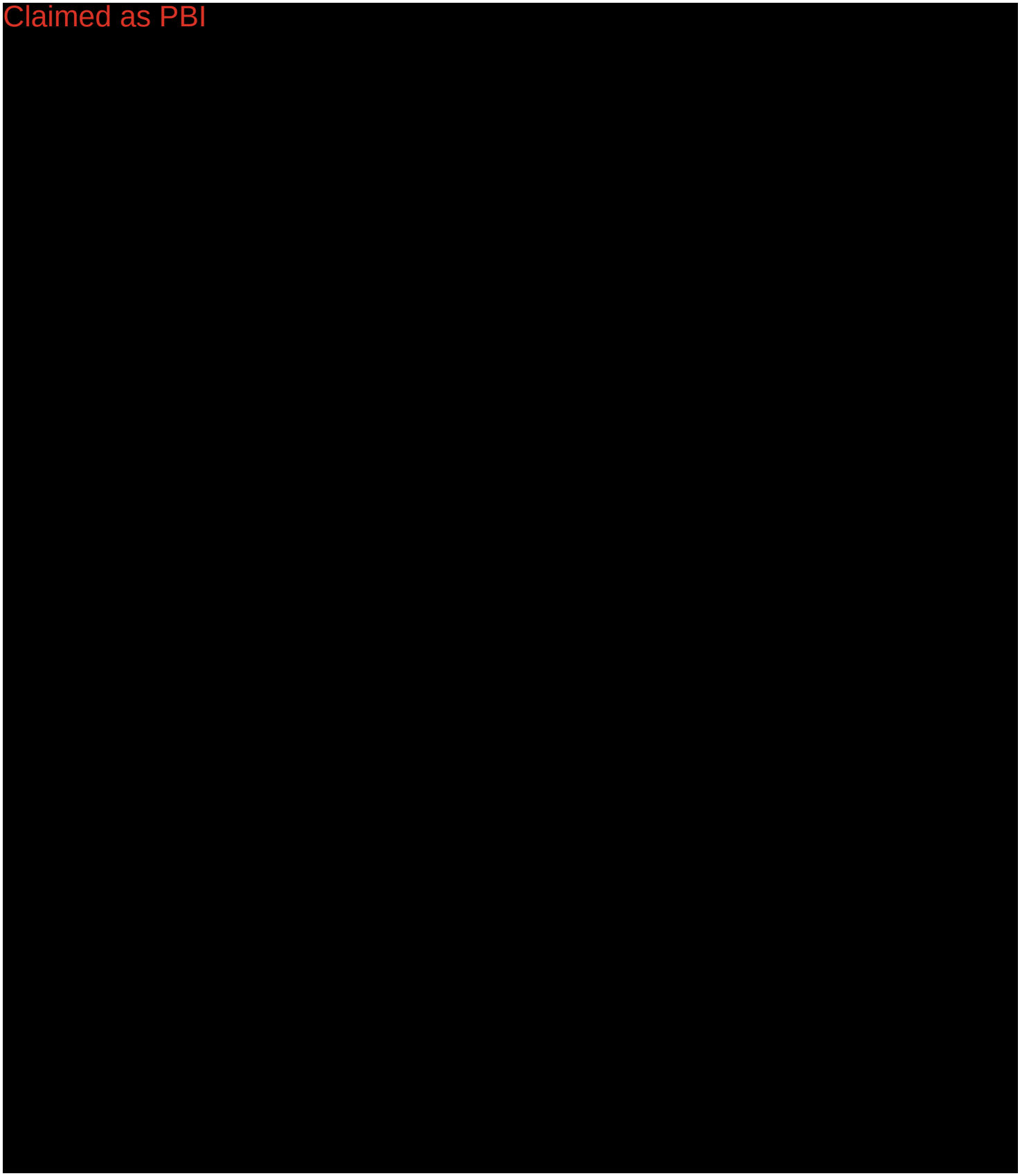

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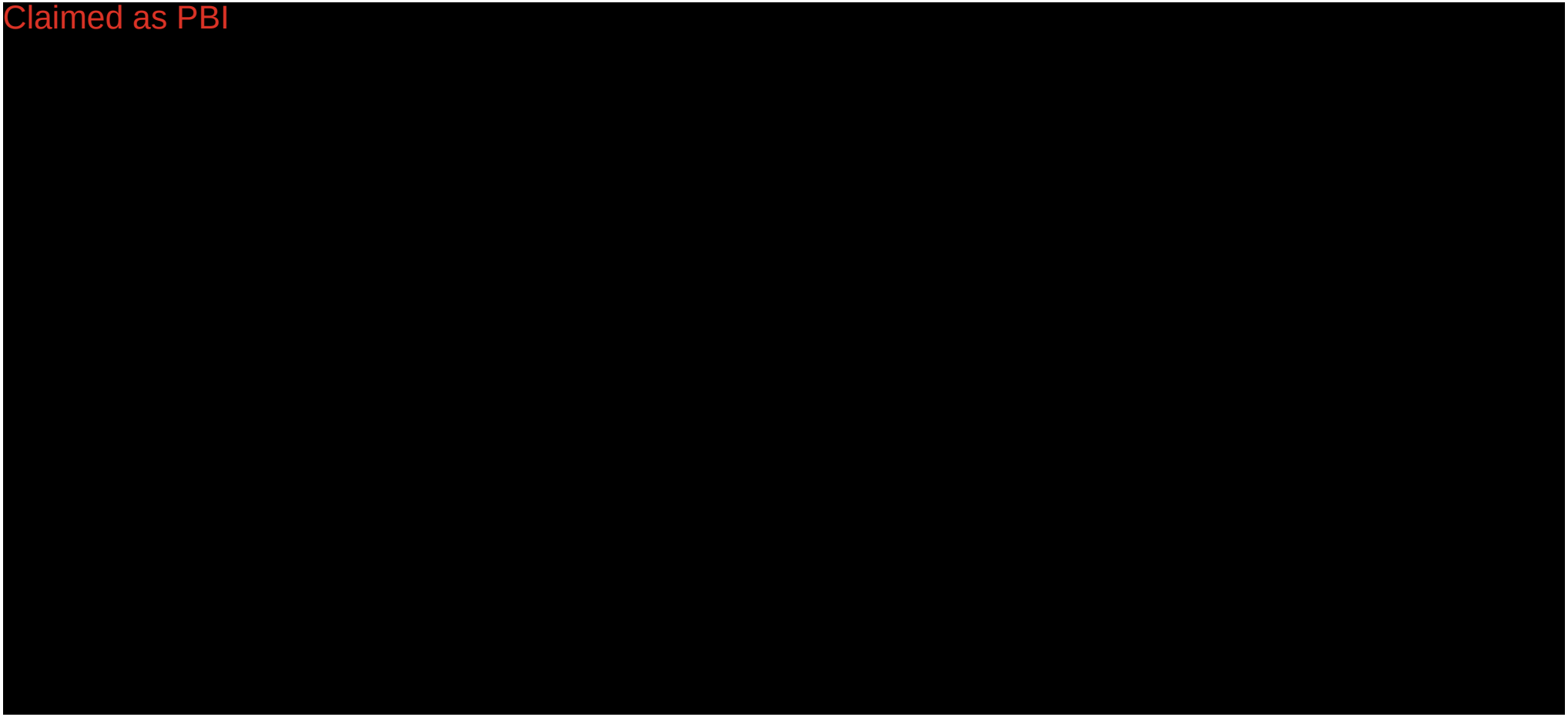


3.2.8 Shale Cut off in the model

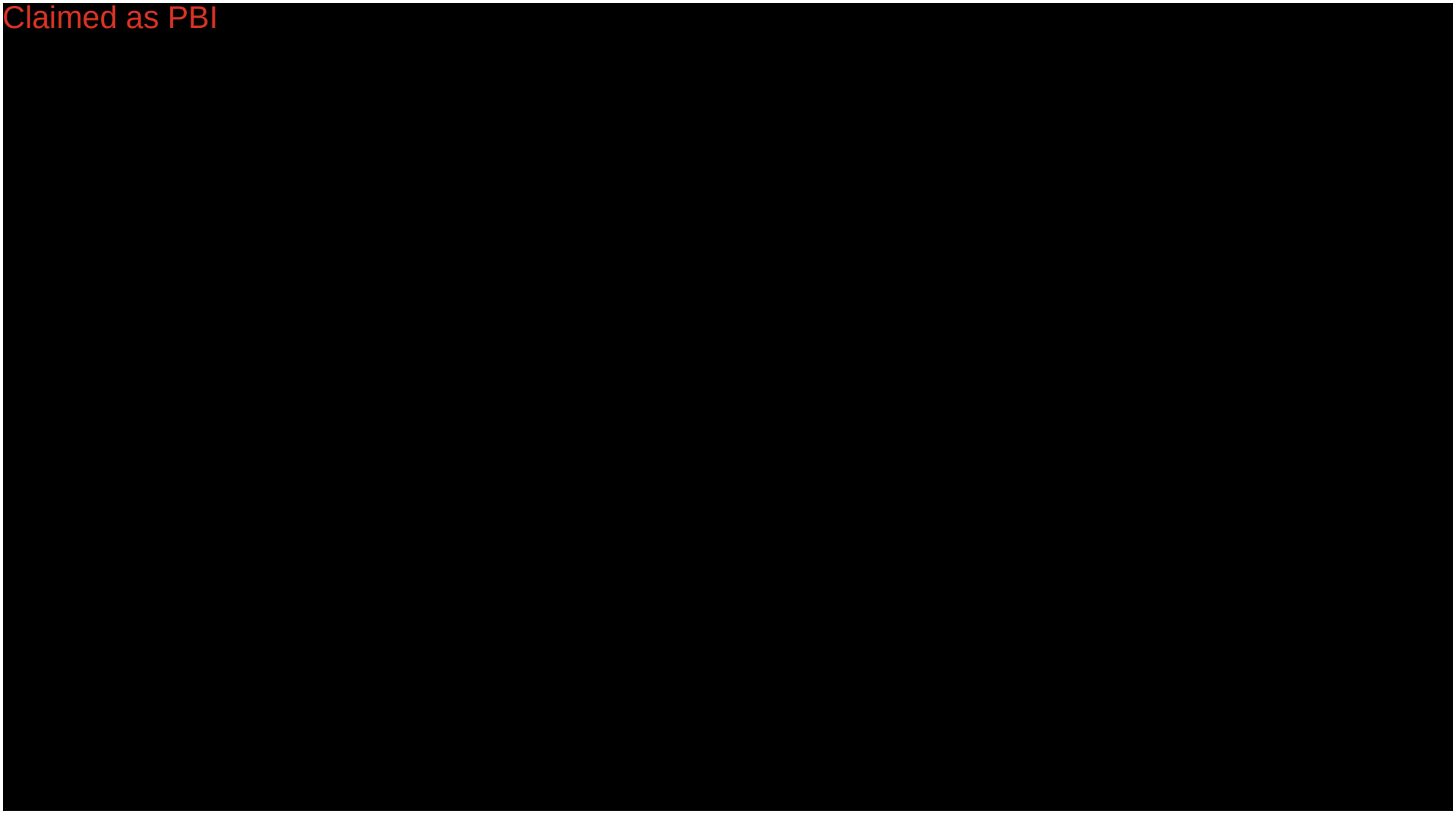
It is essential to account for appropriate rock volume (sand and shale) in the dynamic modeling of CO_2 injection. Claimed as PBI [redacted]

In the injection zone of Bayou Bend offshore model, Claimed as PBI [redacted]

3.2.9 Rock Physics (Pore Volume Compressibility Data)

Claimed as PBI [redacted]

Claimed as PBI



Claimed as PBI

3.2.10 *Boundary Conditions*

Claimed as PBI

Initial conditions for the model are provided in **Table 3-14**. The initial reservoir pressure is estimated to be

Claimed as PBI

Initial conditions for the site will be collected and compared with values used in the model following data collection during the installation of the injection well(s) [Pre-Operational Logging and Testing, Section 6.5].

Claimed as PBI

3.2.12 *Operational Information*

Claimed as PBI

[redacted]

Bayou Bend CCS LLC (Operator) has developed this reconfiguration approach based upon simulation results and plans to update this completions strategy with the data captured during the pre-operational logging and testing phase. In addition, after injection starts, Operator will utilize monitoring data during project execution to guide actual recompletion times to optimize pore space. With each recompletion, operating constraints will be updated based upon any wellbore changes (e.g. additional perforations or squeeze of existing perforations).

As a result of CO_2 injection, salty brine vaporization is known to cause salt precipitation (Bacci, Korre and Durucan 2011). Based on global analogs, the current modeled Claimed as PBI [redacted] values will be measured and compared with values used in the model following data collection during the installation of the injection well(s) [Pre-Operational Logging and Testing, Section 6.5] and once injection performance has been established.

Claimed as PBI

[redacted]

Table 3-15: BBE Proposed operating details for injection wells

Claimed as PBI



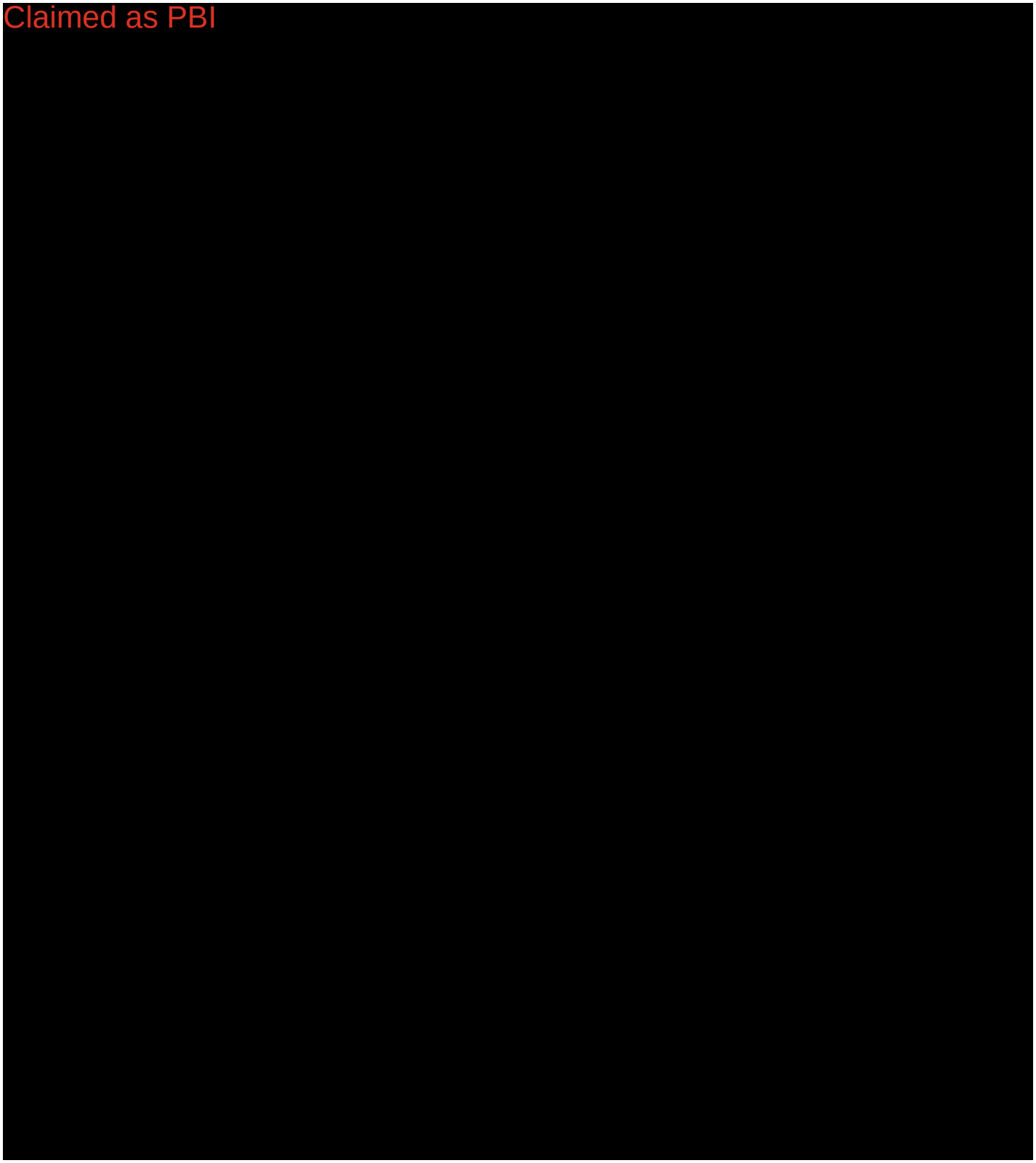
3.2.13 *Fracture Pressure and Fracture Gradient*

Due to limited site-specific rock properties in the project area, fracture pressure and fracture gradient were estimated using available analog information and numerical models. Detailed background and calculations are provided in the Narrative, Section 2.5.6, Geomechanical and Petrophysical Information. The fracture properties were Claimed as PBI

Claimed as PBI

Fracture pressure will be calculated during the pre-operational testing phase [Pre-Operational Testing Plan, Section 6.4]. Claimed as PBI Fracture pressure and gradient results will be re-evaluated and updated in the integrated-reservoir model, as applicable.

Claimed as PBI



3.3 Computational Modeling Results

3.3.1 Predictions of System Behavior

The model was designed to highlight the completion strategy for BBE-Claimed as PBI [redacted]

When the CO_2 is injected, a fraction of the stream will dissolve into the reservoir brine while the remaining buoyant supercritical CO_2 begins to migrate vertically within the target interval until it reaches a baffle or confining zone. Claimed as PBI [redacted]

Claimed as PBI [redacted]

Claimed as PBI [redacted] Note, all pressures remain below the maximum pressure limit (Section 3.2.13).

Throughout the life of the injection, the free phase CO_2 is anticipated to remain supercritical. **Figure 3-27** presents the forecast mass quantities of CO_2 by phase and trapping mechanism over the project life.

Figure 3-28 shows a structure map of the *Amph B* along with four cross sections. **Figure 3-29**, **Figure 3-30**, **Figure 3-31** and **Figure 3-32** show the East-West, North-South, Northwest-Southeast and Northeast-Southwest cross sections through the model of CO_2 saturation for A-A', B-B', C-C' and D-D' respectively at various time steps through the life of the project.

Figure 3-33, **Figure 3-34,** and **Figure 3-35** show the contour maps of pressure differentials at various time steps through the life of the project. By 2052, the entire injection zone is below the critical pressure.

During project execution, computational pressure differentials will be compared to observed monitoring data to identify any discrepancies and, if necessary, update computational model parameters to better match observed data.Claimed as PBI [redacted]

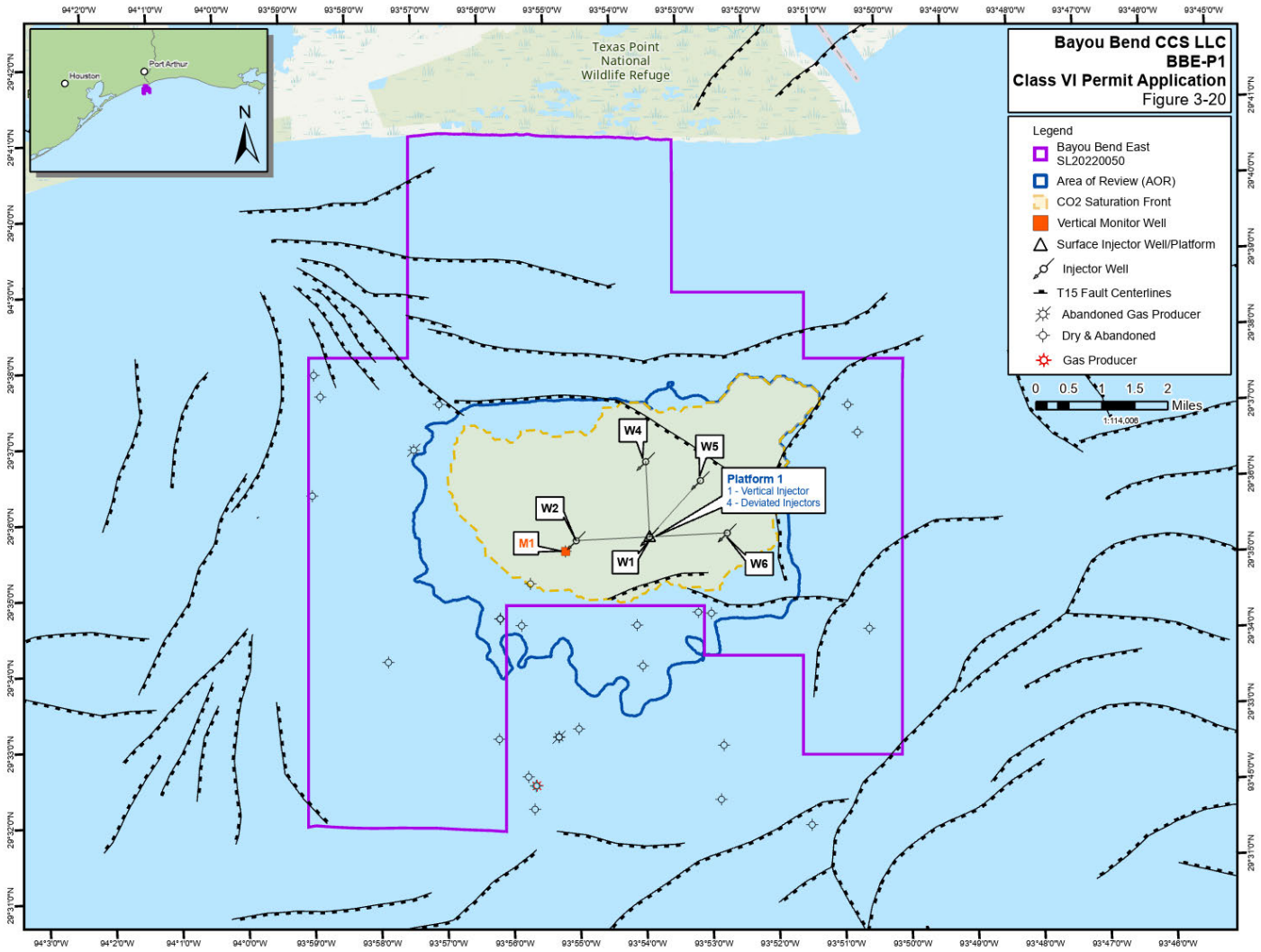


Figure 3-20: Position of injection and monitoring wells in relation to AOR, faults at the top of the T15 (confining zone) and existing penetrative wells.

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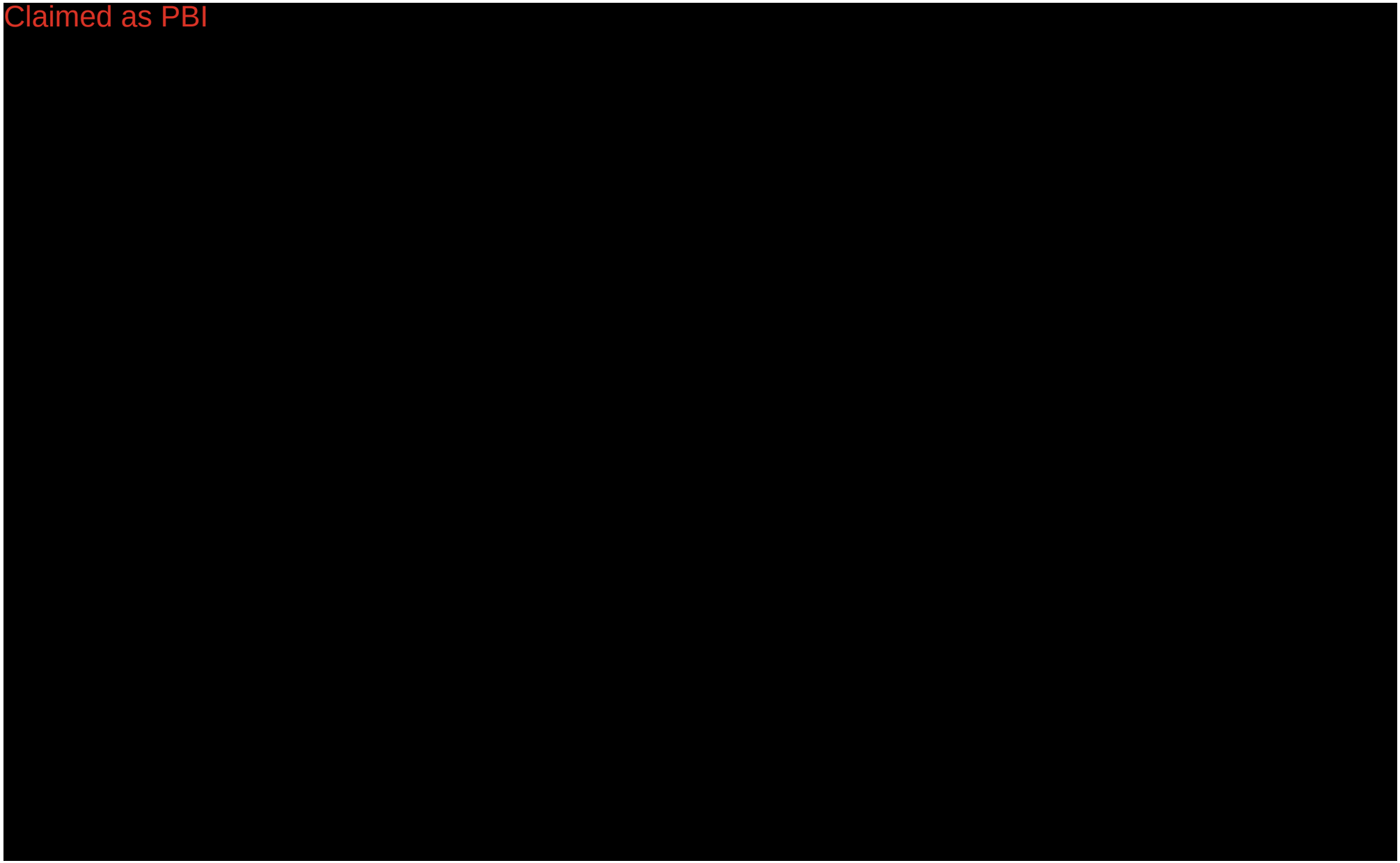

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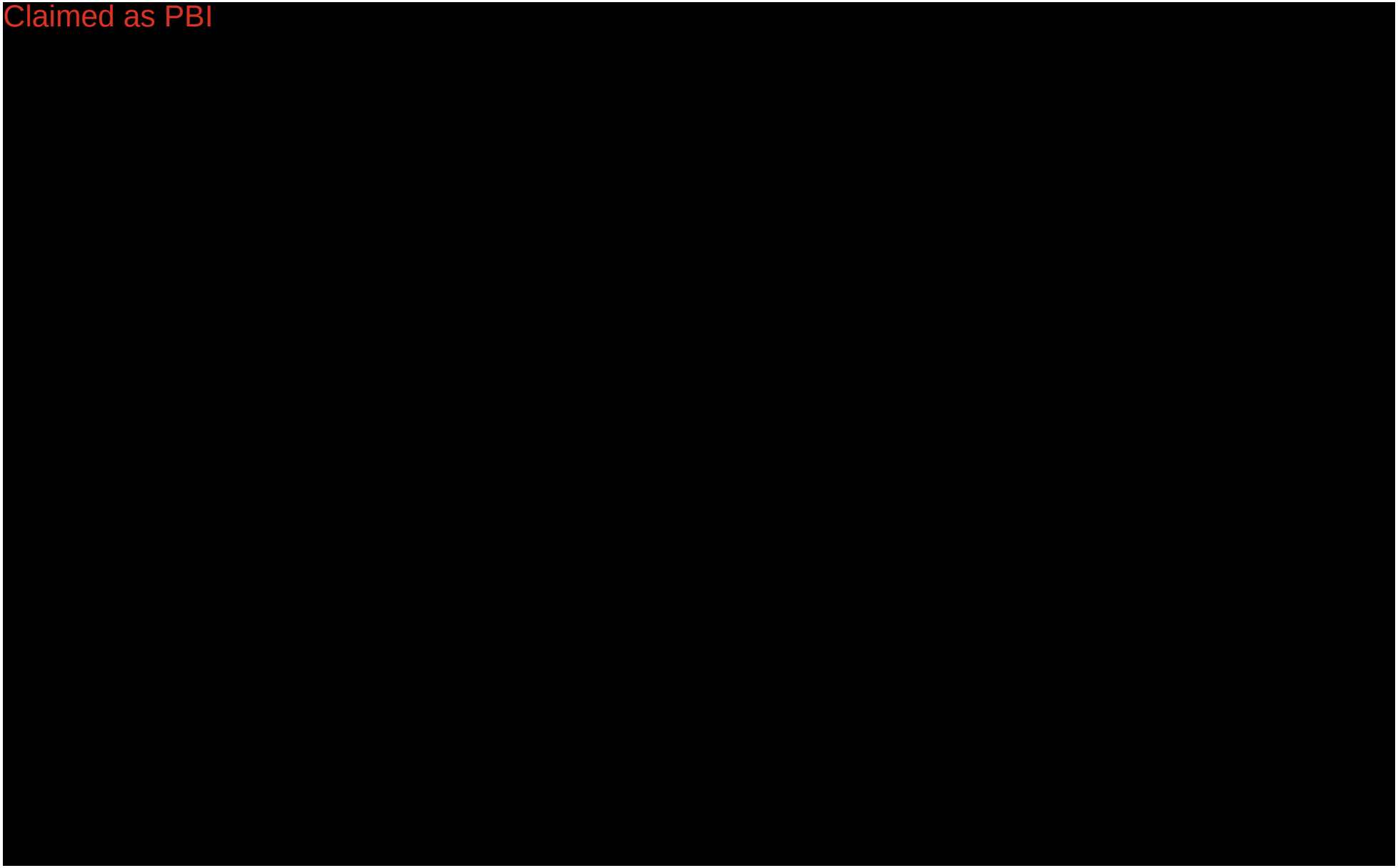

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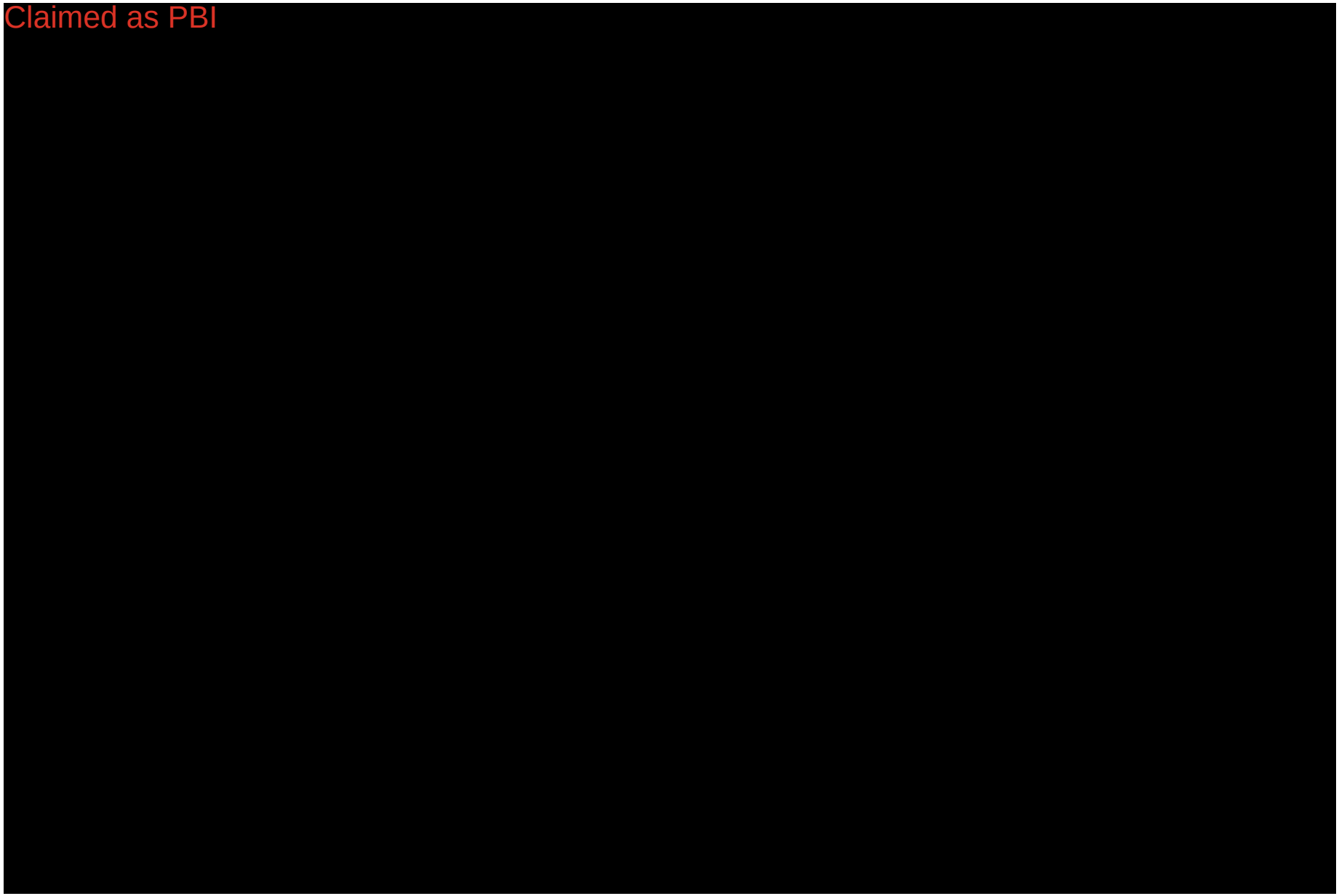

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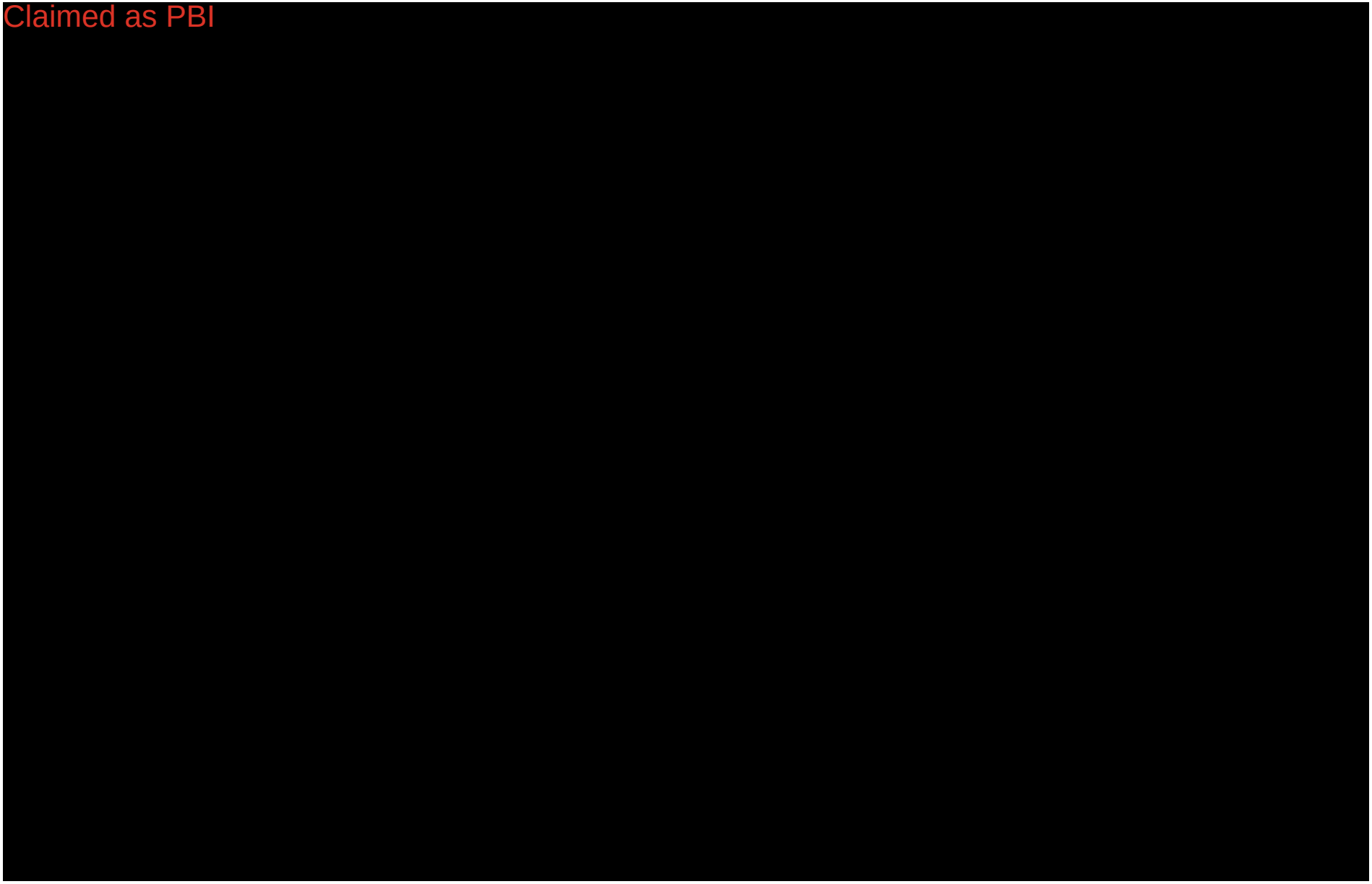

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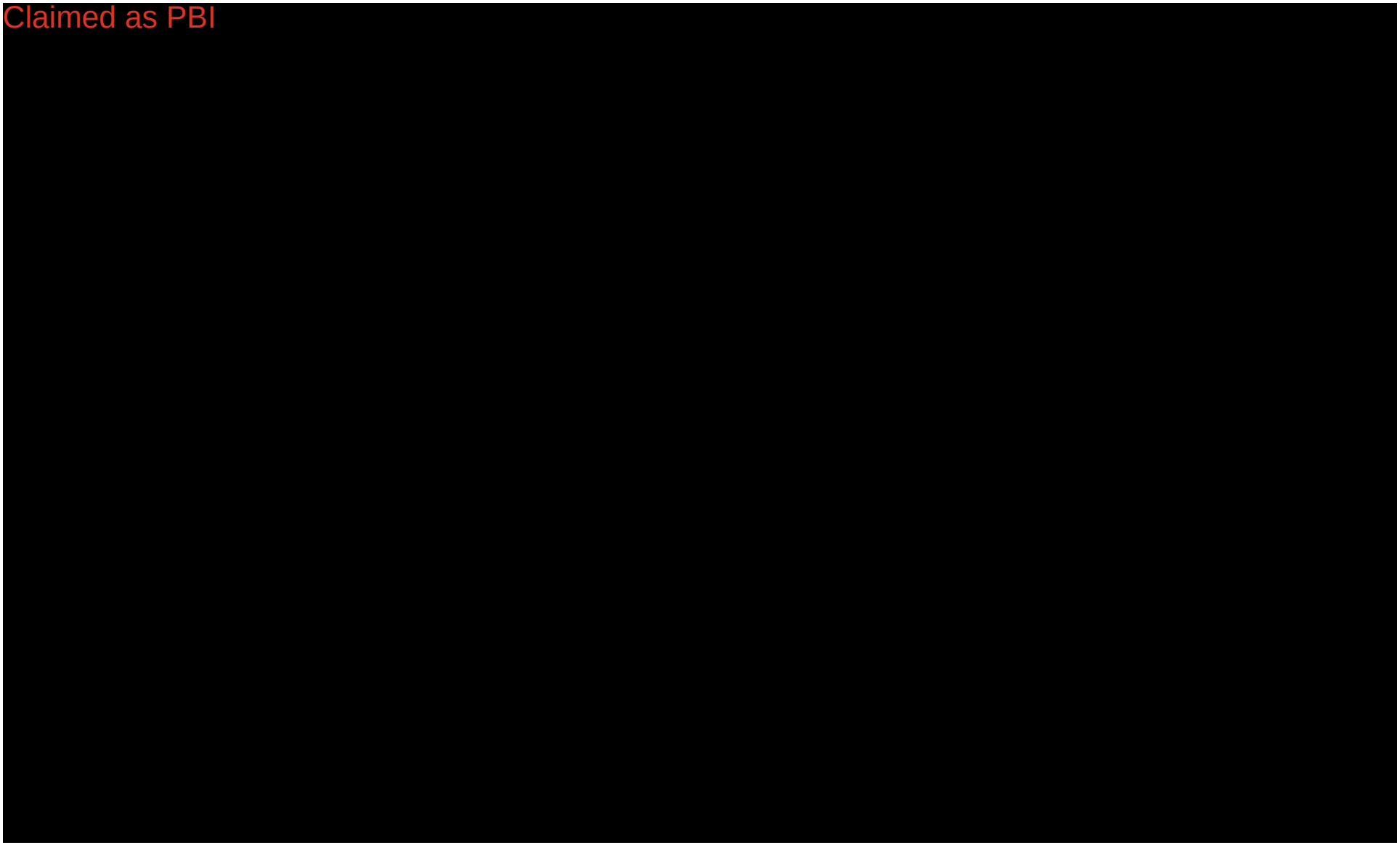

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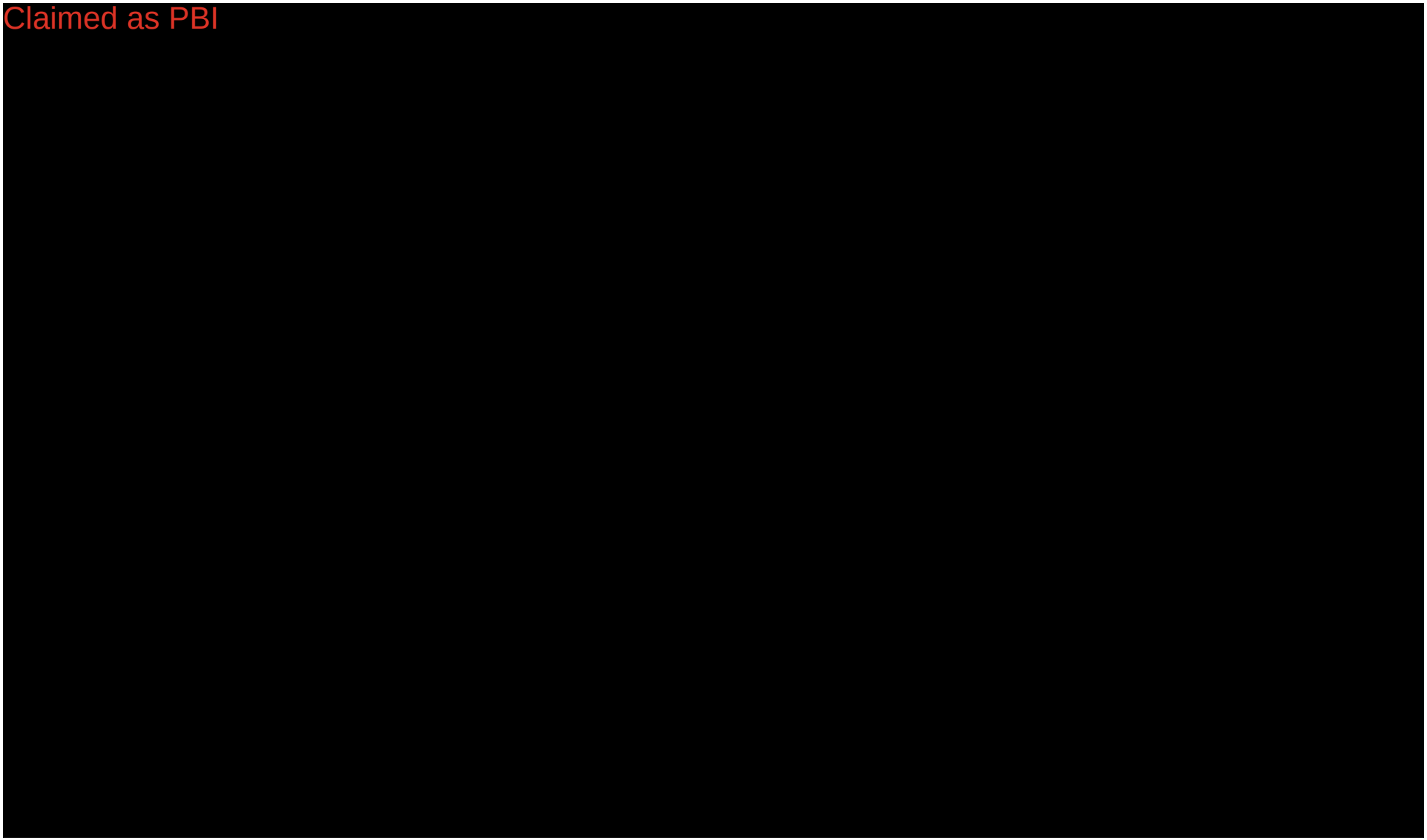

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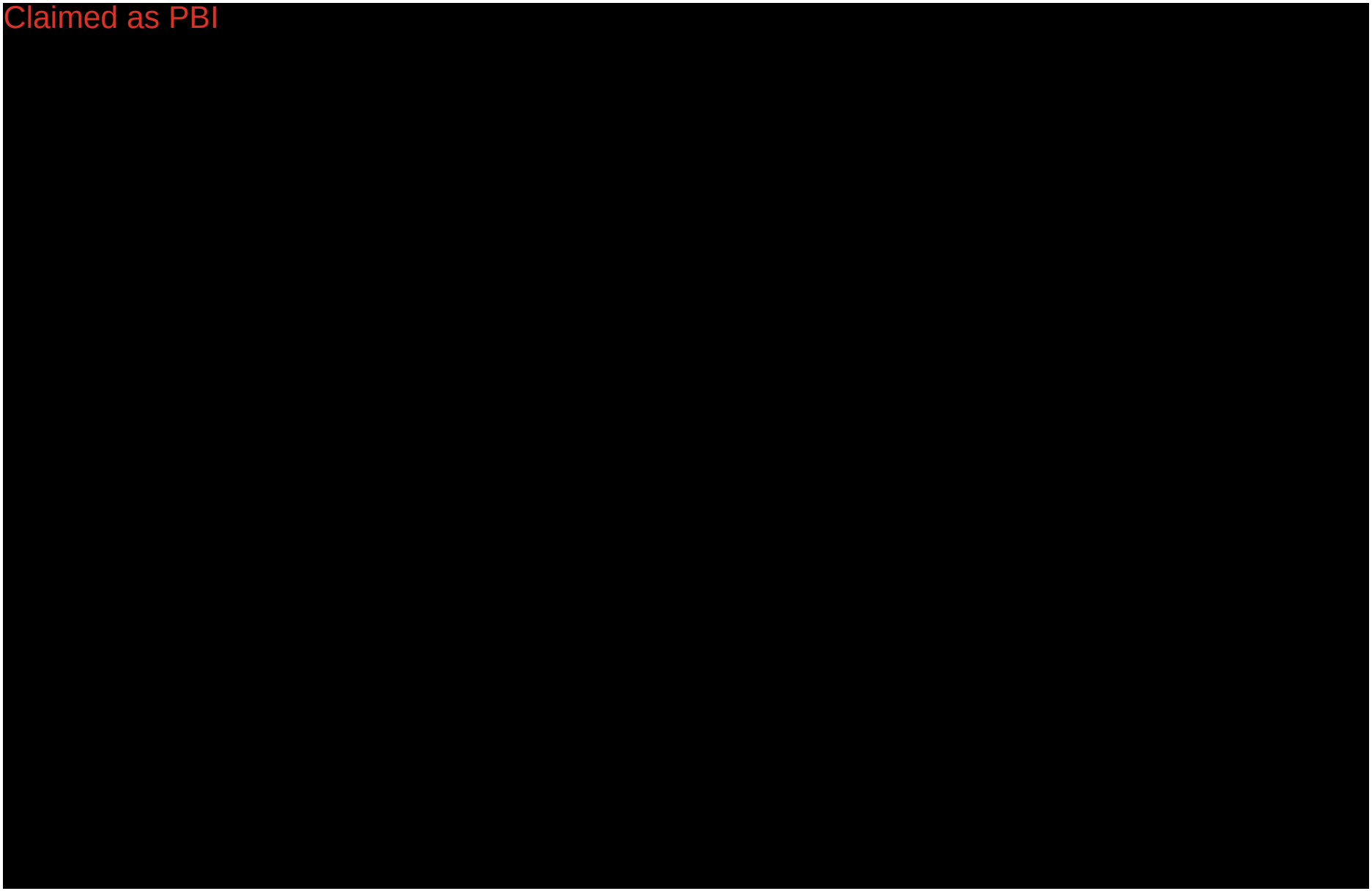

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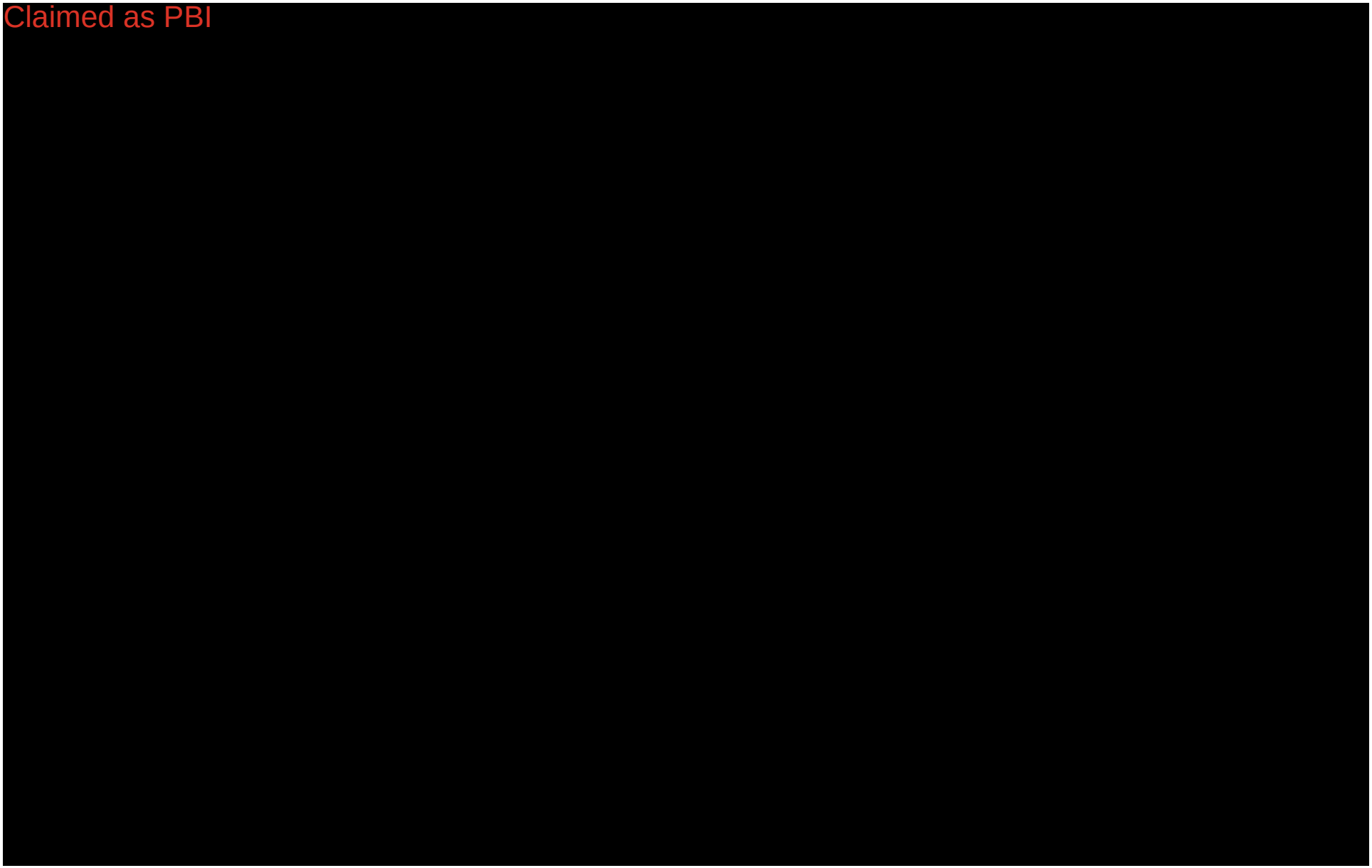

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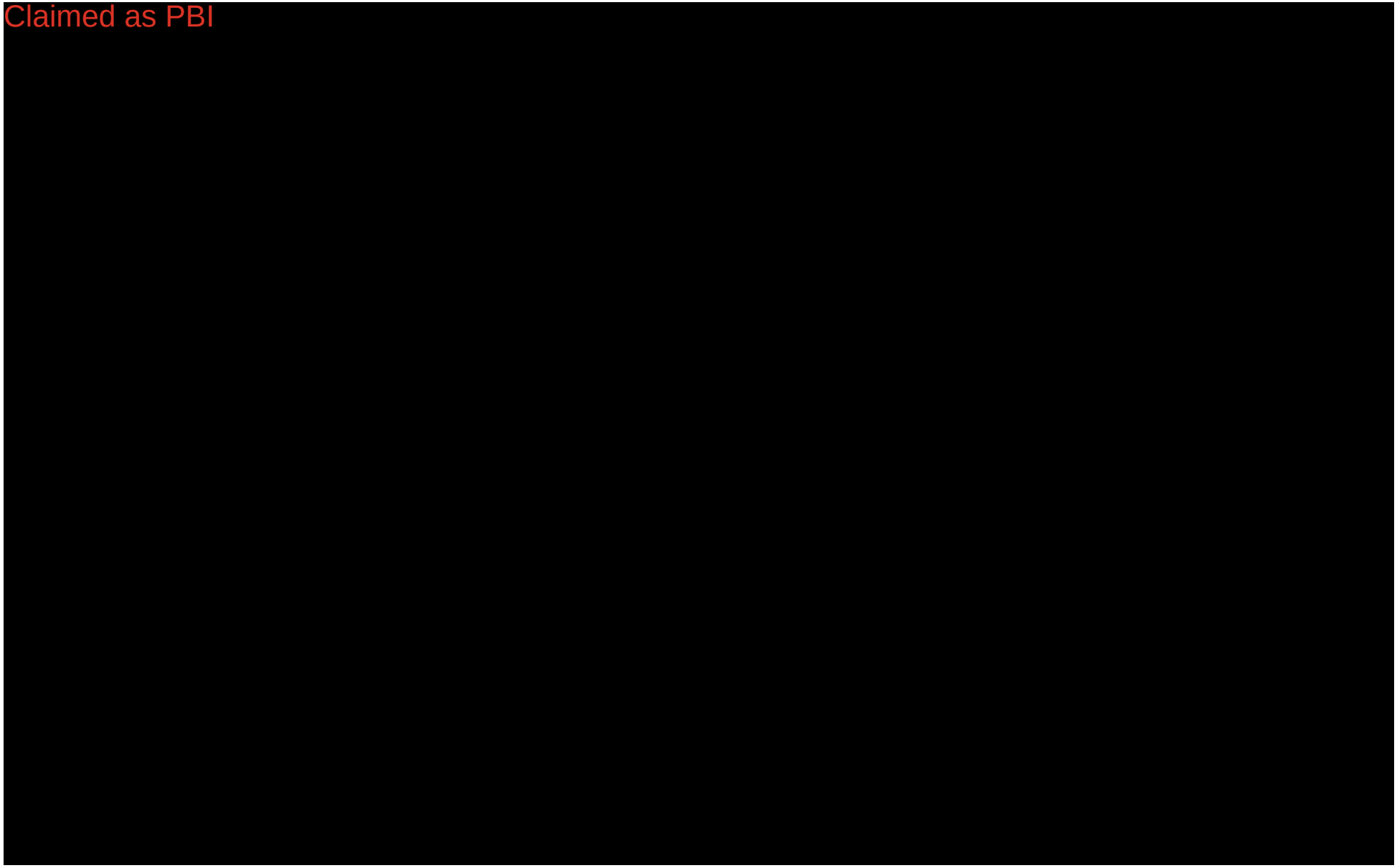

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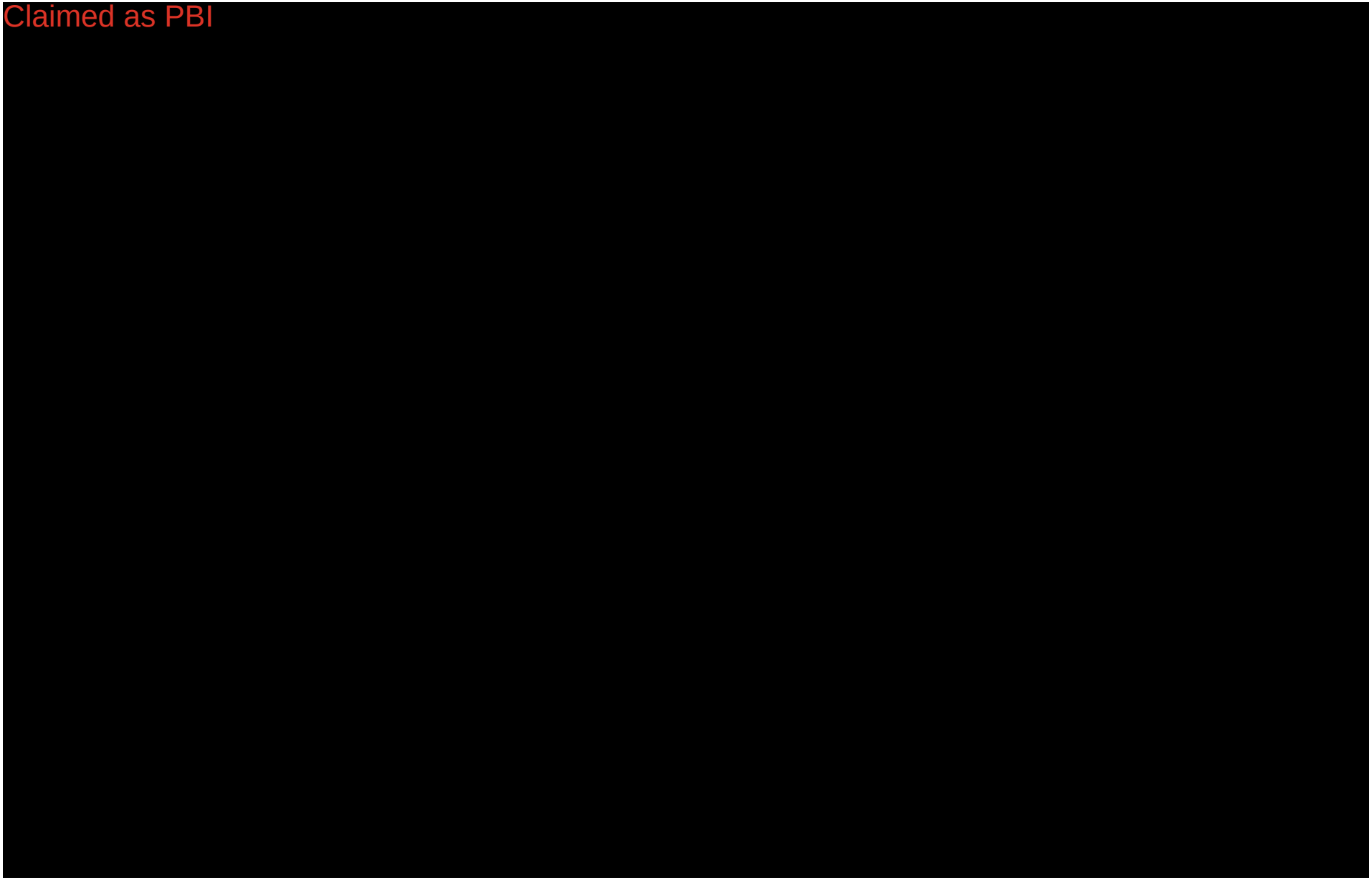

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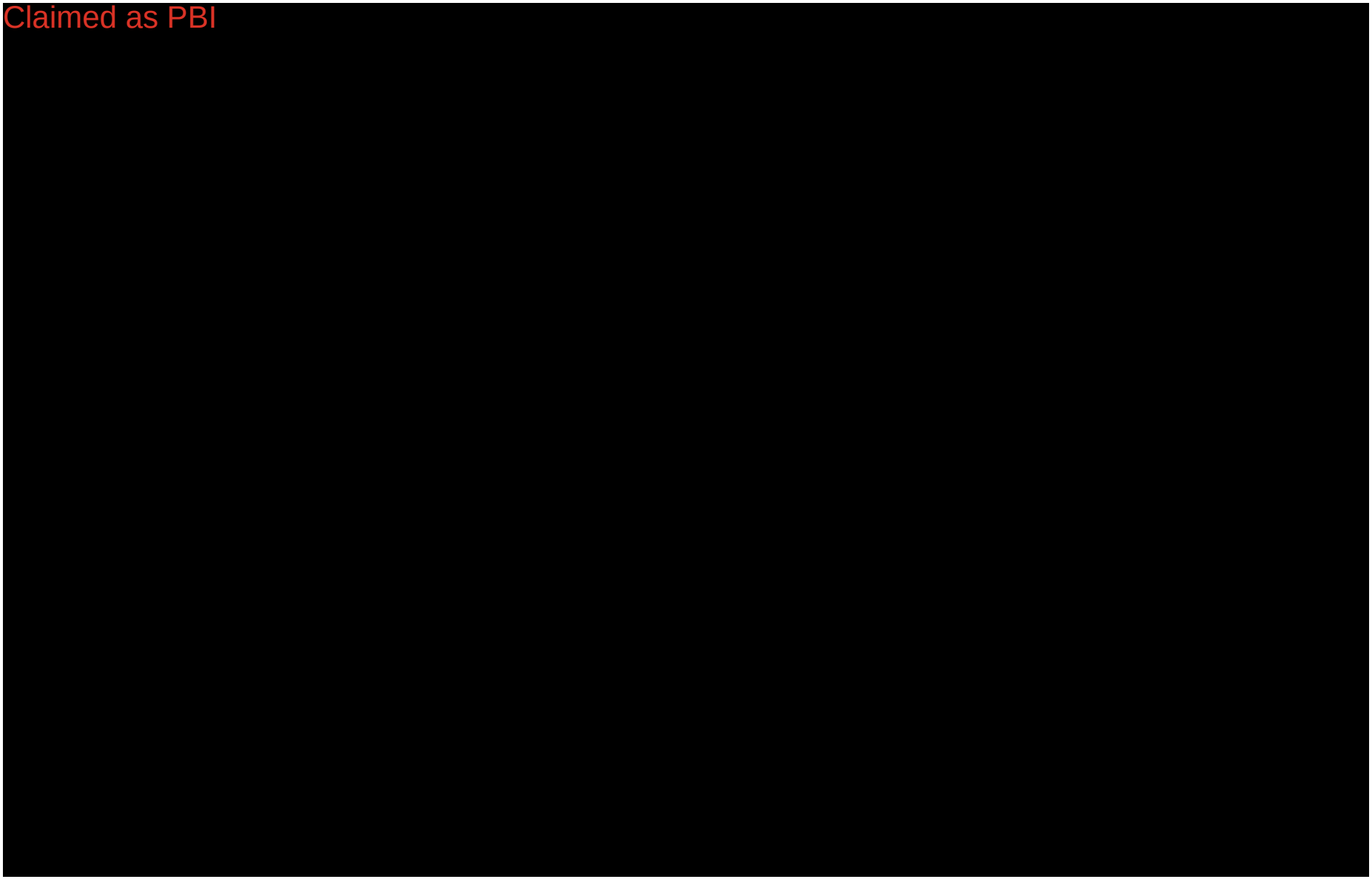

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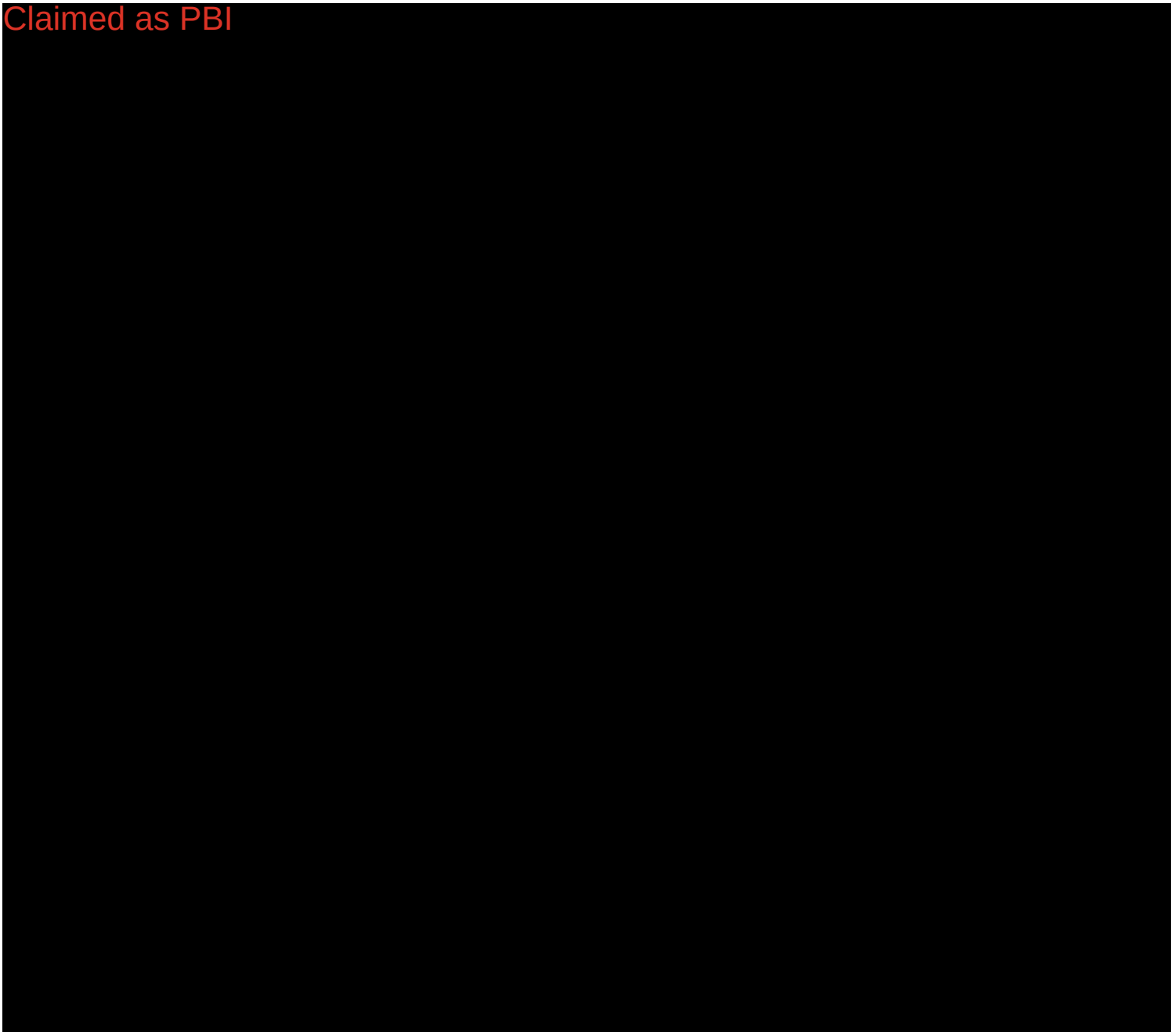

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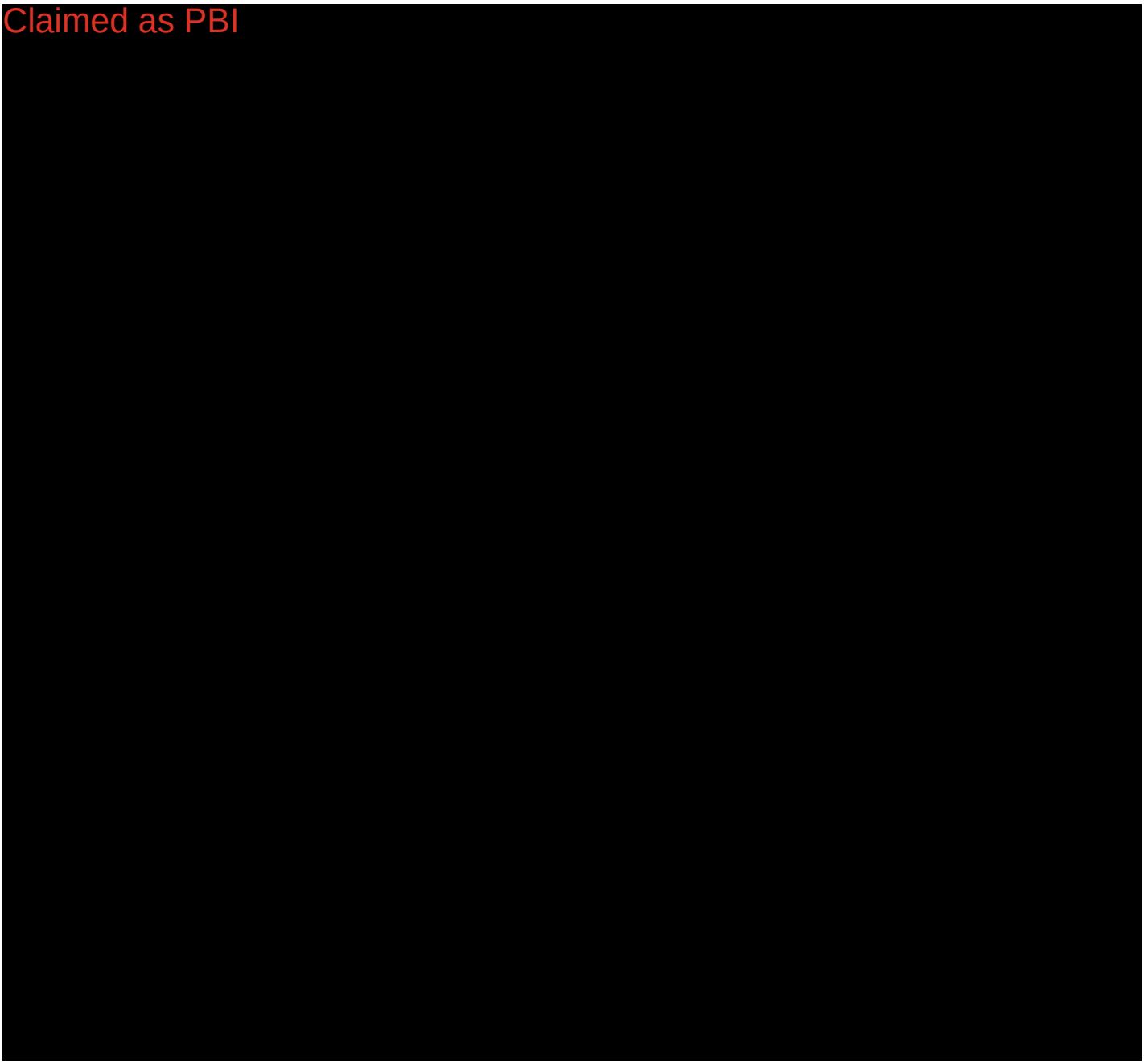


3.3.2 *Model Calibration and Validation*

Claimed as PBI [redacted]

History matching will be conducted throughout the life of the project. As the project progresses, pertinent field data will be collected to recalibrate the model throughout the life of the project.

Fault Transmissibility

Fault seal analysis (FSA) [Narrative, Section 2.3; 40 CFR 146.82(a)(3)(ii)] was used to quantify the flow characteristics of faults with sand-on-sand juxtaposition. Approaches focusing on characterizing the thickness and the permeability of the fault zone are used to inform the impact on fluid flow (Manzocchi et. al., 1999) through modifications to the transmissibility across fault zones. These approaches can be implemented in flow simulations by calculating the impact of the fault thickness and permeability on the transmissibility of grid blocks where the fault intersects the grid. Additionally, the clay content of the strata and the impact of smearing and cataclasis within the fault zone can impact the capillary properties of a fault zone modifying the threshold entry pressure as a function of the shale gouge ratio or SGR (Bretan et. al., 2003).

Fault TMs were applied to simulation models to understand fault transmissivity and seal potential. To capture uncertainty, TMs were calculated using twelve data combinations as follows:

Claimed as PBI [redacted]

3.4 AOR Delineation

3.4.1 Critical Pressure Calculations

While no USDW was identified at BBE [Narrative, Section 2.7.1], the Railroad Commission of Texas (RRC) is mandated to protect surface and subsurface water from pollution under 16 TAC §4.101. The "critical pressure depth" based on the base of the USDW, was instead based on the depth to ensure no discharge to the seafloor Claimed as PBI

The Nicot et.al (2008) and Bandilla et al. (2012) method was used to calculate the critical pressure. Depths were modified to calculate pressure required to cause fluid from the injection zone to reach the seafloor. The critical pressure defines the pressure front and is calculated using the following equation:

$$\Delta P_c = \frac{1}{2} * g * \xi * (z_u - z_i)^2 \qquad \text{[Equation 3-1]}$$

where, g is the acceleration of gravity, z_u is the elevation of the USDW (*mudline*), z_i is the elevation of the injection zone and ξ is a linear coefficient defined by:

$$\xi = \frac{\rho_i - \rho_u}{z_u - z_i} \qquad \text{[Equation 3-2]}$$

ρ_i is the fluid density within the injection zone and ρ_u is the density of the seawater (*normally density of fluid within the USDW*). Claimed as PBI

Claimed as PBI

3.4.2 AOR Delineation

The AOR is delineated by the combination of the CO_2 saturation front and the pressure front to identify and address the artificial penetrations that are impacted by injection activity to prevent the movement of fluids into a protected water source (seafloor) [16 TAC §4.101] and the nearest USDW onshore [40 CFR 146.84(c)(1)]. **Figure 3-36** illustrates the delineated AOR for BBE-P1.

Claimed as PBI

During the project lifetime (20 years of injection and 50 years of post-injection period) the delineated AOR remains offshore. The maximum extent of the CO_2 saturation front occurs at 50-year post-injection (January 1, 2097), and the maximum critical pressure front occurs at the end of injection (January 1, 2047). The AOR is hence delineated by the combination of the CO_2 saturation front at 50-year post-injection and the critical pressure front at the end of injection. **Figure 3-37** shows the overlay of the CO_2 saturation front and the critical pressure front that delineate the AOR outline. Claimed as PBI

Artificial Penetrations (APs) within the AOR were assessed (Section 3.5).

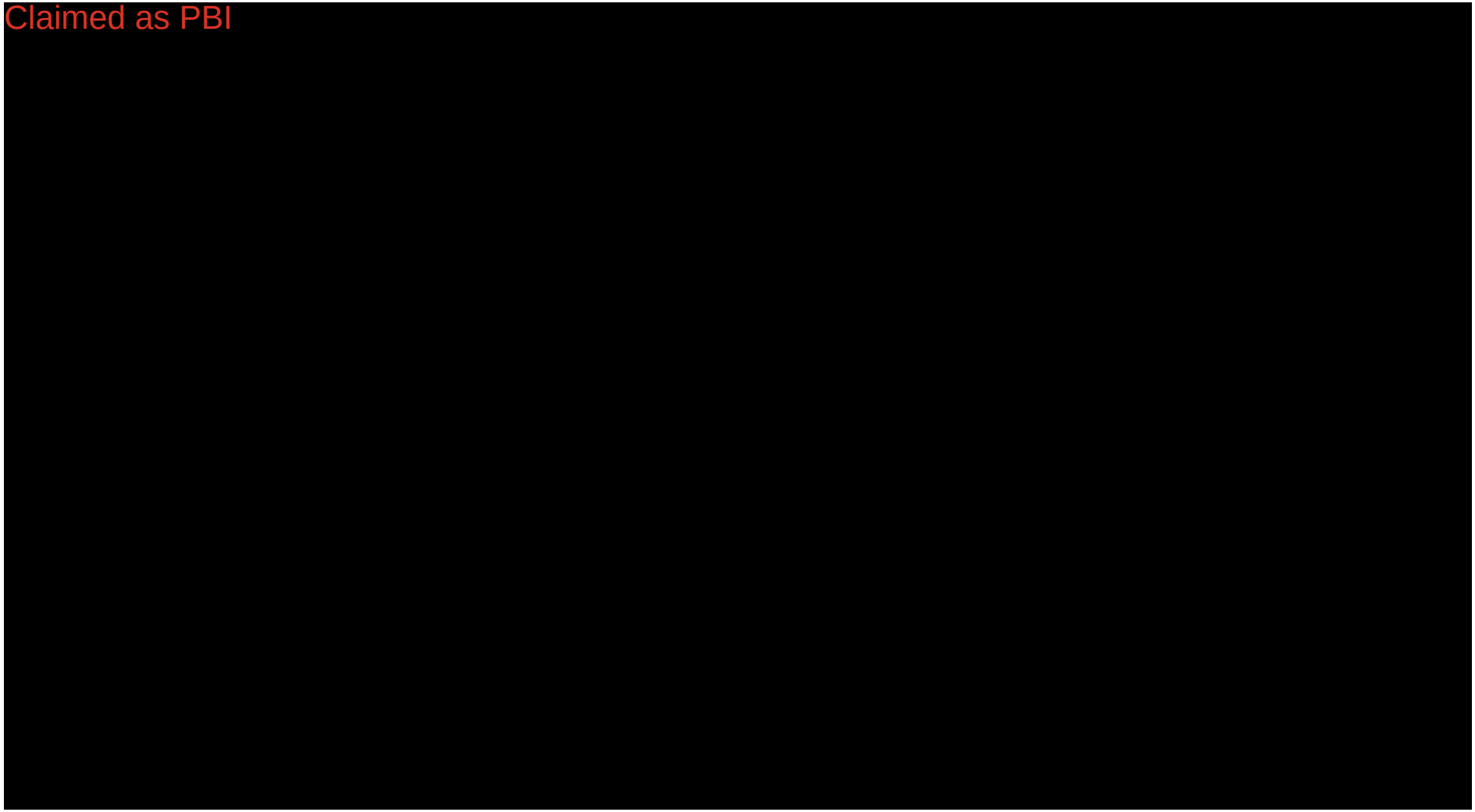
Claimed as PBI



Claimed as PBI



Claimed as PBI



3.4.3 Sensitivity Analysis

Claimed as PBI [redacted]

Permeability

The base case model permeability field was tested for a high and low outcome Claimed as PBI [redacted]

Porosity

Claimed as PBI [redacted]

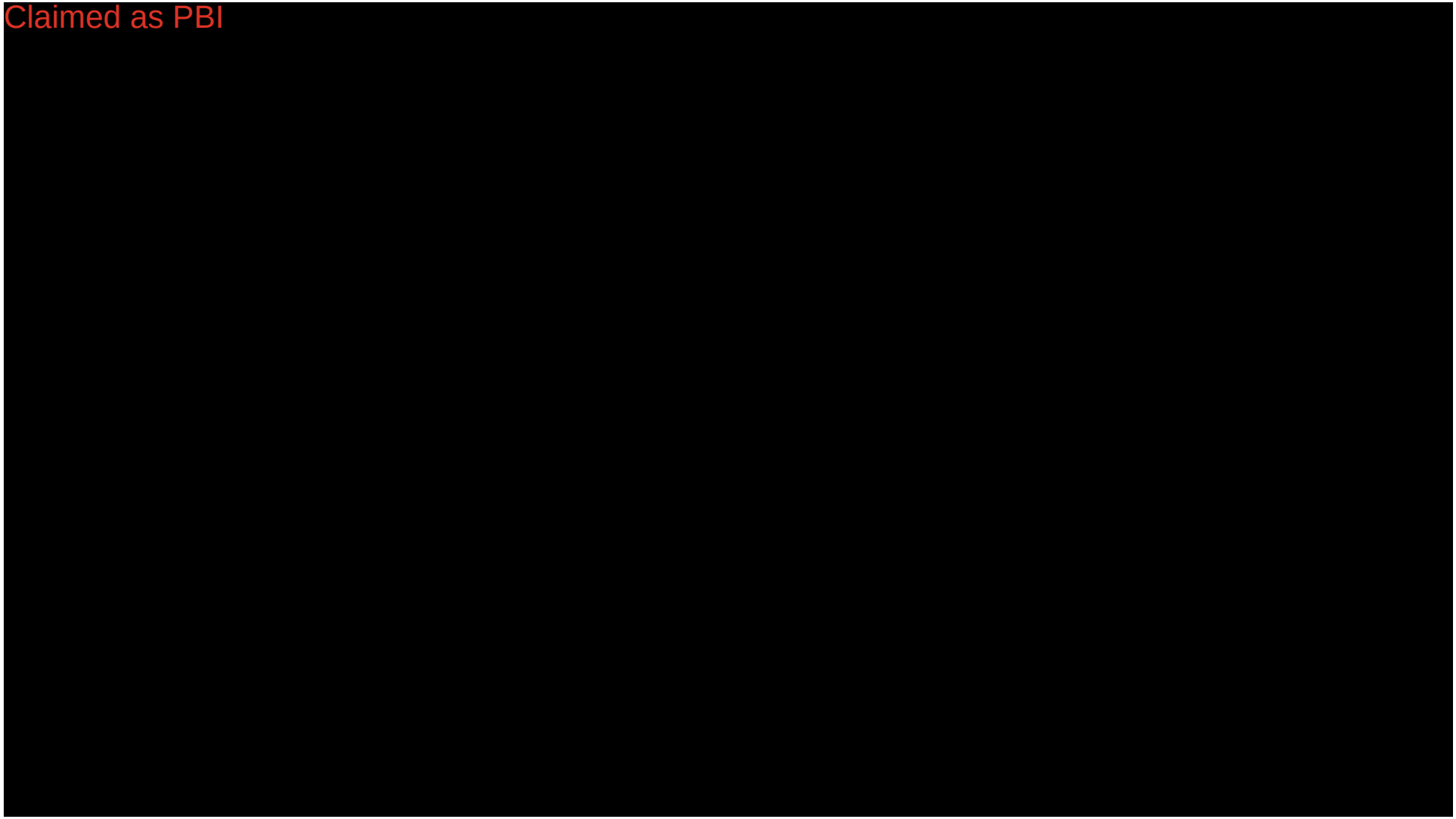
Sensitivity Summary

The Operator carefully considered these sensitivities in designing the Testing and Monitoring Plan. Claimed as PBI [redacted] the selected monitoring technologies, data collection frequencies, and well placement described in detail in the Testing and Monitoring Plan, the development of the CO_2 saturation front and pressure response in the reservoir will be monitored over time. This data will be analyzed and incorporated into periodic AOR Reevaluations (Section 3.6.1).

Claimed as PBI



Claimed as PBI



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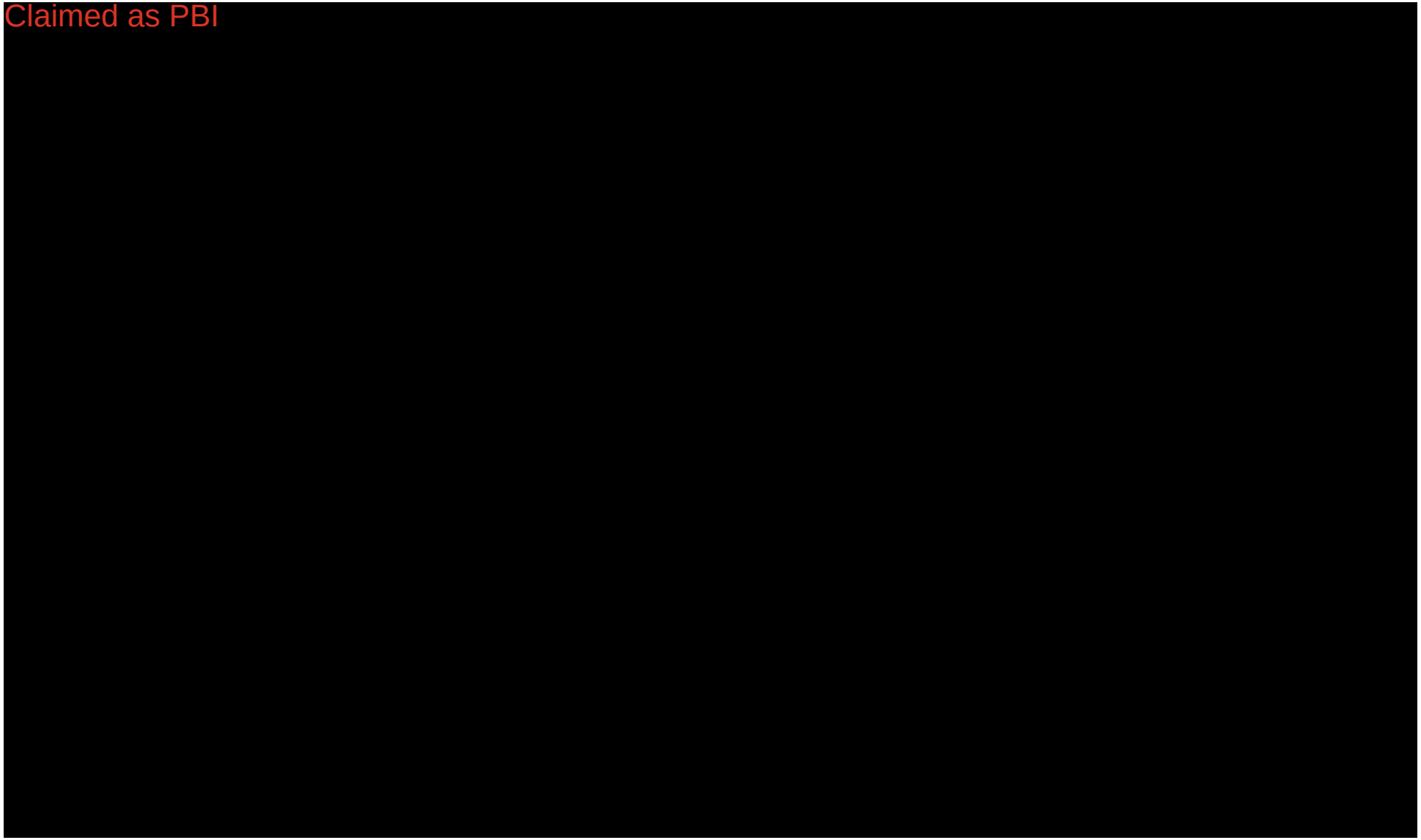


3.5 Corrective Action

3.5.1 *Tabulation of wells within the AOR*

Artificial Penetrations (Wells) within the AOR

An AP records search was conducted per 40 CFR 146.82(a)(4), 40 CFR 146.84(c)(2), 40 CFR 146.82(a)(21) and TAC §5.203(d)(B) requirements. Databases and other information sources used to identify wells include the RRC, S&P Global Well Database, and Chevron well records system inclusive of heritage companies (e.g. Texaco).Claimed as PBI

Claimed as PBI

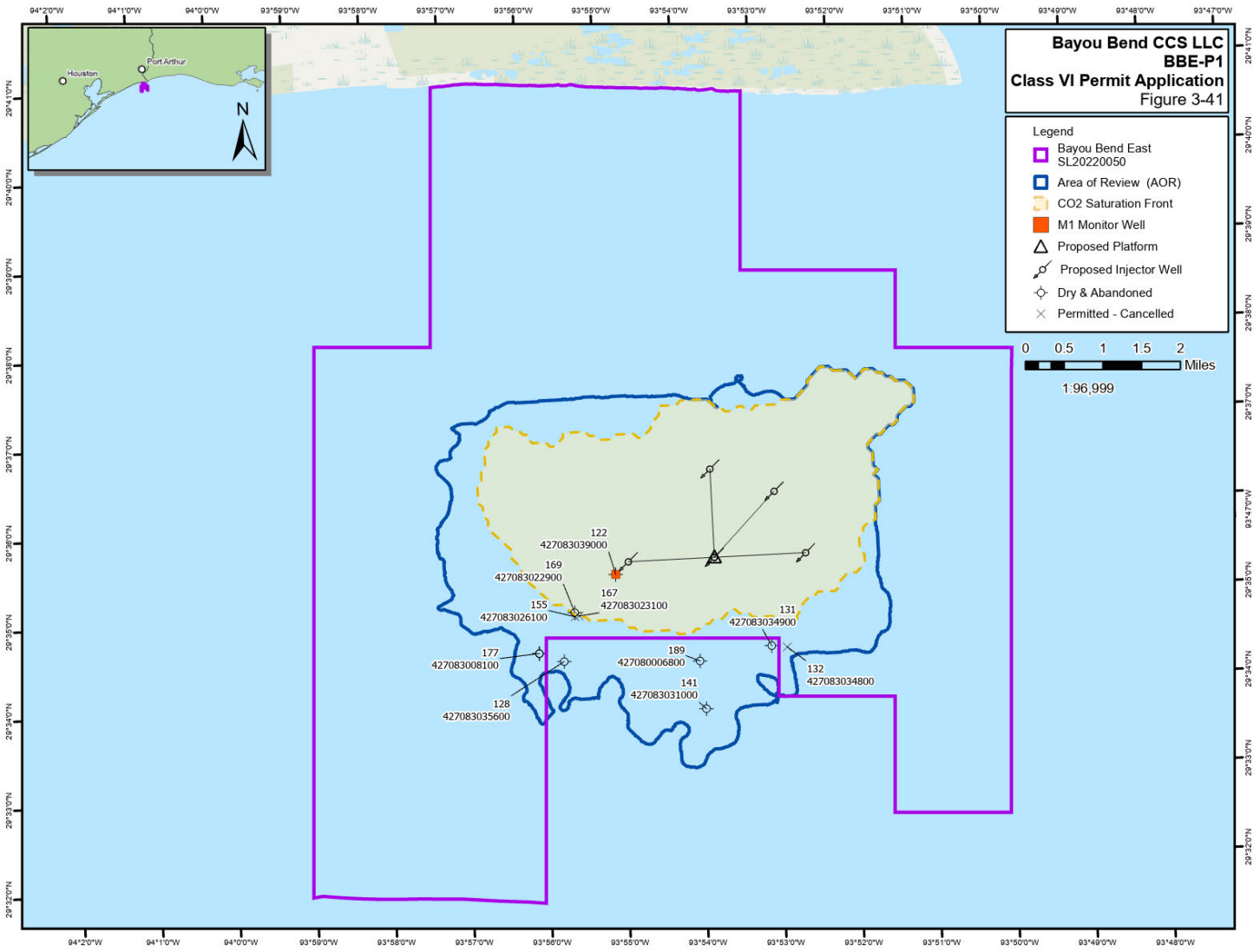


Figure 3-41: Artificial Penetrations within the AOR. Table 3-21 provides detailed information.

Table 3-19: Artificial Penetrations in the AOR

CONTROL NO.	OPERATOR NAME WELL NAME & NO. SURVEY NAME & NO.	API NO.	TOTAL DEPTH (FEET)	DATE DRILLED	WELL TYPE	WELL STATUS	CASING DATA						PLUGGING DATA					IS WELL MUD FILLED? (Y/N)	PERMIT DATE
							CASING TYPE	CASING SIZE (IN)/ CEMENT VOL (SACKS)	DEPTH (FT)	CACLULATED TOC (FT)	CASING PULLED (FT)	CASING REMAINED (FT)	PLUG DEPTH (FT)	CEMENT VOL. (SACKS)	MUD DATA (LOG)	MUD WT. (P&A)	DATE PLUGGED		
167	KILROY CO OF TEXAS INC ST TR 11-L No. 2	427083023100	0	Not Drilled	Canceled / Abandoned Location	ABANDON LOCATION	Confirmed Permited Only	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1979-02-01
169	KILROY CO OF TEXAS INC ST TR 00011-L NE/4 No. 1	427083022900	12177	1979-06-29	Dry Hole	DRY & ABANDONED	Surface Casing Intermediate Casing	13-3/8" / 5600 9-5/8" / 1050	1295 9200	Surface 5,462	90 150	1205 9050	160 to 220 (9-5/8"x 13-3/8") 550 to 650 (9-5/8") 9040 to 9290 (9-5/8")	50 40 95	NO INFO	16.8	1979-08-13	Y	1979-03-26
155	KILROY CO OF TEXAS INC ST TR 11-L NE-4 No. 2	427083026100	0	Not Drilled	Canceled / Abandoned Location	ABANDON LOCATION	Confirmed Permitted Only	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1980-06-23
122	BAYOU BEND CCS LLC SL20220050 No. M 1	427083039000	8408	2023-12-31	Dry & TA	Dry & Temporarily Abandoned	Conductor Surface Casing Protection Casing Long String	24" / Driven 16" / 790 10-3/4" / 1917 7" / 1797	421 930 3946 8400	Driven 140 153 152	0 0 0 0	421 930 3946 8400	No Cement Plugs Well Temporarirly Abandoned to convert to Monitoring Well for Bayou Bend East CCS.	N/A	Yes	9.8	Not Plugged	N (NaBr)	2023-02-27
128	ENRON OIL & GAS CO ST TR 11-L S/2 NE/4 No. 1 GOM ST. TR. 11-L	427083035600	12000	1997-03-12	Dry Hole	DRY & ABANDONED	Conductor Surface Casing Intermediate Casing Interrmediate Casing	24" / Driven 18-5/8" / 670 13-3/8" / 2430 9-5/8" / 1500	350 999 4570 9579	N/A Surface Surface 6499	109 (cut 20' BML) 109 (cut 20' BML) 109 (cut 20' BML) 124 (35' BML)	241 890 4461 9455	198 to 458 (9-5/8") 9292 to 9504 (8-1/2" hole)	75 190	NO INFO	16.8	1997-04-06	Y	1997-02-26
177	BELCO PETROLEUM NORTH AMERICA SL 66716 No. 1	427083008100	9186	1973-11-15	Dry Hole	DRY & ABANDONED	Conductor Surface Casing Intermediate Casing	30" / NO INFO 16" / NO INFO 10-3/4" / NO INFO	221 629 3017	NO INFO	112 119 129	109 510 2888	119 to 290 (16" x 10-3/4") 2900 to 3122 (10-3/4")	100 100	NO INFO	12.3	1973-11-28	Y	1973-10-25
189	TEXACO USA ST TR 00012-L No. 1	427080068000	15000	1966-07-21	Dry Hole	DRY & ABANDONED	Conductor Surface Casing Intermediate Casing Intermediate Casing Intermediate Casing	30" / NO INFO 20" / NO INFO 13-3/8" / NO INFO 9-5/8" / NO INFO 5-1/2" / NO INFO	115 538 3070 9316 10564	NO INFO	28 132 131 132 144	87 406 2939 9184 10420	100 to 630 Below ML (5-1/2" x 9-5/8" Annulus) 100 to 740 Below ML (9-5/8" x 13-5/8" Annulus) 60 to 404 Below ML	142 200 40	NO INFO	16.9	1969-06-10	Y	1966-07-25
141	KILROY CO OF TEXAS INC ST TR 00012-L SW4 No. 1	427083031000	9416	1980-01-27	Dry Hole	DRY & ABANDONED	Surface Casing Intermediate Casing	10-3/4" / NO INFO 7-5/8" / NO INFO	4505 9250	NO INFO	130 4425	4375 4825	300 to 450' (17-1/2" hole) 9150-9300' (9-5/8" hole) 9375-9400' (9-5/8" hole)	75 125 87	NO INFO	14.5	1980-02-23	Y	1979-09-26
131	BASIN EXPLORATION INC HIGH ISLAND 12-L (TX S L M 97277) No. 1 GOM S.T. 12-L NW/4	427083034900	11,505	1996-08-22	Dry Hole	DRY & ABANDONED	Conductor Surface Casing Intermediate Casing Intermediate Casing	30" / Driven 20" / 1175 13-3/8" / 2430 9-5/8" / 1325	347 1015 4505 9442	N/A Surface Surface 4959	142 147 150 155	205 868 4355 9287	130-330' (9-5/8") 4410-4555 (9-5/8") 9250-9450 (9-5/8")	65 110 100	NO INFO	14.5	1996-09-11	Y	1996-08-14
132	BASIN EXPLORATION INC. HI 12-L (TX S/L M-97276) No. 1 GOM S.T. 12-L NE/4	427083034800	0	Not Drilled	Permitted Location	Permitted Location	Confirmed Permitted Only	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1996-08-14

Water Wells

A water well record search was conducted through the Texas Water Development Board to identify potential well penetrations through the confinement zone. The search concluded no water wells are present within the AOR.

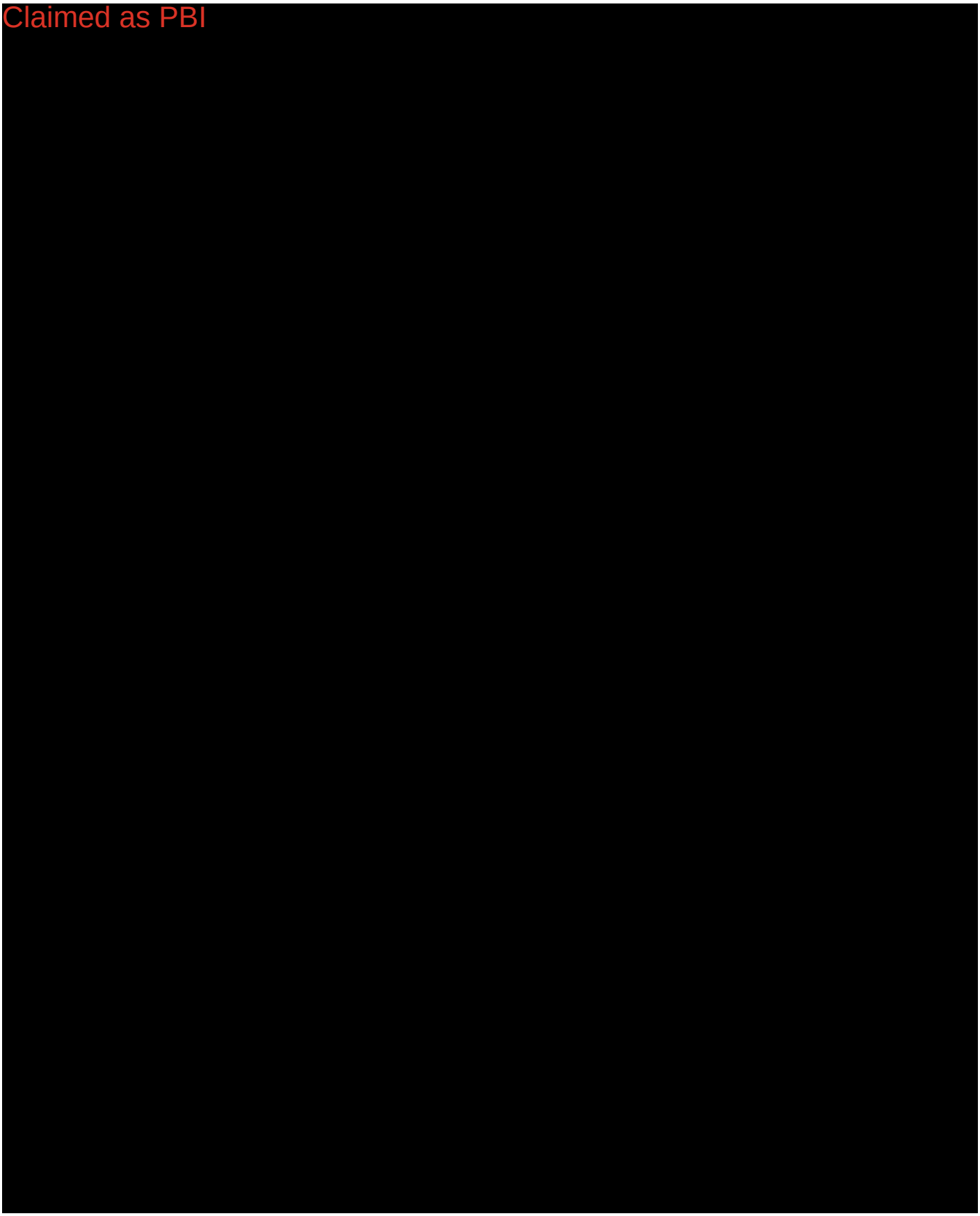
Wells Penetrating the Confining Zone

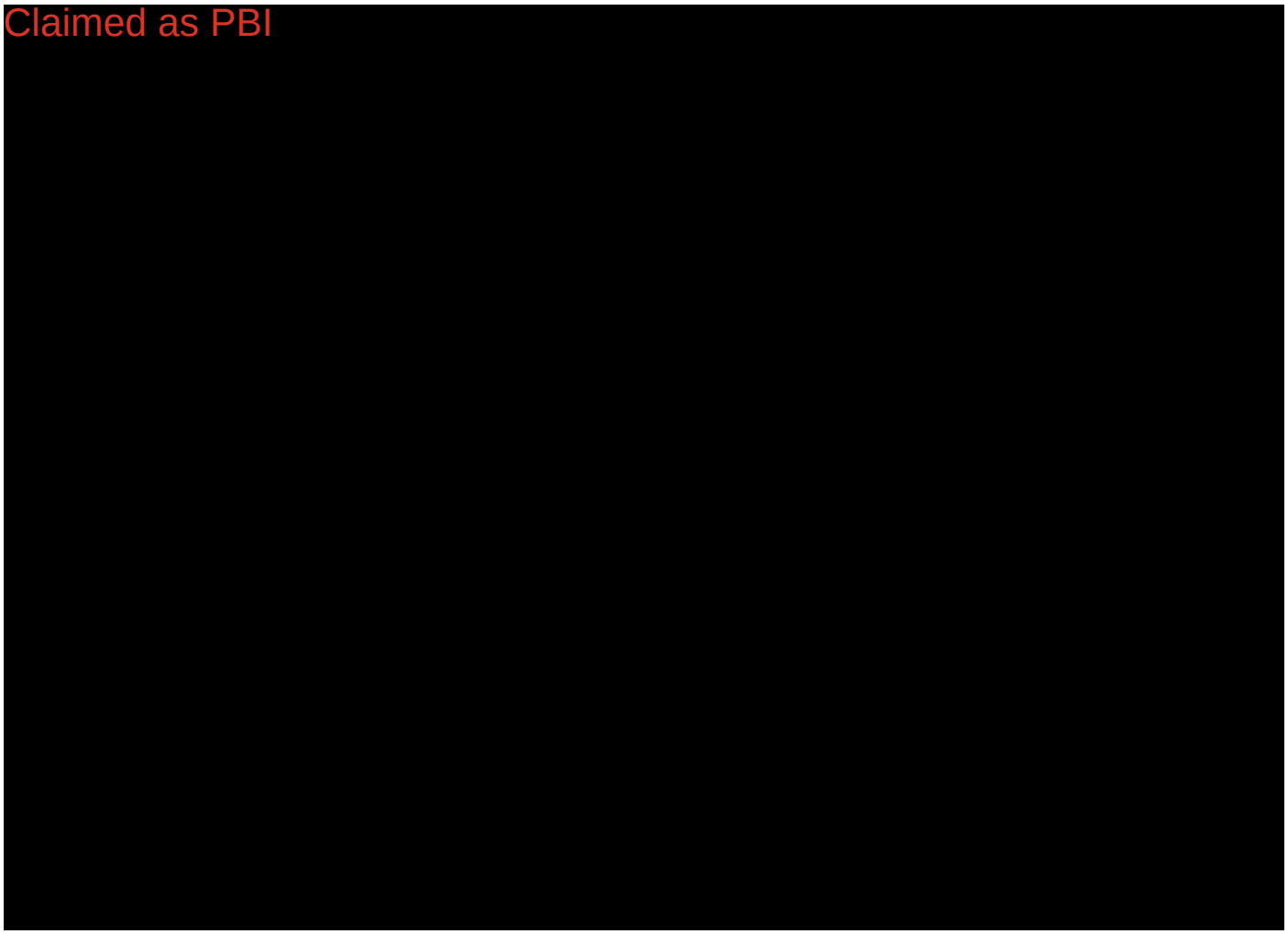
The seven (7) artificial penetrations identified in the AOR with penetration depths penetrating the confining zone were determined based on database records research. Subsurface interpretation of the top of the confining zone and top of the injection zone were documented for each well penetration. This confirmed the wells identified in the AOR penetrate the injection zone and the confining zone. The well data records were used to document the casing sizes / depths, annulus cement tops and abandonment plugs in wellbore schematics (**Appendix 3-2**).

The Corrective Action evaluation for each well has been conducted based on available well records, barrier types, barrier depths to the confining zone, proximity to the injector wells, and modeled CO_2 saturation and pressure front migration. Claimed as PBI

Claimed as PBI

Claimed as PBI





3.5.2 Plan for Site Access

The Operator holds defined agreements with the State of Texas, Offshore Oil and Gas Operators, and transportation companies for full-time access, 24 hours a day, to the sequestration site for the defined AOR and BBE-P1 (SL20220050). The injection wells, monitoring wells, and platform facilities located in state waters will have access via marine supply vessels. The transportation in state waters will utilize local ports in the Texas and Louisiana Gulf Coast region. The Operator will maintain these access routes and facilities throughout the duration of the project.

3.5.3 Corrective Action Schedule

The Corrective Action Schedule is described in **Table 3-22**.

Table 3-22: Corrective Action Schedule.

Claimed as PBI

[redacted]

minimum, the AOR will be reevaluated every five (5) years or as necessary as monitoring and operational conditions warrant.

A monitoring plan to track the saturation front over time is detailed in the Testing and Monitoring Plan. The injection control system monitors operational parameters of the injection facility and storage capacity, with active monitoring above the confining zone. The control system monitors and records the condition of the injection well's containment. If any of these operational parameters move outside the preset norms, then the control system will alert the Operator and instigate a controlled system shutdown. The Operator will reevaluate the above described AOR every five (5) years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

The monitoring plan and controls system is designed to ensure that the injectate is being stored in the intended storage intervals. If a significant deviation from the monitoring plan or modeling occurs, then the Operator will evaluate the data, discuss results with the Director, and develop an appropriate corrective action schedule, if needed.

Claimed as PBI

[redacted]

3.6 Reevaluation Schedule and Criteria

3.6.1 AOR Reevaluation Cycle

The Operator will reevaluate the above described AOR every five (5) years, or as necessary based on triggers described below, during the operation phase and post-injection period, as required by 40 CFR 146.84 (e). The Operator will reevaluate the AOR and will generate and submit to EPA a report comparing computation results and recently obtained field data. This will include reevaluation of artificial penetration corrective actions. If needed, the Operator will describe specific actions to be taken to mitigate discrepancies between monitoring data and computational simulation results.

Every five (5) years, operating and monitoring data will be compiled and analyzed in comparison with computation simulation results. Specifically, data to be gathered and analyzed includes:

- Pressure data from monitoring wells to constrain and define the development of the AOR.
- CO_2 content/saturation from monitoring well and/or monitoring equipment from the injectors to constrain and define saturation front development. This data may be acquired from seismic surveys or cased hole logging.
- Injection rates, injection pressures, and injection volumes to constrain computational model parameters and inputs.
- Fluid samples and corresponding reports analyzing the formation water collected from monitoring wells in above confining zone permeable intervals to evaluate unexpected migration, if any, into shallower formations.

The collection of operating and monitoring data through the project life may be used to refine static and dynamic models that may prove to inadequately represent the subsurface. At each AOR reevaluation, the Operator will evaluate model inputs based on operating and monitoring data and adjust as needed. In the event of model changes, the Operator will submit a report to EPA listing the changes and providing proper justification.

The AOR reevaluation frequency during the post-injection period may be adjusted in the future, based on monitoring results and pursuant to EPA approval.

3.6.2 Triggers for AOR Reevaluation Prior to the Next Scheduled Reevaluation

The Operator will discuss any such events with the Director to determine if an AOR reevaluation is required. If an unscheduled reevaluation is triggered, the Operator will perform the steps described at the beginning of this section of this Plan.

3.7 Additional Information

3.7.1 Acronyms

°F	Degree Fahrenheit

Claimed as PBI

AOI	Area of Interest
AOR	Area of Review
AP	Artificial Penetration
BBE	Bayou Bend East SL20220050
BBE-P1	Bayou Bend East SL20220050 – Phase 1
BOEM	Bureau of Ocean Energy Management
CCS	carbon transport and sequestration
CH_4	methane
CO_2	carbon dioxide

Claimed as PBI

FPP	fracture propagation pressure
FSA	fault seal analysis
ft	feet
GoM	Gulf of Mexico
GR	gamma ray
IX©	INTERSECT©
LBC	Lohrenz-Bray-Clark
LGR	Local-grid refinement

Claimed as PBI

MD	measured depth
MFS	Maximum flooding surfaces

MMT	million metric tonnes
MTA	million metric tonnes per annum
Claimed as PBI	[redacted]
N_2	nitrogen
NIST	National Institute of Standards and Technology
NTG	net to gross
P_{hie}	effective porosity
P_{hit}	total porosity
psi	pounds per square inch
PV	Pore Volume
PVC	Pore Volume Compressibility
PVT	Pressure, Volume, Temperature
S_{WIR}	irreducible water saturation
S_{grmax}	maximum trapped gas saturation
SP	spontaneous potential
RRC	Railroad Commission of Texas
TM	Transmissibility multipliers
TVD	true vertical depth
TVDSS	true vertical depth below sea level
USDW	Underground source of drinking water
Vshale	Shale volume

3.7.2 References

Claimed as PBI

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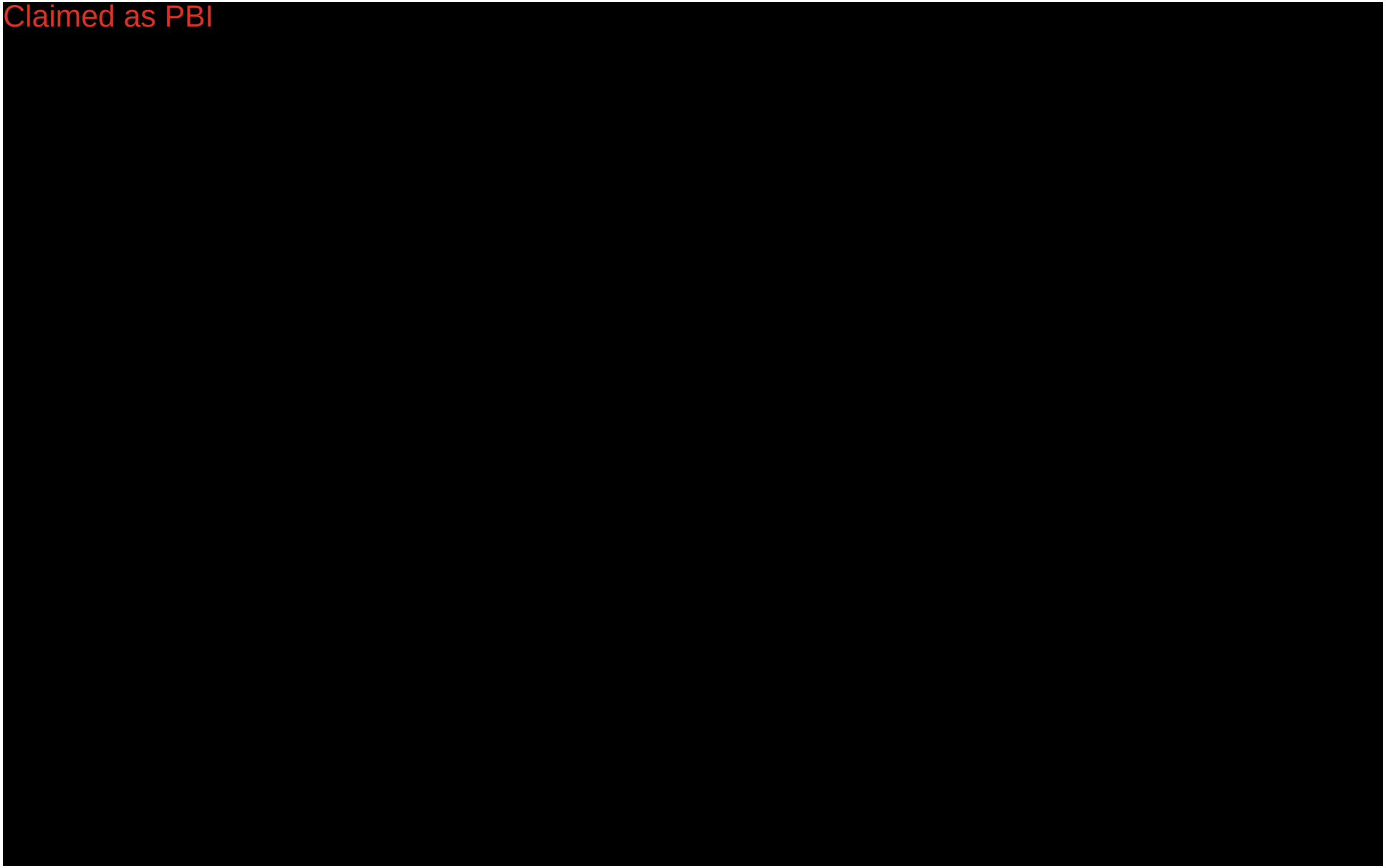
Plan revision number: 003
Plan revision date: September 2026

Claimed as PBI

Claimed as PBI



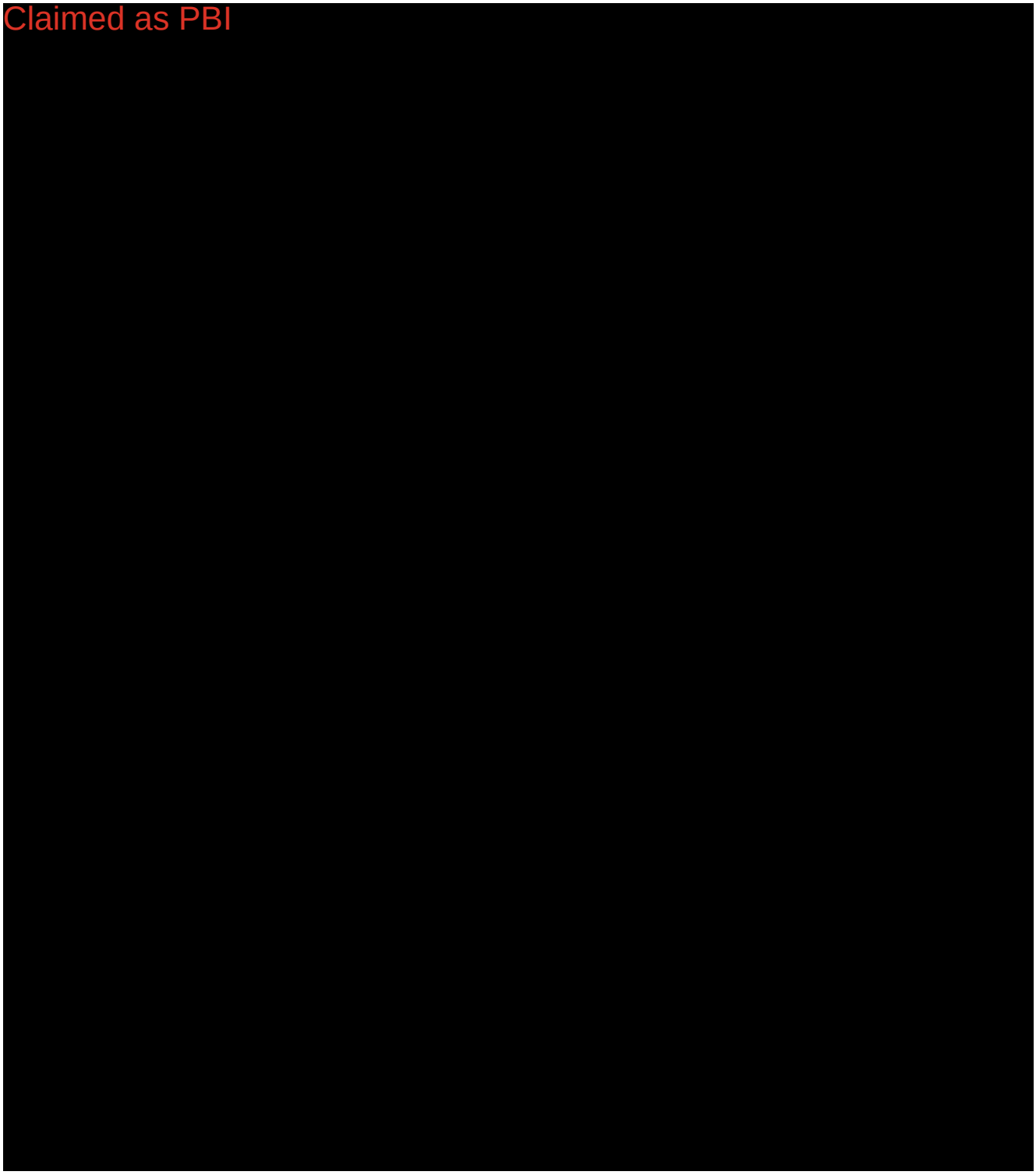
Plan revision number: 003
Plan revision date: September 2026

Claimed as PBI



Plan revision number: 003
Plan revision date: September 2026

Claimed as PBI



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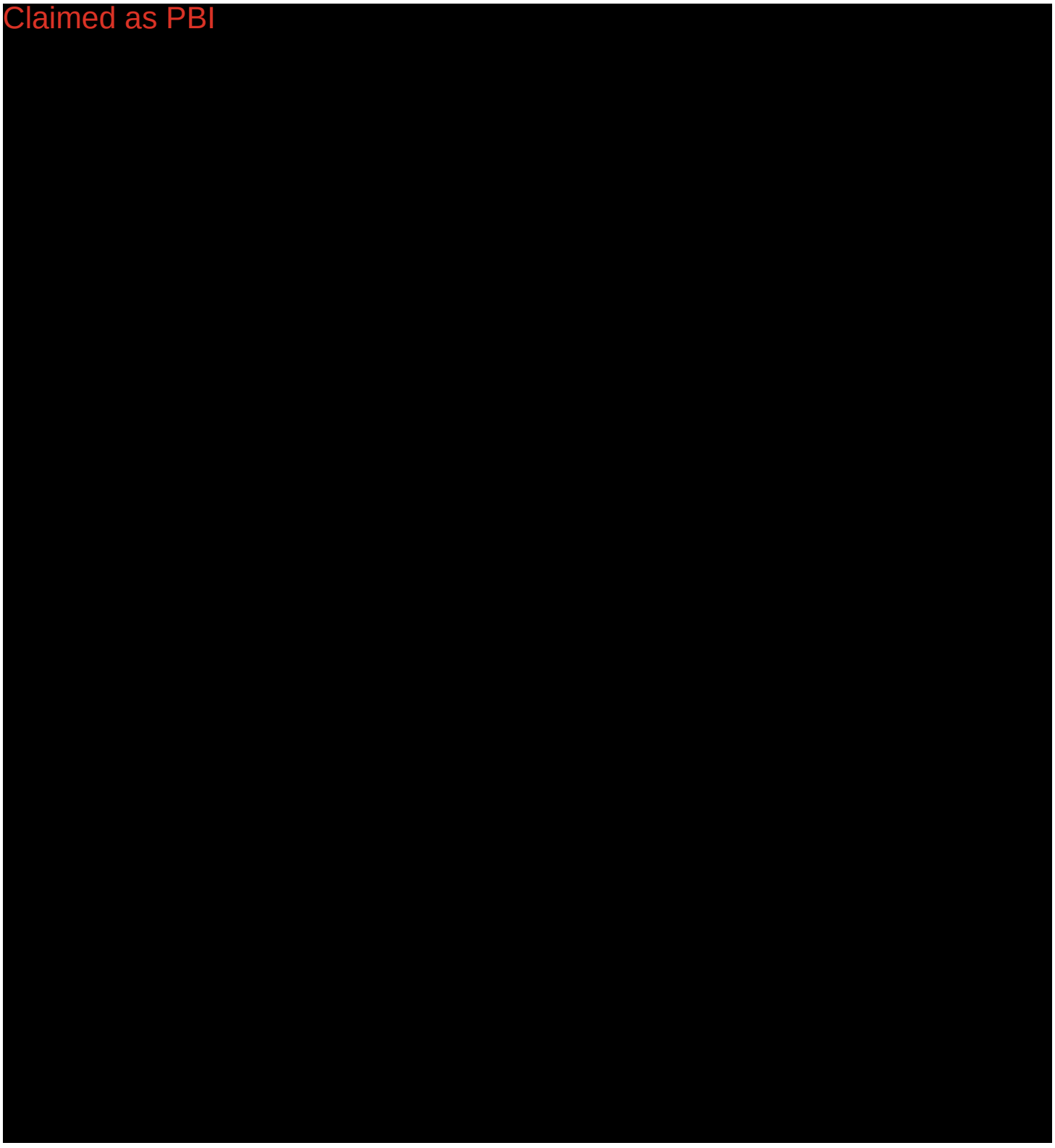
Claimed as PBI



B. Well Construction Plans

5 CONSTRUCTION DETAILS

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CONSTRUCTION DETAILS

BAYOU BEND EAST SL20220050 (BBE)

5.1 Facility Information

Facility Name: BAYOU BEND EAST SL20220050 - PHASE 1 (BBE-P1)
WELL: SL20220050 W1
WELL SURFACE LOCATION: 29.5920225°, -93.89526008°
WELL BOTTOM HOLE LOCATION: 29.5920225°, -93.89526008°

Facility Contact: Claimed as PBI
1500 LOUISIANA STREET, 11TH FLOOR
HOUSTON, TEXAS 77002
Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK 3, 4, 11 AND 12
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

5.2 Introduction

The construction details for the SL20220050 W1 (#W1) are described in this attachment. The values in the table are estimates and may be modified to match the final well and supplier selection details.

The primary information specific to the well construction design is included in the narrative and details specific to each well are referenced in this appendix. The wells will be cased and the casing cemented in compliance with TAC §3.13.

5.3 W1 - Injection Well Construction Details

Claimed as PBI

Coordinate Reference System: NAD 83 Texas South Central

Surface Lat: 29.5920225°
Surface Long: - 93.89526008°
BHL Lat: 29.5920225°
BHL Long: - 93.89526008°

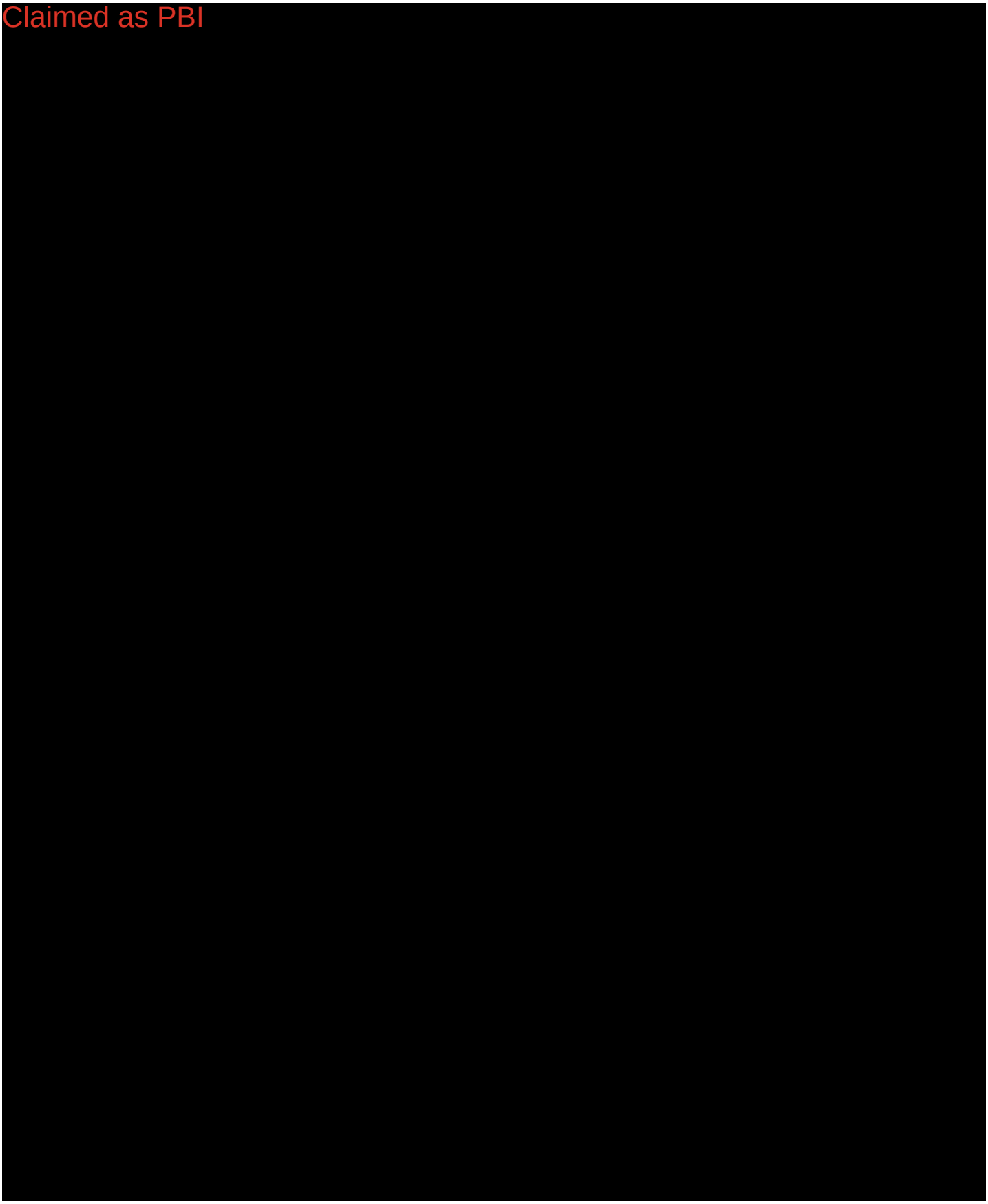
Claimed as PBI



Claimed as PBI



Claimed as PBI



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CONSTRUCTION DETAILS

BAYOU BEND EAST SL20220050 (BBE)

5.1 Facility Information

Facility Name: BAYOU BEND EAST SL20220050 - PHASE 1 (BBE-P1)
WELL: SL20220050 W2
WELL SURFACE LOCATION: 29.59201108°, -93.89528519°
WELL BOTTOM HOLE LOCATION: 29.59189637°, -93.91373689°

Facility Contact: Claimed as PBI

Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK 3, 4, 11 AND 12
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

5.2 Introduction

The construction details for the SL20220050 W2 are described in this attachment. The values in the table are estimates and may be modified to match the final well and supplier selection details.

The primary information specific to the well construction design is included in the narrative and details specific to each well are referenced in this appendix. The wells will be cased and the casing cemented in compliance with TAC §3.13.

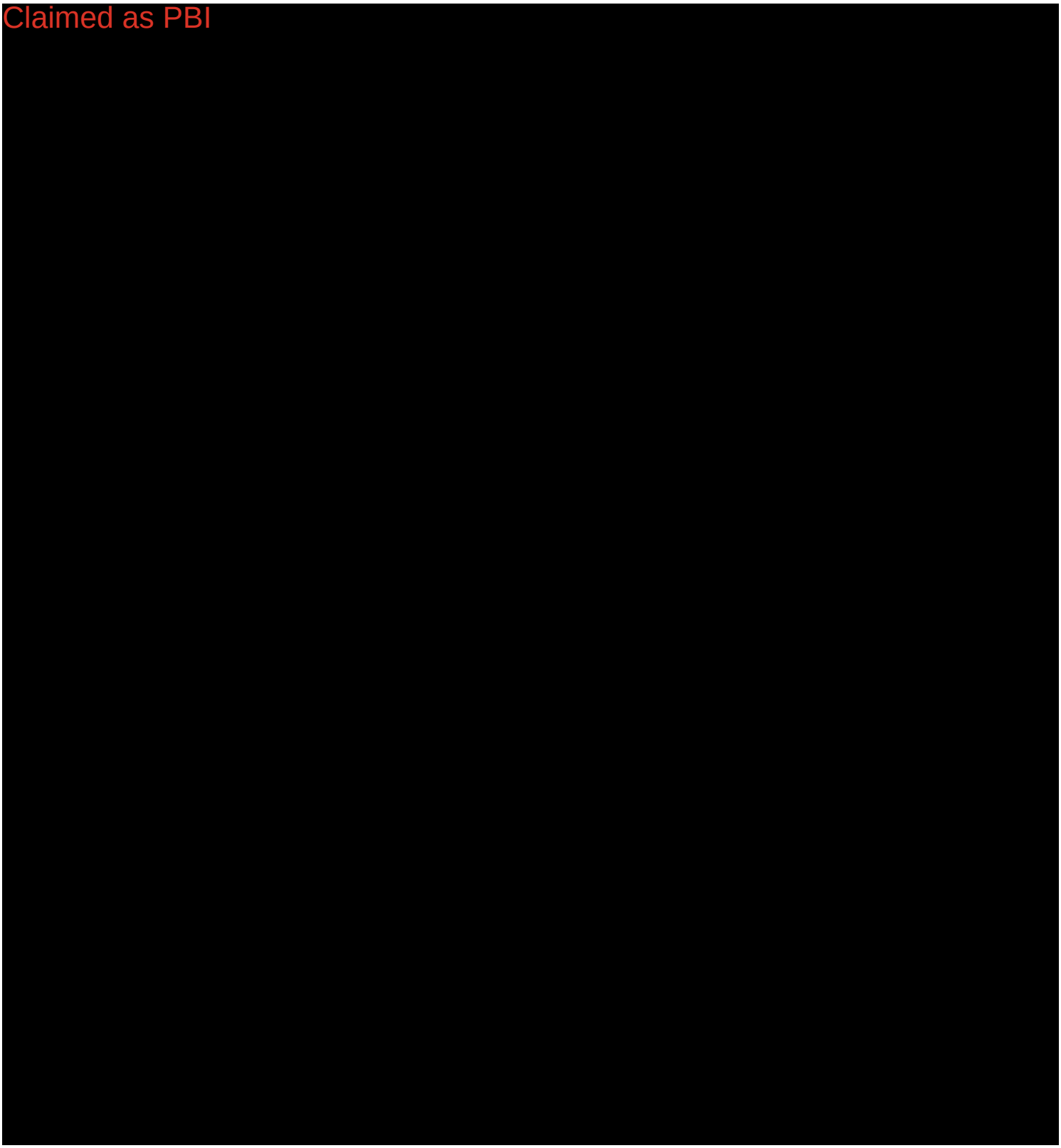
5.3 W2 - Injection Well Construction Details

Claimed as PBI

Coordinate Reference System: NAD 83 Texas South Central

Surface Lat: 29.59201108°
Surface Long: -93.89528519°
BHL Lat: 29.59189637°
BHL Long: -93.91373689°

Claimed as PBI

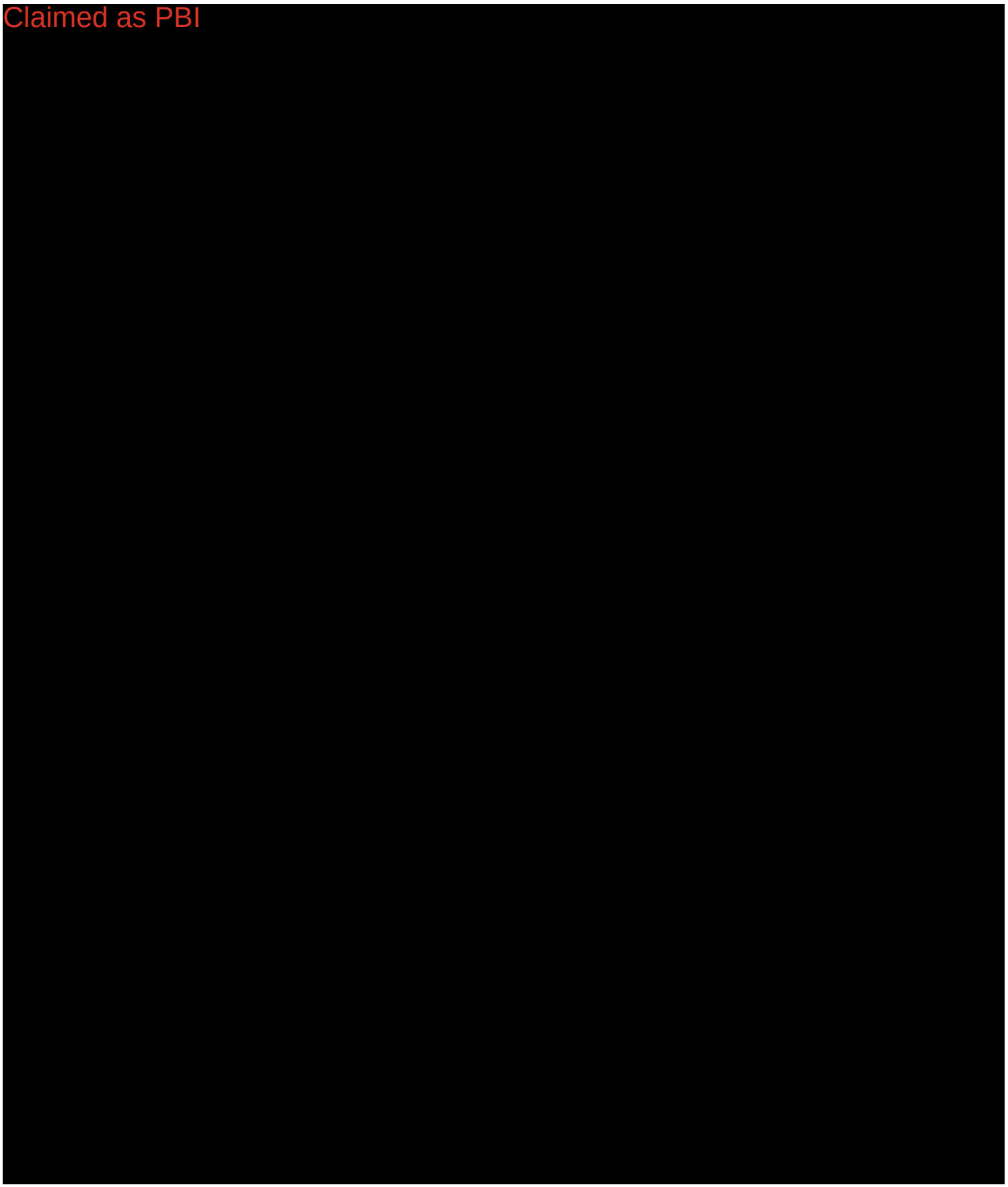


Claimed as PBI



Revision number: 001
Plan revision date: June 2026

Claimed as PBI



Revision number: 002
Plan revision date: July 2026

CONSTRUCTION DETAILS

BAYOU BEND EAST SL20220050 (BBE)

Claimed as PBI

[redacted]

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CONSTRUCTION DETAILS

BAYOU BEND EAST SL20220050 (BBE)

5.1 Facility Information

Facility Name: BAYOU BEND EAST SL20220050 - PHASE 1 (BBE-P1)
WELL: SL20220050 W4
WELL SURFACE LOCATION: 29.5920358°, -93.89528395°
WELL BOTTOM HOLE LOCATION: 29.60861362°, -93.89540328°

Facility Contact: Claimed as PBI

1500 LOUISIANA STREET, 11TH FLOOR

Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK 3, 4, 11 AND 12
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

5.2 Introduction

The construction details for the SL20220050 W4 are described in this attachment. The values in the table are estimates and may be modified to match the final well and supplier selection details.

The primary information specific to the well construction design is included in the narrative and details specific to each well are referenced in this appendix. The wells will be cased and the casing cemented in compliance with TAC §3.13.

5.3 W4 - Injection Well Construction Details

Claimed as PBI

Coordinate Reference System: NAD 83 Texas South Central

Surface Lat: 29.5920358°

Surface Long: -93.89528395°

BHL Lat: 29.60861362°

BHL Long: -93.89540328°

Claimed as PBI



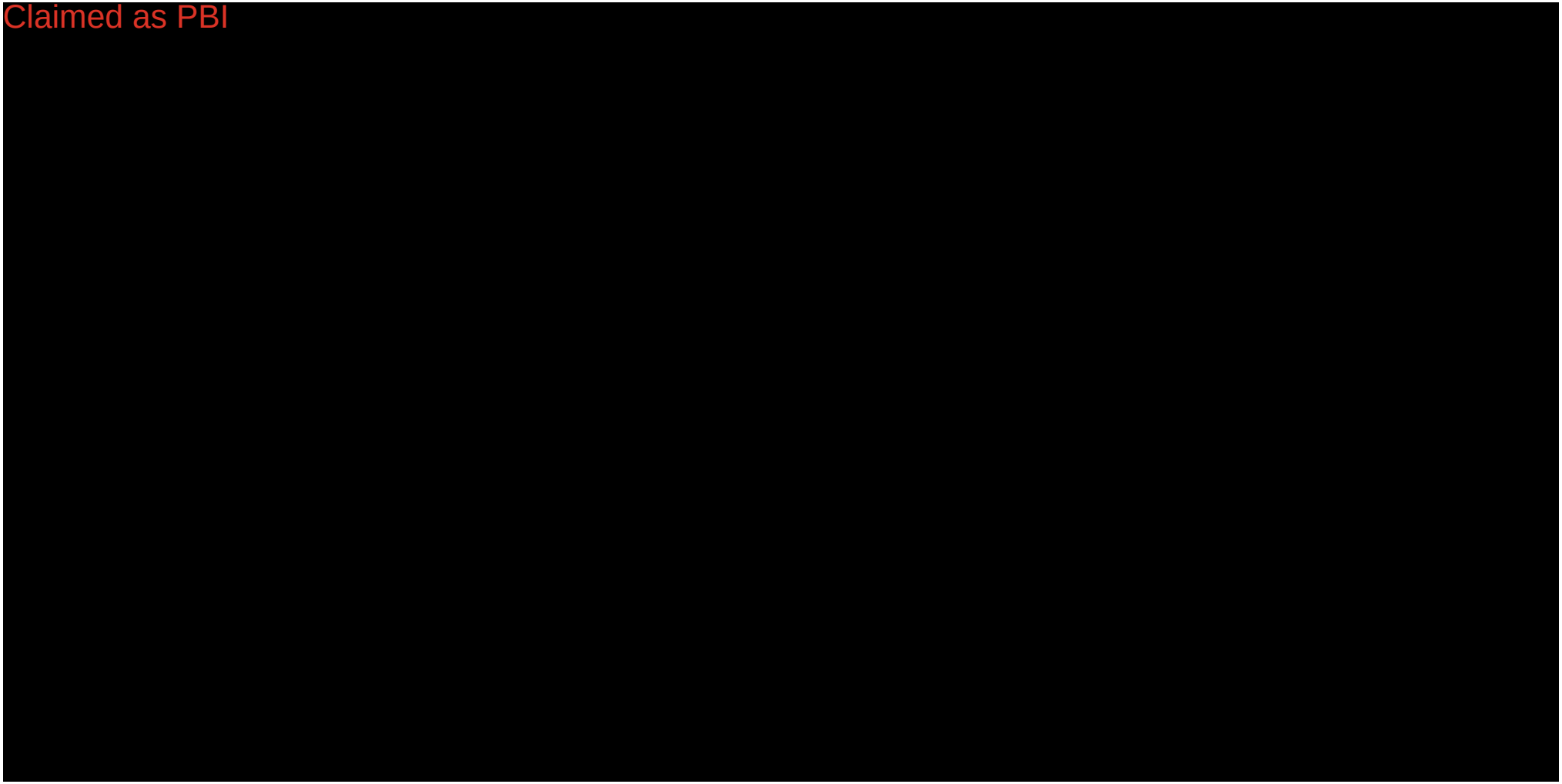
Claimed as PBI



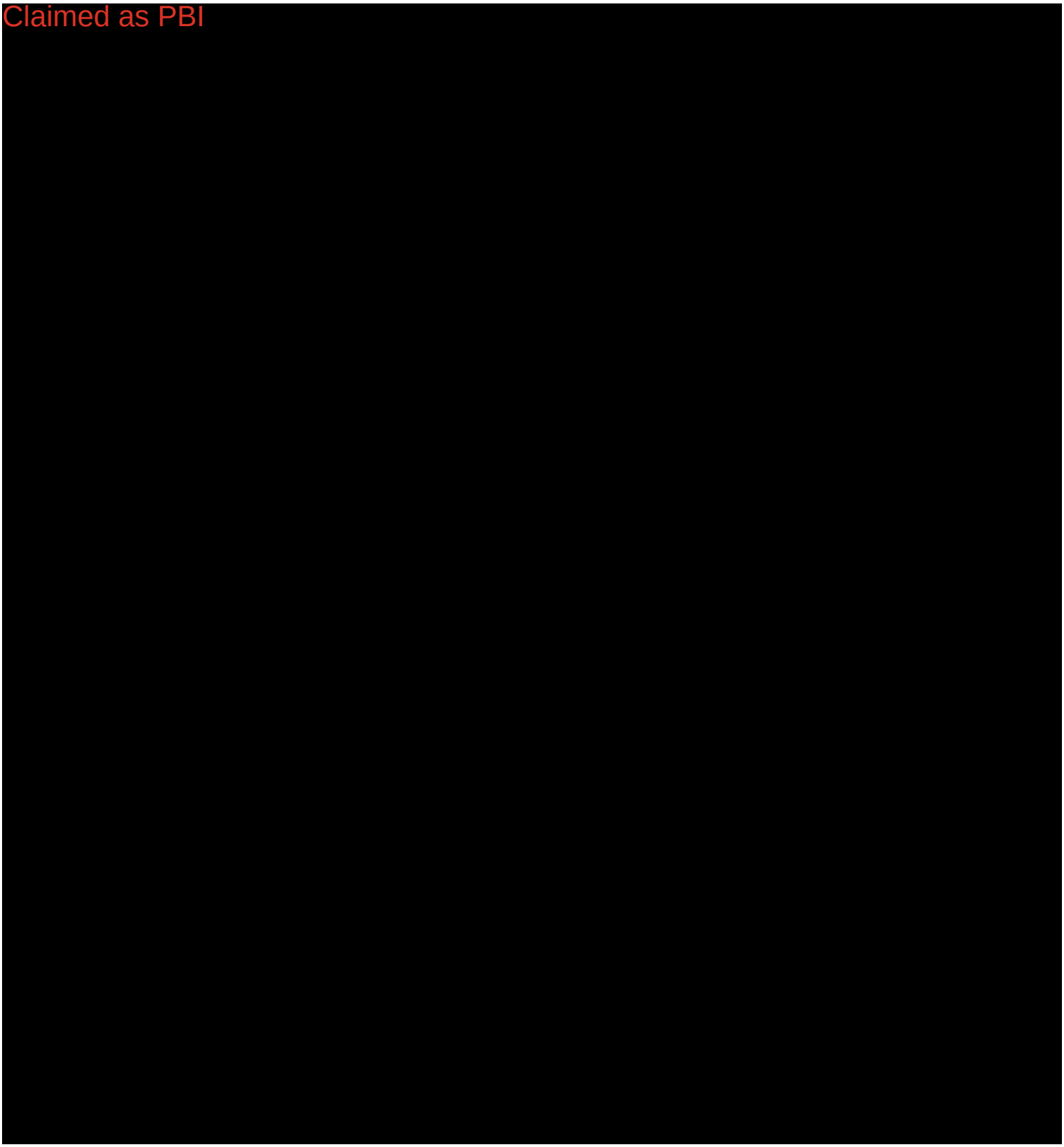
Claimed as PBI



Claimed as PBI



Claimed as PBI



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CONSTRUCTION DETAILS

BAYOU BEND EAST SL20220050 (BBE)

5.1 Facility Information

Facility Name: BAYOU BEND EAST SL20220050 - PHASE 1 (BBE-P1)
WELL: SL20220050 W5
WELL SURFACE LOCATION: 29.59203393°, -93.89523497°
WELL BOTTOM HOLE LOCATION: 29.6039239°, -93.88184566°

Facility Contact: Claimed as PBI
1500 LOUISIANA STREET, 11TH FLOOR
HOUSTON, TEXAS 77002
Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK 3, 4, 11 AND 12
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

5.2 Introduction

The construction details for the SL20220050 W5 are described in this attachment. The values in the table are estimates and may be modified to match the final well and supplier selection details.

The primary information specific to the well construction design is included in the narrative and details specific to each well are referenced in this appendix. The wells will be cased and the casing cemented in compliance with TAC §3.13.

5.3 W5 - Injection Well Construction Details

Claimed as PBI

Coordinate Reference System: NAD 83 Texas South Central

Surface Lat: 29.59203393°

Surface Long: -93.89523497°

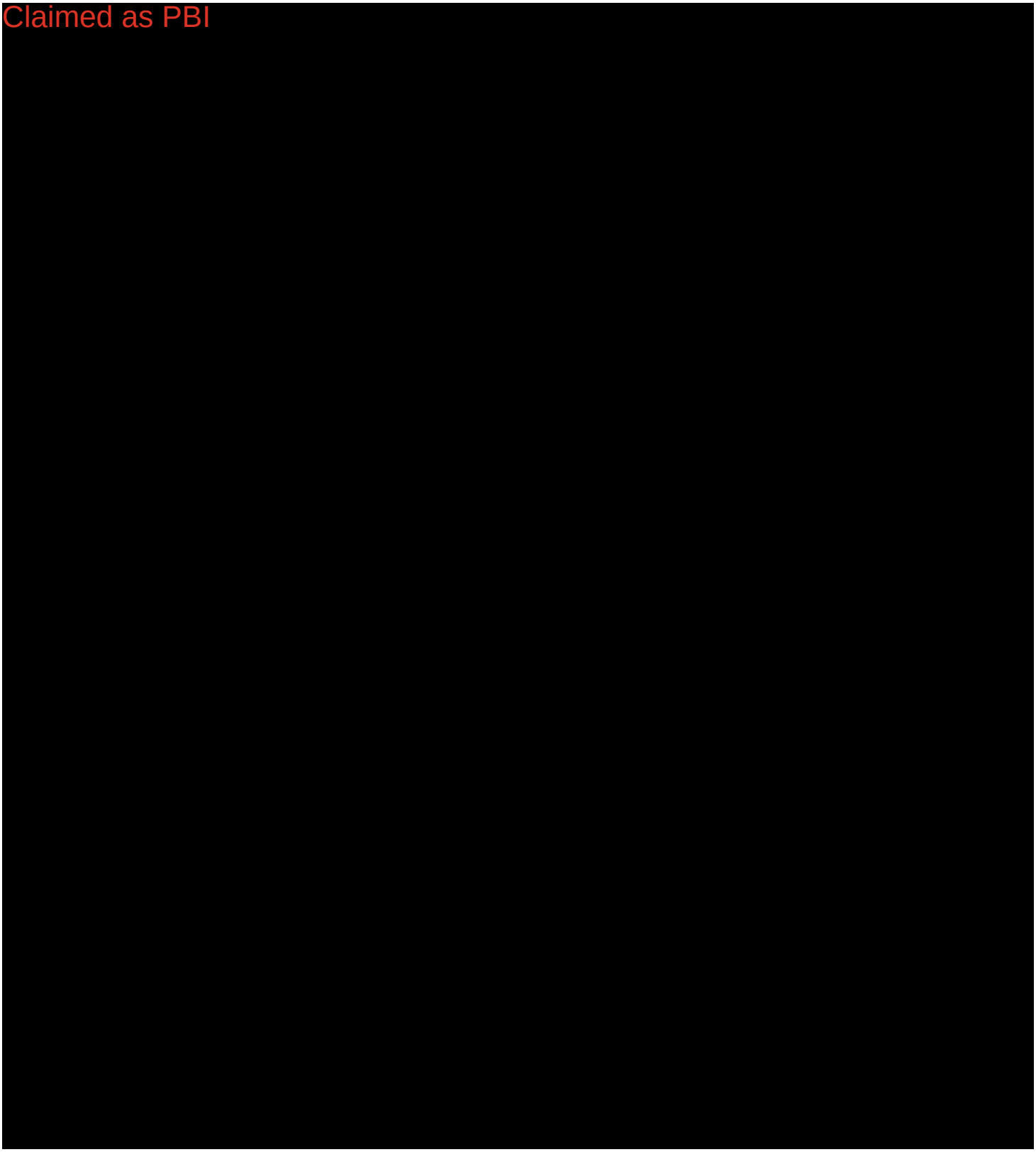
BHL Lat: 29.6039239°

BHL Long: -93.88184566°

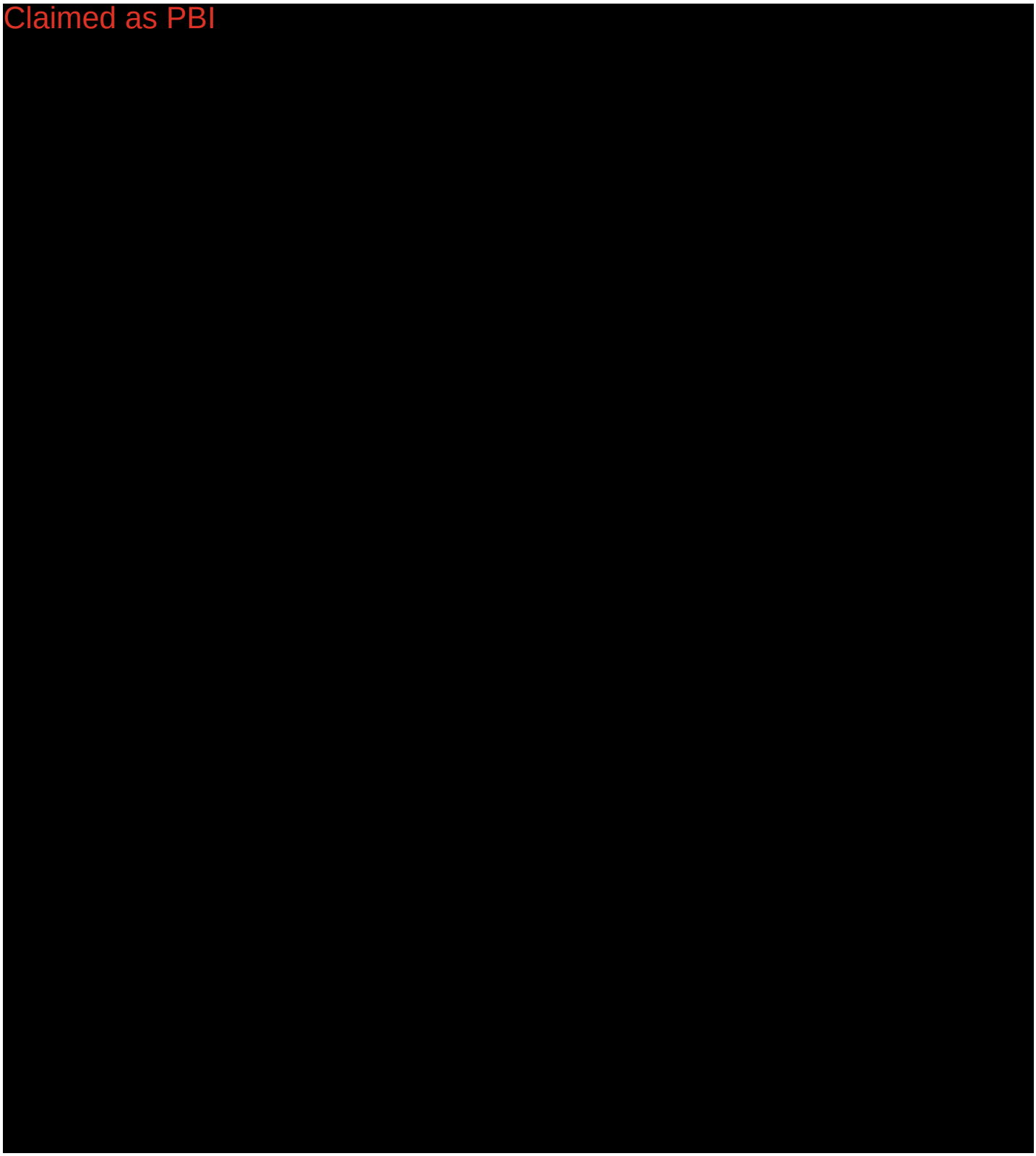
Claimed as PBI



Claimed as PBI



Claimed as PBI



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CONSTRUCTION DETAILS

BAYOU BEND EAST SL20220050 (BBE)

5.1 Facility Information

Facility Name: BAYOU BEND EAST SL20220050 - PHASE 1 (BBE-P1)
WELL: SL20220050 W6
WELL SURFACE LOCATION: 29.59200921°, -93.89523621°
WELL BOTTOM HOLE LOCATION: 29.59215342°, -93.87566908°

Facility Contact: Claimed as PBI
1500 LOUISIANA STREET, 11TH FLOOR
HOUSTON, TEXAS 77002
Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK 3, 4, 11 AND 12
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

5.2 Introduction

The construction details for the SL20220050 W6 are described in this attachment. The values in the table are estimates and may be modified to match the final well and supplier selection details.

The primary information specific to the well construction design is included in the narrative and details specific to each well are referenced in this appendix. The wells will be cased and the casing cemented in compliance with TAC §3.13.

5.3 W6 - Injection Well Construction Details

Claimed as PBI

Coordinate Reference System: NAD 83 Texas South Central

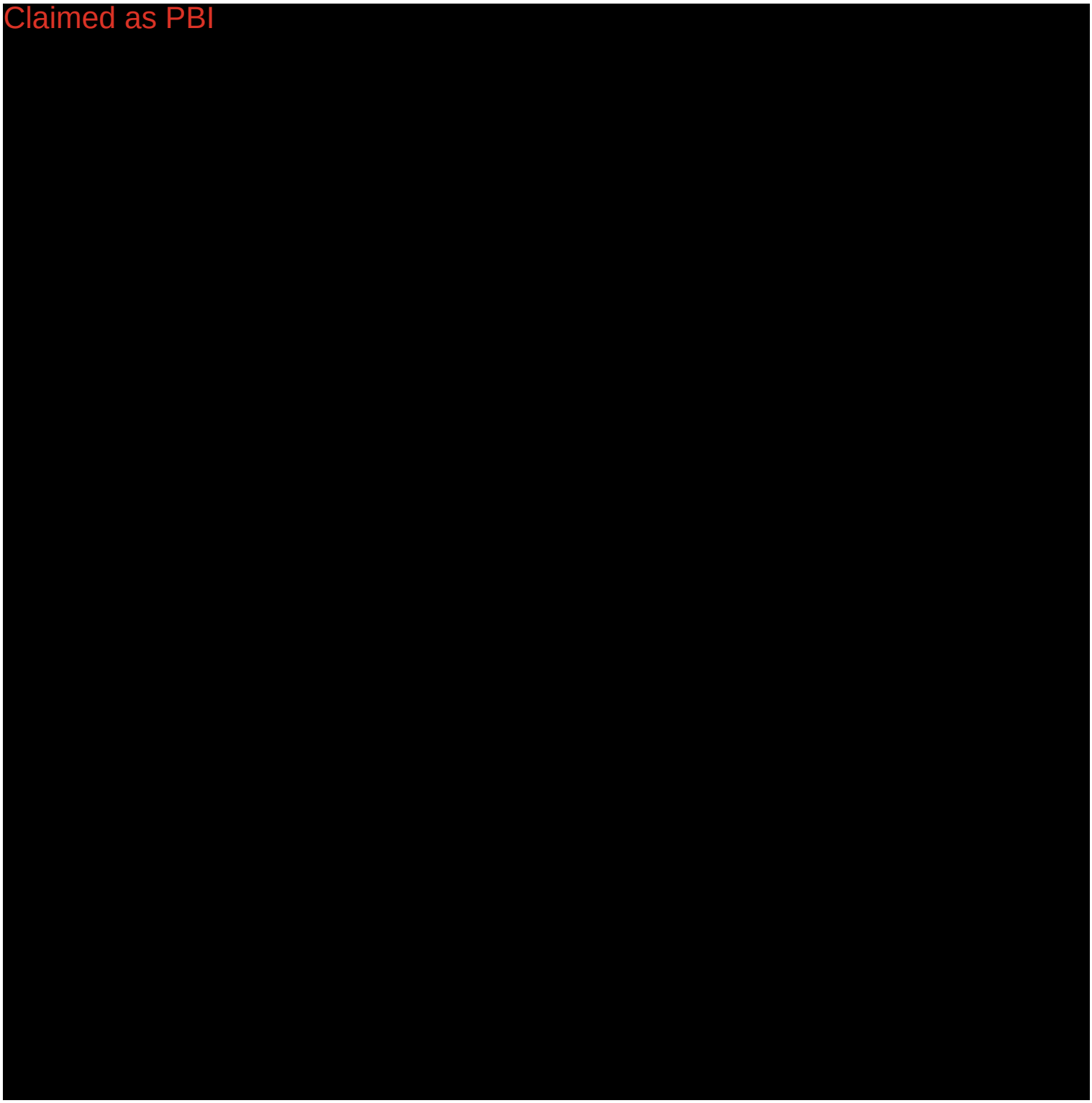
Surface X: 29.59200921°

Surface Y: -93.89523621°

BHL X: 29.59215342°

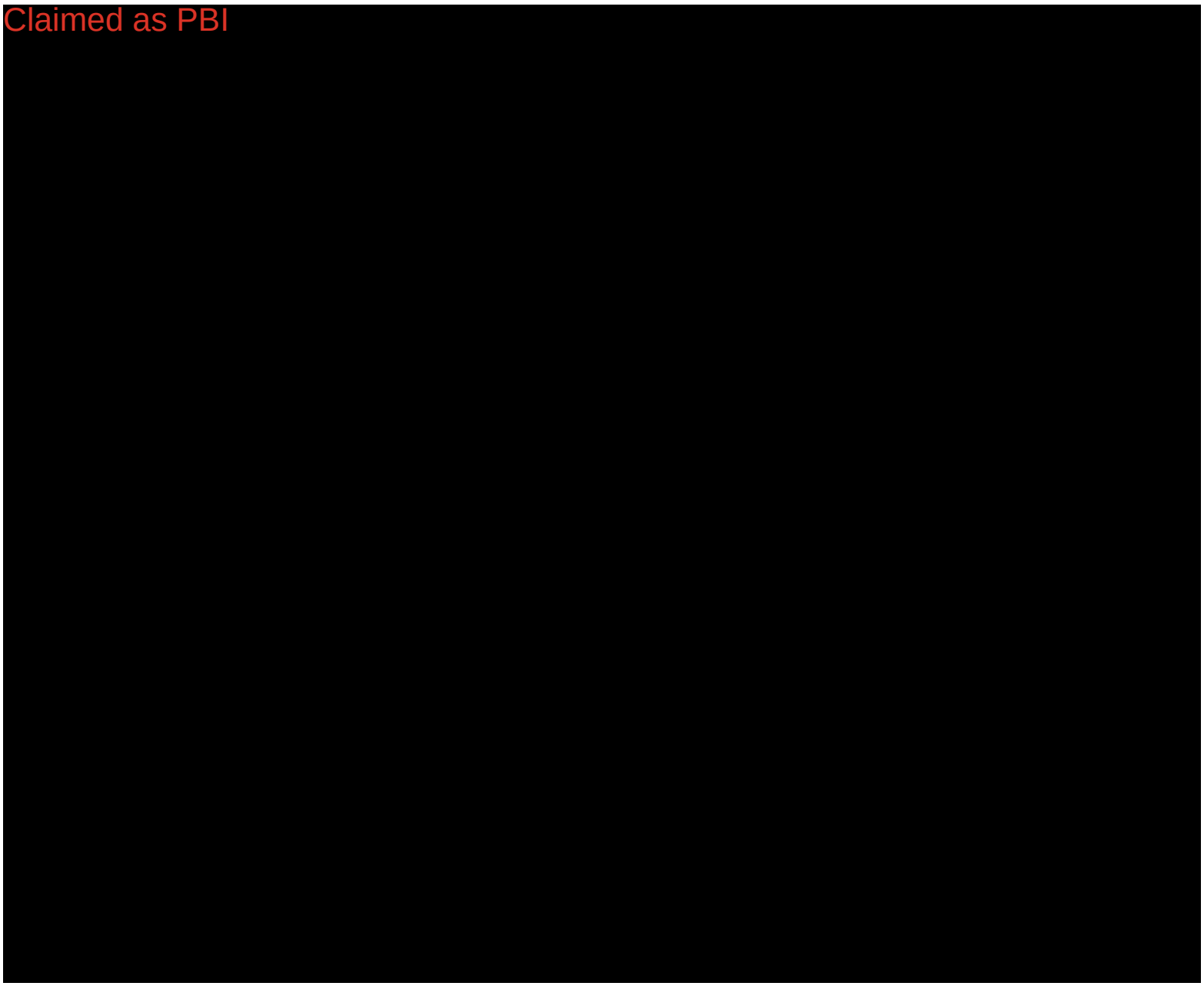
BHL Y: -93.87566908°

Claimed as PBI




Claimed as PBI

Claimed as PBI



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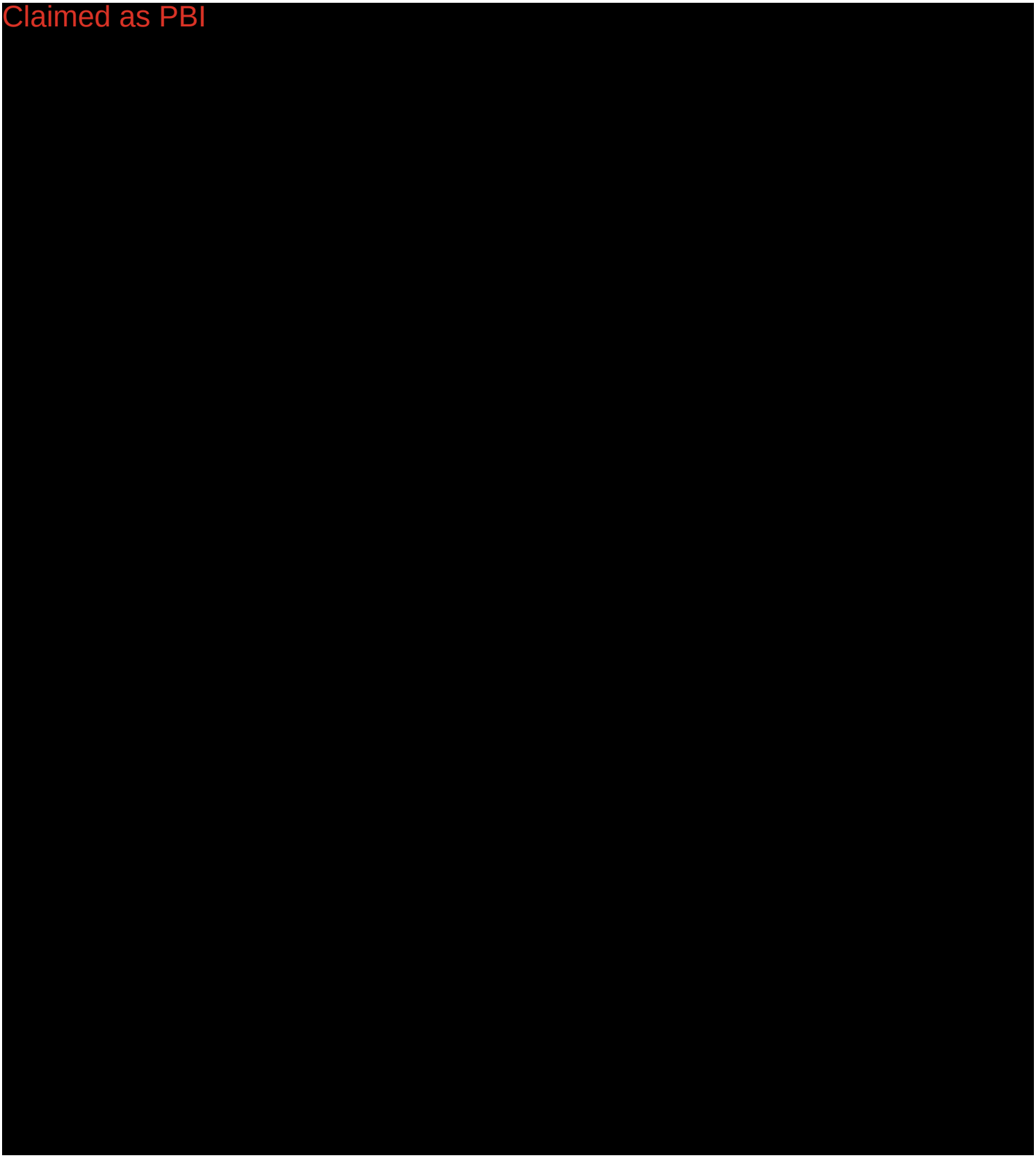

C. Stimulation Plan

Plan revision number: 003
Plan revision date: September 2026

STIMULATION PROGRAM
40 CFR 146.82(a)(9)

BAYOU BEND EAST SL20220050 (BBE)

Facility Information

Facility Name: BAYOU BEND EAST SL20220050 – PHASE 1 (BBE-P1)
SL20220050 W1, SL20220050 W2, SL20220050 W4, SL20220050 W5, SL20220050 W6

Facility Contact: Claimed as PBI
1500 LOUISIANA STREET, 11TH FLOOR
HOUSTON, TEXAS 77002
Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

Stimulation to enhance injectivity is not planned currently at BBE-P1 during initial construction. Data collected during the installation of the injection and monitoring wells will provide additional data for fracture gradient, pore pressure and injectivity to further inform analysis for stimulation needs.

Periodically, enhancement techniques may be necessary to maintain injectivity performance. The techniques may mitigate scale, precipitates, plugging or other impairment sources. Prior to any stimulation, the enhancement fluids will be laboratory tested to ensure compatibilities with reservoir fluids, injection fluids, and tubing and casing materials. These enhancements will remain below 90% of fracture gradient threshold.

If stimulation is needed in the future, a plan will be developed and submitted for review and approval by the UIC Program Director prior to conducting any stimulation.

D. Pre-Injection/Pre-Operational Testing Plan

Revision number: 002
Plan revision date: July 2026

PRE-OPERATIONAL TESTING PROGRAM
40 CFR 146.82(a)
BAYOU BEND EAST SL20220050 (BBE)

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Revision number: 002
Plan revision date: July 2026

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Revision number: 002
Plan revision date: July 2026

6 PRE-OPERATIONAL TESTING PROGRAM
40 CFR 146.82(a)
BAYOU BEND EAST SL20220050 (BBE)

6.1 Facility Information

Facility Mame: BAYOU BEND EAST SL20220050 - PHASE 1 (BBE-P1)
SL20220050 W1, SL20220050 W2, SL20220050 W4, SL20220050 W5, SL20220050 W6

Facility Contact: Claimed as PBI
1500 LOUISIANA STREET, 11TH FLOOR
HOUSTON, TEXAS 77002
Claimed as PBI

Site location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

6.2 Introduction

The logging and testing activities at the five proposed injection wells Claimed as PBI are described in this plan and are restricted to the pre-injection period. Claimed as PBI

Testing and monitoring activities during the operation phase and post-injection period are described in the Testing and Monitoring Plan and the Post-Injection Site Care, respectively.

6.3 Pre-Injection Testing Plan Injection Well(s)

The following tests and logs will be conducted during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The tests and procedures are described below and in the proposed Injection Well Construction Information section of the permit application.

6.3.1 Deviation Checks

Claimed as PBI accordance with Texas Administrative Code §331.82 and 40 CFR 146.87(a)(1).

Claimed as PBI accordance with Texas Administrative Code §331.82 and 40 CFR 146.87(a)(1). If more than 200 ft of surface casing has been run, the Operator may begin the directional survey immediately below the surface casing depth.

6.3.2 Tests and Logs

The following describes tests and logs to be performed during the drilling phase, prior to running casing. The basic logging suite will be run prior to each string of casing. The advanced logging suite and pressures, samples, and stress test will be run prior to running the surface casing, the long string casing and liner.

To be performed during drilling

Tests to be performed during drilling are listed in **Table 6-1**.

Claimed as PBI

Revision number: 002
Plan revision date: July 2026

Claimed as PBI



To be performed during and after casing installation

Tests to be performed during and after casing installation are listed in **Table 6-2**.

Claimed as PBI

[redacted]

Demonstration of mechanical integrity

During well construction, the well will establish mechanical integrity test (MIT) and baseline requirements of the Testing and Monitoring Plan.

For internal mechanical integrity testing, pressure testing of the tubing and casing will be conducted. For external mechanical testing, temperature logs will be run to provide baseline data for comparison to future logging activities. These logs will be conducted while static and geothermal conditions exist before injection occurs. **Table 6-3** is a summary of the MITs and injectivity tests to be performed prior to injection.

Table 6-3: Pre-Operational Testing Schedule.

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT – Internal	Standard Annulus Pressure Test	Prior to Operation
40 CFR 146.89(c)(2)	MIT – External	Temperature Log	Prior to Operation
40 CFR 146.87(e)(1)	Reservoir Test	Pressure Fall-Off Test	Prior to Operation
40 CFR 146.87(e)(3)	Reservoir Test	Injectivity Test	Prior to Operation

Bayou Bend CCS LLC (Operator) will notify EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notice and the opportunity to witness these tests/logs will be provided to EPA at least 48 hours in advance of a given test/log.

6.4 Pre-Injection Testing Plan – Monitoring Wells SL20220050 M1

The monitoring well will be designed for the capability to deliver the Testing and Monitoring Plan requirements over the duration of the injection and monitoring life. The pressure integrity will be confirmed during and after the installation of casing and tubing strings. The pre-operation logging evaluations will confirm external mechanical integrity and establish baseline parameters for comparison against future logs in the Testing and Monitoring Plan.

6.4.1 Tests and Logs

Performed during drilling

Claimed as PBI

[redacted]

Revision number: 002
Plan revision date: July 2026

Claimed as PBI

[redacted]

To be performed during drilling and after casing installation

Tests to be performed during drilling and after casing installation of the monitoring well are listed in **Table 6-5**.

Claimed as PBI



Demonstration of mechanical integrity

Claimed as PBI [redacted]

For internal mechanical integrity testing, pressure testing of the tubing and casing will be conducted following **Table 6-6**. For external mechanical testing, temperature logs will be run to provide baseline data for comparison to future logging activities. These logs will be conducted while static and geothermal conditions exist before injection occurs.

Table 6-6: MIT and the time when the test will be performed, e.g., prior to operation.

Class VI Rule Citation	Monitoring Location(s)	Rule Description	Test Description	Program Period
40 CFR 146.87(a)(4)(i), 40 CFR 146.89(a)(1)	SL20220050 M1	MIT - Internal	Standard Tubing & Casing Test	Prior to Operation
40 CFR 146.87(e)(1)	SL20220050 M1	MIT - External	External Temperature Log	Prior to Operation

Operator will notify EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notice and the opportunity to witness these tests/logs will be provided to EPA at least 48 hours in advance of a given test/log.

6.5 Annulus Pressure Test Procedures for Proposed Injection Wells W1 through W6

An initial casing pressure test will be conducted during the drilling phase utilizing a drilling fluid once the long string and liner are set and cemented in place. After the tubing string and packer are installed, the annulus will be tested with brine to a maximum expected injection pressure plus a safety factor, but not to exceed the design rating of the systems.

Annual Testing Procedure:

1. Shut in injection well to allow annulus to stabilize for 24 hours.
2. The tubing/casing annulus will be filled with fluid, as necessary, and allowed to stabilize.
3. Annular pressure will be increased to the maximum surface injection pressure plus a safety factor. Once pressurized, the annular will be isolated from the pressure source by a closed valve.
4. The annular system will remain isolated for a testing period of 30 minutes. Pressure test measurements will be recorded continuously.
5. Upon a successful test, the pressure will be relieved and the well put back into service.
6. The results will be submitted to the underground injection control (UIC) Program Director.

6.6 Annulus Pressure Test Procedures for Monitoring Well SL20220050 M1

An initial casing pressure test will be conducted during the drilling phase utilizing a drilling fluid once the long string is set and cemented in place. After the tubing string and packer are installed, the annulus will be tested with brine to a maximum expected pressure plus a safety factor, but not to exceed the design rating of the systems.

Annual Testing Procedure:

1. Shut in monitoring well to allow annulus to stabilize for 24 hours.
2. The tubing/casing annulus will be filled with fluid, as necessary, and allowed to stabilize.
3. Annular pressure will be increased to a surface pressure plus a safety factor not to exceed the system integrity. Once pressurized, the annular system will be isolated from the pressure source by a closed valve.
4. The annular system will remain isolated for a testing period of 30 minutes. Pressure test measurements will be recorded continuously.
5. Upon a successful test, the pressure will be relieved and the well put back into service.
6. The results will be submitted to the UIC Program Director.

6.7 Pressure Fall-Off Test Procedures for Proposed Injection Wells W1 through W6

Pressure fall-off and injection tests will be completed on each injection well after construction but prior to carbon dioxide (CO_2) injection. Test results will be submitted to the UIC Program Director electronically within 30 days of the test.

Procedure:

1. Well will be filled with fluid compatible with the injection zone.
2. The fluid will be pumped at various injection rates to establish injectivity performance and reservoir parameters using surface and downhole gauges measuring pressure and temperature. Maximum operating pressure will not be exceeded.
3. The injection rate will then be held constant while maintaining stable operating conditions prior to the fall-off test shut in period.
4. Injection will be stopped and shut in at the wellhead. Any other offset injectors will be held at constant injection rates which will be continuously recorded during the test.
5. Downhole gauges will measure pressure and temperature continuously during the duration of the test until pressure dissipates to initial reservoir conditions.
6. After the test is complete, the well will remain shut in.

6.8 Additional Information

6.8.1 Acronyms

BBE	Bayou Bend East SL20220050
BBE-P1	Bayou Bend East SL20220050 – Phase 1
CCS	carbon transport and sequestration
CO_2	carbon dioxide
MIT	Mechanical Integrity Test
UIC	Underground Injection Control

E. Injection Well Operating Conditions

WELL OPERATION

Well Operation procedures for BBE are provided below, meeting the requirements in 40 CFR 146.82(a)(7) and (10) and 40 CFR 146.88.

Operating Data

Source of CO_2

CO_2 for injection will be sourced from industrial emitters in the area. The emitters will be responsible for the capture and compression of the CO_2. Emitters will be required to meet contractual requirements for impurity and contaminants limits as well as pressure and temperature requirements. Modeling for the established CO_2 composition was done to ensure compatibility with metallurgies in the system, consistent and manageable physical properties, and injectability. Continuous monitoring of the injectant composition and physical properties will be done in multiple parts of the system.

Chemical and Physical Characteristics

Below is a description of the required composition and characteristics of the CO_2 that will be received from emitters to be transported and injected. The CO_2 will be gathered in the dense phase where it behaves like a liquid. This allows for more efficient transport. The physical and chemical characteristics of the injection stream are projected to be a Claimed as PBI [redacted]

Daily Rate and Volume and/or Mass and Total Anticipated Volume and/or Mass of the CO_2 Volume

For the first year of injection, the yearly injection rate per well will be 1.5 MTA. This equates to a daily CO_2 flow rate when the system is operational of approximately 20,548 tonnes per day (t/d) or 4,110 t/d per well. After the first year, the rate will reduce to 1.2 MTA per well, equating to a daily system CO_2 flow rate of 16,438 t/d or 3,288 t/d per well. A total projection of 121.5 MMT of CO_2 will be injected at the BBE site.

Pressure and Temperature of CO_2 Delivered to the Storage Site

The facility system will be designed to accommodate a free flow delivery system of CO_2 from onshore facilities to the wellheads at the offshore platform. The critical pressure and temperature of pure CO_2 will be 1070.6 psia and 87.9°F respectively. As such, the CO_2 product will be supercritical leaving the facilities. Fluid behavior at these conditions will be considered in the design.

Operational Procedures [40 CFR 146.82(a)(10)]

The Operator performed studies to estimate the operational procedures and pressure limits (**Table 7-1)**. The studies include regional geomechanical evaluation to assess critical fracture pressure, subsurface reservoir modeling, and injection pressure modeling with CO_2 phase behavior. These values will be finalized and confirmed after construction of the injection wells (Section 2.5).

Claimed as PBI

[redacted]

Additional details regarding fracture pressure and injection pressure are provided in the AOR and Corrective Action document Section 3.2.

Maximum Wellhead Injection Pressures are referenced in Narrative Section 5.2.2.

Claimed as PBI

[redacted]

Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

CO_2 for injection will be sourced from industrial emitters in the area. The emitters will be responsible for the capture and compression of the CO_2. Claimed as PBI [redacted] The CO_2 stream will be continuously monitored using an online analyzer downstream of the collection point at each facility. Physical samples of the gas will also be collected and sent to a laboratory. These characteristics will be monitored quarterly to meet the requirements of 40 CFR 146.90(a) [Testing and Monitoring Plan, Section 7.3].

Alarms and Automatic Shutoff Systems

A comprehensive array of alarms and automatic shut-off systems to maintain operational safety and ensure compliance with permitted operating parameters have been incorporated into the plan. These systems are integrated with the Process Automation System (PAS) and the Process Control System (PCS), both of which are responsible for monitoring, controlling, and managing emergency responses associated with CO2 injection operations. The design philosophy centers on early identification of deviations and rapid, automated intervention, which helps to protect the integrity of the CO_2 storage system.

Automatic Shut-Off Systems

Automatic shut-off capabilities have been included in the systems design to quickly isolate affected segments or wells in response to alarm conditions. The injection platform will be equipped with hydraulically actuated shutdown valves and surface safety valves that will close automatically upon receiving emergency shutdown signals, experiencing loss of hydraulic power, or detecting downhole exceeding maximum allowable injection pressure. These valves are designed to fail in the closed position, enhancing containment security. High and low flow alarms, along with high- and low-pressure inputs, are managed through a control loop to regulate flow to each injection well.

At the platform, an annulus monitoring system will support the five injection wells, suitable for offshore operation. Pressure and temperature monitoring, alarms, and shutdown signals will be routed back to the platform PAS, which provides both safety and process-related interlocks, including start/stop and open/close sequencing for equipment. A loss of level within a vessel or an increase in pressure indicating loss of long string casing integrity triggers well isolation procedures to maintain safety.

Integration and Operator Interaction

Alarms and automatic shut-off systems are interconnected through programmable logic controllers and communicate to a remote-control center which will be manned 24 hours each day. Operators will have access to real-time data and can intervene manually, when necessary, although the system is engineered to respond autonomously to critical deviations from permitted operating gradients. Acoustic emitters supply audible warnings at sites, and emergency shutdown buttons will be available for manual activation in staffed locations. The PAS ensures that safety and process controls will be accessible both locally and remotely. System redundancy is provided by uninterruptable power supplies, which will maintain functionality during power outages.

F. Testing and Monitoring Plan

Plan revision number: 002
Plan revision date: July 2026

TESTING AND MONITORING PLAN
40 CFR 146.90

Bayou Bend East SL20220050

PBI CROSSWALK FOR BAYOU BEND EAST CLASS VI APPLICATION

Plan Number	Plan Document Title	Contains PBI
07	Testing and Monitoring Plan	Yes
	Appendix 7-1: Quality Assurance and Surveillance Plan	Yes
	Appendix 7-2: Testing and Monitoring Plan Figures	Yes

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LIST OF APPENDICIES

Claimed as PBI

[redacted]

7 TESTING AND MONITORING PLAN
40 CFR 146.90

Bayou Bend East SL20220050

7.1 Facility Information

Facility Name: BAYOU BEND EAST SL20220050 – PHASE 1 (BBE-P1)
SL20220050 W1, SL20220050 W2, SL20220050 W4, SL20220050 W5, SL20220050 W6

Facility Contact: Claimed as PBI
1500 LOUISIANA STREET, 11TH FLOOR
HOUSTON, TEXAS 77002
Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

7.2 Introduction

This Testing and Monitoring Plan describes how Bayou Bend CCS LLC (Operator) will monitor the Bayou Claimed as PBI 40 CFR 146.90. In addition to demonstrating that the wells are operating as planned and the CO_2 saturation and pressure front are moving as predicted, the monitoring data will be used to validate and adjust the reservoir simulation models used to predict the distribution of the CO_2 within the injection zone to support Area of Review (AOR) reevaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan (ERRP).

7.3 Overall Strategy and Approach for Testing and Monitoring

7.3.1 Testing and Monitoring Plan Objectives

The Operator has developed a comprehensive Testing and Monitoring Plan to assess Claimed as PBI

The direct and indirect testing and monitoring tracking proposed methods to be used at BBE-P1 and required per 40 CFR 146.90(g)(1) and (2) are provided in **Table 7-1**. These methods are discussed in the following sections.

Claimed as PBI



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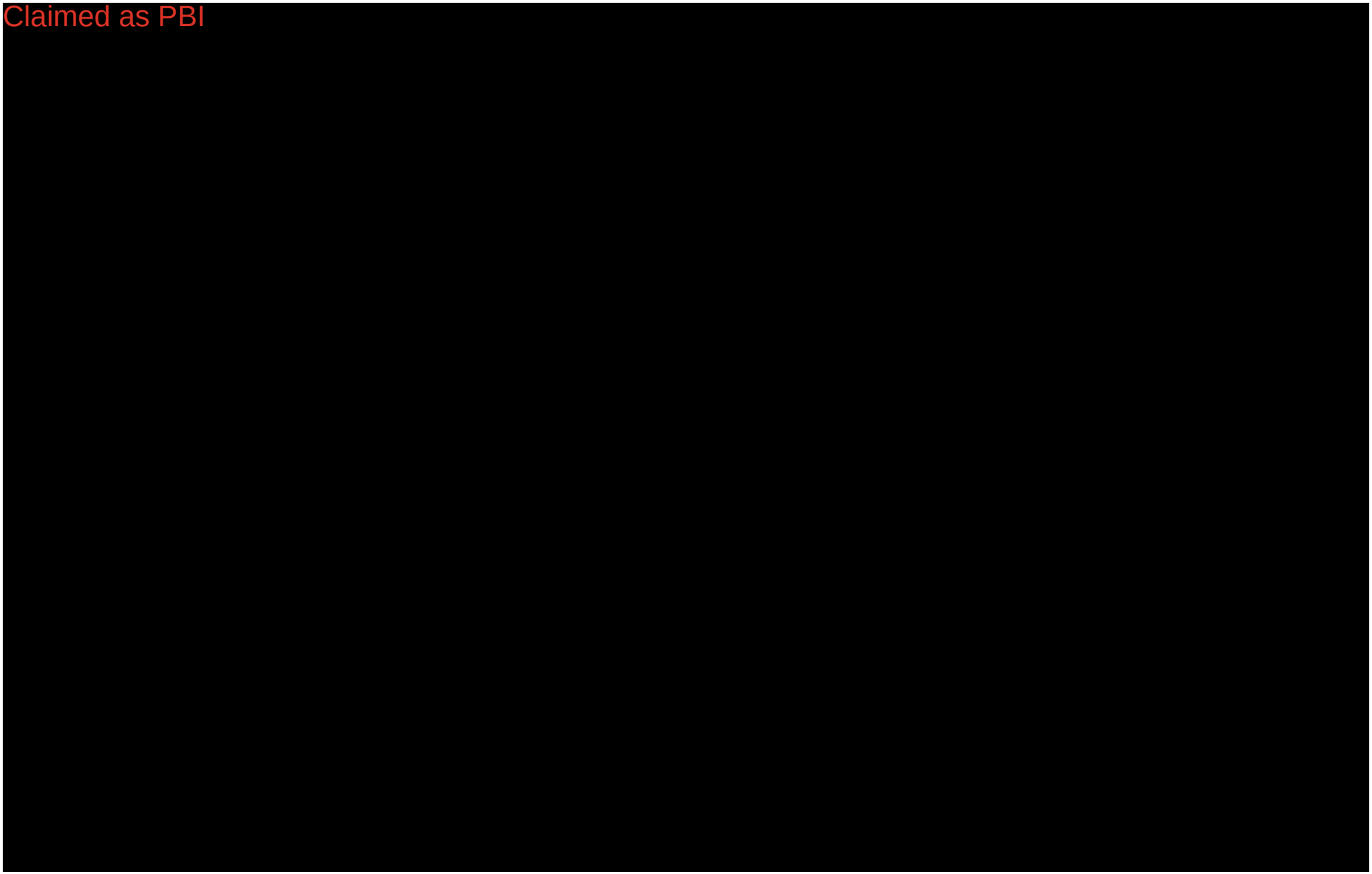


Claimed as PBI

[redacted]

7.3.3 Monitoring Network Design and Strategy

Figure 7-2 below is a schematic diagram illustrating the monitoring plan that the Operator will deploy at

Claimed as PBI

[redacted]

Table 7-2 provides a list of monitoring techniques and their frequency during the different stages of the project. The following sections provide additional details on each methodology.

Claimed as PBI

[redacted]

Table 7-2: Summary of monitoring methodologies and monitoring frequencies for baseline and injection phases.

Monitoring Category	Monitoring Method		Baseline Frequency (1 year)	Injection Phase Frequency (20 years)*
Monitoring Plan Update	Reviewed every 5 years; Updated as required		N/A	As required
CO_2 Injection Stream Analysis	Monitoring of injection stream chemical composition		N/A	Quarterly
CO_2 Injection Process Monitoring	Continuous monitoring of injection process (e.g., injection rate, pressure, and temperature; annulus pressure)		N/A	Continuous
Hydrogeologic Testing	Injection well pressure fall-off testing		1 after well completion	1 per every 5 years
Injection Well Mechanical	*Internal***	Continuous annulus pressure monitoring of pressurized annulus	1 after well completion	Continuous

Claimed as PBI

[redacted]

**Monitoring technologies and reporting frequencies provided in this permit may change, pursuant to UIC Program Director approval based on monitoring data, technology, well/equipment failures, and/or regulatory changes.*

***Internal integrity tests refer to annular space and pressure monitoring. External integrity tests refer to casing and temperature logging.*

7.3.4 Quality assurance procedures

A quality assurance and surveillance plan (QASP) for testing and monitoring activities, required pursuant to 40 CFR 146.90(k), is provided in **Appendix 7-1**.

7.3.5 Reporting procedures

The Operator will provide testing and monitoring results to the UIC Program Director in compliance with the requirements under 40 CFR 146.91.

7.4 Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

The CO_2 stream will be analyzed during the operation phase to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a).

7.4.1 Sampling location and frequency

Claimed as PBI [redacted] other equipment will affect the CO_2 stream at this point, so the analyzer will be exposed to the same CO_2 stream as the wellhead, any downhole equipment, and formation solids and fluids. Physical samples of the gas will also periodically be taken and sent to a qualified laboratory.

Baseline data will be collected quarterly during the first year of injection. No significant changes are anticipated in the CO_2 stream throughout the injection period. However, if significant changes are detected by monitoring equipment, the Operator will make the appropriate operational actions, including but not limited to, collecting laboratory samples, and temporarily shutting in the facility. The operating Central Gathering Facility procedures will outline a plan to identify the cause of the change, assess the impact on the project, and implement corrective actions.

Claimed as PBI [redacted]

7.4.2 Analytical parameters

The Operator will analyze the CO_2 for the constituents identified in **Table 7-3** using the methods listed.

Claimed as PBI [redacted]

Claimed as PBI

[redacted]

7.4.3 Sampling methods

Samples of the CO_2 stream will be collected downstream of the process equipment, at the beginning of the pipeline to the wellhead. This will ensure that the samples are the same CO_2 composition and pressures that will be injected. Samples will be collected in gas cylinders, or equivalent.

7.4.4 Laboratory to be used/chain of custody and analysis procedures

CO_2 stream samples will be collected in gas cylinders, or equivalent, and sent to a qualified laboratory for analysis of the parameters (**Appendix 7-1**). A standardized chain-of-custody form will be used to track the samples from collection to disposal. A copy of the form will be provided to the person or qualified laboratory receiving the samples as well as the person or qualified laboratory transferring the samples. These forms will allow for easy tracking of sample status and will be archived. Detailed instructions on sampling processes, including sample collection, handling, transportation, analysis, and disposal are provided in the QASP (**Appendix 7-1**).

7.5 Continuous Recording of Operational Parameters [40 CFR 146.88I(1), 146.89(b) and 146.90(b)]

The Operator will install and use on each injector continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the CO_2 stream, as required at 40 CFR 146.88I(1), 146.89(b), and 146.90(b).

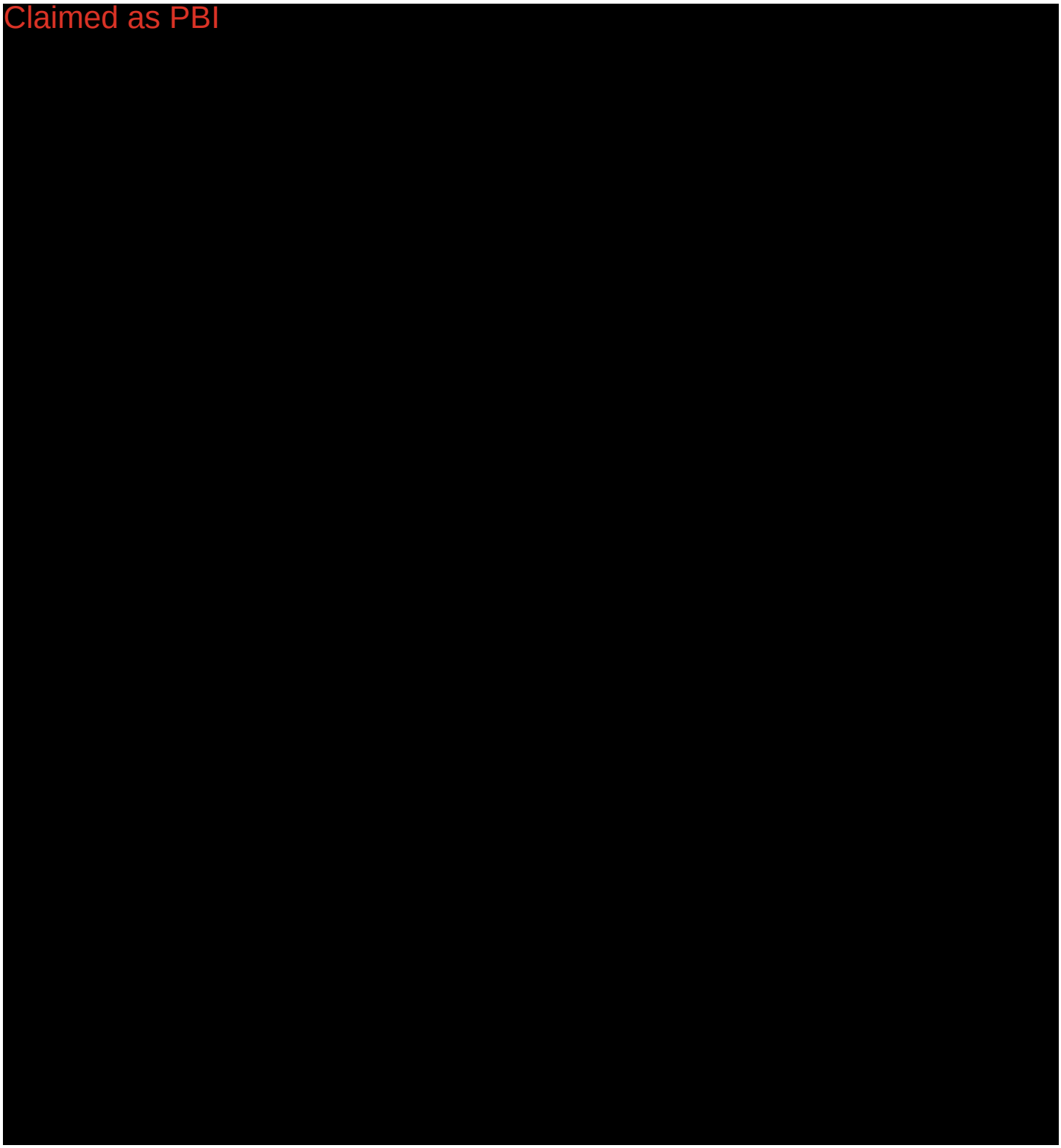
7.5.1 Monitoring location and frequency

The Operator will perform the activities Claimed as PBI [redacted] operational parameters and verify internal mechanical integrity of the injection well. Monitoring will take place at the locations and frequencies shown in the table.

If an anomaly occurs within one of the operating parameters below, available data will be interrogated to determine the most plausible cause of the anomaly and inform any next steps to be taken by the Operator.

Claimed as PBI [redacted]

Claimed as PBI



7.5.2 Monitoring details

Continuous Recording of Wellhead Injection Pressure and Temperature

The CO_2 injection pressure and temperature will be monitored on a continuous basis at each wellhead to ensure that injection pressures do not exceed the calculated maximum allowable injection pressure (MAIP) [Narrative, Table 7-1], determined, in part, by using 90% of the fracture pressure of the injection zone per 40 CFR146.88 (a).

Continuous Recording of Injection Rate

The rate of CO_2 injection into the wells will be monitored by flowmeters located on the injection piping at each injector wellhead, upstream of the choke. The flowmeters will be connected to the Supervisory Control and Data Acquisition (SCADA) system for continuous monitoring and control of the CO_2 injection rate into each well.

Injection Volume

The injection volume into the reservoir will be calculated on a continuous basis based on the injection mass. The pressure and temperature conditions will be accounted for at the measurement. The volume calculated will be used in the computational models to determine storage capacity, flow within the reservoir, and volumes sequestered.

Continuous Recording of Annular Pressure

As described in the Pre-Operational Testing Plan [Section 6.5], the annular pressure will be tested prior to operation by conducting an internal mechanical integrity test. During operations, the pressure on the annulus between the injection tubing and the long-string casing will be measured continuously by an electronic pressure gauge mounted on wellhead. The gauge will be connected to the well control system and the SCADA system to monitor the annular pressure.

Recording of Annulus Fluid Volume

The volume of the annulus fluid between the injection tubing and the long-string casing will be calculated and confirmed during well construction. The annular pressure is expected to fluctuate as atmospheric and injection stream temperatures change during startup, injection, and shutdown operations. The fluid will be added to or removed from the annulus to maintain the pressure in the annulus downhole higher than the pressure inside the tubing, while maintaining a positive pressure in the annulus at surface within a planned range. If fluid volumes must be added or removed to maintain annular pressure during injection, those volumes will be recorded and submitted to the Underground Injection Control (UIC) Program Director.

Continuous Recording of CO_2 Stream Temperature

The temperature of the CO_2 injection stream will be continuously measured using an electronic temperature gauge. The gauge will be mounted to the injection piping at each wellhead and will be electronically connected to the SCADA system. The gauge will be calibrated prior to the start of injection operations and calibrated annually. The thermocouple for measuring surface injection temperature will be recalibrated annually or it will be replaced with a calibrated thermocouple.

7.6 Corrosion Monitoring

To meet the requirements of 40 CFR 146.90(c), the Operator will monitor well materials during the operation phase for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance.

The Operator will monitor corrosion using corrosion coupons. Collection and analysis of samples will be done according to the description below.

7.6.1 Monitoring location and frequency

Corrosion coupons composed of the same material as the well components be placed in discharge piping of the Central Gathering Facility that will go into the injection pipeline. The coupons will be exposed to the same fluid that will be injected into the well. The coupons will be checked on a quarterly basis for signs of corrosion for the first year after injection; sampling beyond that will be determined from initial results and/or industry preferences. Coupons could be checked more frequently if there are operational concerns or other factors that change during injection.

Coupons will be checked for loss of mass, thickness, cracking, pitting, and other signs of corrosion that may be indicative of future potential integrity issues. If signs of corrosion are identified in the coupons, this will trigger further well integrity testing.

7.6.2 Sample description

Table 7-5 below is the list of well construction components and material of construction. There will be a corrosion coupon for each unique material.

Claimed as PBI

[redacted]

7.6.3 Monitoring details

The corrosion monitoring system will be located downstream of the injection pumps onshore, at the beginning of the pipeline to the wellhead. Each material sample will be attached to a separate holder and inserted into a flow-through pipe arrangement continuously during operation. This will ensure that the samples are exposed to the same CO_2 composition that will be seen at the wellhead and injection tubing; temperatures and pressures will be comparable to those at the wellhead. The holders and location of the

system will be included in the Central Gathering Facility design and will allow for continued injection during sample removal.

At the frequency outlined in Section 7.6.1, each coupon will be carefully examined and measured to assess the extent of corrosion, following a standardized procedure. Each coupon will be photographed, visually inspected, dimensionally measured to within 0.0001 inches, and weighed to within 0.0001 grams, following the American Society for Testing and Materials (ASTM) G1-03 Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens (Re-approved 2017).

7.7 Above Confining Zone Monitoring

The Operator will monitor ground water quality and geochemical changes above the confining zone during the operation phase to meet the requirements of 40 CFR 146.90(d).

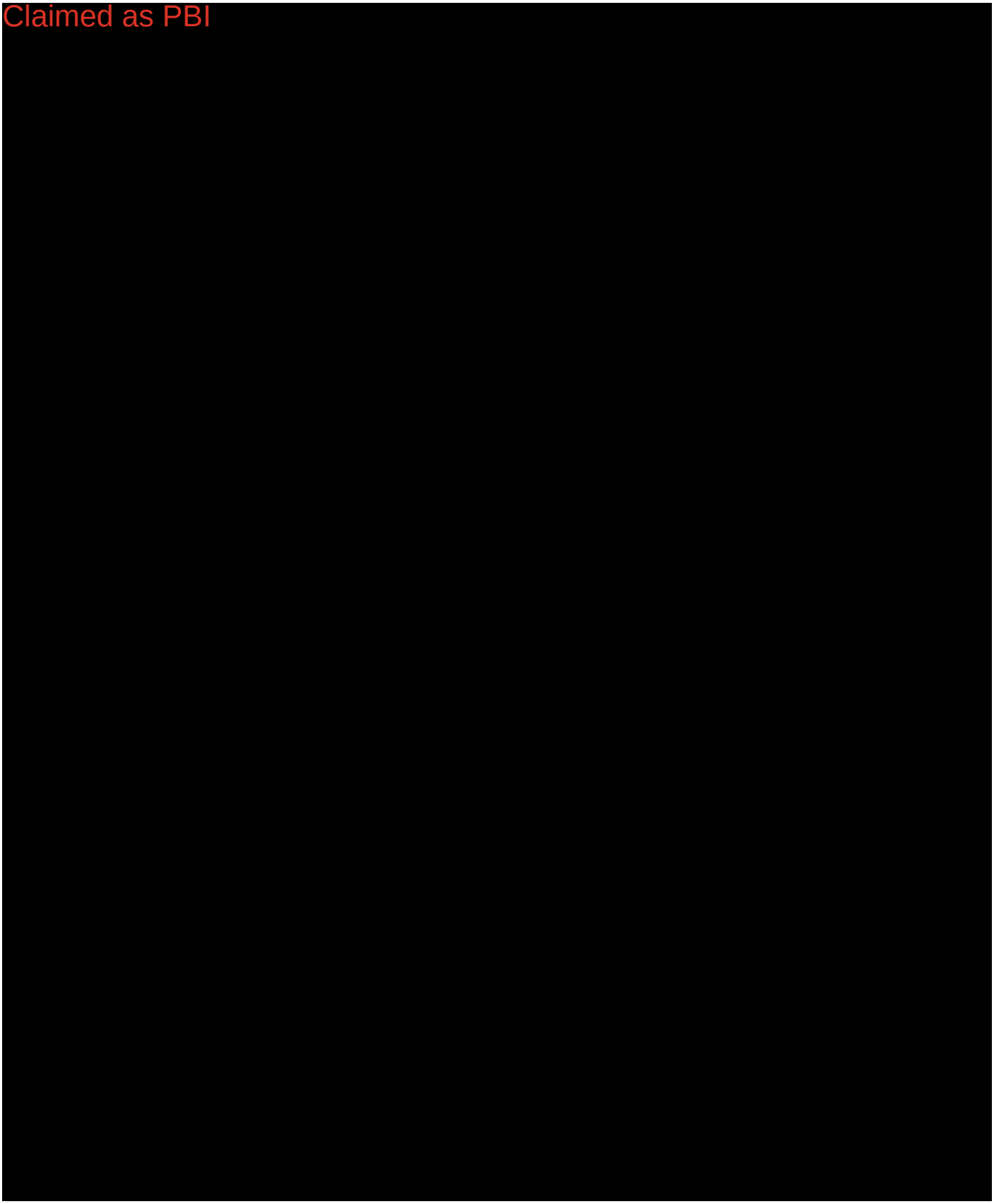
7.7.1 Monitoring location and frequency

Table 7-6 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone.

Claimed as PBI

[redacted]

Claimed as PBI



7.7.2 Analytical parameters

Table 7-7 identifies the parameters to be monitored and the analytical methods Operator will use.

An extensive suite of groundwater parameters will be analyzed quarterly for up to one year prior to the start of injection to capture natural seasonal variability. This suite includes natural intrinsic tracers such as ions, dissolved gases, and isotopes that can be used to determine whether a foreign brine or gas has invaded the groundwater.

After the start of injection, a shorter suite of groundwater parameters will be analyzed once every two years or as needed. An evaluation of the results from the baseline data collection will be used to inform which parameters will be included in this shorter suite. However, the shorter suite will likely include the parameters listed in the "During and Post-injection" section of **Table 7-7**.

The range of concentrations measured during the baseline period will be used to evaluate geochemical changes in the groundwater once injection begins. Geochemical measurements are influenced by a variety of factors including natural and offset industry-induced fluctuations in the groundwater as variability due to sampling and laboratory procedures. For these reasons, multiple sources of evidence are needed to evaluate whether a change has occurred.

Mercury will be analyzed during baseline, but low detections should be considered suspect due to potential contamination from the well casing or during sampling. Zinc will also be analyzed during baseline as it is commonly found in tubing and pipe dope, and there is potential for sample contamination.

Once the project has established baseline conditions, monitoring may be reduced to a subset of analytes that are most likely to change due to interactions with CO_2. Any modification to the parameter list in **Table 7-7** will be made in consultation with the UIC Program Director.

Table 7-7. Summary of analytical and field parameters for groundwater samples.

Claimed as PBI

Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Sr, Tl, Zn, Ca, Fe, K, Mg, Na, Si, B	ICP-MS, EPA Method 6020B, ICP, EPA Method 6010D
Anions: Br, Cl, F, NO_3, NO_2 and SO_4	Ion chromatography, EPA Method 300.0
Alkalinity (total and bicarbonate)	SM 2320B
Total dissolved solids	SM 2540C
Water density (lab)	
Water density (field)	hydrometer
pH (lab)	SM 4500 H+B
pH (field)	Standard Method 4500-H+ B-2000
Specific conductance (lab)	

Parameters	Analytical Methods*
Specific conductance (field)	Standard Method 2510 B-1997
Temperature (field)	Thermistor, Standard Method 2550 B-2000
Turbidity (lab)	
Turbidity (field)	Nephelometric – Optical, 90° Scatter
Oxidation-Reduction Potential (field)	Platinum Button; Ag/AgCl Reference
Dissolved Oxygen (field)	ASTM Method D888-09 I
Dissolved Inorganic Carbon (DIC)	SM 5310B
$^{228}Ra/^{226}Ra$	EPA Method 901.1
$^{87}Sr/^{86}Sr$	ICP-MS
$\delta^{18}O$ and $\delta^{2}H$ of H_2O	Analyzed via CRDS
$\delta^{13}C$ of DIC	IRMS
^{14}C of DIC**	AMS
Dissolved CO_2, N_2, Ar, O_2, He, C1-C6+, by headspace	Isotech/Stratum SOP, similar to RSK-175
$\delta^{13}C$ of CO_2	Isotech/Stratum
$\delta^{13}C$ and $\delta^{2}H$ of Methane, Ethane, Propane	High precision (offline) analysis via Dual Inlet IRMS
Sulfide	SM4500
Dissolved Noble Gasses (He, Ne, Ar, Kr, Xe)	Noble Gas Mass Spectrometry
Total Petroleum Hydrocarbons	EPA 8015B with silica gel cleanup
Ammonium	EPA 350.1
Mercury	EPA 245.1, 245.2
Acetate	
Propionate	
Butyrate	
Claimed as PBI [redacted]	
pH (lab)	
pH (field)	Standard Method 4500-H+ B-2000
Specific conductance (lab)	
Specific conductance (field)	Standard Method 2510 B-1997
Temperature (field)	Thermistor, Standard Method 2550 B-2000
Alkalinity (total and bicarbonate)	SM 2320B
Oxidation-Reduction Potential (field)	Platinum Button; Ag/AgCl Reference
Total dissolved solids	SM 2540C

Parameters	Analytical Methods*
Cationes: Al, Ba, Mn, As, Cr, Pb, Se, Sr, Tl, Zn, Ca, Fe, K, Mg, Na, Si, B	ICP-MS, EPA Method 6020B, ICP, EPA Method 6010D
Anions: Br, Cl, F, and SO_4	Ion chromatography, EPA Method 300.0
Alkalinity (total and bicarbonate)	SM 2320B
Dissolved Inorganic Carbon (DIC)	SM 5310B
$\delta^{13}C$ of DIC	IRMS
Water density (lab)	
Water density (field)	hydrometer
Turbidity (lab)	
Turbidity (field)	Nephelometric – Optical, 90° Scatter
Sulfide (lab)	
* Analytical methods subject to change with approval from UIC Program Director **Specialized analysis we may collect less than frequently depending on results ***Analyte list may change depending on results from baseline assessment	

7.7.3 Sampling methods

Sampling will be performed in accordance with the QASP (**Appendix 7-1**). Claimed as PBI [redacted]

Field measurements for pH, temperature, conductance, and dissolved oxygen will be monitored and recorded. Samples will be preserved and sent to the qualified laboratory via the chain of custody procedures (**Appendix 7-1**).

7.7.4 Laboratory to be used/chain of custody procedures

The geochemical analyses and the isotopic analyses will be performed by qualified laboratories that meet the standards and guidelines set forth in the QASP (**Appendix 7-1**). Samples will be tracked using appropriately formatted chain-of-custody forms.

7.8 External Mechanical Integrity Testing

The Operator will conduct at least one of the tests presented in **Table 7-8** periodically during the injection phase to verify external mechanical integrity as required at 40 CFR146.89(c) and 146.90(e). In combination with the robust well and barrier design [Narrative 5.2.2, Well Design], MITs will verify no significant fluid movement is observed through channels adjacent to the injection well bore.

7.8.1 Testing location and frequency

Claimed as PBI

[redacted]

The mechanical integrity testing frequency reduction time will be proposed to the UIC Program Director after baseline and historical data demonstrate a satisfactory trend.

7.8.2 Testing & Monitoring details

Claimed as PBI

[redacted]

monitoring surface tubing and annular pressures and temperatures to identify any anomalies or possible leaks (**Table 7-3**).

7.8.3 External MIT via logging

The preliminary testing procedures for the wireline well logs in **Table 7-8** will follow Operator and industry standards. The procedures will be approved by the UIC Program Director prior to commencing MIT operations.

The following procedure will be used for logging:

1. If necessary, shut in well to allow for wellbore stabilization.
2. Move in and rig up wireline unit and pressure control equipment.

3. Run the log by lowering the tool from surface to the injection zone at a rate meeting the logging tool performance specifications.
4. Pull the logging tool from the injection interval to surface to take readings at defined locations or full wellbore in agreement with the UIC Program Director.
5. Perform repeat passes, as necessary, to provide wellbore coverage.
6. Rig down and move out wireline unit.
7. Log results will be interpreted and submitted to the UIC Program Director.

7.9 Pressure Fall-Off Testing

The Operator will perform pressure fall-off tests during the injection phase as described below to meet the requirements of 40 CFR 146.90(f).

7.9.1 Testing location and frequency

A pressure fall-off test is planned for, at a minimum, once every five (5) years on each operational injection well and at the end of the injection period. Results of the pressure fall-off tests will be submitted to the UIC Program Director electronically within 30 days of the test. The pressure fall-off testing procedure is described below.

7.9.2 Testing details

Operator will perform pressure fall-off testing with the procedure below.

1. Hold injection rate constant while maintaining as stable operating conditions as possible prior to the fall-off test shut in period. Do not exceed the maximum operating pressure.
2. Shut in well at the wellhead, or as near to the wellhead as feasible. Claimed as PBI [redacted] injection rates for the duration of the test.
3. Continuously measure pressure using downhole pressure gauges for the duration of the test. Conduct the test over a sufficient time period in which pressure is no longer influenced by wellbore storage or skin.

7.10 Carbon Dioxide Saturation Front and Pressure Front Tracking

The Operator will employ direct and indirect methods to track the extent of the CO_2 saturation front and the presence or absence of elevated pressure during the operation phase to meet the requirements of 40 CFR 146.90(g) (**Table 7-1**).

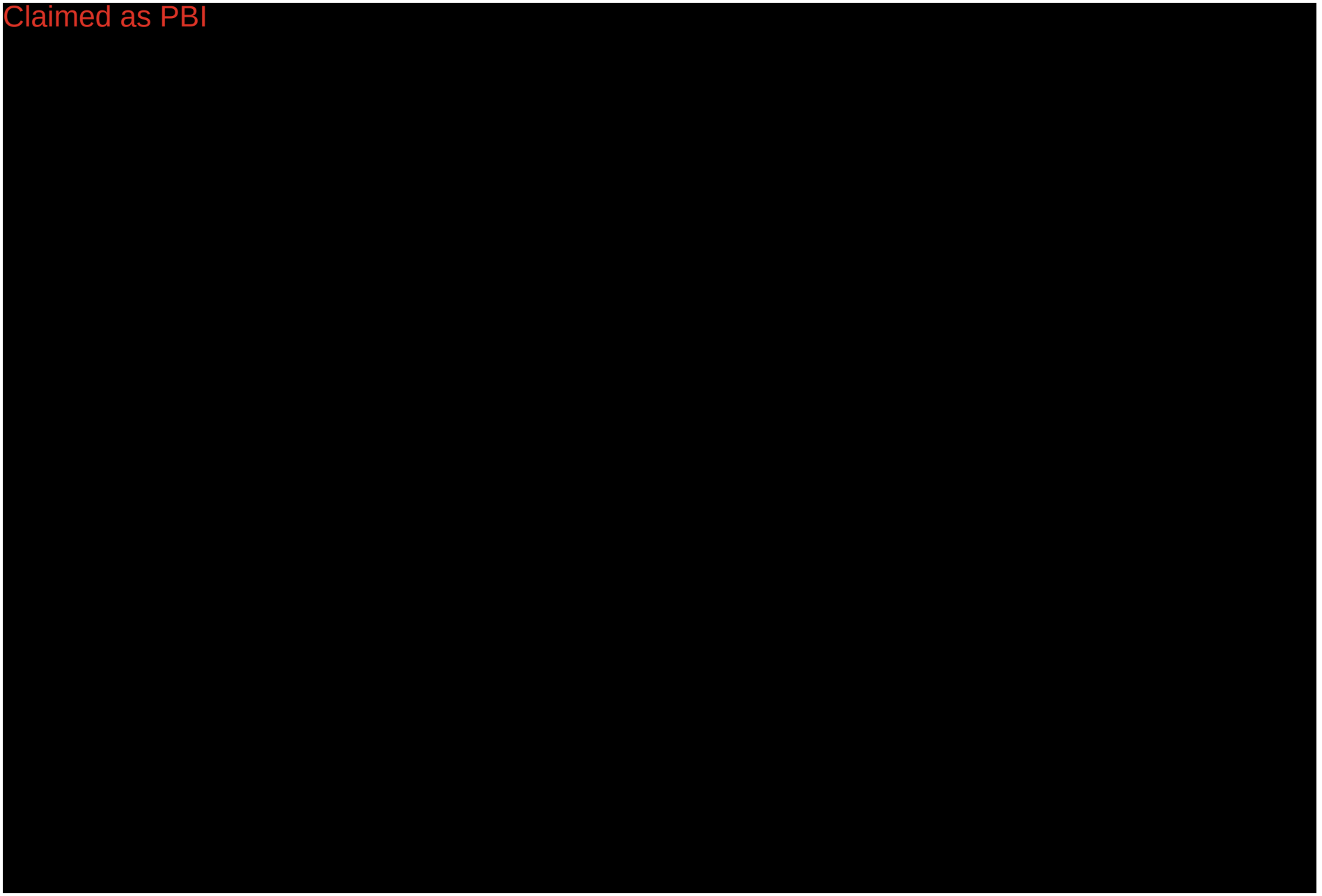
7.10.1 Saturation front monitoring location and frequency

Table 7-9 presents the methods that the Operator will use to monitor the position of the CO_2 saturation front, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in **Table 7-10**. Quality assurance procedures for these methods are presented in the QASP (**Appendix 7-1**).

Claimed as PBI [redacted]

Due to the shallow water depths, the Operator has determined Claimed as PBI [redacted]

Claimed as PBI



7.10.2 Saturation front monitoring details

Claimed as PBI is expected to interact with the formation and its fluids.

Claimed as PBI

will be delivered in the form of laboratory reports. **Table 7-10** identifies the parameters to be monitored and the analytical methods Operator will use. Additional fluid sampling details can be found in the QASP (**Appendix 7-1**).

Claimed as PBI

Table 7-10. Summary of analytical and field parameters for fluid sampling in the injection zone.

Parameters	Analytical Methods
Claimed as PBI	
Total Alkalinity	SM 2320B
Organic Acids (Acetate, Propionate, Butyrate)	APHA SM 5560B
Dissolved sulfide	SM4500
lab pH (25°C)	SM 4500 H+B
Total Dissolved Solids	SM 2540C
Water Density	Density Meter (ASTM D4052/D5002)
Conductivity	U.S. EPA Method 120.1 (Same as APHA SM 2510B and ASTM D1125-95(A)).
Turbidity (lab)	U.S. EPA Method 180.1 (Same as APHA SM 2130B)
Temperature (field)	Field instrument
Dissolved Inorganic Carbon (DIC)*	Standard Method 5310B
$d^{13}C$ Dissolved Inorganic Carbon	Gas Bench/CF-IRMS
dD & $d^{18}O$ H_2O	Analyzed via CRDS
Hydrogen sulfide	ASTM D5623
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Sr, Tl, Zn, Ca, Fe, K, Mg, Na, Si, B, S	ICP-MS, EPA Method 6020B, ICP, EPA Method 6010D
Anions: Br, Cl, F, NO_3, NO_2, SO_4 and PO_4	Ion chromatography, EPA Method 300.0
$\delta^{13}C$ of dissolved Methane, Ethane, Propane, and CO_2, δ^2H of Methane	High precision (offline) analysis via Dual Inlet IRMS
Dissolved CO_2, N_2, Ar, He, O_2, C1 – C6+ by headspace	Lab in-house SOP, similar to RSK-175

7.10.3 Pressure-front monitoring location and frequency

Table 7-11 presents the methods that Operator will use to monitor the position of the pressure front, including the activities, locations, and frequencies Operator will employ (**Appendix 7-1**)

The pressure front will be monitored Claimed as PBI

7.10.4 Pressure-front monitoring details

Claimed as PBI

Claimed as PBI

7.11 Appendix: Quality Assurance and Surveillance Plan

The Quality Assurance and Surveillance Plan for the Testing and Monitoring Plan is provided in **Appendix 7-1**.

7.12 Additional Information

7.12.1 Acronyms

Claimed as PBI

AOR	Area of Review
ASTM	American Society for Testing and Materials
BBE-P1	Bayou Bend East SL20220050 – Phase 1
CCS	carbon transport and sequestration
CO_2	carbon dioxide

Claimed as PBI

ERRP	Emergency and Remedial Response Plan
ft	feet

Claimed as PBI

MAIP	Maximum allowable injection pressure
MIT	mechanical integrity testing
OBS	ocean bottom sensors
PDHG	permanent downhole gauges

Claimed as PBI

QASP	quality assurance and surveillance plan
SCADA	Supervisory Control and Data Acquisition
TL	time-lapse
TVD	true vertical depth
UIC	Underground Injection Control

Claimed as PBI

7.12.2 References

American Society for Testing and Materials (ASTM), 2017. G1-03 Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens. https://www.astm.org/g0001-03r17e01.html. Referenced April 2024. 7.8.3

Plan revision number: 002
Plan revision date: July 2026

Claimed as PBI

G. Well Plugging Plans

8 INJECTION WELL PLUGGING PLAN
40 CFR 146.92(b)

Bayou Bend East SL20220050 (BBE)

8.1 Facility Information

Facility Name: BAYOU BEND EAST SL20220050 - PHASE 1 (BBE-P1)
WELL: SL20220050 W1
WELL SURFACE LOCATION: 29.5920225°, -93.89526008°
WELL BOTTOM HOLE LOCATION: 29.5920225°, -93.89526008°

Facility Contact: Claimed as PBI
1500 LOUISIANA STREET, 11TH FLOOR

Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK 3, 4, 11 AND 12
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

8.2 Introduction

Bayou Bend CCS LLC (Operator) will conduct injection well plugging and abandonment according to the following sections.

Coordinate Reference System: NAD 83 Texas South Central

Surface Lat: 29.5920225°

Surface Long: - 93.89526008°

BHL Lat: 29.5920225°

BHL Long: - 93.89526008°

8.3 Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

The Operator will conduct a downhole pressure test to determine reservoir pressure prior to plugging the injection well as required by 40 CFR 146.92(a). Once downhole pressure has been determined, the Operator will calculate kill fluid density utilizing the existing permanent downhole gauge on tubing to determine bottom-hole reservoir pressure. If a measurement cannot be obtained, then acquire reservoir pressure through wireline in wellbore. The test will be run using slickline or electric-line, based on availability.

The downhole pressure acquisition procedure via logging is as follows:

- Rig up wireline unit.
- Pressure test equipment and test for leaks.

- Run in hole with downhole gauge to record pressures.
- Pull out of hole. Confirm proper tool operation and data acquired.
- Rig down wireline unit.

8.4 Planned External Mechanical Integrity Test(s)

Claimed as PBI [redacted] Operator will conduct at least one of the tests listed in **Table 8-1** to verify external mechanical integrity of the injection well as required by 40 CFR 146.92(a).

A wireline log will be conveyed across the entire length of the wellbore. The data will be evaluated for anomalies that may indicate a loss of mechanical integrity when compared to baseline and historical well logs. If anomalies are detected, the plugging plan will be updated appropriately.

Table 8-1: Planned MITs.

Claimed as PBI [redacted]

8.5 Information on Plugs

The Operator will use the materials and methods noted in **Table 8-2** to plug each injection well. The volumes, cement formulations and depth of the plug or plugs will depend on the final subsurface and downhole conditions of the well as assessed during construction. The cement formulations and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

Cement plugs will be calculated considering available data, which may include casing caliper data or at a minimum nominal casing IDs. Cement simulations and testing will be performed to confirm cement designs meet the minimum height provided in the cement plugging details. Plugging details are based on a vertical well with respect to depth.

Claimed as PBI

[redacted]

8.6 Narrative Description of Plugging Procedures

8.6.1 Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), the Operator will notify EPA Region 6 at least 60 days before plugging the well and provide updated Injection Well Plugging Plan, if applicable.

Notification and/or additional permits related to plugging and abandonment will be obtained from the Texas Railroad Commission, Texas Committee on Environmental Quality, and the United States Army Corps of Engineers. All required Federal and State permits will be acquired prior to starting operations.

Advance notice will also be provided to the above mentioned regulatory and state agencies, and other stakeholders who might be impacted by plugging and abandonment operations.

The procedures described in the following sections are subject to modification during execution as necessary to ensure a plugging operation that protects worker safety and is effective to protect offshore environments. Any significant modifications due to unforeseen circumstances will be described in the plugging report. The completed plugging report with charts and all laboratory information will be sent to the regulatory agencies as required by permits. The plugging report shall be certified as accurate by the Operator and plugging contractor and shall be submitted within 60 days after plugging is completed.

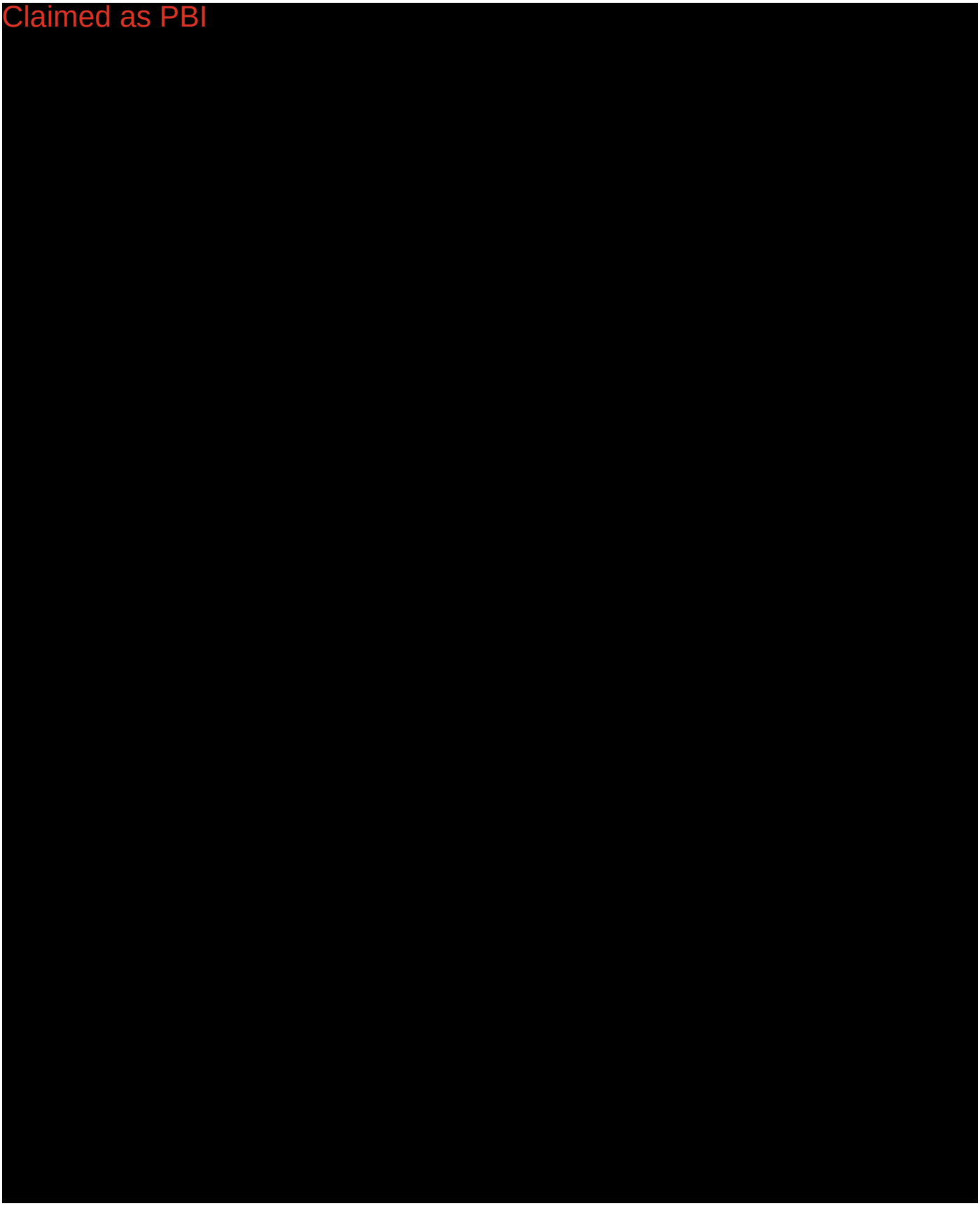
8.6.2 Plugging Procedures

Below includes the generic permanent plugging procedure for SL20220050 W1. The plugging procedure may be revised based on actual wellbore conditions encountered during operations.

Claimed as PBI

[redacted]

Claimed as PBI



8 INJECTION WELL PLUGGING PLAN
40 CFR 146.92(b)

Bayou Bend East SL20220050 (BBE)

8.1 Facility Information

Facility Name: BAYOU BEND EAST SL20220050 - PHASE 1 (BBE-P1)
WELL: SL20220050 W2

WELL SURFACE LOCATION: 29.59201108°, -93.89528519°
WELL BOTTOM HOLE LOCATION: 29.59189637°, -93.91373689°

Facility Contact: Claimed as PBI

1500 LOUISIANA STREET, 11TH FLOOR
HOUSTON, TEXAS 77002

Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK 3, 4, 11 AND 12
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

8.2 Introduction

Bayou Bend CCS LLC (Operator) will conduct injection well plugging and abandonment according to the following sections.

Coordinate Reference System: NAD 83 Texas South Central

Surface Lat: 29.59201108°

Surface Long: -93.89528519°

BHL Lat: 29.59189637°

BHL Long: -93.91373689°

8.3 Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Operator will conduct a downhole pressure test to determine reservoir pressure prior to plugging the injection well as required by 40 CFR 146.92(a). Once downhole pressure has been determined, Operator will calculate kill fluid density utilizing the existing permanent downhole gauge on tubing to determine bottom-hole reservoir pressure. If a measurement cannot be obtained, then acquire reservoir pressure through wireline in wellbore. The test will be run using slickline or electric-line, based on availability.

The downhole pressure acquisition procedure via logging is as follows:

- Rig up wireline unit.
- Pressure tests equipment and test for leaks.
- Run in hole with downhole gauge to record pressures.
- Pull out of hole. Confirm proper tool operation and data acquired.
- Rig down wireline unit.

8.4 Planned External Mechanical Integrity Test(s)

Claimed as PBI Operator will conduct at least one of the tests listed in **Table 8-1** to verify external mechanical integrity of the injection well as required by 40 CFR 146.92(a).

A wireline log will be conveyed across the entire length of the wellbore. The data will be evaluated for anomalies that may indicate a loss of mechanical integrity when compared to baseline and historical well logs. If anomalies are detected, the plugging plan will be updated appropriately.

Table 8-1: Planned MITs.

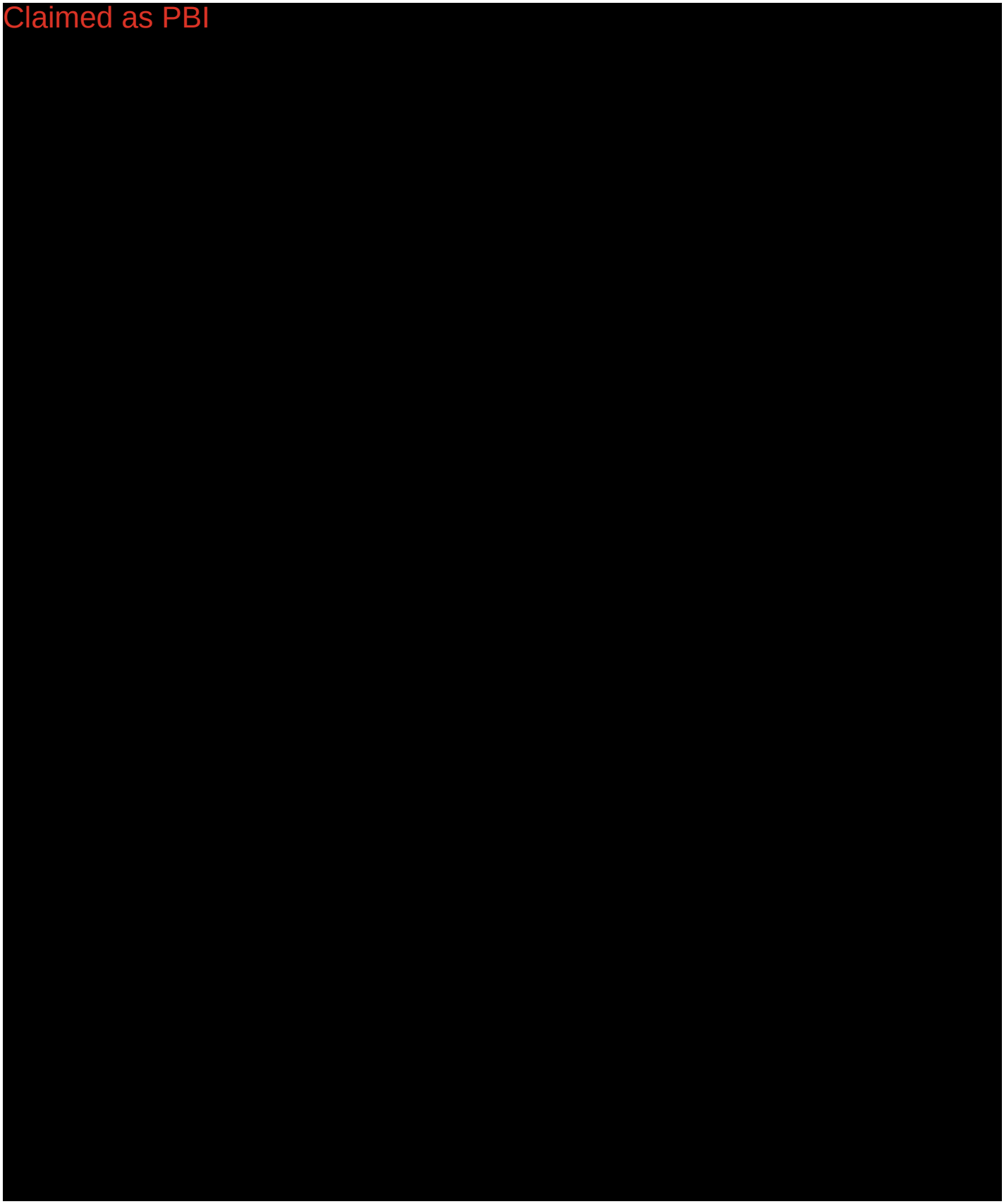
Claimed as PBI

8.5 Information on Plugs

The Operator will use the materials and methods noted in **Table 8-2** to plug each injection well. The volumes, cement formulations and depth of the plug or plugs will depend on the final subsurface and downhole conditions of the well as assessed during construction. The cement formulations and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

Cement plugs will be calculated considering available data, which may include casing caliper data or at a minimum nominal casing IDs. Cement simulations and testing will be performed to confirm cement designs meet the minimum height provided in the cement plugging details.

Claimed as PBI



8.6 Narrative Description of Plugging Procedures

8.6.1 Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), Operator will notify EPA Region 6 at least 60 days before plugging the well and provide updated Injection Well Plugging Plan, if applicable.

Notification and/or additional permits related to plugging and abandonment will be obtained from the Texas Railroad Commission, Texas Committee on Environmental Quality, and the United States Army Corps of Engineers. All required Federal and State permits will be acquired prior to starting operations.

Advance notice will also be provided to the EPA, Railroad Commission of Texas, Texas General Land Office, the United States Coast Guard and other stakeholders who might be impacted by plugging and abandonment operations.

The procedures described in the following sections are subject to modification during execution as necessary to ensure a plugging operation that protects worker safety and is effective to protect offshore environments. Any significant modifications due to unforeseen circumstances will be described in the plugging report. The completed plugging report with charts and all laboratory information will be sent to the regulatory agencies as required by permits. The plugging report shall be certified as accurate by the Operator and plugging contractor and shall be submitted within 60 days after plugging is completed.

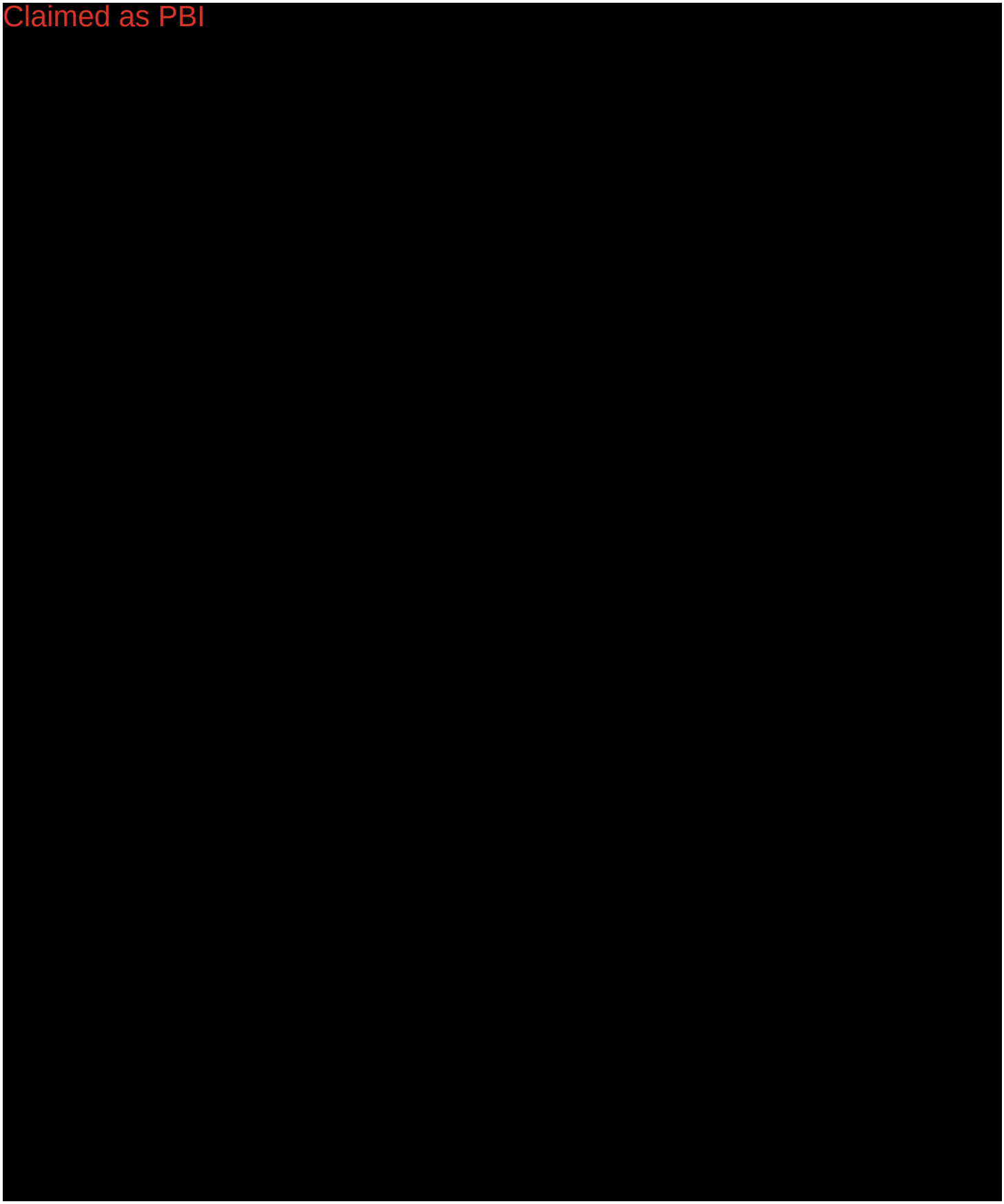
8.6.2 Plugging Procedures

Below includes the generic permanent plugging procedure for SL20220050 W2. The plugging procedure may be revised based on actual wellbore conditions encountered during operations.

Claimed as PBI

[redacted]

Claimed as PBI



Revision number: 002
Plan revision date: July 2026

INJECTION WELL PLUGGING PLAN

BAYOU BEND EAST SL20220050 (BBE)

Claimed as PBI

[redacted]

8 INJECTION WELL PLUGGING PLAN
40 CFR 146.92(b)

Bayou Bend East SL20220050 (BBE)

8.1 Facility Information

Facility Name: BAYOU BEND EAST SL20220050 - PHASE 1 (BBE-P1)
WELL: SL20220050 W4
WELL SURFACE LOCATION: 29.5920358°, -93.89528395°
WELL BOTTOM HOLE LOCATION: 29.60861362°, -93.89540328°

Facility Contact: Claimed as PBI
1500 LOUISIANA STREET, 11TH FLOOR
HOUSTON, TEXAS 77002
Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK 3, 4, 11 AND 12
JEFFERSON COUNTY, TEXAS

29.5920225°, -93.89526008°

8.2 Introduction

Bayou Bend CCS LLC (Operator) will conduct injection well plugging and abandonment according to the following sections.

Coordinate Reference System: NAD 83 Texas South Central

Surface Lat: 29.5920358°

Surface Long: -93.89528395°

BHL Lat: 29.60861362°

BHL Long: -93.89540328°

8.3 Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

The Operator will conduct a downhole pressure test to determine reservoir pressure prior to plugging the injection well as required by 40 CFR 146.92(a). Once downhole pressure has been determined, the Operator will calculate kill fluid density utilizing the existing permanent downhole gauge on tubing to determine bottom-hole reservoir pressure. If a measurement cannot be obtained, then acquire reservoir pressure through wireline in wellbore. The test will be run using slickline or electric-line, based on availability.

The downhole pressure acquisition procedure via logging is as follows:

- Rig up wireline unit.
- Pressure tests equipment and test for leaks.
- Run in hole with downhole gauge to record pressures.
- Pull out of hole. Confirm proper tool operation and data acquired.
- Rig down wireline unit.

8.4 Planned External Mechanical Integrity Test(s)

Claimed as PBI will conduct at least one of the tests listed in **Table 8-1** to verify external mechanical integrity of the injection well as required by 40 CFR 146.92(a).

A wireline log will be conveyed across the entire length of the wellbore. The data will be evaluated for anomalies that may indicate a loss of mechanical integrity when compared to baseline and historical well logs. If anomalies are detected, the plugging plan will be updated appropriately.

Table 8-1: Planned MITs.

Claimed as PBI

8.5 Information on Plugs

The Operator will use the materials and methods noted in **Table 8-2** to plug each injection well. The volumes, cement formulations and depth of the plug or plugs will depend on the final subsurface and downhole conditions of the well as assessed during construction. The cement formulations and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

Cement plugs will be calculated considering available data, which may include casing caliper data or at a minimum nominal casing IDs. Cement simulations and testing will be performed to confirm cement designs meet the minimum height provided in the cement plugging details.

Claimed as PBI

[redacted]

Note: The plugging plan was designed per the requirements of SWR §3.14(d)(11).

8.6 Narrative Description of Plugging Procedures

8.6.1 Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), Operator will notify EPA Region 6 at least 60 days before plugging the well and provide updated Injection Well Plugging Plan, if applicable.

Notification and/or additional permits related to plugging and abandonment will be obtained from the Texas Railroad Commission, Texas Committee on Environmental Quality, and the United States Army Corps of Engineers. All required Federal and State permits will be acquired prior to starting operations.

Advance notice will also be provided to the Texas General Land Office, the United States Coast Guard, and other stakeholders who might be impacted by plugging and abandonment operations.

The procedures described in the following sections are subject to modification during execution as necessary to ensure a plugging operation that protects worker safety and is effective to protect offshore environments. Any significant modifications due to unforeseen circumstances will be described in the plugging report. The completed plugging report with charts and all laboratory information will be sent to the regulatory agencies as required by permits. The plugging report shall be certified as accurate by the Operator and plugging contractor and shall be submitted within 60 days after plugging is completed.

8.6.2 Plugging Procedures

Below includes the generic permanent plugging procedure for SL20220050 W4. The plugging procedure may be revised based on actual wellbore conditions encountered during operations.

Claimed as PBI

[redacted]

Claimed as PBI

8 INJECTION WELL PLUGGING PLAN
40 CFR 146.92(b)

Bayou Bend East SL20220050 (BBE)

8.1 Facility Information

Facility Name: BAYOU BEND EAST SL20220050 - PHASE 1 (BBE-P1)
WELL: SL20220050 W5
WELL SURFACE LOCATION: 29.59203393°, -93.89523497°
WELL BOTTOM HOLE LOCATION: 29.6039239°, -93.88184566°

Facility Contact: Claimed as PBI
1500 LOUISIANA STREET, 11TH FLOOR
HOUSTON, TEXAS 77002
Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK 3, 4, 11 AND 12
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

8.2 Introduction

Bayou Bend CCS LLC (Operator) will conduct injection well plugging and abandonment according to the following sections.

Coordinate Reference System: NAD 83 Texas South Central

Surface Lat: 29.59203393°
Surface Long: -93.89523497°
BHL Lat: 29.6039239°
BHL Long: -93.88184566°

8.3 Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

The Operator will conduct a downhole pressure test to determine reservoir pressure prior to plugging the injection well as required by 40 CFR 146.92(a). Once downhole pressure has been determined, the Operator will calculate kill fluid density utilizing the existing permanent downhole gauge on tubing to determine bottom-hole reservoir pressure. If a measurement cannot be obtained, then acquire reservoir pressure through wireline in wellbore. The test will be run using slickline or electric-line, based on availability.

The downhole pressure acquisition procedure via logging is as follows:

- Rig up wireline unit.
- Pressure tests equipment and test for leaks.
- Run in hole with downhole gauge to record pressures.
- Pull out of hole. Confirm proper tool operation and data acquired.
- Rig down wireline unit.

8.4 Planned External Mechanical Integrity Test(s)

Claimed as PBI Operator will conduct at least one of the tests listed in **Table 8-1** to verify external mechanical integrity of the injection well as required by 40 CFR 146.92(a).

A wireline log will be conveyed across the entire length of the wellbore. The data will be evaluated for anomalies that may indicate a loss of mechanical integrity when compared to baseline and historical well logs. If anomalies are detected, the plugging plan will be updated appropriately.

Table 8-1: Planned MITs.

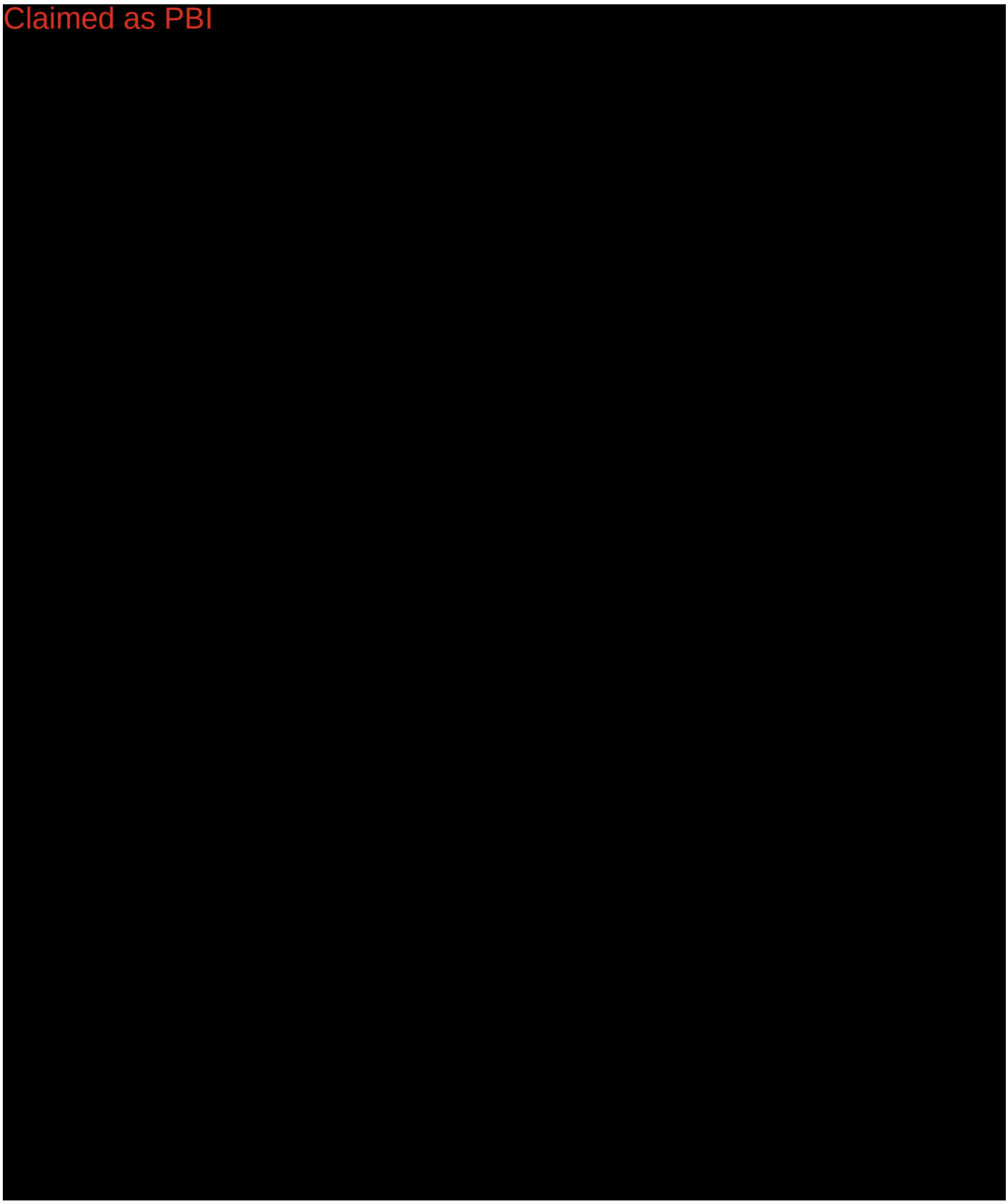
Claimed as PBI

8.5 Information on Plugs

The Operator will use the materials and methods noted in **Table 8-2** to plug each injection well. The volumes, cement formulations and depth of the plug or plugs will depend on the final subsurface and downhole conditions of the well as assessed during construction. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

Cement plugs will be calculated considering available data, which may include casing caliper data or at a minimum nominal casing IDs. Cement simulations and testing will be performed to confirm cement designs meet the minimum height provided in the cement plugging details.

Claimed as PBI



8.6 Narrative Description of Plugging Procedures

8.6.1 Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), Operator will notify EPA Region 6 at least 60 days before plugging the well and provide updated Injection Well Plugging Plan, if applicable.

Notification and/or additional permits related to plugging and abandonment will be obtained from the Texas Railroad Commission, Texas Committee on Environmental Quality, and the United States Army Corps of Engineers. All required Federal and State permits will be acquired prior to starting operations.

Advance notice will also be provided to the Texas General Land Office, the United States Coast Guard, and other stakeholders who might be impacted by plugging and abandonment operations.

The procedures described in the following sections are subject to modification during execution as necessary to ensure a plugging operation that protects worker safety and is effective to protect offshore environments. Any significant modifications due to unforeseen circumstances will be described in the plugging report. The completed plugging report with charts and all laboratory information will be sent to the regulatory agencies as required by permits. The plugging report shall be certified as accurate by the Operator and plugging contractor and shall be submitted within 60 days after plugging is completed.

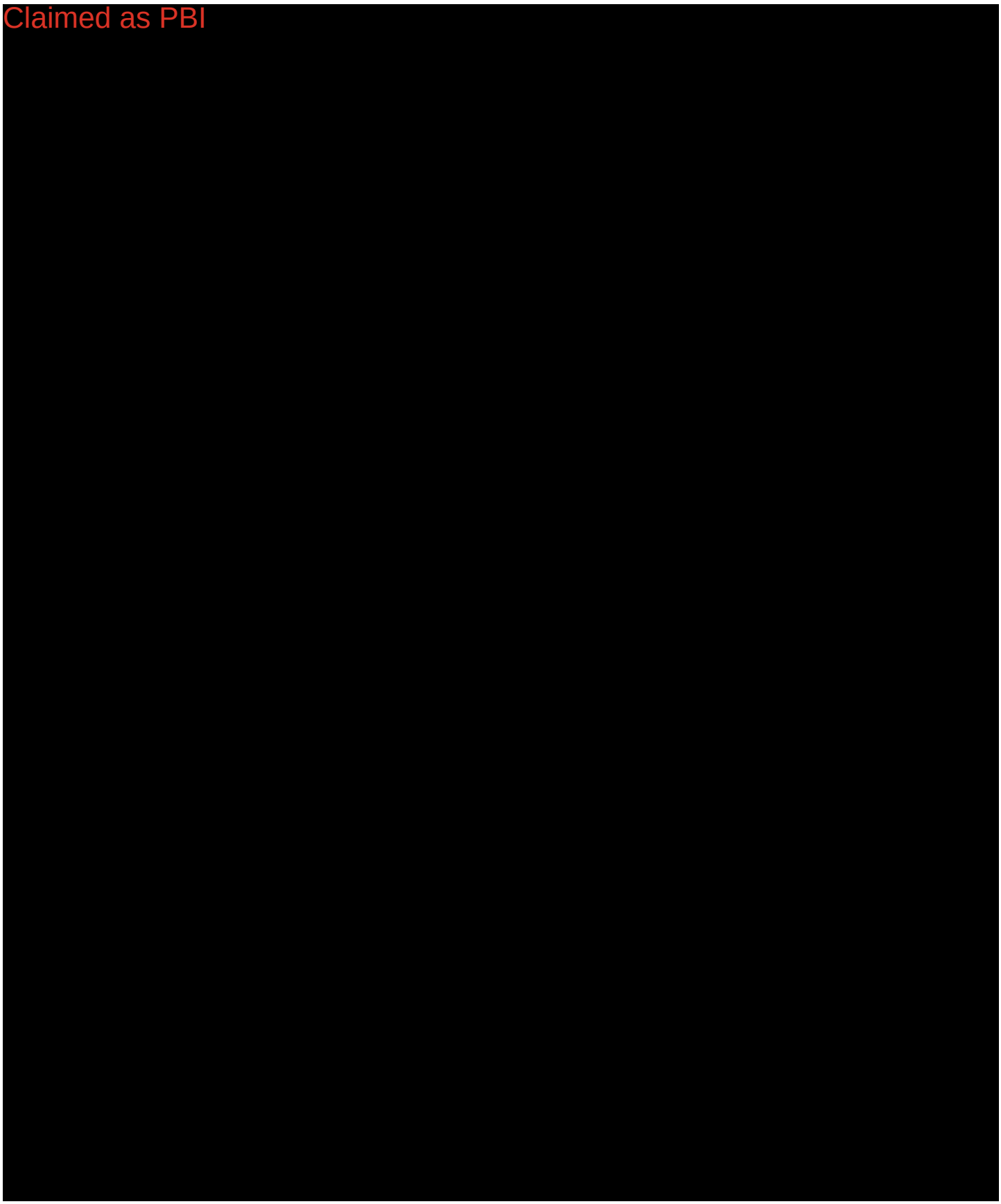
8.6.2 Plugging Procedures

Below includes the generic permanent plugging procedure for SL20220050 W5. The plugging procedure may be revised based on actual wellbore conditions encountered during operations.

Claimed as PBI



Claimed as PBI



8 INJECTION WELL PLUGGING PLAN
40 CFR 146.92(b)

Bayou Bend East SL20220050 (BBE)

8.1 Facility Information

Facility Name: BAYOU BEND EAST SL20220050 - PHASE 1 (BBE-P1)
WELL: SL20220050 W6
WELL SURFACE LOCATION: 29.59200921°, -93.89523621°
WELL BOTTOM HOLE LOCATION: 29.59215342°, -93.87566908°

Facility Contact: Claimed as PBI
1500 LOUISIANA STREET, 11TH FLOOR
HOUSTON, TEXAS 77002
Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK 3, 4, 11 AND 12
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

8.2 Introduction

Bayou Bend CCS LLC (Operator) will conduct injection well plugging and abandonment according to the following sections.

Coordinate Reference System: NAD 83 Texas South Central

Surface X: 29.59200921°

Surface Y: -93.89523621°

BHL X: 29.59215342°

BHL Y: -93.87566908°

8.3 Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

The Operator will conduct a downhole pressure test to determine reservoir pressure prior to plugging the injection well as required by 40 CFR 146.92(a). Once downhole pressure has been determined, the Operator will calculate kill fluid density utilizing the existing permanent downhole gauge on tubing to determine bottom-hole reservoir pressure. If a measurement cannot be obtained, then acquire reservoir pressure through wireline in wellbore. The test will be run using slickline or electric-line, based on availability.

The downhole pressure acquisition procedure via logging is as follows:

- Rig up wireline unit.
- Pressure tests equipment and test for leaks.

- Run in hole with downhole gauge to record pressures.
- Pull out of hole. Confirm proper tool operation and data acquired.
- Rig down wireline unit.

8.4 Planned External Mechanical Integrity Test(s)

Claimed as PBI Operator will conduct at least one of the tests listed in **Table 8-1** to verify external mechanical integrity of the injection well as required by 40 CFR 146.92(a).

A wireline log will be conveyed across the entire length of the wellbore. The data will be evaluated for anomalies that may indicate a loss of mechanical integrity when compared to baseline and historical well logs. If anomalies are detected, the plugging plan will be updated appropriately.

Table 8-1: Planned MITs.

Claimed as PBI

8.5 Information on Plugs

The Operator will use the materials and methods noted in Table 8-2 to plug each injection well. The volumes, cement formulations and depth of the plug or plugs will depend on the final subusurface and downhole conditions of the well as assessed during construction. The cement formulations and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

Cement plugs will be calculated considering available data, which may include casing caliper data or at a minimum nominal casing IDs. Cement simulations and testing will be performed to confirm cement designs meet the minimum height provided in the cement plugging details.

Claimed as PBI



Note: The plugging plan was designed per the requirements of SWR §3.14(d)(11).

8.7 Narrative Description of Plugging Procedures

8.7.1 Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), Operator will notify EPA Region 6 at least 60 days before plugging the well and provide updated Injection Well Plugging Plan, if applicable.

Notification and/or additional permits related to plugging and abandonment will be obtained from the Texas Railroad Commission, Texas Committee on Environmental Quality, and the United States Army Corps of Engineers. All required Federal and State permits will be acquired prior to starting operations.

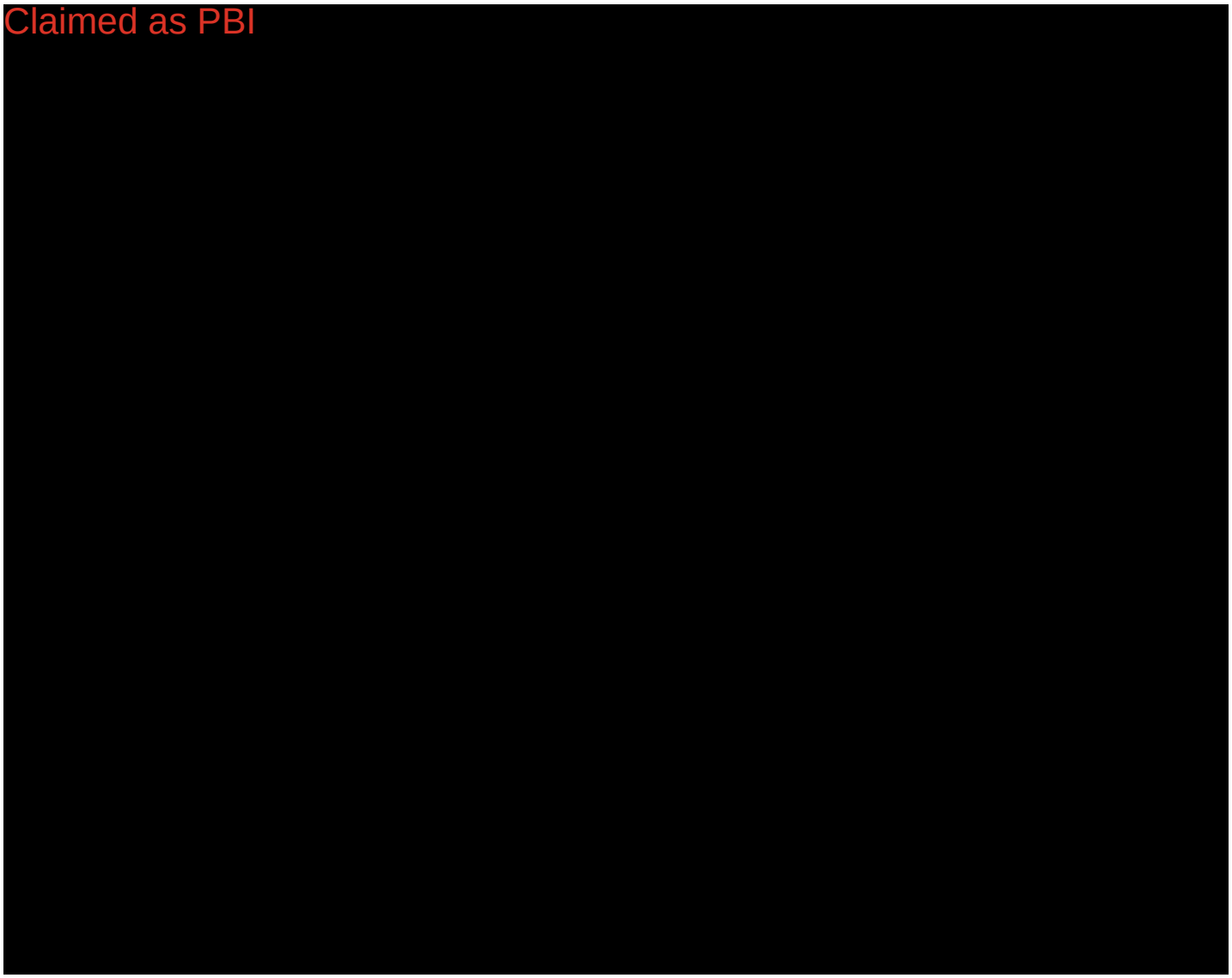
Advance notice will also be provided to the Texas General Land Office, the United States Coast Guard, and other stakeholders who might be impacted by plugging and abandonment operations.

The procedures described in the following sections are subject to modification during execution as necessary to ensure a plugging operation that protects worker safety and is effective to protect offshore environments. Any significant modifications due to unforeseen circumstances will be described in the plugging report. The completed plugging report with charts and all laboratory information will be sent to the regulatory agencies as required by permits. The plugging report shall be certified as accurate by the Operator and plugging contractor and shall be submitted within 60 days after plugging is completed.

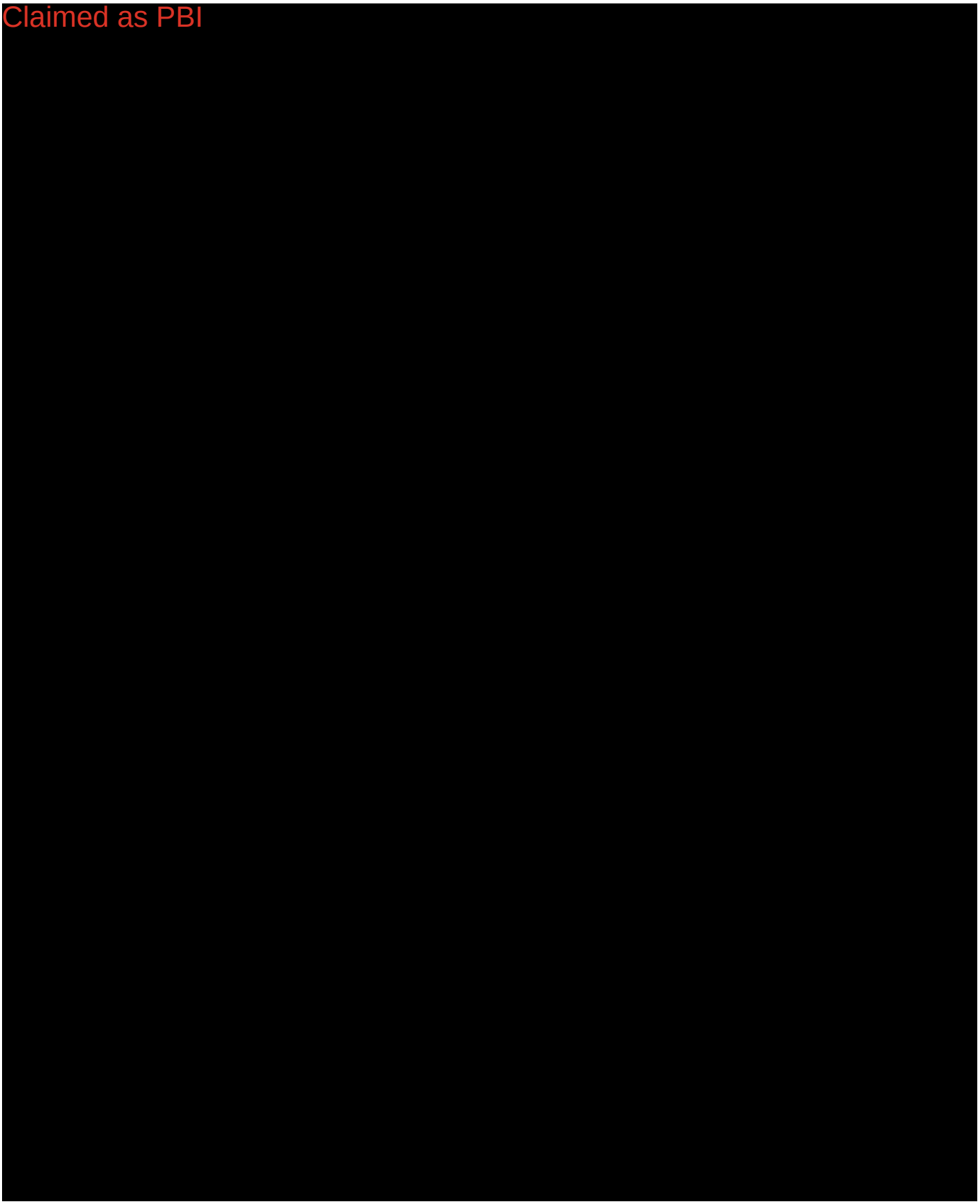
8.7.2 Plugging Procedures

Below includes the generic permanent plugging procedure for SL20220050 W6. The plugging procedure may be revised based on actual wellbore conditions encountered during operations.

Claimed as PBI



Claimed as PBI



8 MONITORING WELL PLUGGING PLAN
40 CFR 146.92(b)

Bayou Bend East SL20220050 (BBE)

8.1 Facility Information

Facility Name: BAYOU BEND EAST SL20220050 - PHASE 1 (BBE-P1)
WELL: SL20220050 M1
WELL SURFACE LOCATION: 29.589622°, -93.916531°
WELL BOTTOM HOLE LOCATION: 29.589622°, -93.916531°

Facility Contact: Claimed as PBI
1500 LOUISIANA STREET, 11TH FLOOR
HOUSTON, TEXAS 77002
Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK 3, 4, 11 AND 12
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

8.2 Introduction

Bayou Bend CCS LLC (Operator) will conduct monitoring well plugging and abandonment according to the following sections.

Coordinate Reference System: NAD 83 Texas South Central

Surface X: 29.589622°

Surface Y: -93.916531°

BHL X: 29.589622°

BHL Y: -93.916531°

8.3 Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

The Operator will conduct a downhole pressure test to determine reservoir pressure prior to plugging the monitoring well as required by 40 CFR 146.92(a). Once downhole pressure has been determined, the Operator will calculate kill fluid density utilizing the existing permanent downhole gauge on tubing to determine bottom-hole reservoir pressure. If a measurement cannot be obtained, then acquire reservoir pressure through wireline in wellbore. The test will be run using slickline or electric-line, based on availability.

The downhole pressure acquisition procedure via logging is as follows:

- Rig up wireline unit.
- Pressure tests equipment and test for leaks.
- Run in hole with downhole gauge to record pressures.
- Pull out of hole. Confirm proper tool operation and data acquired.
- Rig down wireline unit.

8.4 Planned External Mechanical Integrity Test(s)

Claimed as PBI Operator will conduct at least one of the tests listed in **Table 8-1** to verify external mechanical integrity of the monitoring well as required by 40 CFR 146.92(a).

A wireline log will be conveyed across the entire length of the wellbore. The data will be evaluated for anomalies that may indicate a loss of mechanical integrity when compared to baseline and historical well logs. If anomalies are detected, the plugging plan will be updated appropriately.

Table 8-1: Planned MITs.

Claimed as PBI

8.5 Information on Plugs

The Operator will use the materials and methods noted in Table 8-2 to plug the monitoring well. The volumes, cement formulations and depth of the plug or plugs will depend on the final subusurface and downhole conditions of the well as assessed during construction. The cement formulations and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

Cement plugs will be calculated considering available data, which may include casing caliper data or at a minimum nominal casing IDs. Cement simulations and testing will be performed to confirm cement designs meet the minimum height provided in the cement plugging details. Claimed as PBI

Claimed as PBI



8.7 Narrative Description of Plugging Procedures

8.7.1 Notifications, Permits, and Inspections

Notification and/or additional permits related to plugging and abandonment will be provided to or obtained from the US Environmental Protection Agency (Region 6), RRC, Texas Committee on Environmental Quality (TCEQ), and the United States Army Corps of Engineers (USACE). All required Federal and State permits will be acquired prior to starting operations.

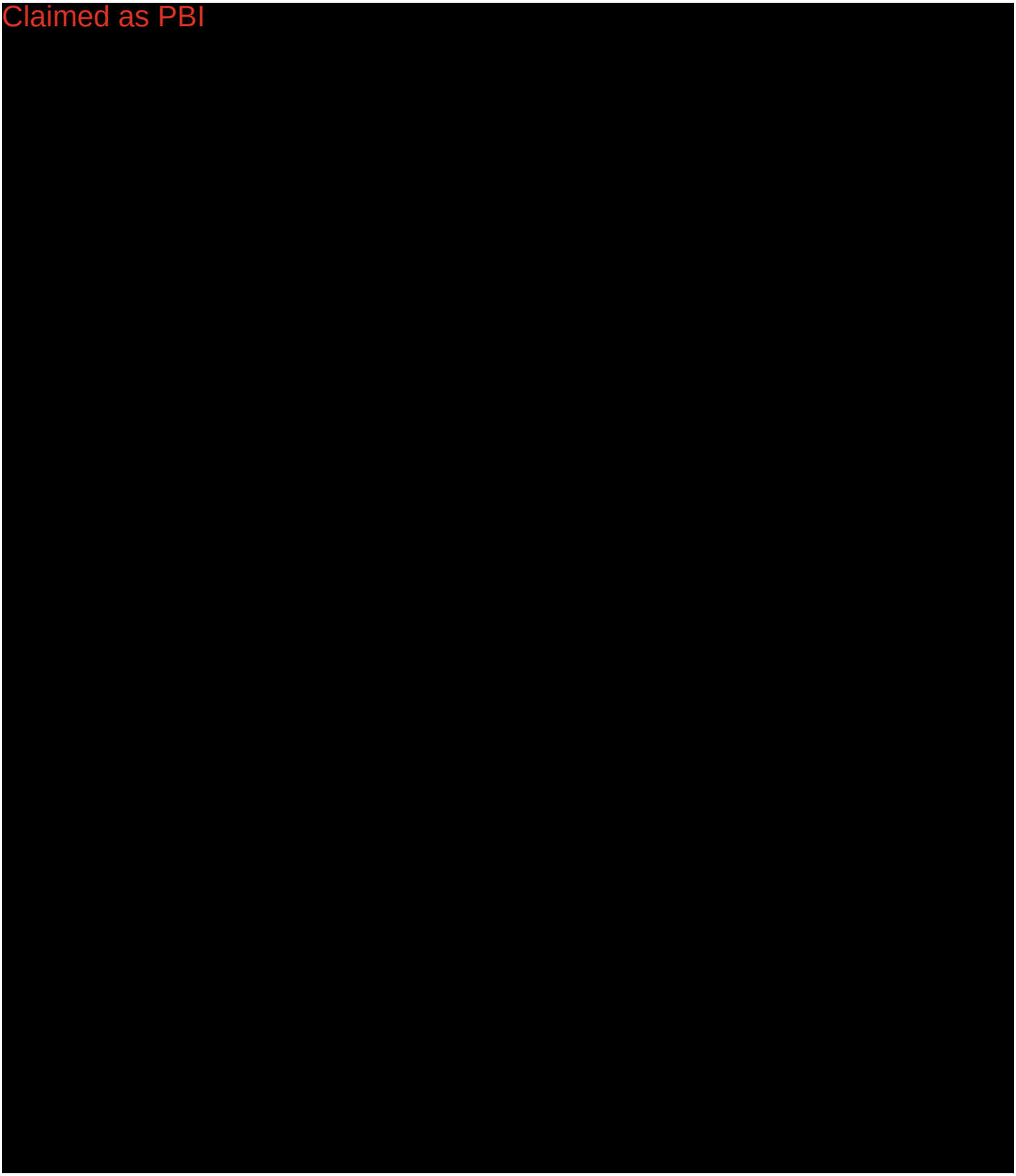
Advance notice will also be provided to the Texas General Land Office, the United States Coast Guard, and other stakeholders who might be impacted by plugging and abandonment operations.

The procedures described in the following sections are subject to modification during execution as necessary to ensure a plugging operation that protects worker safety and is effective to protect potential USDWs. Any significant modifications due to unforeseen circumstances will be described in the plugging report. The completed plugging report with charts and laboratory information will be sent to the regulatory agencies as required by permits. The plugging report shall be certified as accurate by Operator and plugging contractor and shall be submitted within 60 days after plugging is completed.

Claimed as PBI



Claimed as PBI



H. Emergency and Remedial Response Plan

Plan revision number: 003
Plan revision date: September 2026

EMERGENCY AND REMEDIAL RESPONSE PLAN

40 CFR 146.94(A)

Bayou Bend East SL20220050 (BBE)

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10 EMERGENCY AND REMEDIAL RESPONSE PLAN
40 CFR 146.94(A)

Bayou Bend East SL20220050 (BBE)

10.1 Facility Information

Facility Name: BAYOU BEND EAST SL 20220050 – PHASE 1 (BBE-P1)
SL20220050 W1, SL20220050 W2, SL20220050 W4, SL20220050 W5, SL20220050 W6

Facility Contact: Claimed as PBI
1500 LOUISIANA STREET, 11TH FLOOR
HOUSTON, TEXAS 77002
Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

This Emergency and Remedial Response Plan (ERRP) describes actions that Bayou Bend CCS LLC (Operator) shall take to address movement of the injection fluid or formation fluid in the event that there is a endangerment to a local resource (Section 10.2.1) during the construction, operation, or post-injection site care (PISC) periods. An underground source of drinking water (USDW) as defined by 40 CFR §146.3 was not identified for Bayou Bend East (BBE), for additional USDW information refer to Section 10.9.1. Therefore, these described actions apply to address any impact to Texas State Waters in the event that there is endangerment to a local resource.

If the Operator obtains evidence that the injected CO_2 stream and/or associated pressure front may cause an endangerment to a local resource, the Operator must perform the following actions:

1. Initiate shutdown plan for the injection well.
2. Take all steps reasonably necessary to identify and characterize the release.
3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
4. Implement applicable portions of the approved ERRP.

Where the phrase “initiate shutdown plan” is used, the following protocol will be employed: the Operator will immediately cease injection to applicable well. However, in some circumstances, the Operator will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in the Summary of Requirements of the Class VI permit) is appropriate.

10.2 Local Resources and Infrastructure

The Bayou Bend East SL20220050 Phase 1 (BBE-P1) project site is located on the Jefferson County Lease, High Island Block, Jefferson County (SL20220050, General Land Office, April 1, 2022; 40,865 acres) in Texas State Waters, between approximately 4 and 10 nautical miles from shore. The location, resources and infrastructure are located within the 1973 Port Arthur and 1975 Houston United States Geological Survey (USGS) 7.5-minute Quadrangle Maps. Resource and infrastructure addressed in this plan are shown on Figures 10 1 through 10 4. Estimated water depth in the vicinity of the proposed well locations ranges between approximately 19 and 25 feet.

10.2.1 Local Resources

Local resources in the vicinity of the proposed injection wells that may be affected by an emergency event at the project site include:

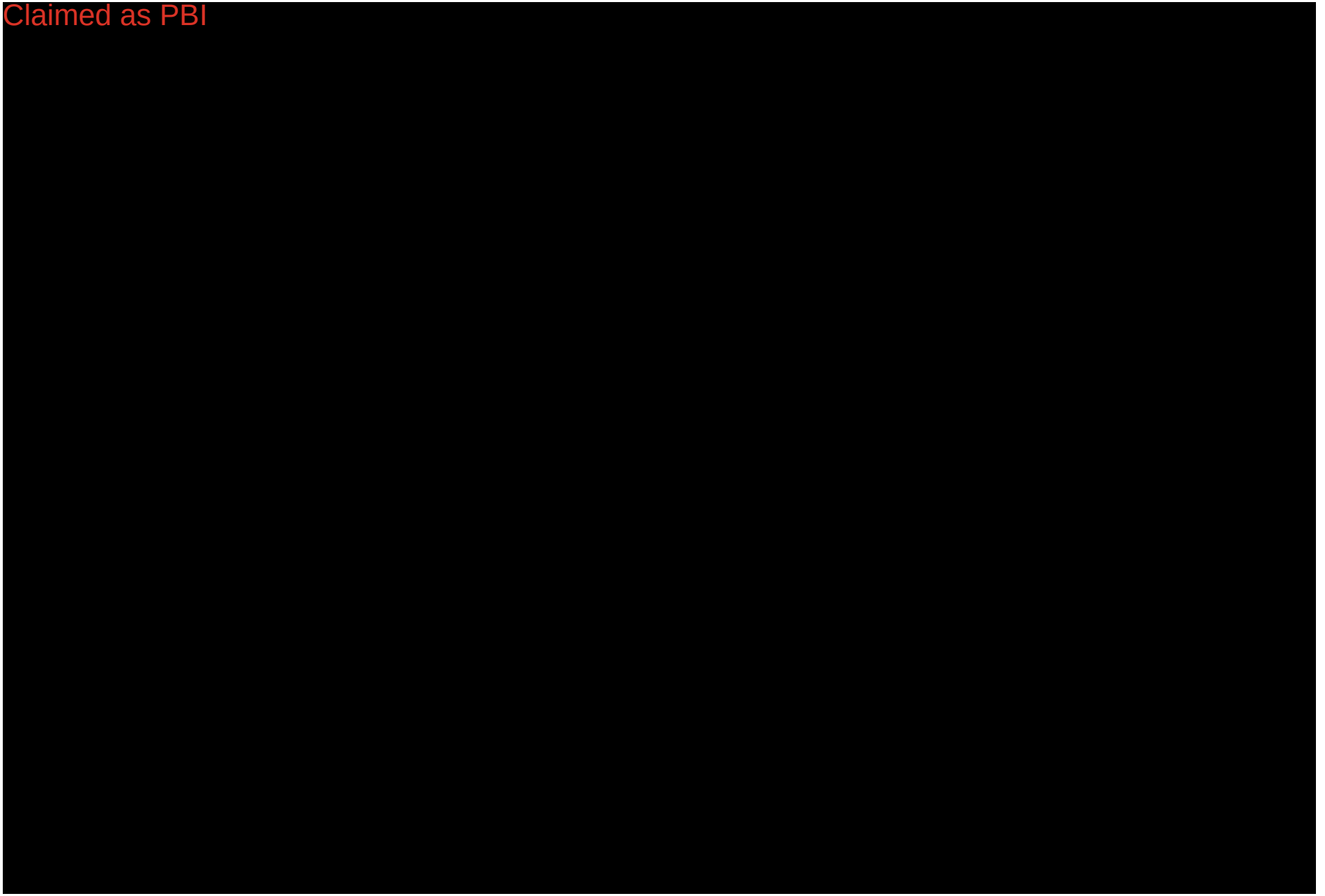
- Cultural Artifacts.
- Threatened and Endangered Species

Cultural Artifacts

A cultural desktop investigation completed for the project by Environmental Resources Management (ERM) on behalf of the Operator in February 2023 reported approximate locations of nine shipwrecks.[1] According to the information collected during the cultural desktop investigation, it is unknown if these are of cultural significance. The Operator's practice is to clear each well location prior to drilling and avoid placing wells or facilities in these locations. No other artifacts of potential cultural significance were identified in the survey (**Figure 10-1**).

[1] ERM, February 2023. *Cultural Resources Desktop Review, Bayou Bend Carbon Capture and Storage Project, Jefferson County, Texas*.

Claimed as PBI



Threatened and Endangered Species

The project location is near the McFaddin National Wildlife Preserve and the Candy Cain Abshier Wildlife Refuge. A desktop biological survey was completed in 2023 that revealed the project location area does contain potential suitable habitat for seven federally listed species including seven state listed species (**Figure 10-2**).[2] These species are the West Indian manatee, shortfin mako shark, giant manta ray, green sea turtle, hawksbill sea turtle, loggerhead sea turtle, and Kemp's ridley sea turtle due to proximity to nearshore and coastal habitats and suitable depths to support these species. Additionally, the southern portion of the project area is located within loggerhead sea turtle critical habitat, containing both nearshore reproductive habitat and *Sargassum* habitat. *Sargassum* is a genus of brown macroalgae that is found in shallow coastal tropical and temperate marine waters that form free floating rafts that can stretch for miles. This floating habitat provides food, refuge, and breeding grounds for an array of animals such as fish, sea turtles, marine birds, crabs, shrimp, and more.

The National Marine Fisheries Service (NMFS) Essential Fish Habitat (EFH) Mapper identified 59 EFH species including shrimp, reef fish, coastal migratory pelagic species, and highly migratory species such as sharks with potential to occur within the Project area. In addition, on July 20, 2023, United States Fish and Wildlife Service (USFWS) identified the Project area as critical habitat for the Green Sea Turtle[3]. The NMFS[4] proposed the Project area as critical habitat for the Green Sea Turtle on July 19, 2023. The Project plans to avoid migrating, nesting, and breeding areas and will implement best available technologies (BAT), as needed, or required in ecologically sensitive areas that might be nesting, breeding, and/or migratory zones for threatened or endangered species.

Up to 26 marine mammal species including the six federally listed species are identified by federal and state databases to have the potential to occur within the Project area. The most likely cetacean species to occur within the area is the common bottlenose dolphin or Atlantic bottlenose dolphin (*Tursiops truncatus*) and Atlantic spotted dolphins (*Stenella frontalis*). The remaining identified species could occur in the area but are rare along the east Texas coast.

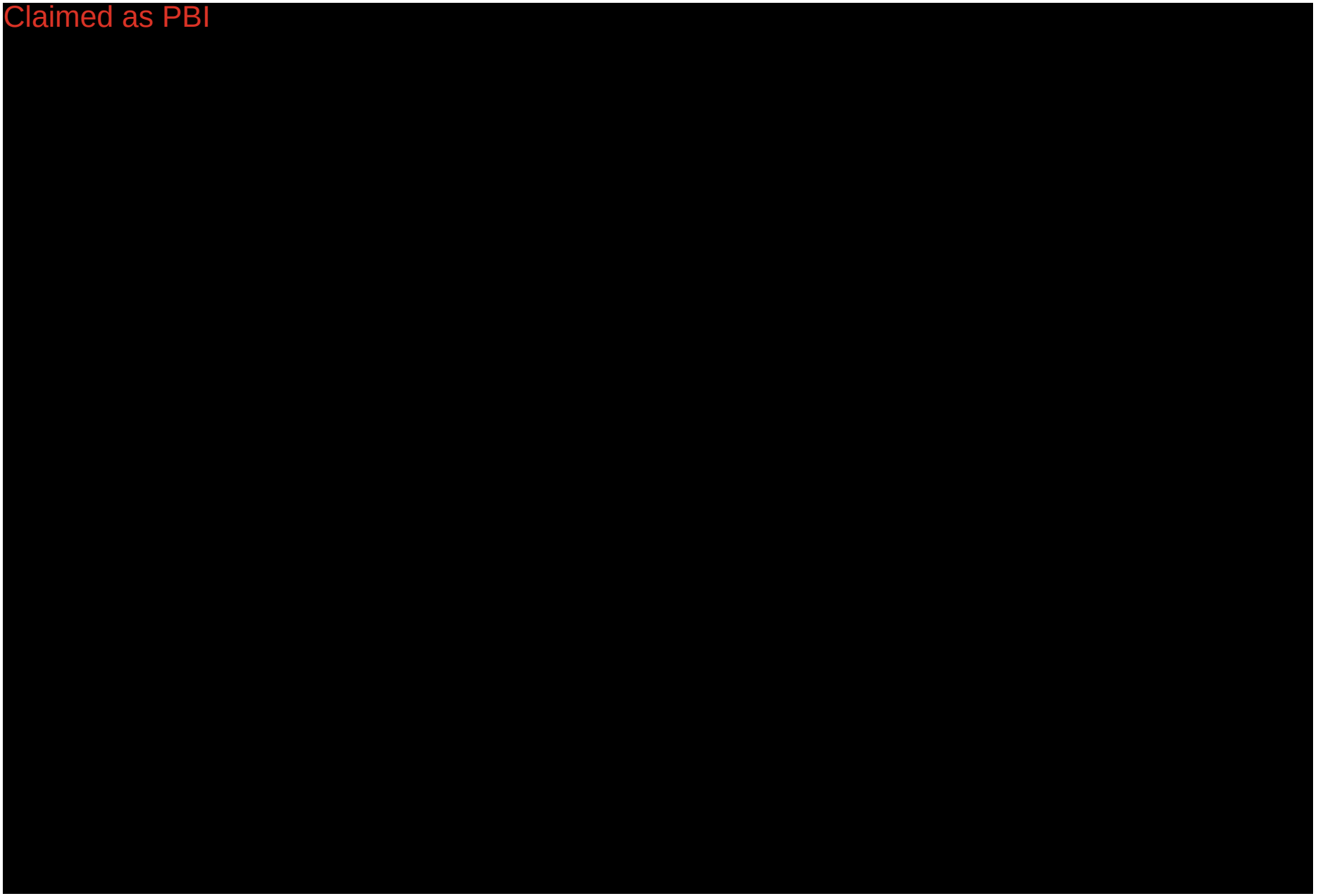
No artificial reefs, oyster reefs, or seagrass areas were identified in the studies. Field studies will be completed at injection and monitoring well locations, prior to drilling, to confirm absence of reefs or seagrass. Additionally, BAT will be implemented during drilling, construction, operation, and PISC phases of the project to minimize potential impacts.

Claimed as PBI

[3] Green Sea Turtle Critical Habitat | U.S. Fish & Wildlife Service (fws.gov)

[4] Federal Register: Endangered and Threatened Wildlife and Plants: Proposed Rule To Designate Marine Critical Habitat for Six Distinct Population Segments of Green Sea Turtles

Claimed as PBI



10.2.1.1 Infrastructure

Infrastructure in the vicinity of the proposed injection wells that may be affected by an emergency at the project site (**Figure 10-3**) include:

Claimed as PBI

[redacted]

- Commercial Fishing
- Maritime Transportation
- Existing Wells/Well Platforms

Claimed as PBI



10.3 Potential Risk Scenarios

The following events related to BBE activities that could potentially result in an emergency response:

- Injection or monitoring well integrity failure
- Injection well monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.)
- Potential brine or CO_2 leakage to Texas State Waters
- Natural disaster
- Induced seismic event

The Emergency Response Organization (ERO) consists of the following teams.

- Facility Emergency Response Teams (FERTs): The FERT is responsible for organizing and managing at-the-site tactical response operations.
- Incident Management Team (IMT): The IMT is organized to carry out the following major functions: command, operations, planning, logistics, and finance.
- Crisis Management Team (CMT): The CMT is organized to provide support and guidance to the IMT for crisis communications, emergency response and business continuity operations.

These teams are supported by personnel and contractors based in the Houston Area. If needed, these teams can be supplemented by personnel and contractor resources located outside the region.

Resource personnel that are available and/or on call for emergency and response actions include but not limited to company employees and contractors from the following functional teams.

- Facilities
- Health, Safety and Environmental
- Communications / Corporate Affairs / Legal
- Well Source Control
- Finance / Procurement

Equipment used to implement response actions associated with an emergency and remedial response will vary, depending on the severity of the event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment and materials (such as a drilling rig, logging equipment, etc.) is required, the Operator will be responsible for its procurement.

To aid in the phased commitment of response resources, incidents/emergency events are classified by severity into three levels. Response actions will depend on the severity of the event(s) triggering an emergency response. Emergency events are categorized as shown in **Table 10-1.**

Table 10-1: Degrees of risk for emergency events.

Emergency Condition	Definition
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Moderate emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

A major emergency requires the activation of an IMT and may also trigger the activation of the CMT. The CMT will be activated based on the support needs of the IMT.

Table 10-2 provides guidance on the relationship that exists between the severity of an incident and the elements of the ERO that are most likely to respond to the incident.

Table 10-2: BBE Emergency Response Organization, Levels of Response

Severity	Levels of Response		
	FERT	IMT	CMT
Level 1: Minor	X		
Level 2: Moderate	X	X	
Level 3: Major	X	X	X

10.4 Emergency Identification and Response Actions

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The following potential risk scenarios identified are:

- Well integrity failure
- Injection well monitoring equipment failure
- Potential brine or CO_2 leakage to Texas State Waters
- Natural disaster
- Induced seismic event

10.4.1 Well Integrity Failure

Integrity loss of the injection or monitoring well may endanger local resources within Texas State Waters. Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
    - Wellhead pressure exceeds the specified shutdown pressure specified in the permit.
    - Annulus pressure indicates a loss of external or internal well containment.
    - Mechanical integrity test results identify a loss of mechanical integrity.

Response actions:

- Immediately notify the BBE facility supervisor or delegate.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- The facility supervisor will make an initial assessment of the incident and Level and activate the ERO (FERT, IMT, and/or CMT), as applicable.
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- The ERO will work with subject matter experts (SMEs) to make a final decision on the Level of the incident, based on the information available, within 24 hours of notification.
- For a Level 1 Incident
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity:
    - Shut in well (close flow valve), if applicable.
    - Vent CO_2 from surface facilities, if applicable.
    - Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure; identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Level 2 or 3 Incident:
    - Shut in well (close flow valve), if applicable.
    - Vent CO_2 from surface facilities, if applicable.
    - Limit access to authorized personnel only.
    - Communicate with BBE personnel and local authorities to initiate evacuation plans, as necessary.
    - Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure; identify and implement appropriate remedial actions to repair damage to the well (in consultation with the UIC Program Director).
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).

10.4.2 Injection Well Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger local resources within Texas State Waters.

Response actions:

- Immediately notify the BBE facility supervisor or delegate.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- The facility supervisor will make an initial assessment of the incident and Level and activate the ERO (FERT, IMT, and/or CMT), as applicable.
- The ERO will work with SMEs to make a final decision on the Level of the incident, based on the information available, within 24 hours of notification.
- For a Level 1 Incident
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity:
    - Shut in well (close flow valve), if applicable.
    - Vent CO_2 from surface facilities, if applicable.
    - Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure; identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Level 2 or 3 Incident:
    - Shut in well (close flow valve), if applicable.
    - Vent CO_2 from surface facilities, if applicable.
    - Limit access to authorized personnel only.
    - Communicate with BBE personnel and local authorities to initiate evacuation plans, as necessary.
    - Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of failure; identify and implement appropriate actions to repair damage to the well (in consultation with the UIC Program Director).
    - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).

10.4.3 Potential Brine or CO_2 Leakage to Texas State Waters

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or CO_2 leakage to Texas State Waters.

Response actions:

- Immediately notify the BBE facility supervisor or delegate.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).

- The facility supervisor will make an initial assessment of the incident and Level and activate the ERO (FERT, IMT, and/or CMT), as applicable.
- The ERO will work with SMEs to make a final decision on the Level of the incident, based on the information available, within 24 hours of notification.
- For all incidents (Levels 1, 2, or 3):
    - Shut in well (close flow valve), if applicable.
    - Vent CO_2 from surface facilities, if applicable.
    - Collect confirmation sample(s) of groundwater and analyze indicator parameters.
    - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
        - Install additional monitoring points, if needed, near the impacted area to delineate the extent of impact, and
        - Evaluate impacts to the Texas State Waters.
        - Proceed with efforts to mitigate and remediate unsafe conditions.
        - Continue monitoring and remediation on a frequent basis (frequency to be determined by the Operator and the UIC Program Director) until unacceptable adverse impact has been fully addressed.

10.4.4 Natural Disaster

Well problems (integrity loss, leakage, or malfunction) may arise because of a natural disaster impacting normal operations at the site. An earthquake may disturb surface and/or subsurface facilities; and weather-related disasters (e.g., tornado, hurricane, or lightning strike) may impact surface facilities that initiate the response actions below.

Response actions:

- Immediately notify the BBE facility supervisor or delegate.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- The facility supervisor will make an initial assessment of the incident and Level and activate the FERT, IMT, and/or CMT, as applicable.
- The ERO will work with SMEs to make a final decision on the Level of the incident, based on the information available, within 24 hours of notification.
- For a Level 1 incident:
    - Conduct assessment to determine whether there has been a loss of mechanical integrity.
    - If there has been a loss of mechanical integrity:
    - Shut in well (close flow valve), if applicable.
    - Vent CO_2 from surface facilities, if applicable.
    - Limit access to authorized personnel only.
    - Monitor well pressure, temperature, and annulus pressure to verify integrity loss and determine the cause and extent of any failure.
    - Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).

- For a Level 2 or 3 incident:
    - Shut in well (close flow valve), if applicable.
    - Vent CO_2 from surface facilities, if applicable.
    - Limit access to authorized personnel only.
    - Communicate with BBE personnel and local authorities to initiate evacuation plans, as necessary.
    - Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure.
    - Determine if any leaks to Texas State Waters occurred.
    - If impact or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).

10.4.5 Induced Seismic Event

Based on the project subsurface and operating conditions, it is highly unlikely that injection operations would induce a seismic event outside a 4-mile radius from the wellhead. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within a 4-mile radius of the injection well.

Claimed as PBI

[redacted]

Table 10-3 provides a summary of operating states, probable incident level, threshold conditions, and response actions. The operating state corresponds to threshold criteria that in turn corresponds to the site's potential risk and level of seismic activity and corresponding response actions. The actual incident Level will be evaluated and determined at the time of the event.

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in **Table 10-3**. The table corresponds to each level of operating state with the threshold conditions and operational response actions.

Table 10-3: Bayou Bend Induced Seismicity Response Actions[5]

Operating State	Probable Incident Level[6]	Threshold Condition	Response Action
Green	Not applicable	Seismic events[7] less than or equal to M 1.5	• Continue normal operation. • Monitor and record seismic activity at regular intervals until baseline conditions are restored.
Yellow	Level 1	Five or more seismic events within a 30-day period having a magnitude greater than M 1.5 but less than or equal to M 2.0	• Continue site activities per permit conditions. • Activate FERT to monitor operational performance and identify issues of potential concern. • Within 24 hours of the incident, notify the UIC Program Director. • Monitor and record seismic activity at regular intervals until baseline conditions are restored.
Orange	Level 1 or 2	Seismic event greater than M 1.5, but less than M 2.0 AND local observation or "felt" report;[8] OR Seismic event greater than or equal to M 2.0 with no local observation or "felt" report.	• Continue site activities per permit conditions. • Activate FERT to monitor operational performance and identify issues of potential concern. • Within 24 hours of the incident, notify the UIC Program Director. • Initiate corrective actions and, if applicable, implement Level 2 protocols by activating the IMT. • Monitor and record seismic activity at regular intervals until baseline conditions are restored or through the period of corrective action (as applicable), until baseline conditions are restored. • Report findings to UIC Program Director within 25 business days of initial notification.

[5] Assumed operating baseline is less than or equal to an M 1.0 seismic event.

[6] The actual incident level will be evaluated and determined at the time of the event.

[7] Seismic event to be measured and detected within a 4-mile radius of the injection well.

[8] Confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel it?" reporting system at: https://www.usgs.gov/data/did-you-feel-it

Red	Level 2 or 3	Seismic event greater than M 2.0, AND Local observation or "felt" report and/or reports of damage.	• Assess situation and implement either Level 2 or Level 3 protocols based on available information (i.e., activate FERT, IMT, and notify or activate CMT). • Restrict site access to authorized personnel. • Within 24 hours of the incident, notify UIC Program Director. • Monitor operational performance and identify issues of potential concern. • Initiate corrective actions as follows: – Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director). – Determine if leaks to Texas State Waters occurred. – Monitor and record seismic activity at regular intervals until baseline conditions are restored or through the period of corrective action (as applicable), until baseline conditions are restored. – Report findings to UIC Program Director within 25 business days of initial notification.

10.5 Response Personnel and Equipment

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. BBE Operations Manager
2. BBE Facility Supervisor
3. BBE Health, Safety and Environmental Manager
4. BBE Project Engineer(s)
5. BBE Corporate Communications
6. BBE Operating Committee Members

A site-specific emergency contact list will be developed and maintained during the life of the project. BBE will provide the current site-specific emergency contact list to the UIC Program Director.

Table 10-4: Contact Information for Key Local, State, and Other Authorities

Agency	Phone Number
Railroad Commission of Texas (RRC) 24-hour emergency reporting line	844-773-0305 (toll-free) or 512-463-6788
Beaumont Police Department	911 or 409-832-1234
Taylor Landing Police Department	911 or 512-352-5551
Texas State Police	911 or 855-492-3244
Texas State Emergency Response Commission	211 or 877-541-7905
Environmental Services Contractor (ERM)	713-775-4505
Emergency Response Contractor (E3 Environmental)	844-333-0939
UIC Program Director, Region 6 EPA	214-665-7252
EPA National Response Center (24 hours)	800-424-8802
Texas Geological Survey	512-471-0140
U.S. Army Corps of Engineers, Galveston Division	409-766-3800
U.S. Coast Guard	361-749-5217
Texas General Land Office	512-784-2640
U.S. Fish and Wildlife Service, Humble, Texas	281-230-7225
U.S. Fish and Wildlife Service, Liberty, Texas	936-336-9786
U.S. Fish and Wildlife Service (Austin Field Office)	512-937-7371
Texas Parks and Wildlife, Coastal Fisheries Field Office, Sabine Lake Ecosystem	409-983-1104
Texas Parks and Wildlife, Coastal Fisheries Field Office, Galveston Bay Ecosystem	281-534-0110
National Marine Fisheries Service, Galveston, Texas	409-766-3500
University of Texas Medical Branch, Galveston, Texas	409-772-9505
Memorial Hermann Texas Medical Center, Houston, Texas	713 704-4000
Christus Southeast Texas, Beaumont, Texas	409-892-7171

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, BBE shall be responsible for its procurement.

10.6 Emergency Communications Plan

BBE has developed a Stakeholder Engagement and Communication Plan and will be responsible for issuing public communications regarding emergency response events. Communications will be bilingual dependent on local community population, if needed, and phrased in understandable ("plain language") terms. The objective is to clearly communicate what happened and if there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, including but not limited to potential or actual impacts to drinking water or other environmental resources, including impacts to the surrounding community.

BBE will describe what happened, any impacts to the environment or other local resources, what responses were taken, and the status of the response. For responses that occur over the long-term (e.g., ongoing cleanups), BBE will provide periodic updates on the progress of the response action(s).

BBE will communicate with entities who may need to be informed about or respond to the event, including local water systems, CO_2 source(s) and pipeline operators, landowners, and regional or other response teams.

10.6.1.1 Communication Protocols

The Communications Plan includes communication protocols to enable effective and organized communication and timely action. Communication over the networks is regulated through these protocols. A protocol not only defines who will talk to whom over a network, but also specifies what they will talk about and when.

The Communications Plan provides for communication of information on the nature and status of FERT response operations and the IMT and CMT members. All media inquiries will be directed to BBE external and media communications at: info@bayoubend.com.

The timing and content of routine updates will vary depending on the nature and status of the emergency and could include any or all of the following topics:

- Status of personnel (i.e., people on-site, unaccounted for, accounted for, injured, etc.)
- Status of source
- Incident weather
- Changes in organization / assignments
- Location(s) of muster and/or shelter areas
- Location(s) of staging area(s), if established
- Available resources by staging area, if established
- Location of the isolated areas
- Results of site characterizations, particularly from air sampling

- Location of decontamination area(s)
- Protective personnel equipment (PPE) requirements
- Progress/problems being addressed by response teams
- Specific needs

10.7 Plan Review

The ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) re-evaluation;
- Within 90 business days following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, BBE will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If one of the reviews listed above indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within 90 business days following an event that initiates the ERRP review procedure.

10.8 Staff Training and Exercise Procedures

BBE will include ERRP training into all onboarding training for employees fit-for purpose. Visitors and occasional workers will receive site-specific training as warranted. Facility response personnel will receive more in-depth training, including detailed emergency response procedures. Desktop or actual drills using different and most probable emergency scenarios shall be conducted at least once per calendar year. Periodic refresher training will be provided, not less than annually, to well operators, facility safety and environmental personnel, the facility manager, facility supervisor, and corporate communications. The training plan will document that the above listed personnel have been trained and possess the required skills to perform their relevant emergency response activities described in the ERRP.

10.9 Additional Information

10.9.1 Underground Sources of Drinking Water

Claimed as PBI

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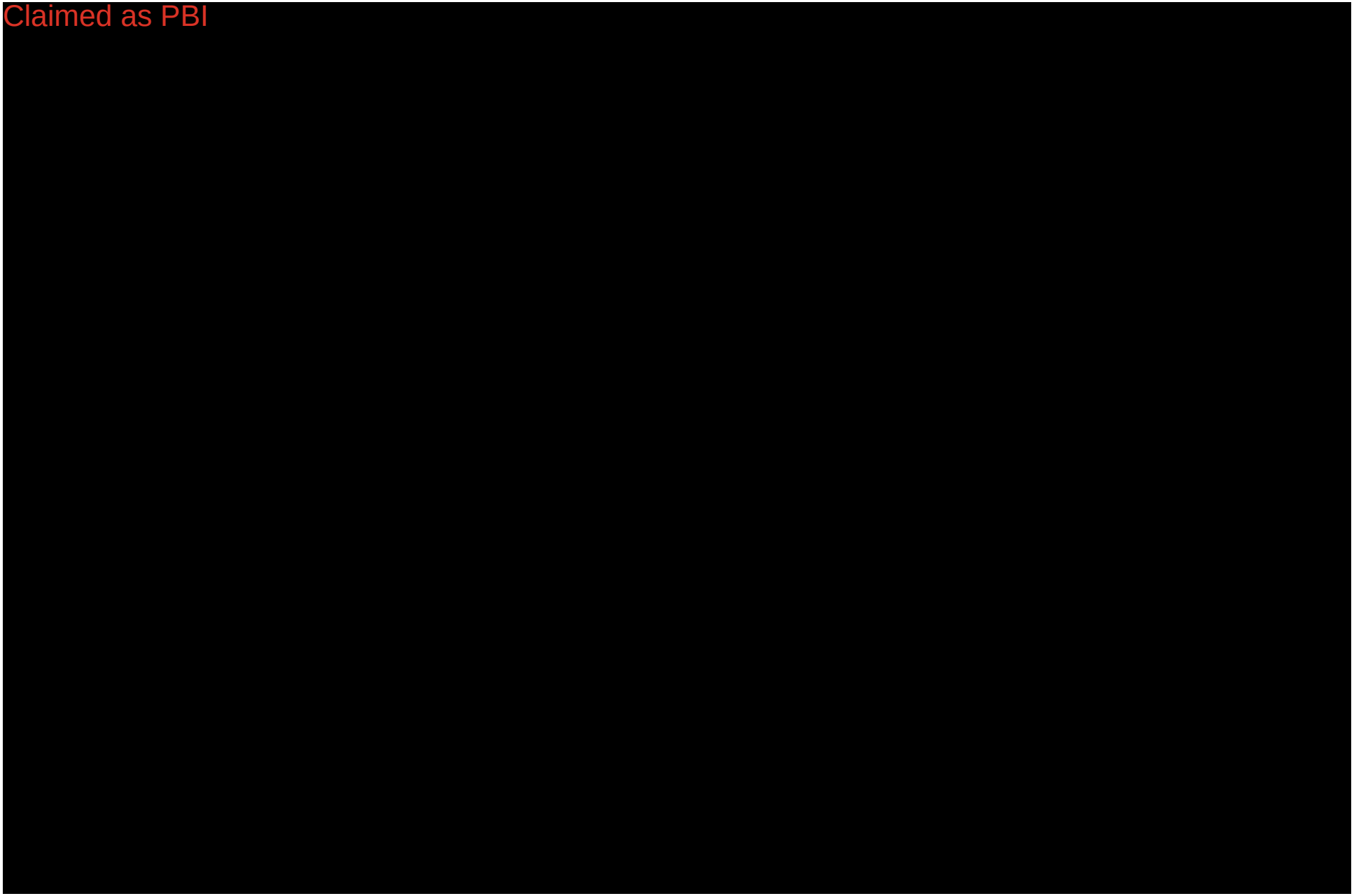
Claimed as PBI



10.9.2 Acronyms

AOR	Area of Review
BAT	best available technologies
BBE	Bayou Bend East SL20220050
BBE-P1	Bayou Bend East SL20220050 – Phase 1
BGS	below ground surface
CCS	carbon transport and sequestration
CMT	crisis management team
CO_2	carbon dioxide
DAS	Distributed acoustic sensing
EFH	Essential fish habitat
ERM	Environmental resources management
ERO	Emergency response organization
ERRP	Emergency Response Plan
FERT	facility emergency response teams
IMT	incident management team
NMFS	National Marine Fisheries Service
PISC	Post-injection Site Care
PPE	Protective Personnel Equipment
RRC	Railroad Commission of Texas
SME	Subject Matter Expert
TDS	total dissolved solids
UIC	Underground Injection Control
USDW	underground sources of drinking water
USFWS	United States fish and wildlife service
USGS	United States Geological Survey

I. Post-Injection Site Care and Site Closure Plan

Plan revision number: 003
Plan revision date: September 2026

POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

Bayou Bend East SL20220050 (BBE)

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Figure 9-5: Critical pressure evolution after cessation of injection at the beginning of 2047 for the duration of the PISC period. Image is taken at the beginning of the year shown on the top of each pane. Well locations are bottomhole locations. At and after 2052, no region of the model has pressure differential greater than 58 psi, and thus no critical pressure front is shown. 11

Figure 9-6: Monitoring well plugging schematic 22

9 POST-INJECTION SITE CARE AND SITE CLOSURE PLAN 40 CFR 146.93(A)

Bayou Bend East SL20220050 (BBE)

9.1 Facility Information

Facility Name: BAYOU BEND EAST SL20220050 – PHASE 1 (BBE-P1)
SL20220050 W1, SL20220050 W2, SL20220050 W4, SL20220050 W5, SL20220050 W6

Facility Contact: Claimed as PBI
1500 LOUISIANA STREET, 11TH FLOOR
HOUSTON, TEXAS 77002
Claimed as PBI

Site Location: GULF OF MEXICO, TEXAS STATE WATERS
HIGH ISLAND BLOCK
JEFFERSON COUNTY, TEXAS
29.5920225°, -93.89526008°

9.2 Introduction

This Post-Injection Site Care (PISC) and Site Closure Plan describes the activities that Bayou Bend CCS LLC (Operator) will perform to meet the requirements of 40 CFR 146.93. The Operator will monitor ground water quality above the confining zone and track the position of the carbon dioxide (CO_2) saturation front and pressure front. No underground source of drinking water (USDW) has been identified at Bayou Bend East SL20220050 (BBE). The Operator will conduct monitoring for at least 50 years unless an alternative timeframe duration is discussed and approved by the Underground Injection Control (UIC) Program Director following the cessation of injection. Following approval for site closure, the Operator will plug monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

9.3 Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

The location of injectors and monitoring well in relation to the Area of Review (AOR) and faults penetrating through Claimed as PBI

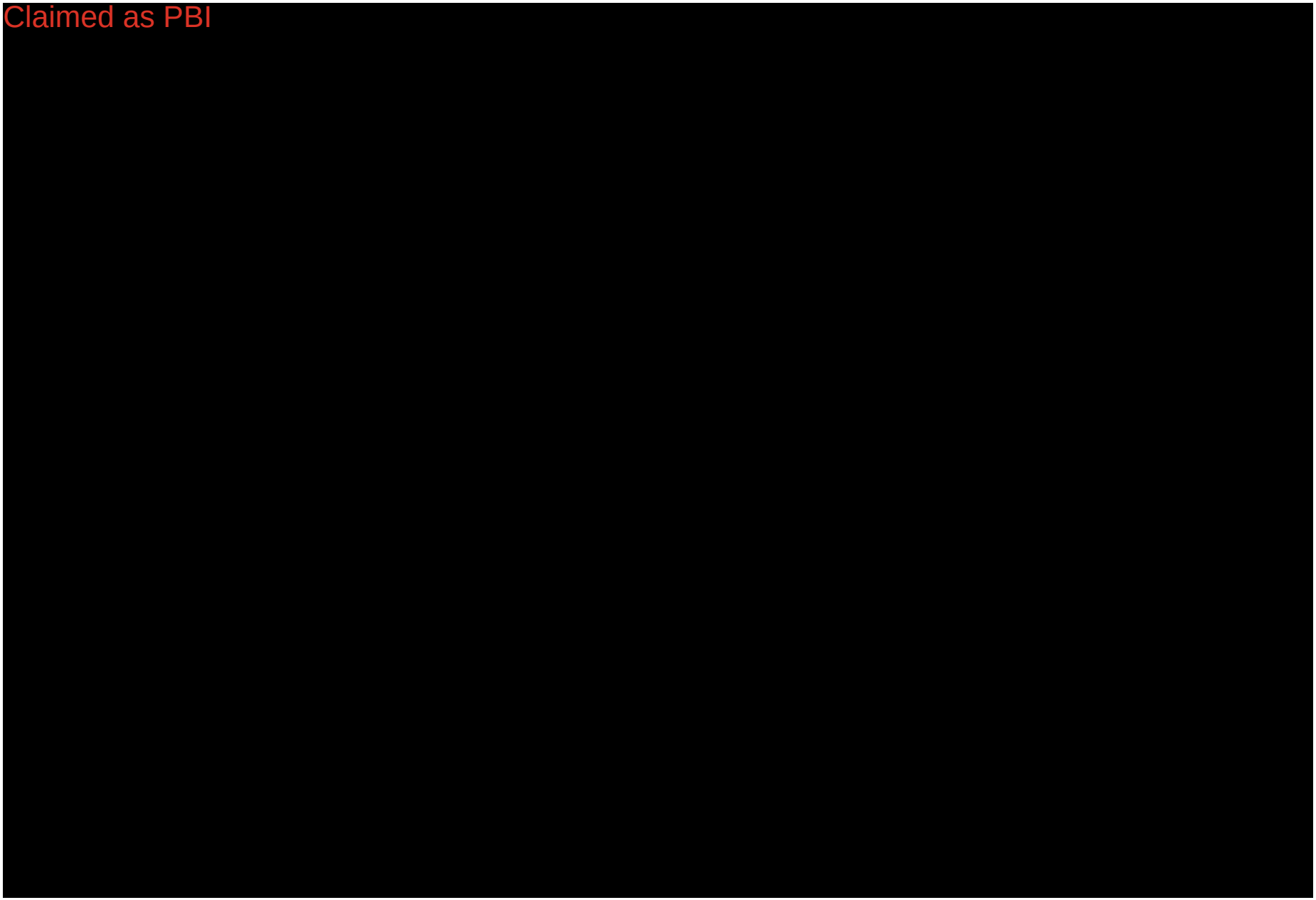
Claimed as PBI

Claimed as PBI

Additional information on the projected post-injection pressure declines and differentials is presented in the AOR and Corrective Action Plan.

Table 9-1 demonstrates the maximum reservoir pressure differential near each wellbore and the year at which this occurs. Claimed as PBI

Claimed as PBI



Claimed as PBI



Claimed as PBI



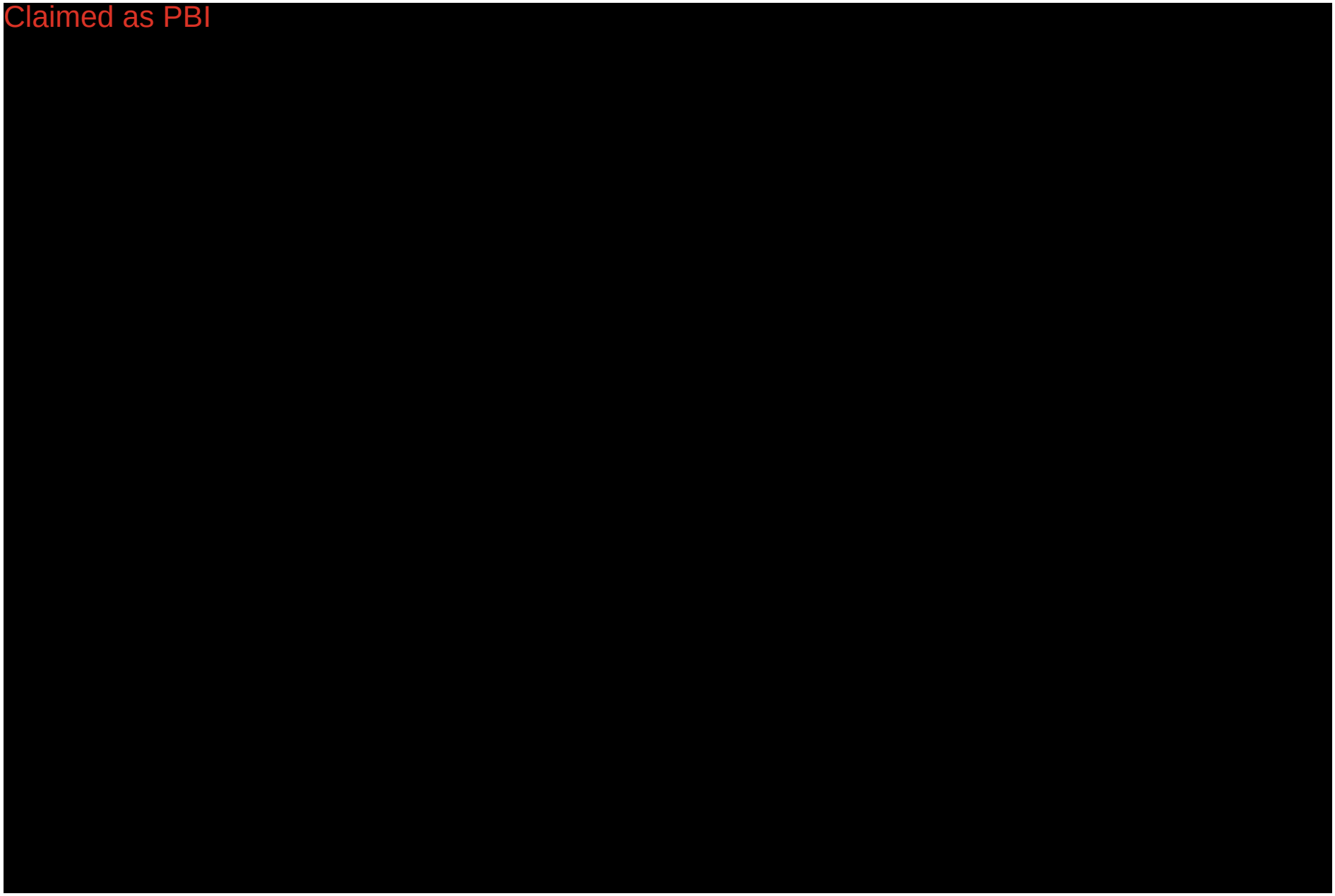
Claimed as PBI



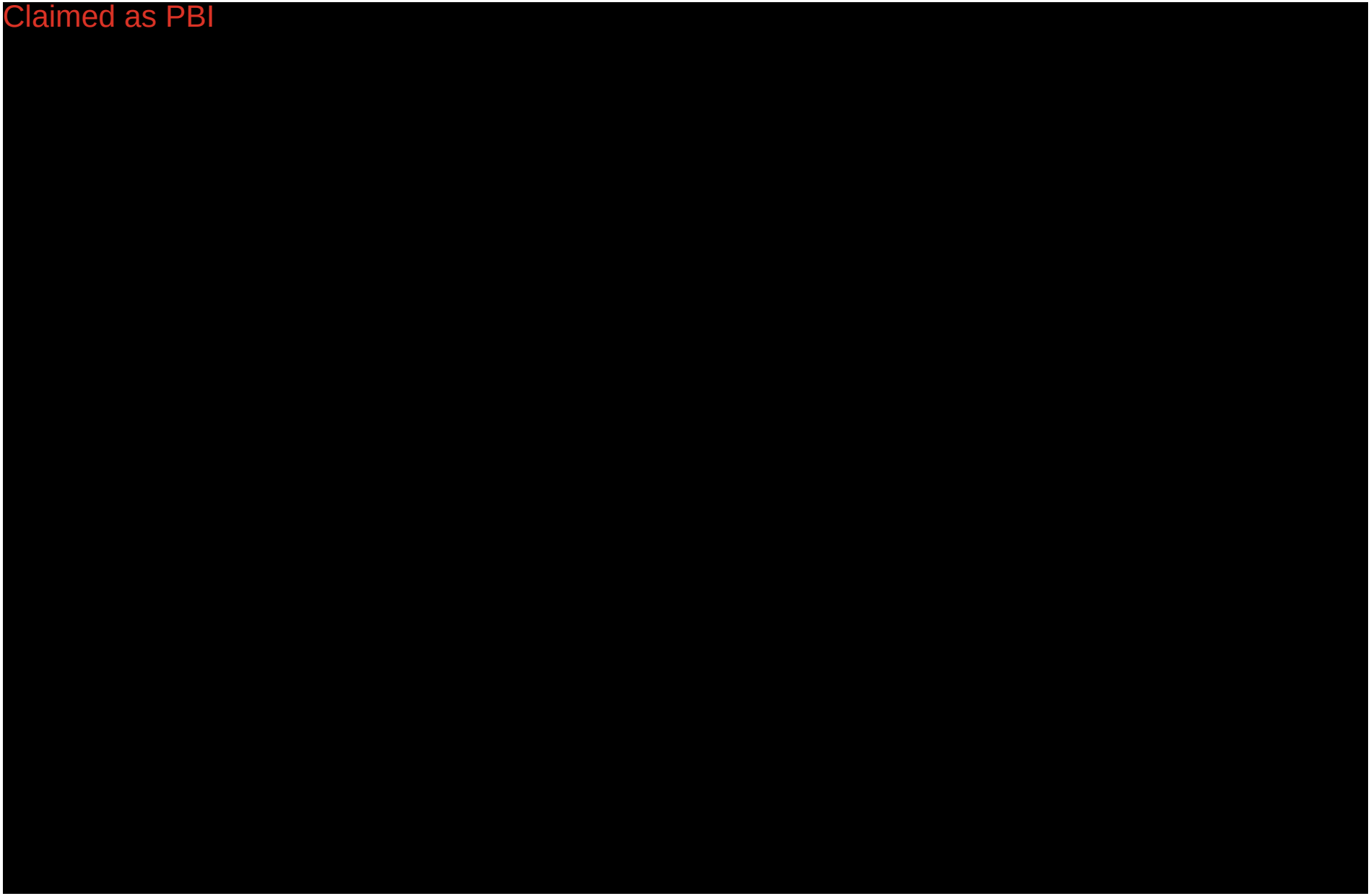
9.4 Predicted Position of the CO_2 Saturation Front and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 9-4 shows the predicted extent of the CO_2 saturation front at various intervals throughout the PISC timeframeClaimed as PBI [redacted] **igure 9-5** demonstrates the pressure front throughout the PISC timeframe with the bottom right frame demonstrating Claimed as PBI [redacted] These maps are based on the final AOR delineation modeling results submitted pursuant to 40 CFR 146.84.

Claimed as PBI



Claimed as PBI



9.5 Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Claimed as PBI [redacted] The Operator will leverage existing injection and monitoring wells from the operation phase (**Figure 9-1**) of the project. The results of post-injection period testing and monitoring will be submitted annually, within 90 days following the anniversary of the date on which injection ceases or alternatively with prior approval of the UIC Program Director, as described under Section 9.5.3 below.

9.5.1 Monitoring Above the Confining Zone

Table 9-2 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. **Table 9-3** identifies the parameters to be monitored and the analytical methods.

Claimed as PBI [redacted]

Measurements will be collected continuously at 1-minute sampling (unless data during the operation phase suggests otherwise), and gauges will be replaced if they fail. Monitoring will continue from after the last day of injection to site closure. Additional monitoring technology may be deployed based on CO_2 movement.

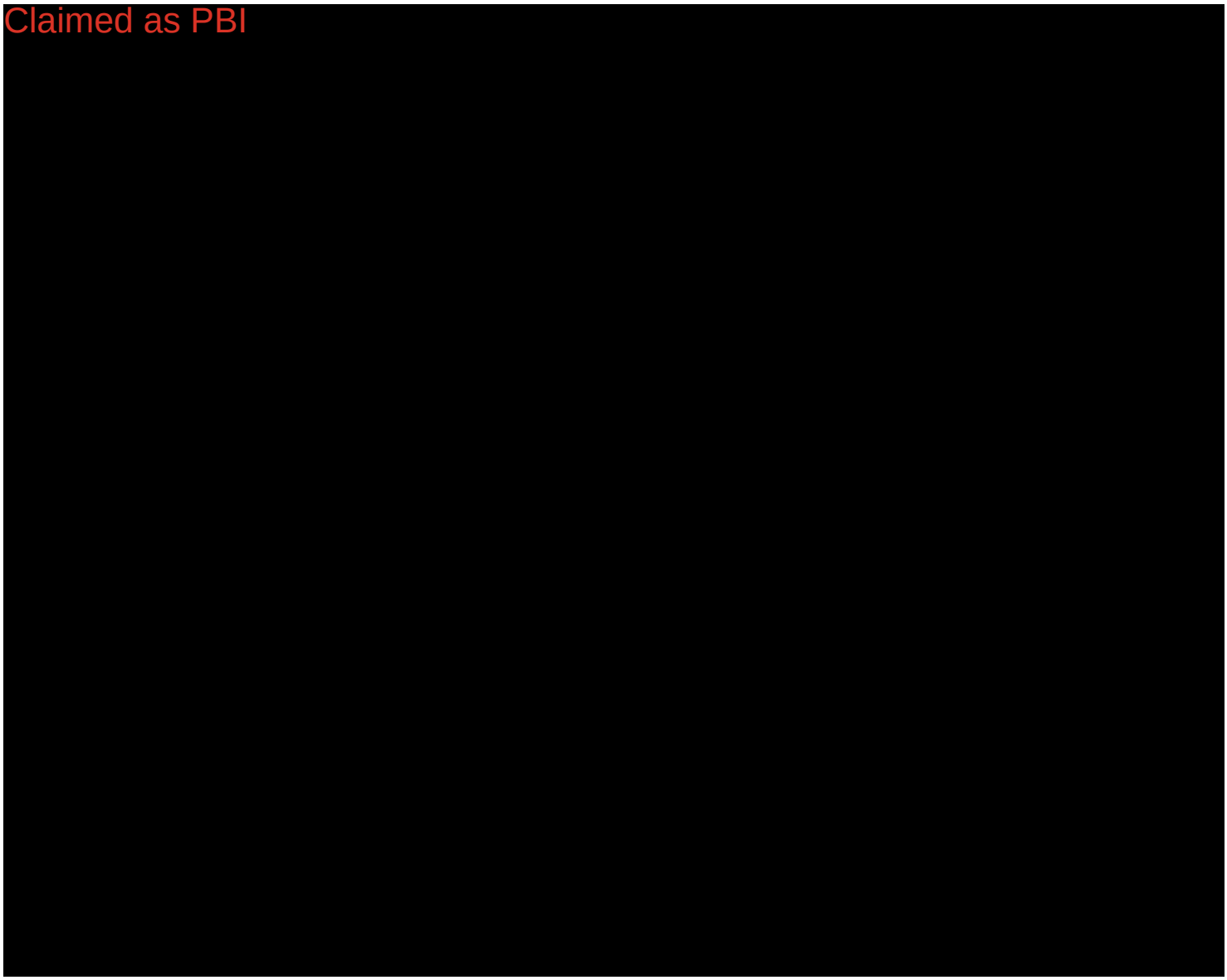
Claimed as PBI



Table 9-3. Summary of analytical and field parameters for ground water samples during the PISC phase of the project.

Parameters	**Analytical Methods***
Claimed as PBI	
pH (lab)	
pH (field)	Standard Method 4500-H+ B-2000
Specific conductance (lab)	
Specific conductance (field)	Standard Method 2510 B-1997
Temperature (field)	Thermistor, Standard Method 2550 B-2000
Alkalinity (total and bicarbonate)	SM 2320B
Oxidation-Reduction Potential (field)	Platinum Button; Ag/AgCl Reference
Total dissolved solids	SM 2540C
Cations: Al, Ba, Mn, As, Cr, Pb, Se, Sr, Tl, Zn, Ca, Fe, K, Mg, Na, Si, B	ICP-MS, EPA Method 6020B, ICP, EPA Method 6010D
Anions: Br, Cl, F, and SO_4	Ion chromatography, EPA Method 300.0
Alkalinity (total and bicarbonate)	SM 2320B
Dissolved Inorganic Carbon (DIC)	SM 5310B
$\delta^{13}C$ of DIC	IRMS
Water density (lab)	
Water density (field)	hydrometer
Turbidity (lab)	
Turbidity (field)	Nephelometric - Optical, 90° Scatter
Sulfide (lab)	
* Analytical methods subject to change with approval from UIC director ** Analyte list may change depending on results from baseline assessment	

Claimed as PBI



9.5.2 Carbon Dioxide Saturation and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

Claimed as PBI

Table 9-5 presents the indirect methods that the Operator will use to monitor the CO_2 saturation, including the activities, locations, and frequencies the Operator will employ. Claimed as PBI

Any updates to the PISC period will be discussed with and approved by the UIC Program Director within 30 days per TAC §5.206(k)(1)(C).

Claimed as PBI

Table 9-6 presents the direct methods that will be used to monitor the injection zone pressures and temperatures during early PISC period. Wellhead pressure and temperature gauges will be maintained on the injector wells after injection ceases and until they are plugged and abandoned. The drop in reservoir pressure at the injector locations will be used in simulation model updates to estimate the extent of the pressure front. Measurements will be recorded every hour at each wellhead until the injectors are Plugged and abandoned.

Fluid sampling will not be performed in the injection zone during the PISC period. The Operator will rely on indirect monitoring techniques (i.e. seismic or logs) to detect saturation changes.

Table 9-5. Post-injection period saturation front monitoring.

Claimed as PBI

Table 9-6. Post-injection period pressure-front monitoring.

Claimed as PBI

[redacted]

9.5.3 Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

Post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to annually, within 90 days following the anniversary of the date on which injection ceases or alternatively with prior approval of the UIC Program Director. The reports will contain information and data generated during the reporting period, i.e. well-based monitoring data, seismic surveying, and the results from updated site models.

9.6 Alternative Post-Injection Site Care Timeframe [40 CFR 146.93(c)]

Not applicable to this project at this time.

9.7 Non-Endangerment Demonstration Criteria

Prior to approval of the end of the post-injection period, the Operator will submit a demonstration of non-endangerment of USDWs to the UIC Program Director, per 40 CFR 146.93(b)(2) and (3). While no USDW was identified at BBE [Narrative, Section 2.7.1], the Railroad Commission of Texas (RRC) is mandated to protect surface and subsurface water from pollution under 16 TAC §4.101. This demonstration will include non-endangerment to the seafloor.

The owner or operator will issue a report to the UIC Program Director. This report will make a demonstration of USDW non-endangerment based on the evaluation of the site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration evaluation uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and supporting data, and any other information necessary for the UIC Program Director to review the analysis. The report will include the following sections:

9.7.1 Introduction and Overview

A summary of relevant background information will be provided, 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.

9.7.2 Summary of Existing Monitoring Data

A summary of previous monitoring data collected at the site, pursuant to the Testing and Monitoring Plan of this permit and this PISC and Site Closure Plan, including data collected during the injection and post-injection periods of the project, will be submitted to help demonstrate non-endangerment. Data submittals will be in a format acceptable to the UIC Program Director [40 CFR 146.91(e)], and will include a narrative explanation of monitoring activities, including the dates of monitoring events, changes to the monitoring program over time, and an explanation of monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization [40 CFR 146.82(a)(6) and 146.87(d)(3)].

9.7.3 Summary of Computational Modeling History

The computational model results demonstrate the non-endangerment of the USDW with the following points:

- The high quality of the injection zone in sequestration of CO_2.
- The stabilization of the CO_2 saturation front in the 50-year PISC duration once injection ends (**Figure 9-4**)
- The rapid dissipation of pressure in the injection interval once injection ends (**Figure 9-2** and **Figure 9-5**)
- The maintenance of integrity in the confining zone through geomechanical modeling [Narrative, Section 2.5.6].

Claimed as PBI

In addition, during the post injection monitoring period, the monitoring data that will be used to validate and calibrate the computational model includes injection zone and above zone pressure data and periodic seismic surveys.

9.7.4 Evaluation of Reservoir Pressure

During the PISC period, the pressure within the injection zone is expected to dissipate rapidly once the injection ends. The pressure in the injection zone is the principal risk for fluid movement through artificial penetrations as well as to the integrity of the confining zone, thus reducing the risk to existing USDWs.

Claimed as PBI

pressures will be compared to the predicted pressure from the computational model and the accuracy of these values will provide confidence in the forecasted reservoir pressures.

9.7.5 Evaluation of Carbon Dioxide Saturation Front

Claimed as PBI

Claimed as PBI [redacted] data will be used to demonstrate the stabilization of the CO_2 saturation front and calibrate the computational model. Claimed as PBI [redacted]

9.7.6 Evaluation of Emergencies or Other Events

Table 9-7 provides a summary of the monitoring data that will be collected during the PISC period and used to demonstrate that injection zone fluids have not migrated above the confining layer. Data collected through the injection and PISC phases of the project will be compared to the baseline data gathered pre-injection.

The Emergency and Remedial Response Plan (ERRP) includes further discussion of how emergencies or other events will be addressed by the project.

Table 9-7: Summary of monitoring data used to demonstrate non-endangerment.

Claimed as PBI [redacted]

9.8 Site Closure Plan

The Operator will conduct site closure activities to meet the requirements of 40 CFR 146.93(e) as described below. The Operator will submit a final Site Closure Plan and notify the permitting agency at least 120 days prior of its intent to close the site. Once the permitting agency has approved closure of the site, the Operator will plug the monitoring wells and submit a site closure report to the UIC Program Director. The activities, as described below, represent the planned activities based on information provided to UIC Program Director. The site closure plan to be implemented following cessation of injection may employ different and/or updated methods and procedures based on discussion and approval by the UIC Program Director within 30 days per TAC §5.206(k)(1)(C). Upon cessation of injection, the operator will submit an amended plan or demonstrate to the UIC Program Director through monitoring data and modeling results that no

amendment to the plan is needed. A final Site Closure Plan will be submitted to the UIC Program Director for approval with the notification of the intent to close the site.

9.8.1 Plugging Monitoring Wells

The Operator will use the materials and methods noted in **Table 9-8** to plug each monitoring well. The volume and depth of the plug or plugs will depend on the final geology and downhole conditions of the well as assessed during construction. The cement(s) formulated for plugging will be compatible with the CO_2 injectate. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

Cement plugs will be calculated considering available data, which may include casing caliper data or at a minimum nominal casing internal diameter (IDs). Cement design and testing on balanced plugs along with cement simulations to confirm cement designs meet the minimum height provided in the cement plug details. Plugging details included in **Table** 9-8 are based on vertical well with respect to depths.

Claimed as PBI

[redacted]

Plan revision number: 003
Plan revision date: September 2026

Narrative Description of Monitoring Well Plugging Procedures

Notification and/or additional permits related to plugging and abandonment will be provided to or obtained from the US Environmental Protection Agency (Region 6), RRC, Texas Committee on Environmental Quality (TCEQ), and the United States Army Corps of Engineers (USACE). All required Federal and State permits will be acquired prior to starting operations.

Advance notice will also be provided to the Texas General Land Office, the United States Coast Guard, and other stakeholders who might be impacted by plugging and abandonment operations.

The procedures described in the following sections are subject to modification during execution as necessary to ensure a plugging operation that protects worker safety and is effective to protect potential USDWs. Any significant modifications due to unforeseen circumstances will be described in the plugging report. The completed plugging report with charts and laboratory information will be sent to the regulatory agencies as required by permits. The plugging report shall be certified as accurate by Operator and plugging contractor and shall be submitted within 60 days after plugging is completed.

Below includes the generic permanent plugging procedure for the proposed injection wells. In consultation with the UIC program Director, the plugging procedure may be revised based on actual wellbore conditions encountered during operations:

1) Move in rig or hydraulic workover unit and rig up.
2) Kill the well to allow for the removal of the completion string.
3) Pull Monitoring Tubing and packer from well (as necessary).
4) Trip in hole with work string to top of sump packer.
5) Mix and pump spacer and cement plug #1 across Claimed as PBI [redacted]
6) Trip out of balanced plug at rate that prevents disrupting the plug.
7) Trip in hole with cement retainer and set same ~50 feet Claimed as PBI [redacted]
8) Trip out of hole with cement retainer running tool.
9) Trip in hole with work string to cement retainer.
10) Mix and Pump spacer and cement plug #2.
11) Trip out of balanced plug at rate that prevents disrupting the plug.
12) Trip out of hole to ~300 ft below mud line.
13) Mix and Pump spacer and cement plug #3.
14) Trip out of hole to surface.

Representative Monitoring Well Plugging Schematic

A representative schematic of the SL20220050 M1 monitoring well post plugging operations can be seen in **Figure 9-6**.

Claimed as PBI

9.8.2 Site Closure Report

The Operator will perform site closure activities to meet the requirements of 40 CFR 146.93(e) as provided in this Plan and as described in the Injection Well Plugging Plan (Section 8 of this Class VI UIC Application). The Operator will submit a final Site Closure Plan and notify the permitting agencies at least 120 days prior of its intent to close the site. Once the permitting agencies have approved closure of the site, the Operator will plug the monitoring well and submit a site closure report to EPA, the RRC, and other regulatory agencies, as required. The activities, as described below, represent the planned activities based on information required by EPA. The site closure plan to be implemented following cessation of injection may employ different and/or updated methods and procedures based on discussion and approval by the UIC Program Director. A final Site Closure Plan will be submitted to the UIC Program Director for approval with the notification of the intent to close the site, and other regulatory agencies as required (e.g., RRC). A site closure report will be prepared and submitted within 90 days following site closure, documenting the following:

- Plugging of injection wells, stratigraphic test well, monitoring well, if not previously plugged and abandoned.
- Location of sealed injection well on a plat of survey that has been submitted to the local zoning authority,
- Notifications to state and local authorities as required at 40 CFR 146.93(f)(2),
- Records regarding the nature, composition, and volume of the injected CO_2, and
- Post-injection monitoring records.

The Operator will record a notation to the property's deed on which the injection well was located that will indicate the following:

- That the property was used for CO_2 sequestration,
- The name of the regulatory agencies to which a plat of survey with injection well location was submitted,
- The total volume of fluid injected,
- The formation into which the fluid was injected, and
- The period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by the Operator for a period of 10 years following site closure. Additionally, the Operator will maintain the records collected during the post-injection period for a period of 10 years after which these records will be delivered to the UIC Program Director.

9.9 Additional Information

9.9.1 Acronyms

Claimed as PBI

AOR	Area of Review
BBE	Bayou Bend East SL20220050
BBE-P1	Bayou Bend East SL20220050 – Phase 1
CO_2	carbon dioxide
DAS	distributed acoustic sensing
ID	internal diameter
PISC	Post-Injection Site Care
RRC	Railroad Commission of Texas
TCEQ	Texas Commission on Environmental Quality
TVDSS	true vertical depth below sea level
UIC	Underground Injection Control
USACE	United States Army Corps of Engineers
USDW	underground sources of drinking water

Claimed as PBI

J. Financial Assurance Demonstration

COST ESTIMATES FOR CLASS VI CORRECTIVE ACTION, INJECTION WELL PLUGGING, POST INJECTION SITE CARE AND SITE CLOSURE, AND/OR EMERGENCY AND REMEDIAL RESPONSE [40 CFR 146.82(A)(14) AND 146.85] 40 CFR 146.85(a)(1)(iii)/TAC§5.203(n)

BAYOU BEND EAST SL20220050 (BBE)

Pursuant to the financial responsibility requirements at 40 CFR 146.85 Bayou Bend CCS LLC shall maintain financial responsibility and resources to meet the requirements of 40 CFR 146.85 and the conditions of this permit. Financial responsibility shall be maintained through all phases of the project. Bayou Bend CCS LLC will provide financial responsibility through a Standby Letter of Credit in an amount sufficient to cover the costs of corrective action, injection well plugging, post-injection site care and site closure, and emergency and remedial response. The form of the Standby Letter of Credit has been approved by the RRC of Texas and will be issued and in place before authorization to inject.

During the active life of the geologic sequestration project Bayou Bend CCS LLC, must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument and provide this adjustment to the UIC Program Director in an electronic format. Bayou Bend CCS LLC shall adjust the prior cost estimate by the percentage change in the GDP Implicit Price Deflator (FRED series GDPDEF) since the prior estimate. Bayou Bend CCS LLC must also provide to the Director written updates of adjustments to the cost estimate in an electronic format within 60 days of any amendments to the project plans that address the cost items covered in the financial assurance plan.

Bayou Bend CCS LLC shall provide notification to meet the requirements of 40 CFR §146.85 and the conditions of this permit.

- Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use Bayou Bend CCS LLC, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such an increase to the Director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after Bayou Bend CCS LLC has received written approval from the Director.
- Bayou Bend CCS LLC must notify the Director by certified mail and in an electronic format of adverse financial conditions, such as bankruptcy, that may affect the ability to carry out injection well plugging, post-injection site care and site closure, and any applicable ongoing actions under the Corrective Action and/or Emergency and Remedial Response.
    - If Bayou Bend CCS LLC, or a third-party provider of a financial responsibility instrument is going through a bankruptcy, Bayou Bend CCS LLC, must notify the Director by certified mail and in an electronic format of the commencement of voluntary or involuntary proceedings under Title 11 (Bankruptcy), U.S. Code, which names Bayou Bend CCS LLC as the debtor within 10 days after commencement of the proceeding.
    - A guarantor of a corporate guarantee must make such a notification, if he or she is named as debtor, as required under the terms of the guarantee.

- A permittee who fulfills the requirements of financial assurance by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee (or issuing institution) or suspension/revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy.

Bayou Bend CCS LLC must establish other financial assurance or liability coverage, acceptable to the Director, within 60 days of a change to the Area of Review and Corrective Action Plan.

Financial Responsibility GSDT Submissions
GSDT Module: Financial Responsibility Demonstration ***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]***

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FRANCHISE TAX ACCOUNT STATUS

This record as of October 20, 2026 at 12:49:47

STANDARD CHARTERED BANK

Texas Taxpayer Number:	30115062900
Mailing Address:	1095 AVENUE OF THE AMERICAS FL 37 NEW YORK, NY 10036 - 0357
Right to Transact Business in Texas:	ACTIVE
Domicile State:	
Effective Registration Date:	06/21/1990
Comptroller File Number:	0019902309

Claimed as PBI