Revision number: 003
Plan revision date: September 2026

CLASS VI PERMIT APPLICATION NARRATIVE
40 CFR 146.82(a)

BAYOU BEND EAST SL20220050 (BBE)

PBI CROSSWALK FOR BAYOU BEND EAST CLASS VI APPLICATION

Plan Number	Plan Document Title	Contains PBI
00	Narrative	Yes
	Appendix 1: Analytical Results	Yes
	Appendix 2: Copies of references used in support of this application for BBE-P1	Yes
	Appendix 3: Narrative Figures	Yes
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
	Appendix 3-4 AOR and Corrective Action Plan Figures	Yes
	Appendix 3-5: Supplemental Model Output Figures	Yes
04	Financial Responsibility	Yes
05	Injection Well Construction	Yes
	Injection Well Construction Figures	Yes
06	Pre-Operational Logging and Testing Plan	Yes
07	Testing and Monitoring Plan	Yes
	Appendix 7-1: Quality Assurance and Surveillance Plan	Yes
	Appendix 7-2: Testing and Monitoring Plan Figures	Yes
08	Well Plugging Plan	Yes
	Well Plugging Plan Figures	Yes
09	Post Injection Site Care and Site Closure Plan	Yes
	Post-Injection Site Care and Site Closure Plan Figures	Yes
10	Emergency and Remedial Response Plan	Yes
	Emergency and Remedial Response Plan Figures	Yes

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Appendix 4: Certification Documentation

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1 PROJECT BACKGROUND AND CONTACT INFORMATION

GSDT Submission - Project Background and Contact Information

GSDT Module: Project Information Tracking
Tab(s): General Information tab; Facility Information and Owner/Operator Information tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:
☒ Required project and facility details ***[40 CFR 146.82(a)(1)]***

Bayou Bend East SL20220050 (BBE) is a Bayou Bend CCS LLC (Operator) proposed Texas State Waters carbon transport and sequestration (CCS) project. Operator is a joint venture between Chevron U.S.A. Inc. (Chevron), through its Chevron New Energies division, TotalEnergies, and Equinor. The project objective is to develop a CCS facility in Southeast Texas to reduce emissions from regional industrial facilities by transporting and sequestering carbon dioxide (CO_2) from industrial sources in the Beaumont/Port Arthur areas to support local, regional, and national lower carbon aspirations.

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 (**Figure 1-1**). Proposed injection activities are planned for 20 years followed by a post-injection monitoring period of 50 years. BBE-P1 is designed for injection of 7.5 million metric tonnes per annum (MTA) for the first year of injection and 6-MTA for the remaining 19 years of CO_2 into five (5) injection wells from one offshore platform. The cumulative amount of sequestered CO_2 is expected to total 121.5 million metric tonnes (MMT) over the life of the project.

Neither an injection depth waiver nor aquifer exemption expansion will be requested as part of this permit application.

Additionally, the Operator sought to conduct a balanced review of environmental, social, economic, and other factors in the vicinity of the BBE project area. Communities potentially adversely and disproportionately affected by human health, environmental, climate-related, and/or other cumulative harms or risks were identified and are being engaged. They will continue to proactively be engage through the permitting process and during project operations to promote the just treatment and meaningful involvement of the affected community in Underground Injection Control (UIC) permitting actions.

No federally recognized Native American tribal lands or territories are located within Jefferson or Chambers County (Texas Historical Commission, 2023).

Key project and facility details required by 40 CFR 146.82(a)(1) have been submitted directly in the Project Information Tracking module of the GSDT.

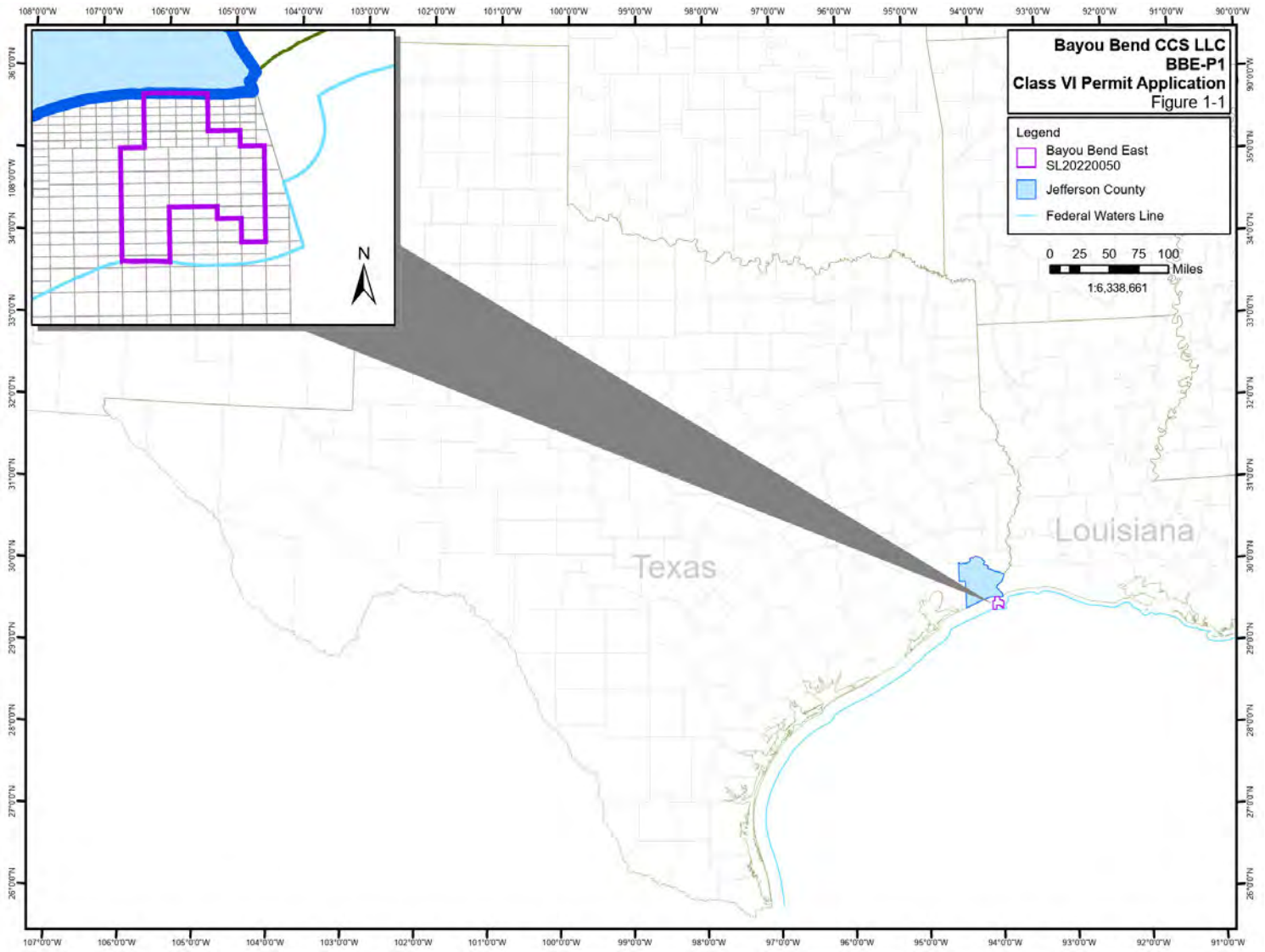

Figure 1-1: Location of the proposed BBE-P1; Jefferson County Lease, High Island Block (SL20220050), Texas.

2 SITE CHARACTERIZATION

Detailed site characterization information required per 40 CFR 146.82(a)(2), (3), (5), and (6), is provided in the following sections. Geologic and hydrogeologic data described in the site characterization sections below were used to develop a conceptual model of the proposed BBE-P1 geologic sequestration site.

2.1 Regional Geology, Hydrogeology, and Structural Geology [40 CFR 146.82(a)(3)(vi)]

The BBE-P1 geologic sequestration site is located along the southeastern flank of the Gulf Coastal Plain, which is underlain by a thick succession of Cenozoic strata that recorded the evolution of drainage within the central part of North America (**Figure 1-1**). The coastal plain succession thickens and becomes younger into the Gulf of Mexico (GoM). A regional cross section of this area is provided as **Figure 2-1**. **Figure 2-2** shows the BBE-P1 site, including the existing infrastructure and wells, as well as the site bathymetry.

The GoM Basin formed during the Late Triassic and Early Jurassic Epochs as the North American tectonic plate rifted apart from the South American and African plates (Salvador, 1987). By Late Jurassic time, the Atlantic Ocean became linked with the GoM, resulting in widespread deposition of the Louann Salt (Salvador, 1987). During the early Cretaceous, the GoM experienced a low supply of clastic sediment, resulting in predominantly carbonate deposition (Winker and Buffler, 1988).

By Late Cretaceous through the Paleocene, a series of basins formed across the Western Interior Seaway, below what is now the Great Plains of North America, in response to Laramide Orogenesis (Galloway et al., 2000 and 2011). Laramide uplifts delivered abundant sediment into basins across Wyoming, Colorado, and New Mexico. At this time, limited mixed carbonate and siliciclastic deposition occurred in the northwestern GoM. After filling of the Laramide basins, an influx of sediment into the northern GoM Basin formed extensive fluvial and deltaic deposits that caused progradation of the continental margin into the GoM by tens of kilometers (Galloway et al., 2000 and 2011).

By latest Eocene time, deltaic sedimentation decreased until the Oligocene Epoch, when sediment-input volumes increased into what is now the present-day south Texas region (Galloway et al., 2000 and 2011), culminating in deposition of widespread Anahuac Formation near the end of the Oligocene. By early Miocene time, fluvial and deltaic deposition continued along the Gulf Coast region. Sediment supply into the GoM Basin was controlled by southeast-flowing river systems that eventually shifted to a dominantly southerly drainage pattern by Miocene time (Galloway, 2005).

Galloway defined a series of basin-margin “genetic stratigraphic sequences” that record distinct depositional episodes for the northwestern GoM Basin (**Figure 2-3**; Galloway et al., 2000 and 2011). Four basin-margin depositional episodes for the Miocene stratigraphic succession were based on regionally

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Principal depositional components of the lower Miocene include the development of the south-trending Newton fluvial system, which fed into the High Island or Calcasieu delta across the Texas–Louisiana border (**Figure 2-4**; Olariu et al., 2019; Galloway et al., 1986; and Galloway, 1989).

The large-scale depositional patterns that were established by the Miocene, continued into the Pliocene and Pleistocene. In the Plio-Pleistocene, deposition began to be strongly influenced by higher frequency and larger amplitude climatic variations that generated shorter genetic sequences which recorded an overall progradation of the Gulf Coast depositional system into the basin (Galloway et al., 2000 and 2011).

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Figure 2-1: Published schematic geologic cross section (left, Treviño and Meckel, 2017), representative seismic volume (center, Olariu et al., 2018), and reference well log (right, modified from Wallace et al., 2014) for LM1 and LM2 CO_2 injection targets along strike of the BBE-P1 project area (red star; Treviño and Meckel, 2017). Spontaneous potential (SP) and deep resistivity curves from Conquest Petroleum, State Tract #201, Brazoria Co., Texas. Modified from Wallace et al., (2014).

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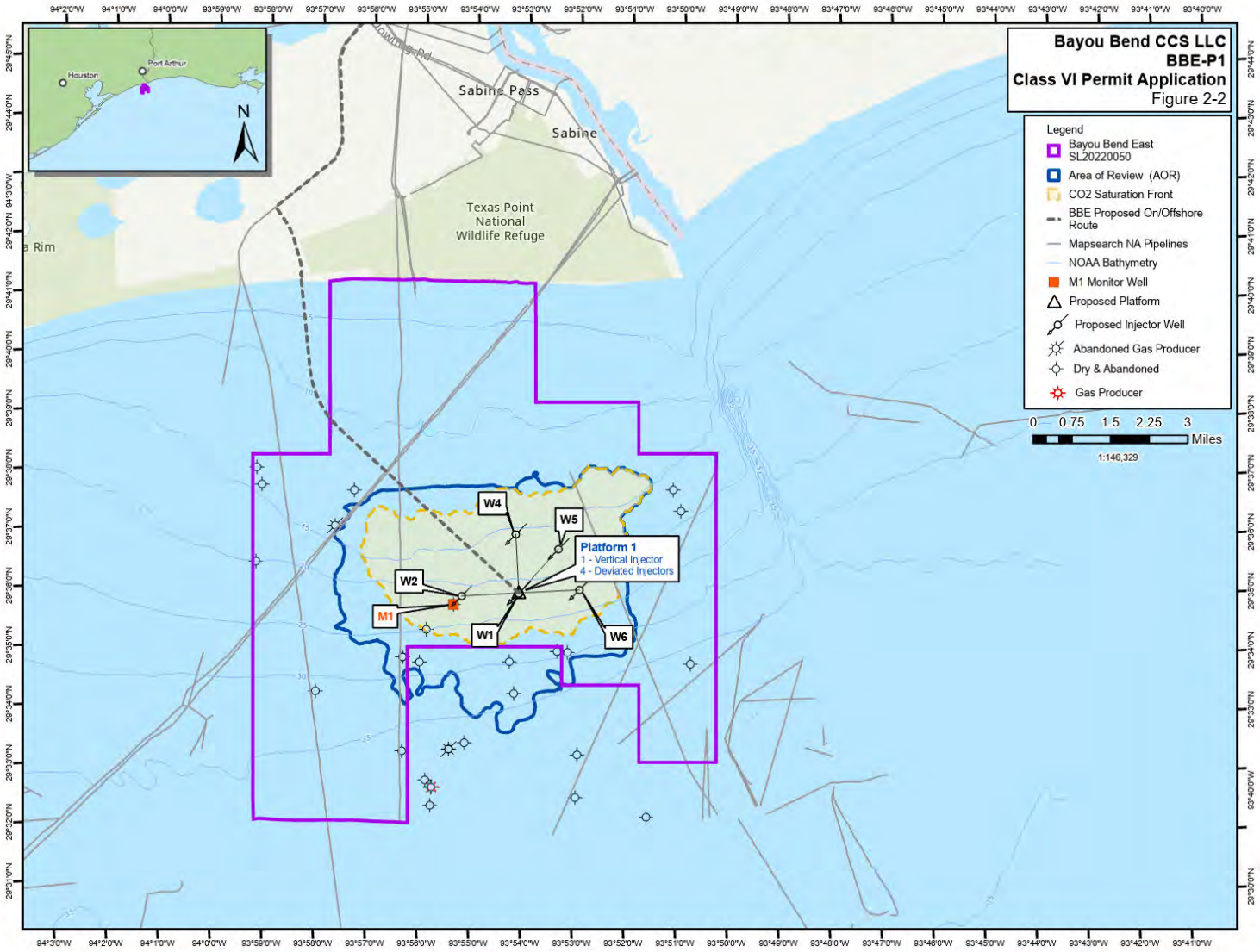

Figure 2-2: Location of the BBE-P1 project, including infrastructure, existing and proposed wells, bathymetry, and Area of Review. The Geologic Storage Facility is identified by the Area of Review delineated boundary.

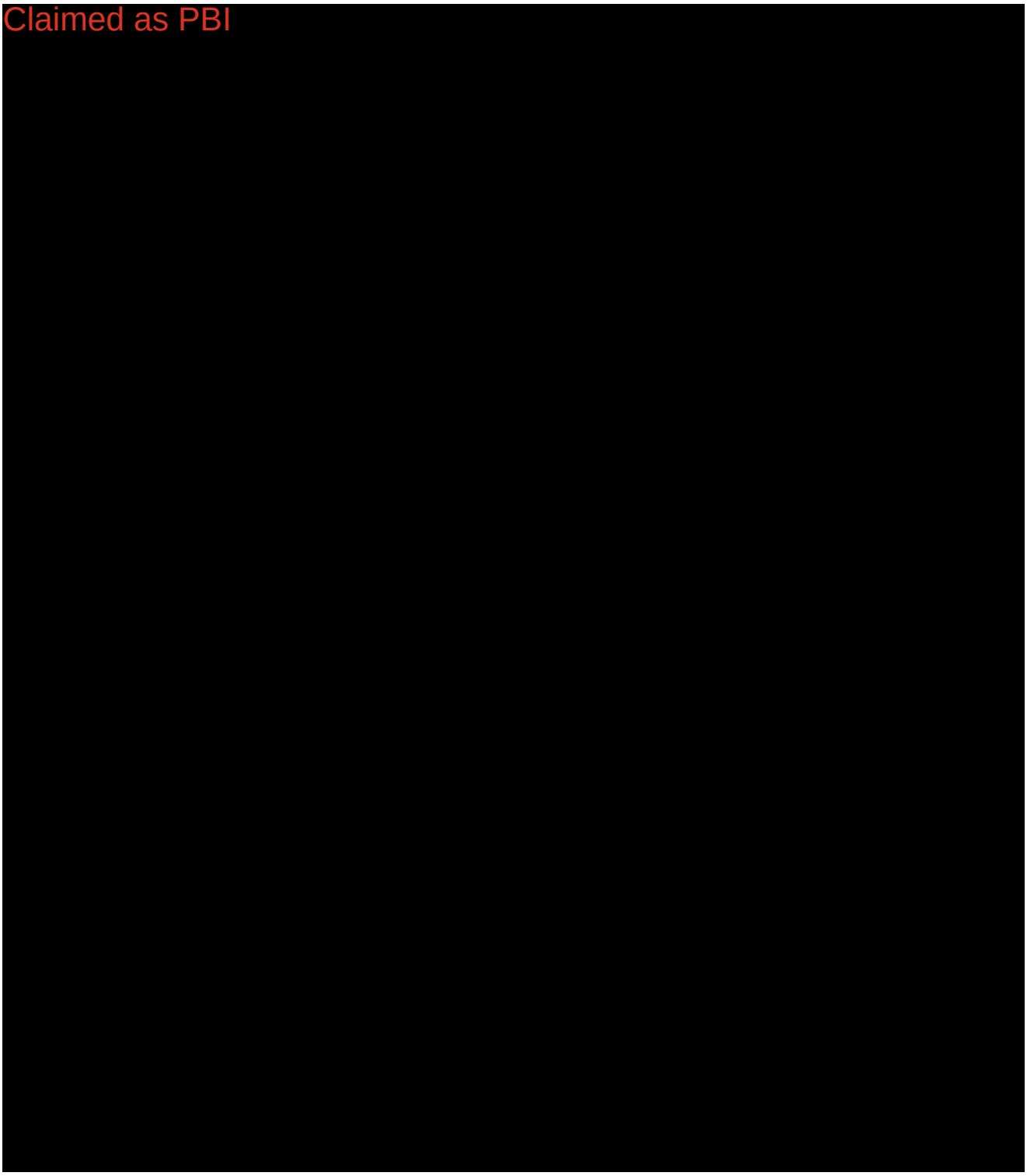

Figure 2-3: Chronology of GoM depositional episodes, biostratigraphic datum markers, major lithostratigraphic units, regional hydrostratigraphic units, and proposed injection and confining zones (Baker, 1979; Galloway et al., 2000 and 2011; and Young et al., 2012).

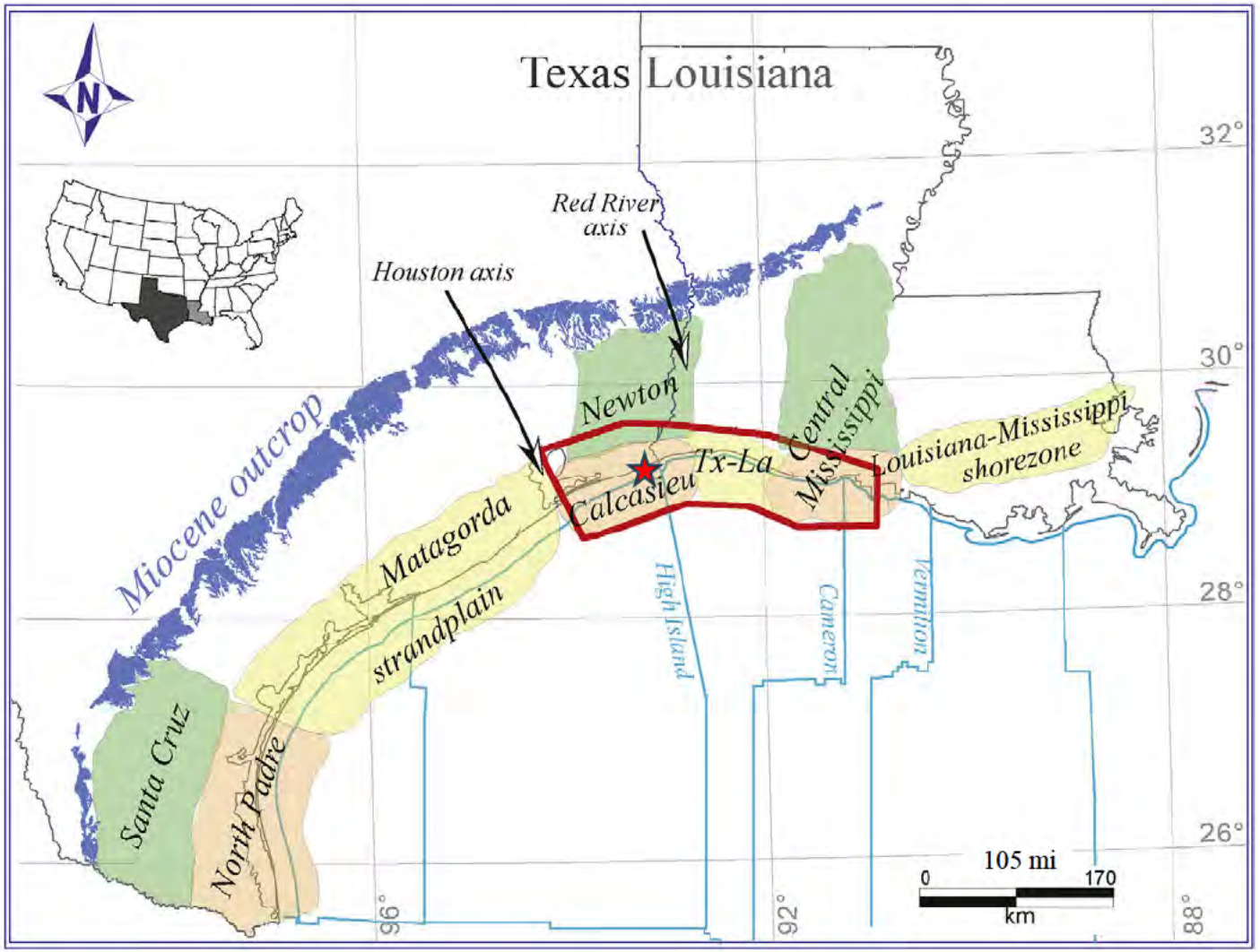

Figure 2-4: Location of updip Miocene outcrop belt and down-dip paleogeography of the Calcasieu Delta and Newton fluvial system (from Olariu et al., 2019). Red star denotes location of BBE-P1 site.

2.1.1 Stratigraphy

Gulf Coast deposits consist of sand, silt, and clay that record deposition in fluvial, shallow-marine, and deep-marine settings. The lower Miocene updip succession is dominated by fluvial deposition and these depositional successions become increasingly dominated by marine sedimentation downdip (**Figure 2-5** and **Figure 2-6**) (modified from Galloway et al., 1986). Compaction and variations in sediment supply and tectonic subsidence caused depocenters to shift the shoreline over time. Geological changes in depocenter activity resulted in lateral shifts in facies associations both along strike and dip. The overall geometry of the Texas coastal succession resulted in the preservation of thicker accumulations of sediment down dip, toward the GoM.

Miocene-aged lithostratigraphic units are exposed along the coastal plain as relatively broad, shore-parallel swaths (**Figure 2-4**) that dip toward the GoM. The geologic age of these regional surface geologic units are progressively younger towards the Gulf Coast. Generally, these morphostratigraphic belts define a coast-parallel depositional framework that has dominated much of the development for millions of years. In addition, the individual width of each depositional episode reflects its relative stratigraphic thickness in relation to other swaths and stratigraphic units (i.e., in general, the broader the outcrop swath, the greater the deposit thickness).

The stratigraphic succession described for the project area focuses on the Oligocene Frio Formation, Oligo-Miocene Anahuac (Shale) Formation, Miocene Fleming Group (Oakville and Lagarto Formations [Fms]) Miocene Goliad Fm, Mio-Pliocene Willis Fm, and the Plio-Pleistocene Lissie, and Beaumont formations (**Figure 2-3**). Thin Holocene alluvial and coastal marsh deposits are locally preserved (Baker, 1979; Young et al., 2012). These lithostratigraphic units have relatively consistent updip and downdip trends in depositional environment, overall lithology, and sand quality that serve as analogs for defining correlation frameworks and locating optimal injection sites **(Figure 2-1).**

The Oligocene Frio Formation represents a series of deltaic and marginal-marine deposits that are the down dip equivalent of the nonmarine Catahoula Formation. The Frio Formation is a major clastic wedge that prograded more than 60 miles into the GoM Basin. Progradation was followed by a period of aggradation and eventual retrogradation and end of the Frio depositional package marked by the Anahuac Formation (Galloway et al., 2000 and 2011). Shoreline conditions remained relatively constant during Frio deposition, resulting in the development of narrow and thick, homogenous belts of sand that comprise 25-40 percent of the cumulative Frio section, which locally exceeds 12,000 feet (ft) in thickness (Galloway, Henry, & Smith, 1982b).

Following Frio deposition, thick shale of the Oligo-Miocene Anahuac Formation was deposited during an extensive marine transgression across the Gulf Coastal Plain that occurred at the end of Oligocene. The resulting transgression left a thick succession of shale that acts as a regionally continuous stratigraphic seal. The Anahuac Formation is recognized 6,200 to 7,500 ft beneath the sea level in the project area and wedges out in the northern portion of the project area, beneath the present coastal plain (**Figure 2-5**) (Galloway, et al, 1986).

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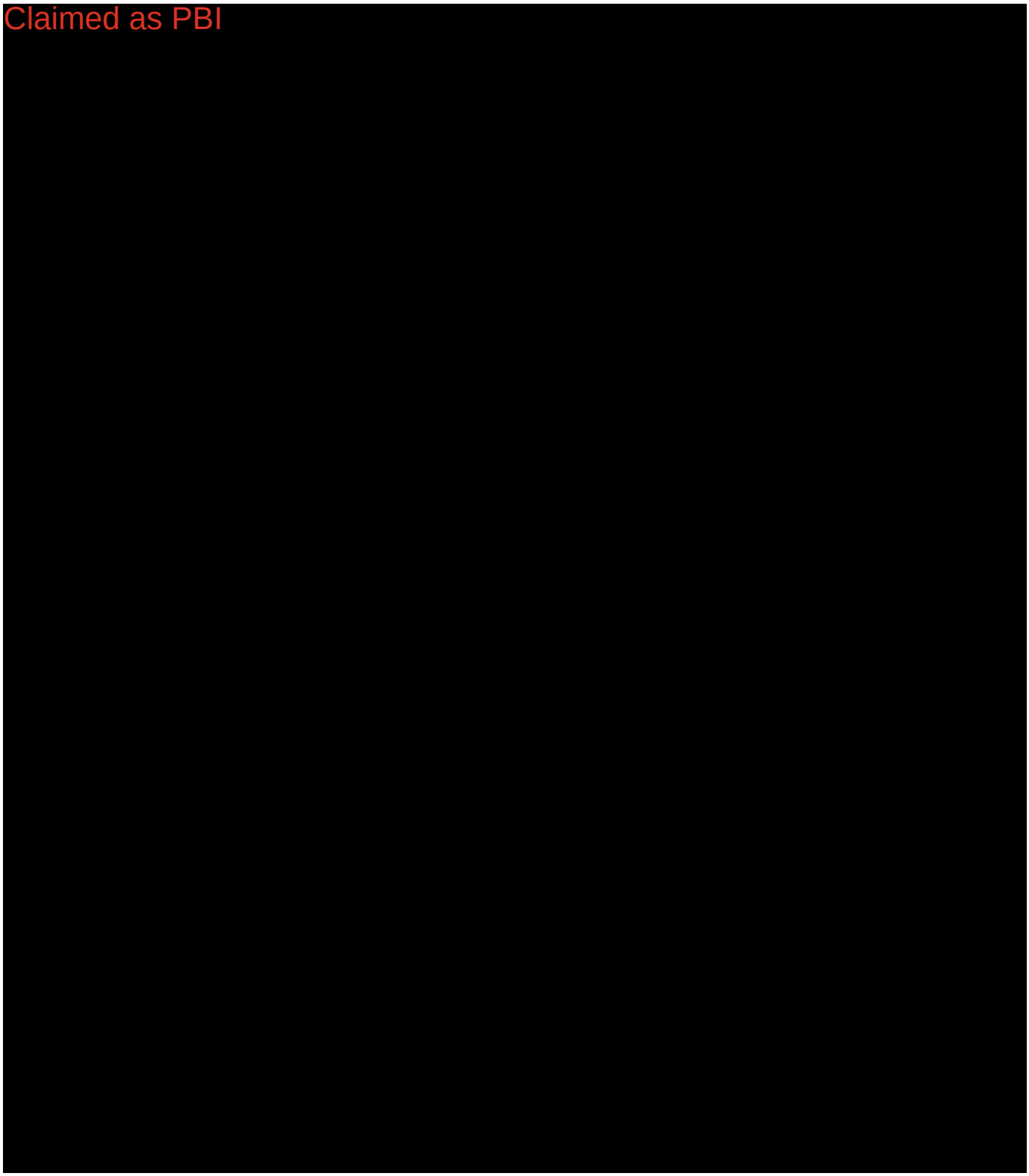

Figure 2-5: The Lower Miocene updip successions are dominated by fluvial deposition and these depositional successions become increasingly dominated by marine sedimentation downdip (modified from Galloway et al., 1986).

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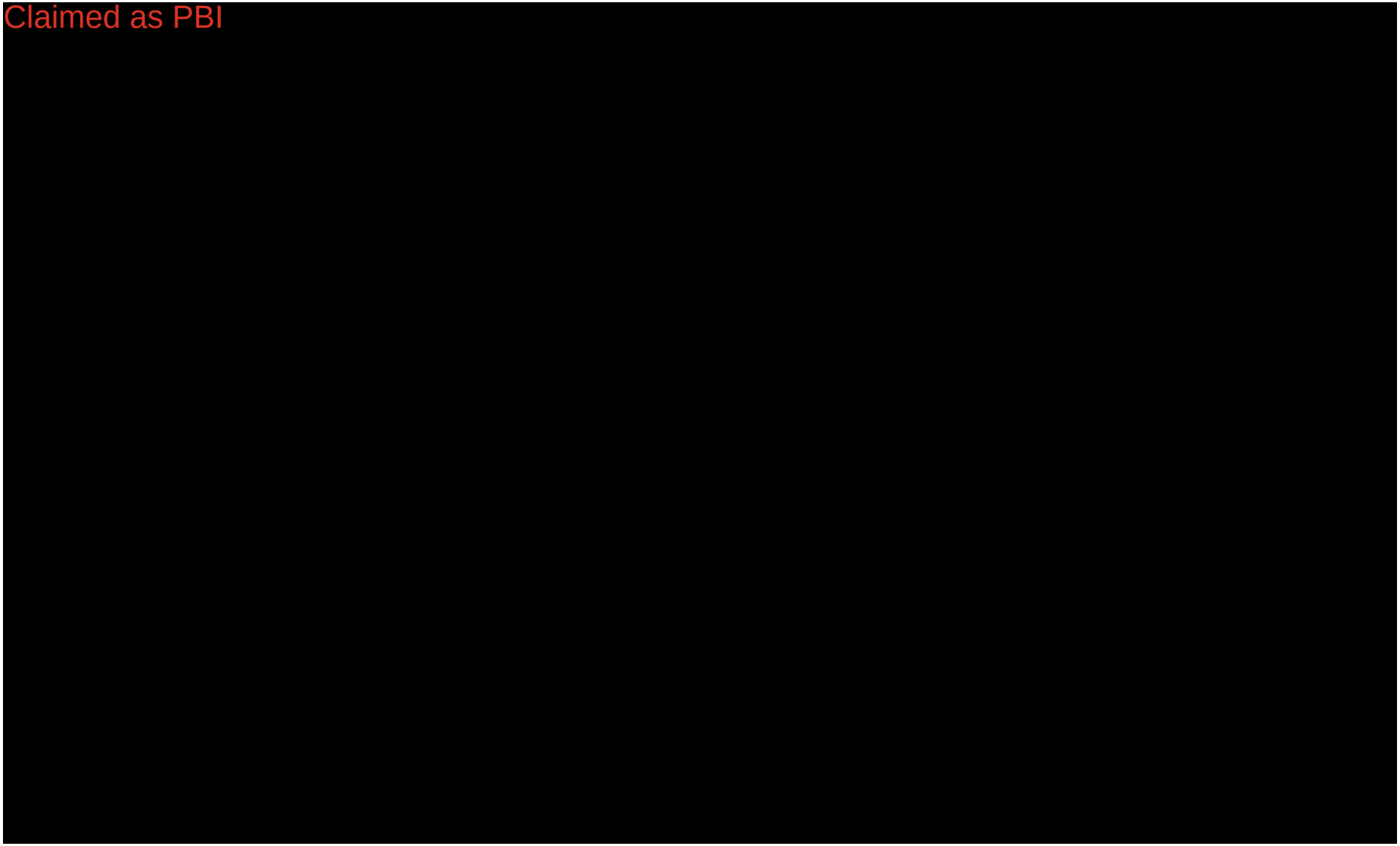

Figure 2-6: The Lower Miocene updip succession are dominated by fluvial deposition and these depositional successions become increasingly dominated by marine sedimentation downdip (modified from Galloway et al., 1986).

Overlying the Anahuac Formation is the Miocene Fleming Group, which contains the Oakville (LM1) and Lagarto (LM2) Formations **(Figure 2-3**). Deposition of the Fleming Group occurred in shallow-marine environments across a broad, submerged, shelf-platform that developed during earlier Frio and Anahuac deposition. Three major depositional regimes characterize the Fleming Group: fluvial; deltaic; and marginal marine (Galloway et al. 1986). Sediment supply during deposition of the Fleming Group resulted in several thousand feet of high net to gross sand bodies deposited with sediment primarily derived from south-trending river systems like the Newton fluvial system near the BBE project area. Sands from these fluvial systems are generally well connected and laterally extensive (Young, et al, 2012; Carr, et al, 2016).

Miocene formations along the Texas Gulf Coast are typically separated into Lower Miocene 1 (LM1), Lower Miocene 2 (LM2), Middle Miocene (MM) and Upper Miocene (UM) lithostratigraphic units. The Oakville Formation (LM1) and Lagarto Formation (LM2) exhibit a relatively consistent downdip (proximal-to-distal) progression of depositional environments and facies associations that are consistent with coastal plain and near-shore environments.

Deposits of the LM1 and LM2 are distinguished using benthic foraminifera associated with maximum flooding surfaces (MFS) that overlie major Miocene units (**Figure 2-3)**. The base of the LM1 unit is defined as the Anahuac Shale. The *Siph D* shale package within the Oakville Formation (LM1) is named after the foram *Siphonina davisi* and represents a regionally extensive flooding surface. The *Marg A* shale overlies the LM1 unit and is named after the foram *Marginulina ascensionensis*. The *Amph B* shale defines the shale overlying LM2 and represents a major marine transgression. Galloway et al. (1986) delineated 11 biostratigraphically defined flooding surfaces across the region that are labeled, in decreasing stratigraphic order: MFS1 through MFS12. Additional stratigraphic control comes from biostratigraphic subdivisions and mappable MFS across the Miocene succession (Olariu et al., 2019).

Lagarto Formation sandstone consists of fine- to very fine-grained sand composed mostly of quartz and less amounts of feldspar detritus (Curray, 1960). Shale contains clay minerals, including montmorillonite, kaolinite, illite, chlorite, and mixed-layer smectite-illite, whereas siltstone contains clay, silt, and very fine-grained sand (Curray, 1960).

Proximal (updip) rocks of the Oakville Formation are associated with terrestrial deposition and contain (calcium-carbonate) cemented sandstone and mudstone that were laid down in river channels, on floodplains, and as crevasse splays. Distal deposits represent deltaic, barrier island, lagoonal, strandplain, and marine shelf deposits composed of fine-to coarse-grained sandstone and interbedded shale. Seaward of the Oakville shelf edge, correlative sediments were deposited along the continental slope as upper-slope sandstone and shale that thicken on the downthrown sides of normal growth faults (Galloway, et al, 1986; Galloway, Henry, and Smith, 1982).

Proximal (updip) rocks of the Lagarto Formation are differentiated from the underlying Oakville strata by their overall finer grain size. Proximal regions of the LM2 (Lagarto Fm) generally contain muddy, stacked fluvial and coastal plain sediments. Downdip, LM2 deposits coarsen and reflect deposition in fluvial, deltaic, and barrier environments. As with the underlying LM1 (Oakville Fm), the Lagarto shelf and upper-slope fine-grained sandstone and mudstone thicken across normal growth faults into the GoM Basin **(Figure 2-1**) (Galloway et al., 1986). Deposits of the lower Oakville Formation are the result of offlap as

the Fleming Group shoreline migrated basinward across the older Frio shelf. Younger strata of the Lagarto Formation are dominated by strong vertical stacking and minor backstepping due to later marine transgressions (Galloway et al., 1986).

The Miocene Goliad Formation is recognized regionally across the Texas Coastal Plain where it forms a basinward-thickening progradational wedge of fluvial and deltaic deposits that overlie the Fleming Group and older rocks (**Figure 2-3**). Galloway subdivided the Goliad Formation into his MM and UM genetic sequences (e.g., Galloway et al., 2000 and 2011). A shale containing *Textularia stapperi* (Text W) defines the top of the MM unit, the lower member of the Goliad Formation. The upper member of the Goliad Formation is defined by the *Rob E* shale. Regionally, the Goliad Formation ranges from 200 to >1,500 ft in thickness and consists of claystone, sandstone, conglomerate, and limestone.

The Mio-Pliocene Willis Formation unconformably overlies the Goliad Formation and older rocks. The Willis Formation is unconformably overlain by the Lissie Formation and locally by the Beaumont Group and undivided alluvial and coastal plain deposits. The Pleistocene Lissie Formation contains clay, silt, sand, and gravel laid down by meandering rivers. The Pleistocene Beaumont Group consists of multi-colored clays with limestone nodules and interbedded sand that ranges from 25 to 400 ft in thickness. The Beaumont Group unconformably overlies the Lissie Formation and underlies undifferentiated Holocene coastal marsh deposits along the Texas and Louisiana Gulf Coastal Plain **(Figure 2-3)**.

Below the Lower Miocene formations, the rapid accumulation of sediments into the basin fed by deltas led to the generation of over-pressured zones as rapid burial built up fluid pressures to a level where they exceeded hydrostatic pressures (Jones, 1969). The LM1 *Siph D* shale / Oligocene Anahuac Fm of over-pressured rock commonly forms the effective base of the CO_2 injection into the Cenozoic section and has been mapped across the Texas coastal zone by Pitman (2011).

Environment of Deposition (EoD)

Conceptual models provide a way to integrate well-log and seismic data into a three-dimensional framework that can be used to identify and model spatial relationships, reservoir architectures, connectivity, and heterogeneity trends. Paleogeographic reconstructions of the Gulf Coast Basin indicate fluvial- and wave-dominated deltaic sedimentation (e.g., Galloway et al., 2000 and 2001; Olariu et al., 2019) during deposition of Lagarto Fm (LM2). Examination of well log character with legacy well data and published paleogeographic reconstructions identified six distinct facies associations that are used to guide the construction of the static 3D model (**Table 2-1**). Seismic data has sufficient resolution to detect geomorphological features and the well log character is tied to seismic geomorphology to further validate EoD.

Facies associations are interpreted from well-log character within parasequence-sets defined by nine fine-scale horizons representing Claimed as PBI [redacted] of well-log character and vertical transition of facies associations within the parasequence sets are used to define dominant environment of deposition per fine-scale zone (**Figure 2-7**).

Distributary channels are identified in well-logs as low gamma ray (GR) and low spontaneous potential (SP), sand-rich packages with sharp bases and sharp tops. Vertical trends within these packages are

commonly blocky to upward fining. These deposits typically occurred directly overlying- or up-dip of mouth-bar and proximal delta-front facies associations.

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Figure 2-7: Comparison of the principal environment of deposition and zones in the proposed injection zone (T12-T5) of a fluvially dominated delta and an incised valley (Posamentier and Allen, 1993; Labourdette et al., 2008; Martinius et al., 2013).

Table 2-1: Summary of interpreted Environments of Deposition (EoD) for the injection and confining zones

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Mouth-bars are identified as low GR and Low SP, sand-packages with upwards coarsening profile and sharp top. Well-log character is dominantly homogeneous, with minimal log serration. Sharp tops asso associated with these packages are commonly associated with overlying distributary channels and interpreted to reflect subsequent incision of the mouth-bar.

Proximal delta front deposits are identified as strongly upward-coarsening packages with upwards-decreasing serrated well log character. Bases are typically moderate-to-high sand content, expressed as moderate GR and SP values, but exhibiting clear serration. Well-log serration decreases upwards and becomes increasingly blocky and sand rich. This upwards decrease in serration is interpreted to reflect progradation of a delta-front deposit dominated by waning sediment gravity flows. These deposits are commonly directly overlying- or updip of distal delta front deposits.

Distal delta front deposits exhibit a strongly upward-coarsening, highly serrated well log character. Packages are typically sand-poor (moderate GR and SP) at the base and increase upwards to moderate sand content (moderate to low GR and SP). Well-serration is high and consistent from base to top, reflecting high vertical heterogeneity. These deposits are interpreted to reflect the distal component of prograding delta-fronts, where deposition is dominated by interbedded sandstones and siltstones resulting from waning sediment gravity flows.

Sand-prone delta/coastal plain and Incised Valley deposits exhibit thick, blocky, sand-rich packages of low GR and low SP with sharp bases and tops. Thicknesses of blocky packages are thicker than distributary channel packages and commonly occur in multiples that are amalgamated, locally separated by high GR, high SP shale-rich interbeds. Thicknesses and presence of shales varies across wells, suggesting irregular and non-correlative packages due to incision. Local thicknesses of these packages reach 200 ft, which is greater than proximal-delta front, mouth-bar, and distributary-channel deposits combined. These amalgamated packages with variable thickness and local occurrence of shales are interpreted to reflect deposition channelization within a sand-rich coastal plain. Incised valley fills are normally recognized in well logs and seismic by an abrupt thickening of sandstone on coarsening-upward mouth-bar and delta-front deposits. The thickness of these typically sharp-based paleovalley fills are generally greater than individual mouth-bars and delta-front successions that comprise shallow-marine parasequences.

Sand-poor delta/coastal plain deposits exhibit a well log character of interbedded blocky- to fining-upwards sand-rich packages separated by distinct shale-rich or interbedded/serrated packages. Sand-rich packages are commonly sharp-based and commonly show minimal internal serration at the base and more pronounced serration at the top. These deposits are interpreted to reflect a moderately shale-prone coastal/delta plain incised by delta-plain channels.

Seismic Character

Seismic resolution within the vicinity of the BBE-P1 project is high and was used to further validate environment of deposition interpretations from well-log character. Spectral decomposition and seismic amplitude were viewed in stratal slices and tied to well log character at parasequence set scale to detect geobodies to provide insights into depositional processes. Three dominated seismic geomorphological characters were identified (**Figure 2-8**) Claimed as PBI

- Deltaic lobe (distributary channel, mouth-bar, and delta-front deposits) (**Figure 2-8 C and D**)
- Incised valleys (**Figure 2-8 B**)
- Coastal plain channel deposits (**Figure 2-8 A**)

Spectral decomposition and red-green-blue color blending were used to increase detectability of geomorphic features by using both frequency and amplitude spectra within the seismic data. This was conducted due to the high-net yet interbedded character of the LM2 injection zone. Red-Green-Blue colors (**Figure 2-8 D-B**) correspond to unique, specified frequency ranges.

In spectral decomposition stratal slices, delta-lobe deposits **(Figure 2-8 D-C**) exhibit a distinct lobate geometry down-dip of a narrow channel-form feature. Commonly multiple of these deposits are laterally offsets within stratal slices, interpreted to be the result of compensational-stacked delta-lobes composed of distributary channels, mouth-bars, and delta-front deposits. Updip channel-form deposits are 0.1-0.5 miles wide and lobate mouth-bar and delta-front features are commonly 2-4 miles wide. Spectral decomposition character exhibits a radial change, indicating radial changes in stratigraphic heterogeneity, interpreted to reflect the progradational nature of these deposits.

Incised valleys are imaged as sharp-edged channel-form features 0.5-3 miles wide that continue the whole length of the area of interest (**Figure 2-8 B**). Lateral edges are sharp and distinct and vary from straight to sinuous. In cross section (**Figure 2-8 B-B'**), these deposits exhibit a scoured base that truncates reflectors and shows multiple internal scoured surfaces that are 160-250 ft thick. Collectively these observations indicate significant incision that was outsized relative to surrounding deposits and interpreted as incised valleys. The two incised valleys shown in **Figure 2-8** are included in the model.

Coastal plain channel deposits exhibit multiple laterally offset channel features 0.25-0.75 miles wide with high amplitudes (sand-rich) within a mottled, variable amplitude (heterogeneous to sand poor) background (**Figure 2-8 A**). Multiple channel-form features are identified on the stratal slices and show bifurcations, common regional but multiple local orientations, and are moderate to highly sinuous.

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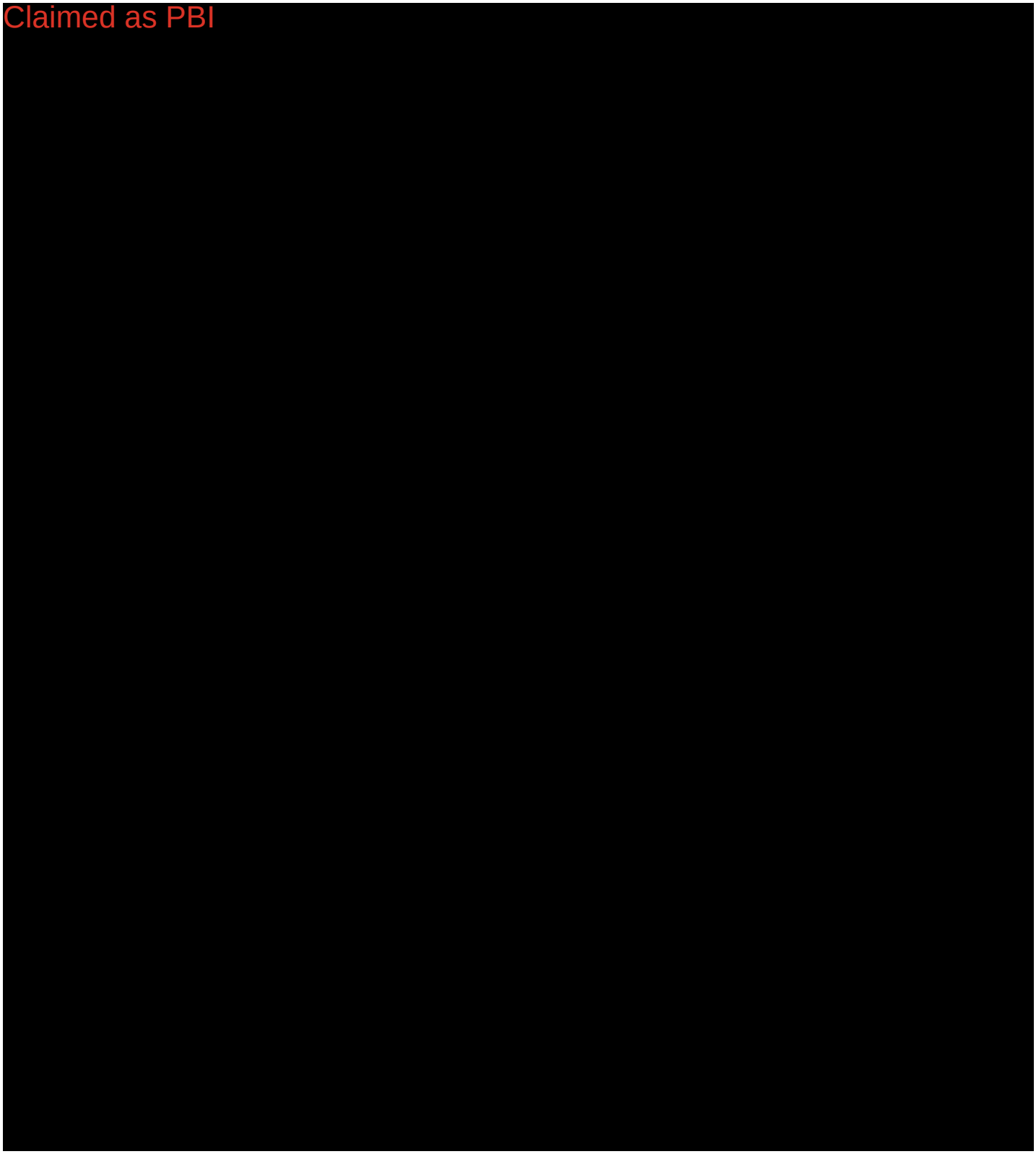

Figure 2-8: Seismic geomorphological examples of channel-belts and incised valley fills in the Lagarto Formation using seismic amplitudes and spectral decomposition of frequencies 12, 16, and 20 Hertz (Hz).

2.1.2 Regional Structural Geology

Gravity has been the driving force in Gulf Coast tectonics since the opening of the GoM. When the GoM opened in the Jurassic Period, the Gulf Coast region became a trailing continental margin that foundered and subsided (Hall et al.,1982). Sediments accumulated on the margin and adjacent oceanic crust, which caused further subsidence in response to the sedimentary loading. Continual subsidence has created depocenters for additional sediment accumulation, which has produced the thick wedge of clastic sediments that continue to increase in thickness, as well as prograde further into the basin (Hall et al., 1982).

On a regional scale, growth faulting and diapirism of salt or shale (**Figure 2-9)** are the principal structural mechanisms of the Gulf Coast. Each is the result of sediment loading creating instability in the strata. The potential effects of each mechanism on the structural setting of the BBE-P1 site are discussed below. Structural cross sections in the strike and dip orientations, respectively **Figure 2-13** and **Figure 2-14,** will be referenced in the discussion that follows. Salt domes are common along parts of the Texas Gulf Coast (Ewing, 1991). These diapirs form as salt from the Jurassic Louann salt rise through overlying strata to form spires, banks, and domes that are responsible for local increases in water salinity.

Gravity-induced tectonism is relatively passive, characterized by the dominance of tensional forces and relatively low seismicity. Similarly, faulting of the type generally seen in the Gulf Coast tends to initiate in areas of high sedimentation rates, particularly along shorelines and along shelf margins. Once the center of deposition shifts to a new location (for example, when the position of a river mouth shifts laterally due to avulsion), the fault movement that has resulted from the buildup of sediments at the former location tends to diminish and eventually ceases. Faulting occurs when large masses of unconsolidated sediments at the outer shelf margin slump downward and laterally into adjacent basins (Van Siclen, 1967; Bruce, 1972; O'Neill & Van Siclen, 1984). This movement along faults results in the displacement of large volumes of sediments over distances that range from a few feet to several miles. Because these tectonic processes generally occur gradually over time, and the strata being affected are ductile to slightly brittle, the stresses released generate little or no seismogenic activity (Van Siclen, 1967; Bruce, 1972; O'Neill and Van Siclen, 1984).

Additional geologic structures are related to growth faulting, mainly in response to sediment loading where poorly consolidated sediment loads the underlying strata to a point of gravitational instability and collapse. Individual faults tend to be somewhat arcuate and have displacements ranging from hundreds to thousands of feet. Larger fault systems are composed of numerous interconnected faults that collectively may extend for tens of miles along strike (Weber, 1975; Kreitler, 1988).

Claimed as PBI [redacted] higher ratio of shale is appreciably larger for the upper confining units, thus, enhancing the sealing aspect of these growth faults. The lithology and lateral continuity of the upper confining units, which include the containment interval Claimed as PBI [redacted] demonstrated on the structural cross sections described below (**Figure 2-13** and **Figure 2-14**).

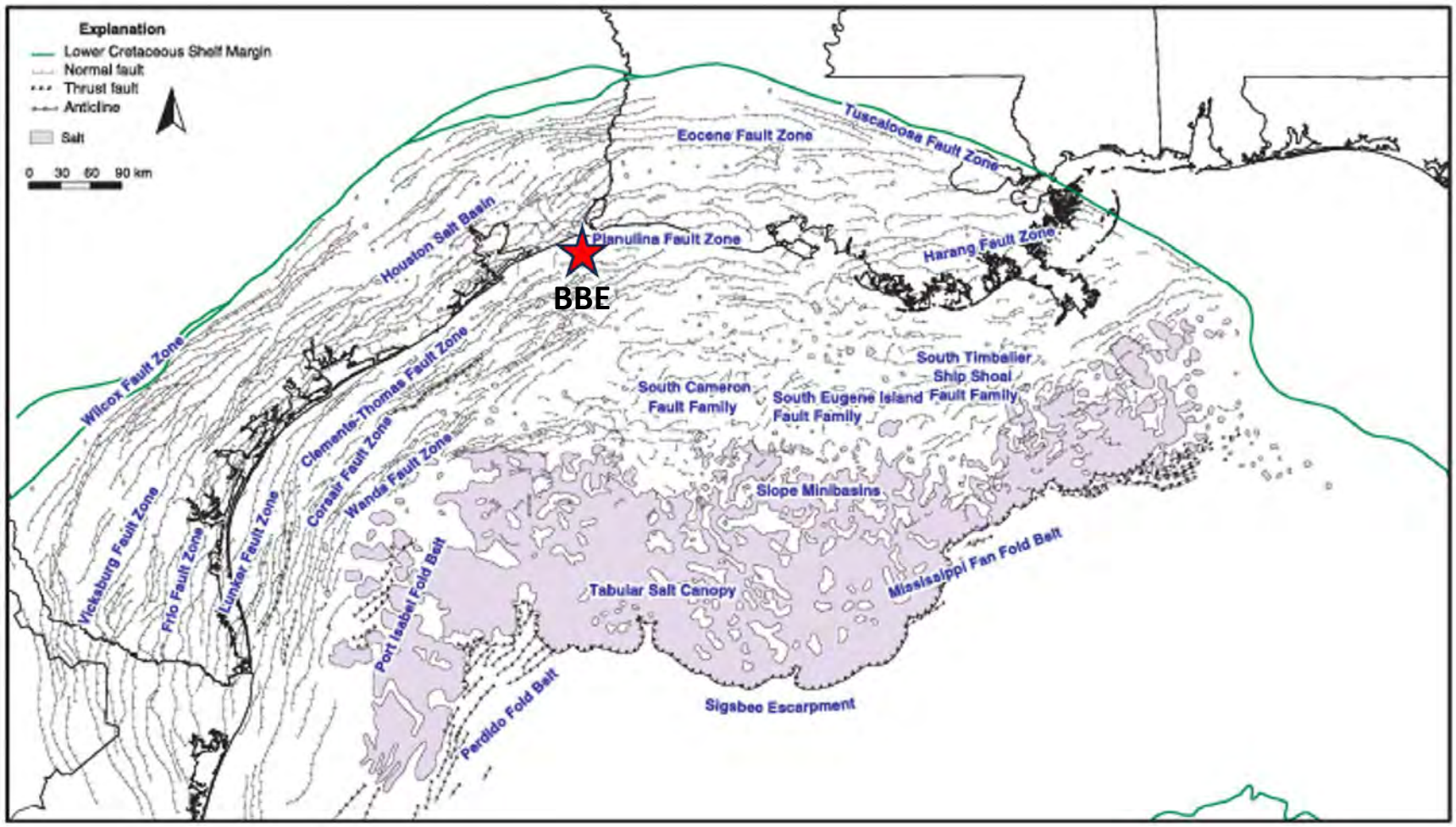

Figure 2-9: Structural context and extensional faulting at BBE (star) and surrounding areas. Modified after Galloway (2008) and Watkins et al. (1995).

2.1.3 Regional Faults and Fractures

Claimed as PBI

[redacted]

The prevalence of shale and the existence of shale-to-shale contact across faults above the proposed injection intervals are displayed in the cross section **Figure 2-10.**

In the confining zone, shale is juxtaposed against shale across the fault (**Figure 2-10**), with low-permeability fill. Clay smear is likely to occur in the fault plane, as discussed below. These conditions will aid in the prevention of vertical migration through the faults and confine wastes to the injection zone.

Clay smear occurs commonly in fault zones with layered sands and shales. Overburden pressure on beds undergoing normal faulting is greater than the pressure in the fault zone. If the shale is fluid enough and the fault moves slowly enough (Naruk, et al., 2002), plastic shales squeeze into the fault zone, resulting in clay smeared along the fault. Intervals with 40% clay can form clay smears. An outcrop study in New Mexico found that clay smears tend to be continuous for two to six times the thickness of the clay source bed (Cerveny, et al., 2005). Furthermore, “the thickness of the clay smear along the fault increases with the thickness of the source shale bed and decreases with distance from the source shale” (Cerveny, et al., 2005). Shale smear in a fault zone can therefore be almost continuous along the length of the fault in sequences of alternating sands and shales, except opposite thick sand beds. Shale smear may be discontinuous along the fault plane across thick sand beds as the distance from the smearing shale layers increases.

Additionally, shale smear will reduce porosity and permeability (Cerveny, et al., 2005). Whether clay is present in the fault zone or not, reduced permeability in the zone retards the vertical movement of fluid via faults.

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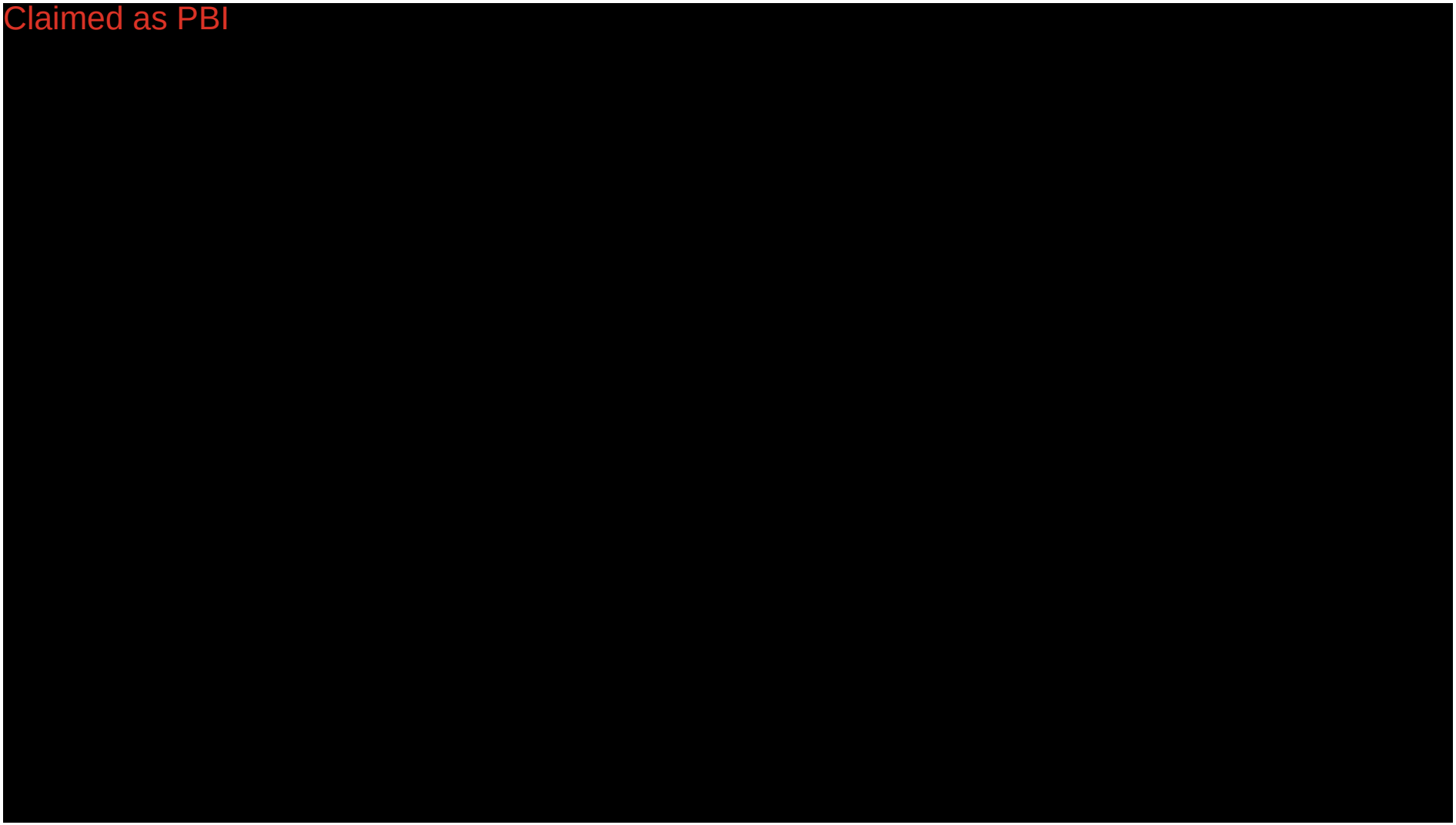

Figure 2-10: Dip-oriented section showing extensional growth faulting along the Clemente-Tomas fault system. Maximum displacement and growth are accommodated in the LM1. Regional thickness of LM2 increases basinward (to the SE). Cross Section location (red line) and proximity to BBE-P1 acreage (red star) are annotated on the map. Figure modified after Nicholson (2012) and Treviño and Meckel (2017).

2.1.4 Regional Hydrogeology

The onshore Gulf Coast aquifer system of eastern Texas, a series of shoreline-parallel aquifers of variable

Claimed as PBI

Downdip equivalent formations offshore have similar geologic characteristics (Section 2.1.1; **Figure 2-3**); however, are observed at deeper depths and based on petrophysical calculations, higher salinity content (Section 2.7.1).

The Gulf Coast aquifer system consists of a broad low-relief coastal plain that gently rises from sea level to coastal uplands in the north, which are up to 900 ft above sea level (Chowdhury and Turco, 2006). The Gulf Coast aquifer system consists of a thick succession of homoclinally dipping stratigraphic units that are recharged by the major rivers of Texas, including the mouth of the nearby Sabine River (Young et al, 2012). There are five hydrostratigraphic units identified along the Gulf Coast of Texas, listed below from oldest to youngest: Catahoula Aquitard; Jasper Aquifer; Burkeville Aquitard; and the Evangeline and Chicot Aquifers (Baker, 1979; Williamson and Grubb, 2001; and Young et al., 2012). **Figure 2-11** shows a hydrostratigraphy column that includes Lower Miocene aquifers: Jasper Aquifer and Burkeville Aquitard.

The Catahoula Aquitard is comprised of the Oligoene Frio and Anahuac Formations, corresponding to the Catahoula Group observed at BBE. At BBE-P1, the Catahoula Aquitard contains sparse sandstone and generally acts as a barrier to flow between the overlying Jasper Aquifer and deeper aquifers.

The Jasper Aquifer contains porous and permeable sandstone units that are thick enough to constitute a regional water-bearing interval. Sandstone of the Oakville and Frio Formations mark the base of this aquifer, whereas the top of the Jasper Aquifer is alternately defined within the Oakville, at the top of the Oakville, or in the overlying Lagarto Formation. Due to this variation and the general updip thinning, aquifer thickness ranges from 200 ft to over 3000 ft. Water quality in the onshore formation varies from fresh (<1,000 milligram per liter [mg/L]), in updip areas near sources of recharge, to moderately and highly saline (>3,000 mg/L), in downdip areas away from recharge areas (Young et al., 2012). Claimed as PBI

Claimed as PBI

Overlying the Jasper Aquifer is the Burkeville Aquitard. The Burkeville Aquitard consists of siltstone and claystone separating the aquifers in the underlying Oakville Formation from those in the Lagarto Formation or overlying Goliad Formation. Depending on sandstone quality encountered in the Oakville and lower Lagarto, the base of the Burkeville Aquitard is variably defined within the Oakville or lower part of the Lagarto Formation. The top of the Burkeville Shale varies from within the upper Lagarto Formation upsection to the base of the Goliad Sandstone. Overall thickness of the Burkeville aquitard is commonly between 300 and 500 ft (Baker, 1979).

The Evangeline Aquifer overlies on the Burkeville Aquitard and includes the Goliad Formation. The base of the Evangeline Aquifer locally extends into the Lagarto Formation where thick, porous, and permeable water-bearing sandstones are recognized. Evangeline Aquifer thickness ranges from as little as 400 ft on the outcrop and in the shallow subsurface to approximately 200 ft in the deep subsurface near the modern

coastline. Water quality onshore varies from fresh (<1,000 mg/L) to slightly saline (1,000– 3,000 mg/L), with salinity increasing generally with depth and distance from recharge areas (Young et al., 2012). Claimed as PBI

The Chicot Aquifer overlies the Evangeline Aquifer and includes Mio-Plio-Pleistocene formations and unnamed lithologic units. The Chicot Aquifer is typically sandier than the Evangeline Aquifer and exhibits multiple static water levels. Thickness varies from zero where the Evangeline crops out to more than 1000 ft at the present coastline. Claimed as PBI Chowdhury et al., 2006; Young et al., 2012).

Coastal groundwater systems typically have an onshore tapering saline wedge that occurs below fresher terrestrial groundwater. Relatively narrow mixing zones of fresher and more saline groundwater occur along the boundary of the salt-water groundwater wedge (Cooper, 1964).

Claimed as PBI

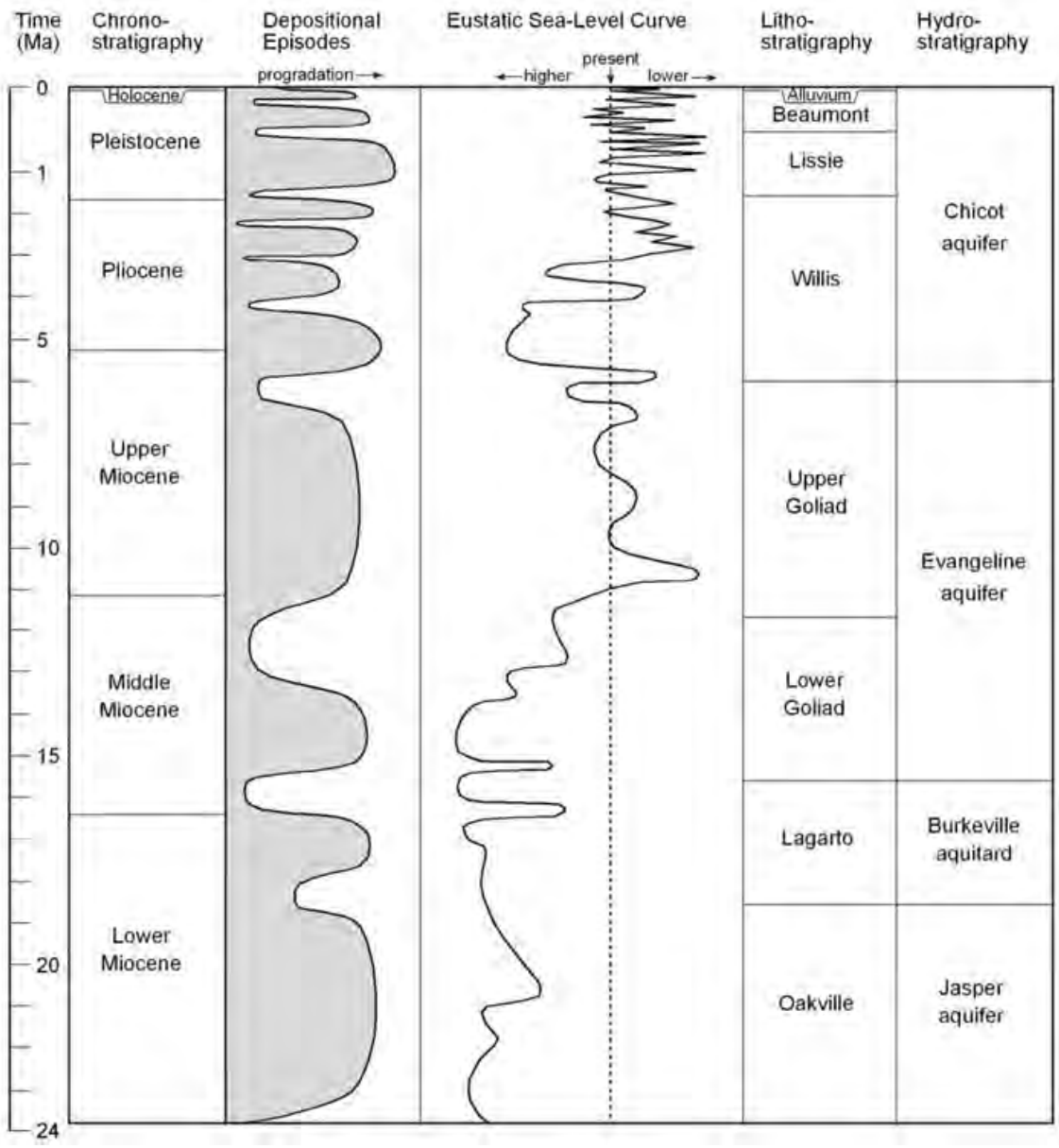

Figure 2-11: Chronostratigraphic chart of Miocene to Holocene depositional episodes, northwest GoM. Lithostratigraphic and hydrostratigraphic boundaries are approximate. Depositional episodes from Galloway et al. (2000) and sea-level curve from Haq et al. (1987). Geologic ages in millions of years ago (Ma) from Berggren et al. (1995). **(**From Young et al., 2012**)**

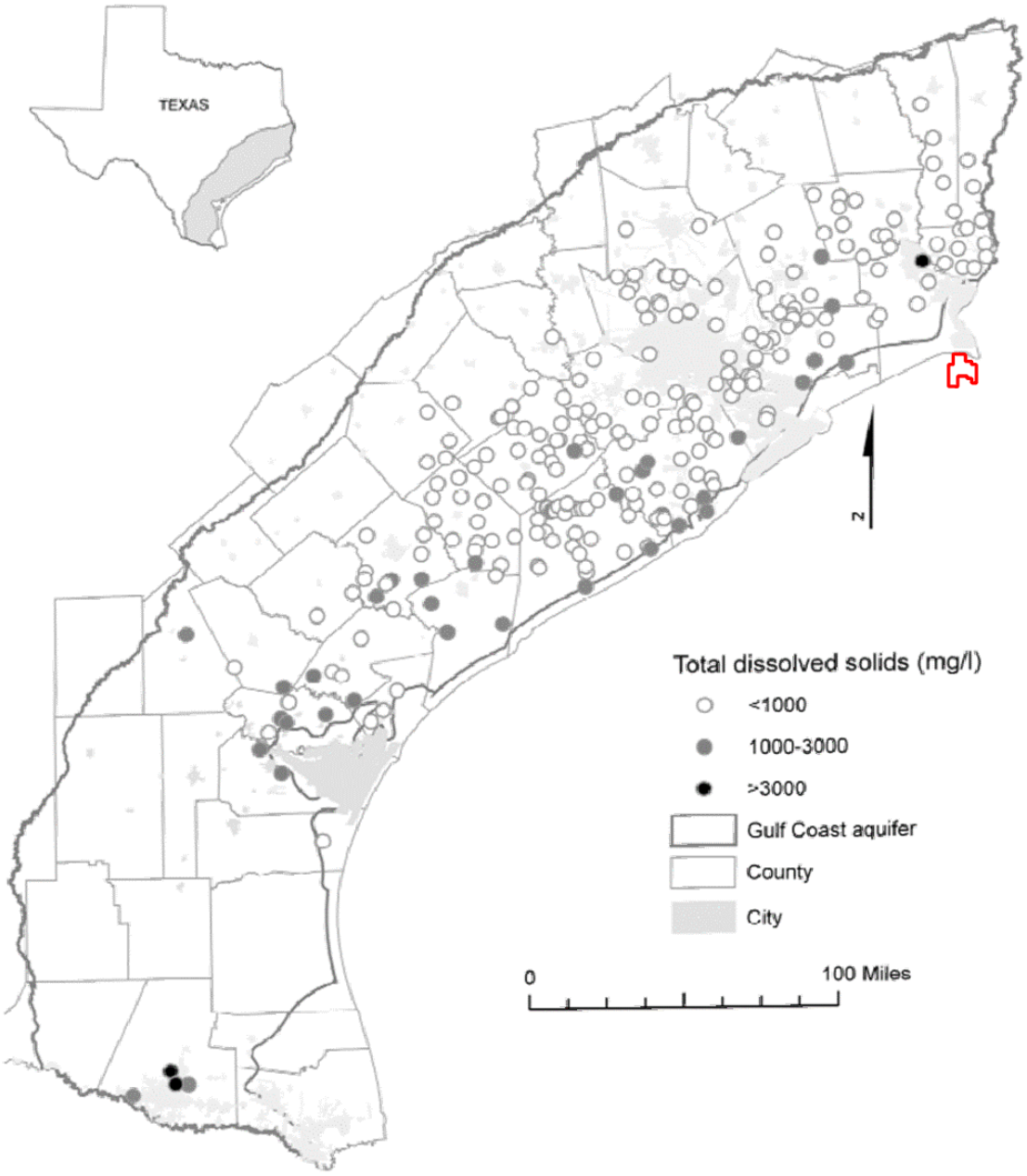

Figure 2-12: Distribution of total dissolved solids concentrations in the Chicot Aquifer. (from Chowdhury et al., 2006). BBE shown in red.

2.2 Maps and Cross Sections of the AOR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

This section provides maps and cross sections per 40 CFR 146.82(a)(2) and (3)(i).

2.2.1 Local Cross Sections

Two structural cross sections are presented as **Figure 2-13** and **Figure 2-14**, representing sections in the dip and strike orientations, respectively. These cross sections illustrate the nature of the reservoir continuity and regional thickness of both the upper confining zone and the injection zone.

2.2.2 Local Structure and Isochore Maps of the Injection and Confining Zones

Local structure and isopach maps of Claimed as PBI provided as **Figure 2-15** and **Figure 2-16**, respectively. The structure map of the upper confining zone shows a low-angle dip from northwest down towards the southeast at approximately 1-3 degrees within the lease. Within the BBE lease, the top of the confining zone is anticipated to range in depth from approximately 5,150 ft – 6,470 ft TVDSS.

Claimed as PBI

Claimed as PBI In general, the structure map of the injection zone shows a low-angle dip towards the southeast at Claimed as PBI The top of the injection zone is anticipated to range in depths from approximately 5,470 ft to approximately 6,970 ft TVDSS within the lease Claimed as PBI

The local structure map of the basal confining zone is provided as **Figure 2-19**. The base of the injection zone ranges in depths from approximately 7,590 ft to 9,710 ft TVDSS.

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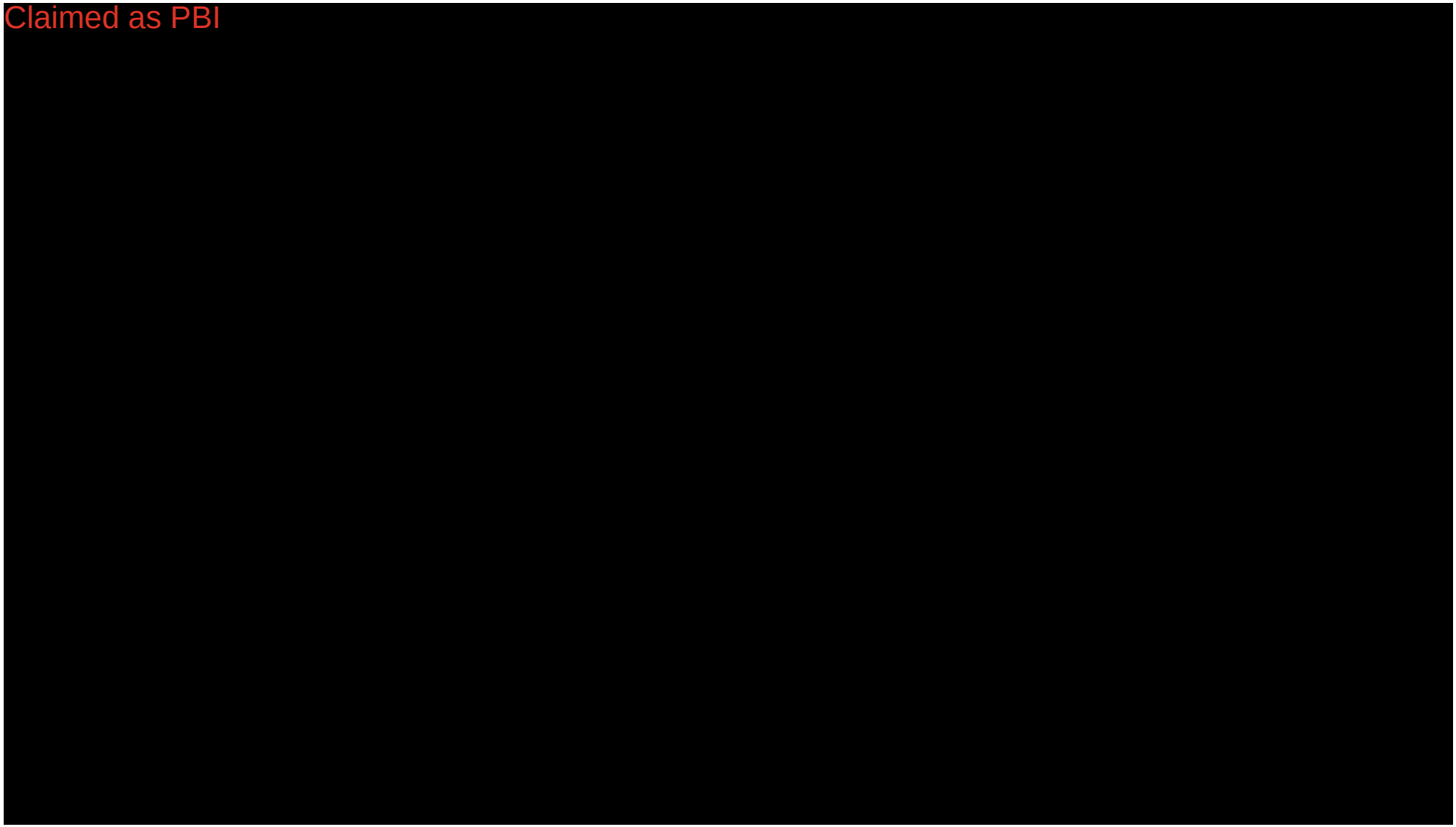

Figure 2-13: Depositional strike oriented cross section with the proposed vertical injector well W1 location projected (flattened on Amph B). There is no USDW offshore.

Claimed as PBI



Figure 2-14: Depositional dip oriented cross section with proposed vertical injector well W1 location projected (flattened on Amph B). There is no USDW offshore.

Claimed as PBI

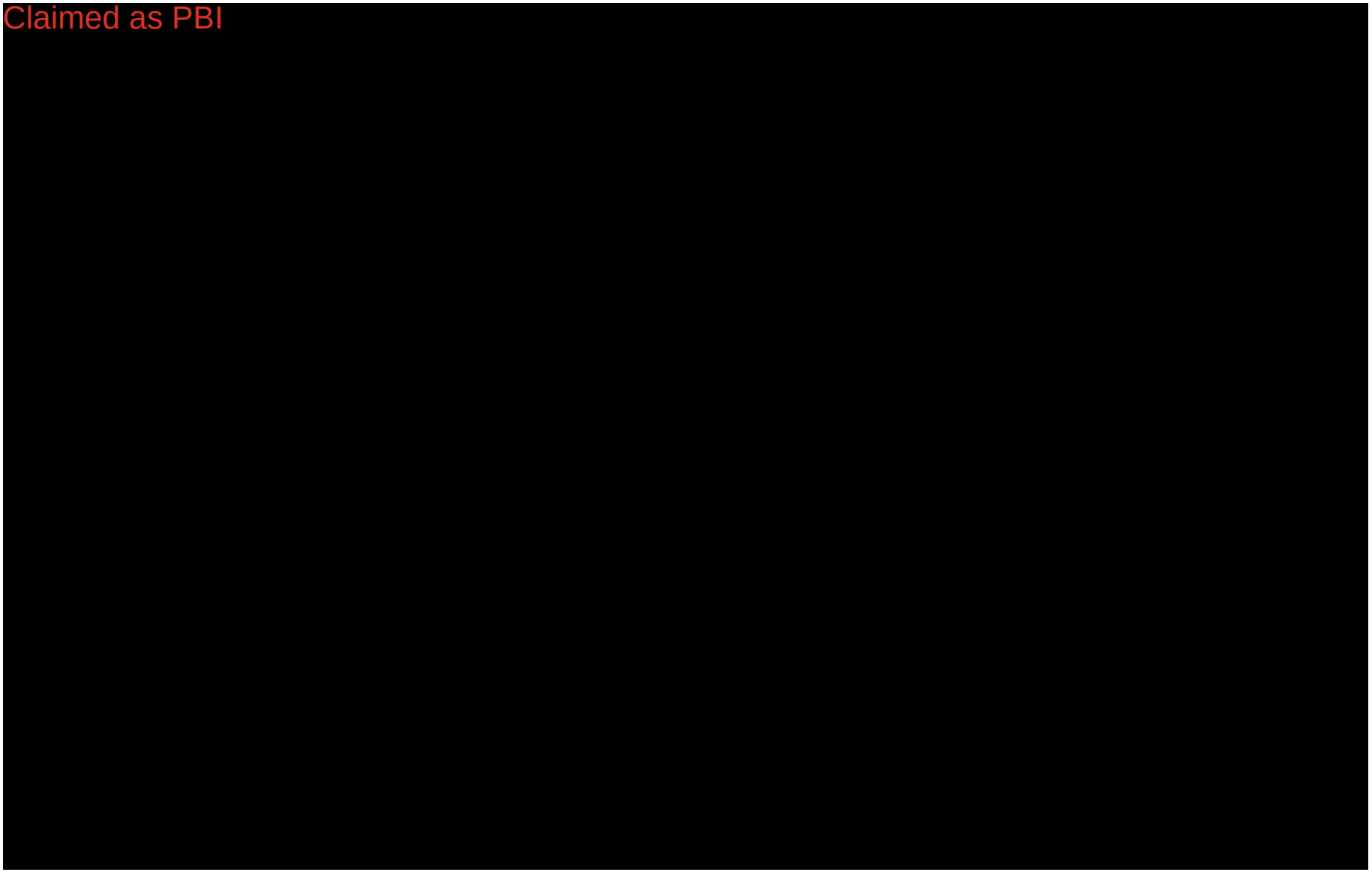

Figure 2-15: Structure map of the top of the *Amph B* proposed primary confining zone (T15 surface) in ft TVDSS.

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Figure 2-16: Isopach (true stratigraphic thickness [TST]) thickness map in ft of the *Amph B* confining zone (T15 – T13 intervals)**.**



Figure 2-17: Structure map of the top of the Lower Miocene proposed injection zone (T12 surface) in ft TVDSS.

Claimed as PBI



Figure 2-18: Isopach (TST) thickness map in ft of the Lower Miocene injection zone (T12 – T5 intervals).

Claimed as PBI



Figure 2-19: Structure map of the top of the basal confining zone (T4 surface) in ft TVDSS.

2.3 Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

BBE and surrounding area is an extensional regime of mixed Upper Eocene mud-prone and allochthonous salt detachments (Rowan, 1995; Galloway, 2008). Deformation in the area is similar in style and mechanism to the regionally-extensive Clemente-Thomas growth fault zone (**Figure 2-10**), which is an extensional growth fault system with maximum displacement, as much as 4000 ft (Treviño and Meckel, 2017), Claimed as PBI accommodation space is filled with synkinematic growth deposition, which can have a three-fold increase in cross-fault interval thickness.

At BBE-P1, these features are observed to a lesser magnitude, with maximum displacement and growth deposition observed in the Oligocene Frio along listric growth faults. These fault systems are commonly associated with minor splays and antithetic faulting (**Figure 2-20**) typical of those observed regionally (Galloway, 2008).

2.3.1 Fault Characterization and Style

Claimed as PBI Faults were categorized and prioritized based on a set of interpretation criteria:

1. Radial extensional faulting with associated diapirism
    - Salt diapirs and related withdrawal synclines are common in the Gulf Coast Basin (Galloway, 2000). Claimed as PBI A local minibasin and associated extensional faulting occurs in a radial pattern surrounding this feature. Some of the associated faults extend into the BBE acreage (**Figure 2-20**, inset B). These faults tend to exhibit higher than average displacement (**Figure 2-21**) and may extend up to the shallow limit of seismic resolution.
2. Locally extensive growth faults
    - These faults originate from regional mud-prone Eocene detachment surfaces and are through-going into the overburden intervals (**Figure 2-20**, insets B and C). Maximum growth and displacement are accommodated by Paleogene sediments. While there are regional changes in Miocene thickness, cross-fault thicknesses are typically constant, indicating post-kinematic faulting local to the project area.
3. Synthetic normal faults
    - In addition to the deeply detaching growth faults, synthetic extensional faults are common. These faults may detach at variable levels within the mud-prone Paleogene intervals (**Figure 2-20**, inset C). Claimed as PBI
4. Antithetic normal faults
    - Local antithetic normal faulting is commonly associated with salt withdraw and minibasin development. Claimed as PBI

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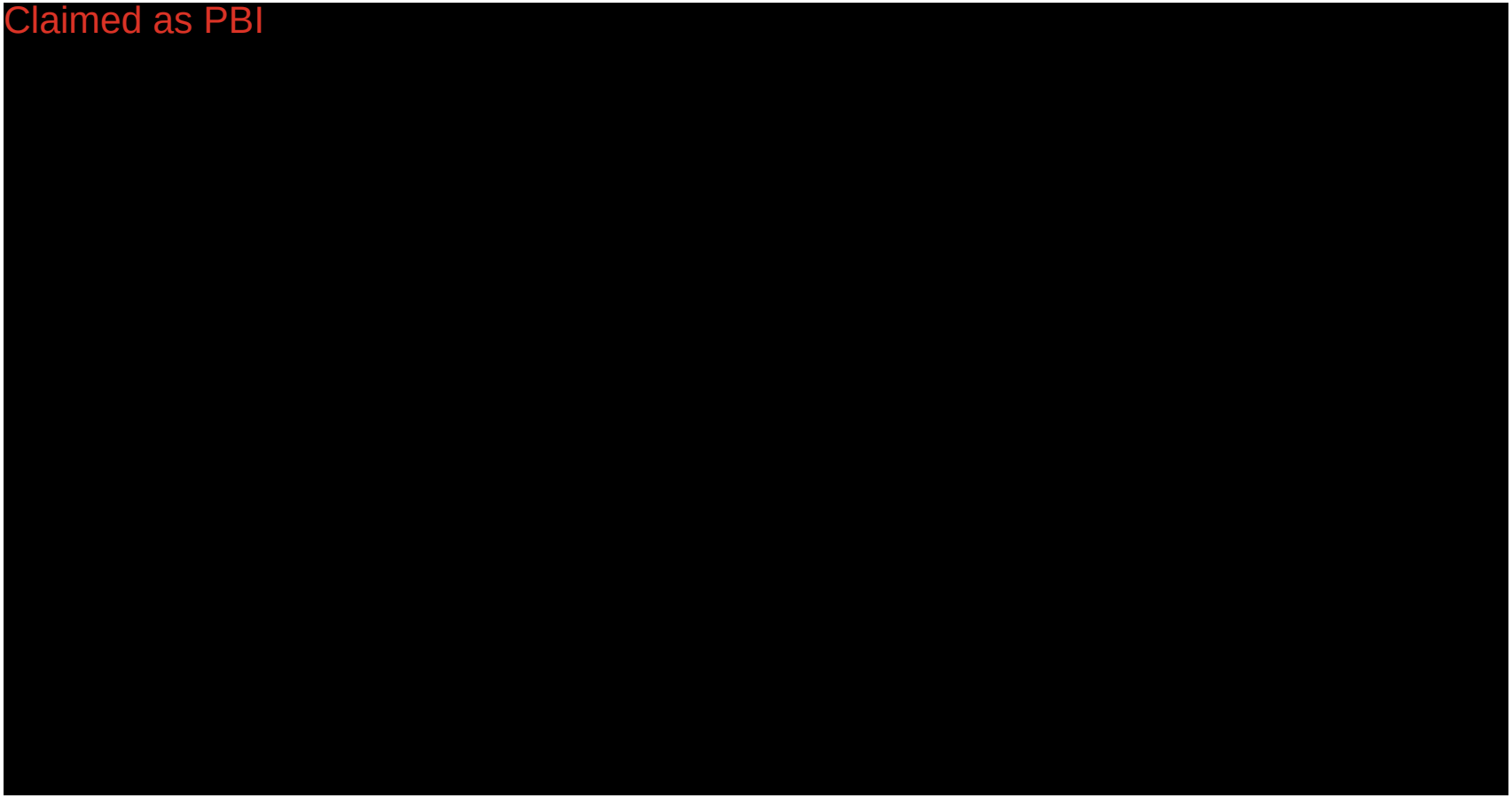

Figure 2-20: Faulting styles within the BBE acreage. (A) Structure map on top *Amph B* surface. Major faults interpreted for structural modeling, including those transecting the BBE acreage (outlined in red), are shown with black outlines. Line locations for insets B-D are color-coded and annotated accordingly. (B) Interpreted faults (green dashed lines) that radially extend from the salt diapir (S) located in NW corner outside of the main acreage. These faults exhibit evidence for the most recent movement within the BBE acreage. (C) Locally extensive growth faults and associated synthetic normal faults (blue dashed lines). Faults in this category generally dip to the south and can have multiple detachments on mud-prone sediments within the Lower Miocene. Synthetic splays commonly branch from the main faults, and in many instances go from the 'minor' splay to a new 'major' fault. (D) Antithetic normal faults (purple dashed lines). This fault type is most abundant local to the diapir (S). Note: Surfaces Top *Amph B*, Top T12, and Top T4 of the LM injection interval are annotated by black dashed lines to illustrate offset.

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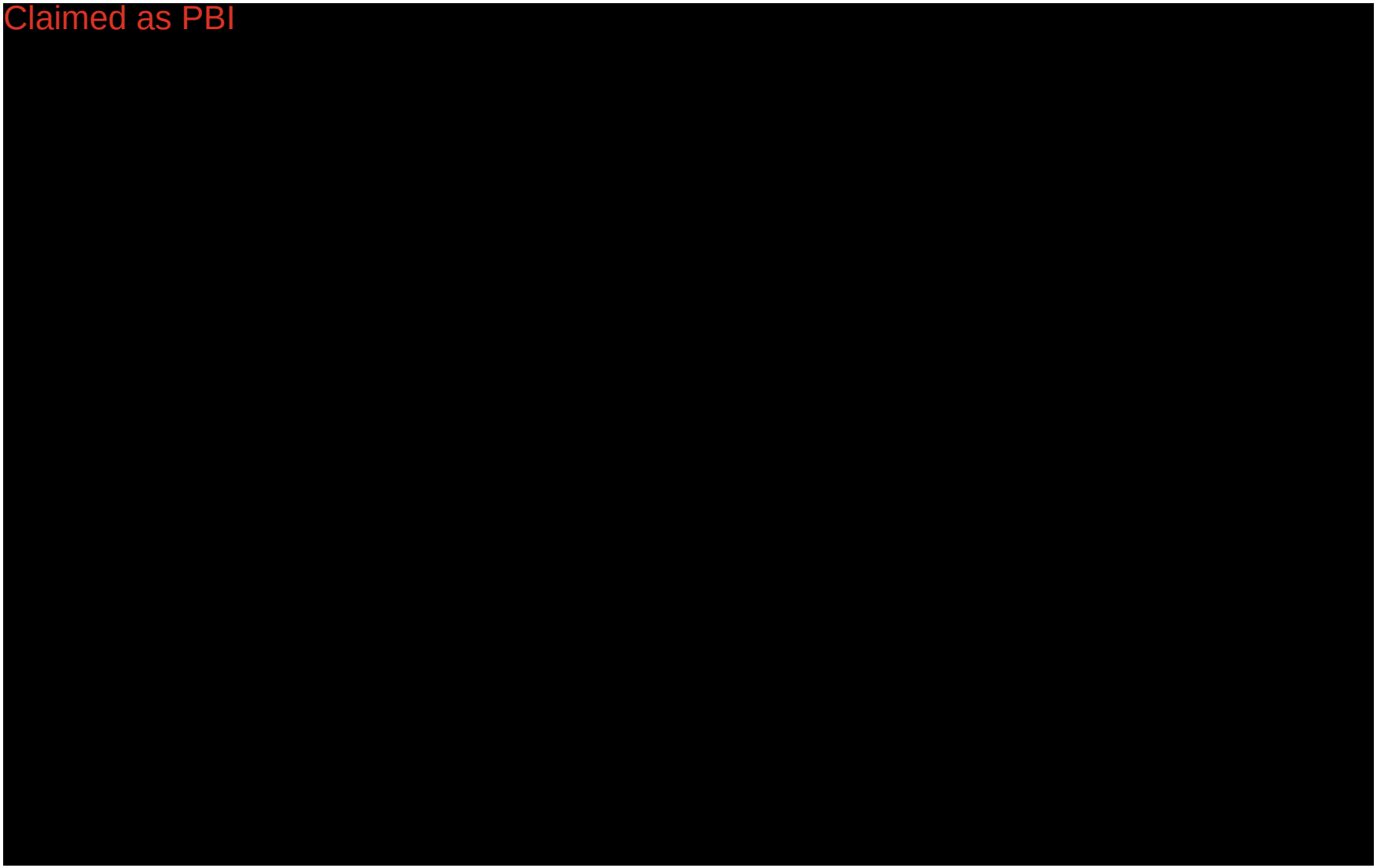

Figure 2-21: Fault slip displacement distribution (A) modeled from the T15 to the T4 stratigraphic horizons (Lagarto and Oakville Formations) and associated property overlay (B) applied to faults within BBE acreage and near acreage boundary (C). Histogram (A) is sampled based on grid size, where each cell has an associated displacement value. Magnitude of displacement varies along the fault plane (B).

2.3.2 Fault Displacement

Fault property analysis was performed in Petrel© 2022 using volume-based structural modeling. Horizons are interpreted to fault intersections, where they are offset and continued on the opposite side of the fault. Slip displacement, sometimes referred to as simply displacement herein, is defined as the total translational offset of a horizon or interval across a fault plane. This is not to be confused with fault throw, which is defined as the vertical displacement from the fault-plane intersection of a stratigraphic horizon on the footwall to the same respective horizon intersecting the fault-plane on the hanging wall.

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2.3.5 Fault Clay Content and Seal Potential

Based on proven accumulations of conventional oil and gas deposits (Galloway et al., 1986), the extensional fault systems of the Lower Miocene are presumed to have excellent seal potential for carbon storage reservoirs (Silva et al., 2023). High fault clay content of interbedded shales and mudstones contribute to fault seal potential in the BBE acreage. In the containment interval and the confining zone, the combination of fault displacement and zone thickness occasionally results in shale on shale juxtapositions and reservoir (flow unit) juxtapositions against low-permeability basin fill. Fault juxtaposition of shale also indicates the likelihood of clay smear along the fault plane (e.g., Vrolijk et al., 2016), which may act as a fluid barrier to

lateral and vertical flow. These conditions likely prevent vertical migration up the faults and confine CO_2 to the injection zone.

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2.3.6 Fault Clay Content, Shale Smear, and Gouge

Fault zone clay content is the proportion of clay admixed within the fault zone, contributing to fault capillary seal potential. This property, also referred to as shale gouge ratio (SGR), is calculated from the volume of clay in deformed host rock intervals, thickness, and magnitude of slip (offset) of the respective intervals (Yielding et al., 1997). The SGR property can be computed within a structural model, when clay volume (Vclay) is calculated as a proportion of shale volume (Vshale). The higher abundance of shale in the stratigraphy, the higher the proportion of Vclay and thus, SGR, contributing to fault seal potential.

Recently published simulation results (Silva et al., 2023) offer analogs for BBE-P1. Claimed as PBI [redacted] Their results show a range in SGR values from 58% to 82% and multiple injection scenarios, where small amounts of CO_2 have the potential for cross-fault lateral migration over the project lifespan (modeled in one scenario). The authors note that there are no scenarios where vertical fault migration is observed. Claimed as PBI [redacted]

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[redacted]

2.3.7 Fault Transmissibility

The influence of faults on fluid flow presents a challenge in reservoir simulation. The combination of displaced lithologies across the fault plane and the properties of the fault rock and fault zone are difficult to constrain and scale to a reservoir model. Common practice in reservoir simulation is to apply a transmissibility multiplier (TM) (Manzocchi et al., 1999) to calculate fault transmissibility at a cellular level. This method scales physical properties of the fault and host rock to the model by incorporating the grid size as a distance metric. Typically ranging from 0 to 1, the TM is a scalar adjustment due to the material within the fault zone.

A range in grid and fault permeabilities was used to model transmissibility multipliers for the BBE-P1 model and to capture uncertainty in the physical constraints on fault transmissibility (host rock permeability, fault rock permeability, and fault thickness). Inputs to the transmissibility multipliers include SGR (discussed above) fault thickness, and fault permeability.

2.3.8 Fault Permeability

In the absence of direct fault rock permeability measurements, globally published expressions relating SGR to fault rock permeability (Manzocchi et al., 1999, Sperrevik et al., 2002) were used to constrain a range for modeling BBE-P1 fault properties. The average modeled fault permeability in the region of the BBE site acreage varies by two orders of magnitude between the two models. This is expected based on the ranges and maximum permeabilities represented by the two global models.

The Sperrevik et al. (2002) model requires the maximum burial depth of the modeled intervals and the depth at time of deformation, both in meters. Aligned with the approach documented in Silva et al. (2023), shallow burial depth (200 meters) was used to represent the timing of deformation. The present-day overburden is presumed to represent maximum burial depth.

2.3.9 Fault Thickness

Fault thicknesses can be inferred based on a positive covariation with displacement. A ratio of 1:100, fault thickness to displacement, is a standard default and was used to calculate spatially varying fault transmissibility multipliers in Petrel© 2022. This ratio aligns with globally observed thickness to displacement ratios for fault rock (e.g., Childs et al., 2009).

2.3.10 Fault Transmissibility Multipliers for Simulation

Using the input parameters described above, spatially varying TM results were generated in Petrel© 2022.

To capture uncertainty, TMs were calculated using twelve permutations: average values for grid permeability (high, medium, low), fault permeability (high, low) and fault thickness ratios (1:100 and 1:10). The results show a wide range in values with just over two orders of magnitude, in accordance with the broad range of inputs. The range is driven by the lithologic heterogeneity of cross-fault stratigraphy and the variable displacement accommodated by each fault.

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2.3.11 Fault Stability

A subset of 17 faults located in or next to the lease area was selected to perform a stability analysis (**Figure 2-22**). For this analysis, the stresses computed from the numerical Mechanical Earth Model (MEM) were projected into the fault surfaces and used to compute both the effective normal and tangential or shear

stresses acting on the faults. Because the faults are not perfect planes but have some waviness, the fault surfaces have been discretized into triangular elements of about 30 m size, and the stress projection has been done in each of the individual triangles using the MEM stresses from that location.

Results of the analysis are shown in **Figure 2-23**, **Figure 2-24** and **Figure 2-25** (the faults have been separated in three groups for clarity), in the form of shear vs effective normal stress diagrams in the so-called Mohr space. Each point represents the state of stress in one of the triangular elements. The points are color coded according if they Claimed as PBI located above or below (blue).

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Figure 2-22: Faults selected for the stability analysis.

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Figure 2-23: Results of the stability analysis for faults 10, 14, 19, 36, 68 and 81. The Mohr diagrams show the distribution of normalized effective normal vs shear stresses acting on each of the faults. For the purposes of this analysis, the faults have been discretized in 30 m size triangular elements. Red dots indicate elements located within the LM sands, and blue dots elements located elsewhere. The black dashed lines indicate different values of friction coefficient.

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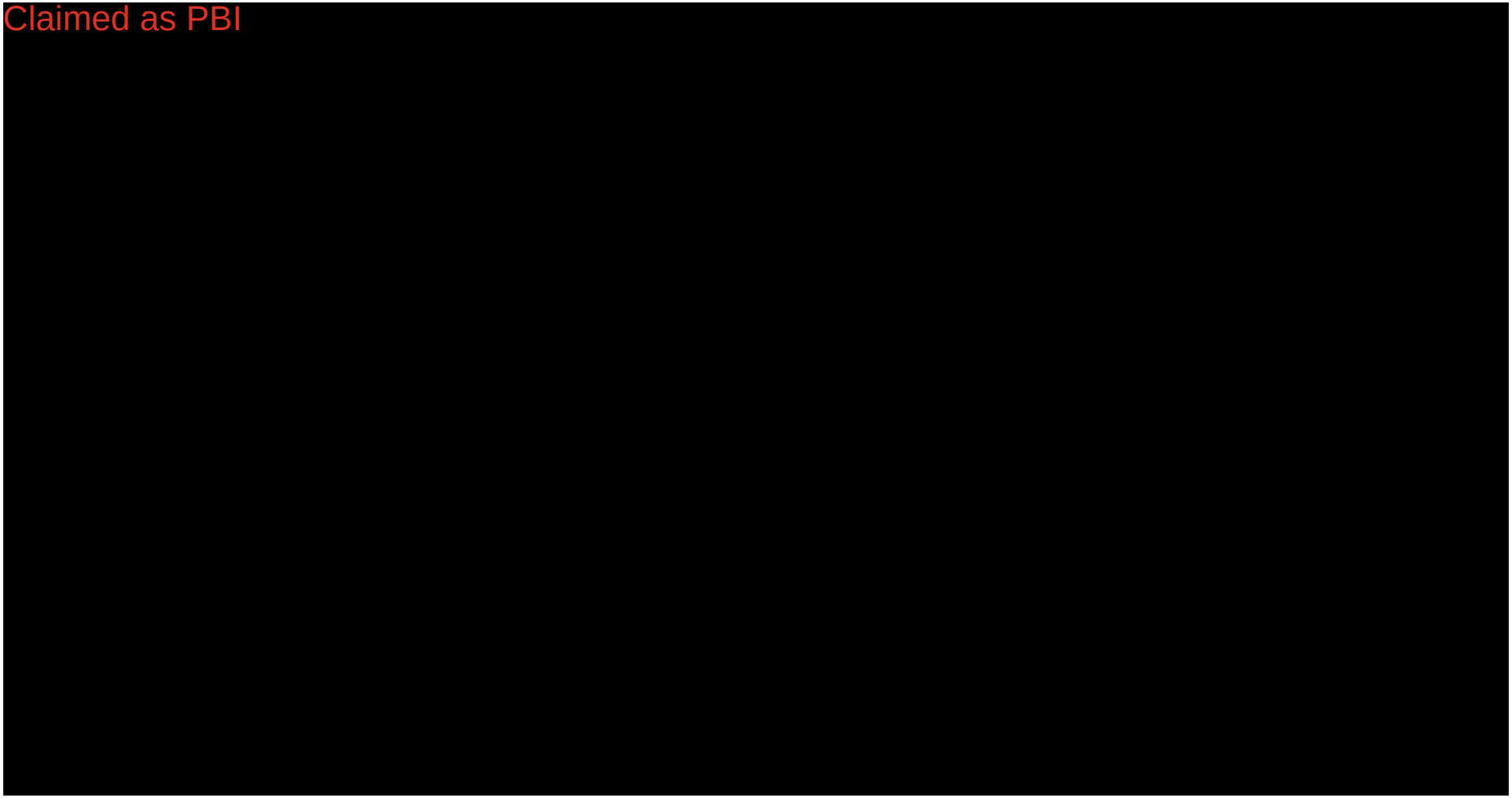

Figure 2-24: Results of the stability analysis for faults 12, 27, 74, 78, 79 and 80. The Mohr diagrams show the distribution of normalized effective normal vs shear stresses acting on each of the faults. For the purposes of this analysis, the faults have been discretized in 30 m size triangular elements. Red dots indicate elements located within the LM sands, and blue dots elements located elsewhere. The black dashed lines indicate different values of friction coefficient.

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Figure 2-25: Results of the stability analysis for faults 4, 28, 29, 75 and 77. The Mohr diagrams show the distribution of normalized effective normal vs shear stresses acting on each of the faults. For the purposes of this analysis, the faults have been discretized in 30 m size triangular elements. Red dots indicate elements located within the LM sands, and blue dots elements located elsewhere. The black dashed lines indicate different values of friction coefficient.

2.4 Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

This section describes the overall geologic character of the injection and confining zones to support storage.

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Table 2-2: Definition of proposed confining and injection zones and intervals at BBE.

Zone of interest	Description
USDW	None (Section 2.7.1)
Proposed Tertiary Upper Confining Zone	*Rob E* shale (Upper Goliad Fm)
Proposed Secondary Upper Confining Zone	*Text W* shale (Lower Goliad Fm)
Proposed Upper Confining Zone	*Amph B* shale (Lagarto Fm)
Proposed Injection Zone	T5 – T12 sands Oakville (LM1) / Lagarto Fms (LM2)
Proposed Injection Interval Unit 1	Retrogradational sands T11 – T12
Proposed Injection Interval Unit 2	Aggradational sands T7 – T10
Proposed Injection Interval Unit 3	Progradational sands T5 – T6
Proposed Basal Confining Zone	*Siph D* shale (Oakville Fm)
Secondary Basal Confining Zone	Anahuac Fm

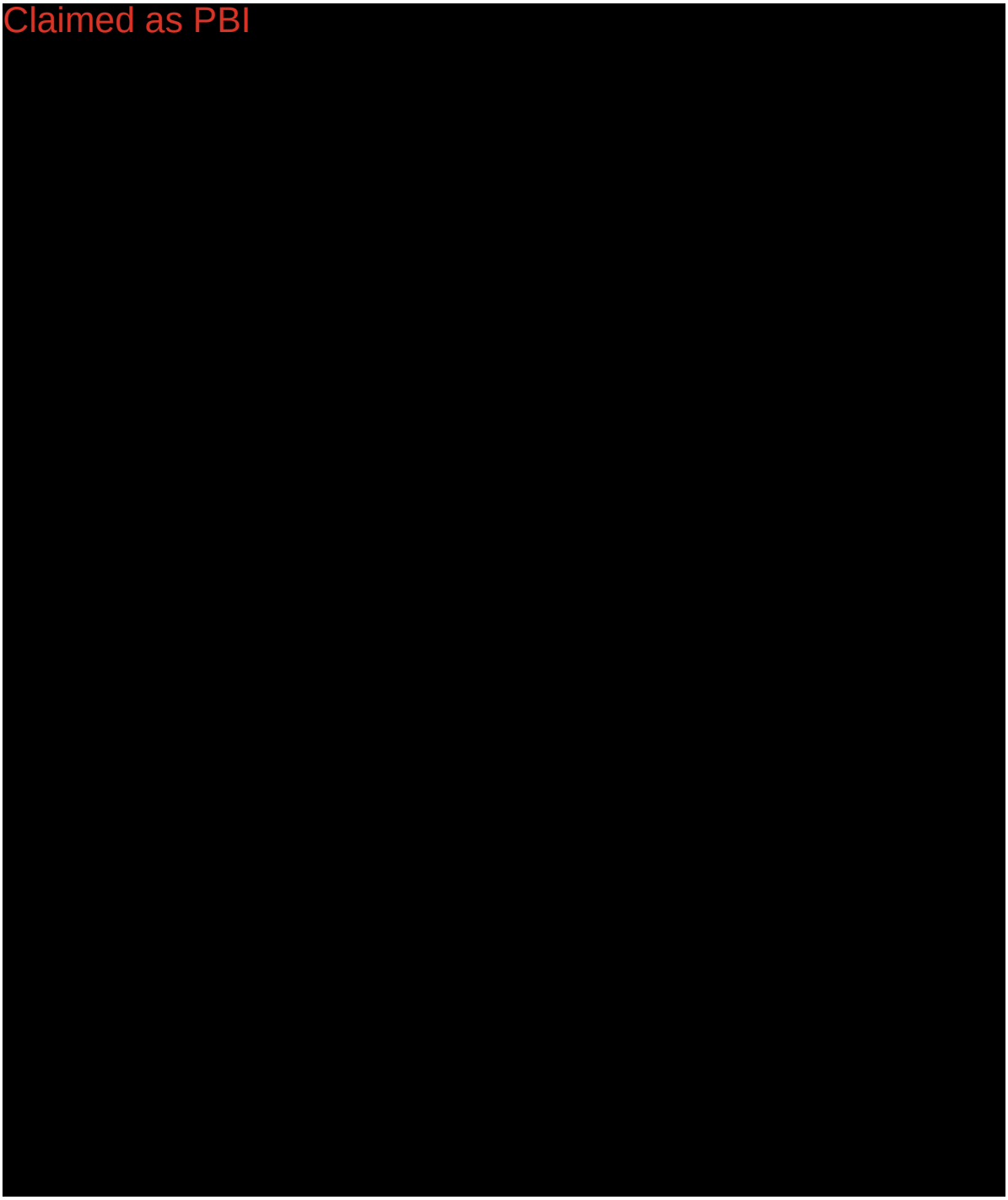

Figure 2-26: High-Island 4 reference well (type log) with key observations used to define multiple zonation scales. Large-scale zonation used to define major sequence stratigraphic trends. Mid-scale zonation used to define sand-rich packages capped by regionally mappable flooding surfaces.

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Figure 2-27: Schematic geologic cross section (left), and reference well type log (right) for Miocene CO_2 injection targets along strike of the BBE project area Treviño and Meckel, 2017).

2.4.1 Proposed Upper Confining Zone

The primary upper confining zone for BBE-P1 is the top of the Lagarto Formation (LM2). Claimed as PBI

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2.4.2 Proposed Injection Zone

The proposed injection zone includes multiple sands within Oakville (LM1) and Lagarto (LM2) formations

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2.4.3 Proposed Injection Intervals

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Figure 2-28: The lease boundary (red polygon) and well-section lines used to define the local stratigraphic framework for BBE.



Figure 2-29: Overview depositional strike oriented cross section.

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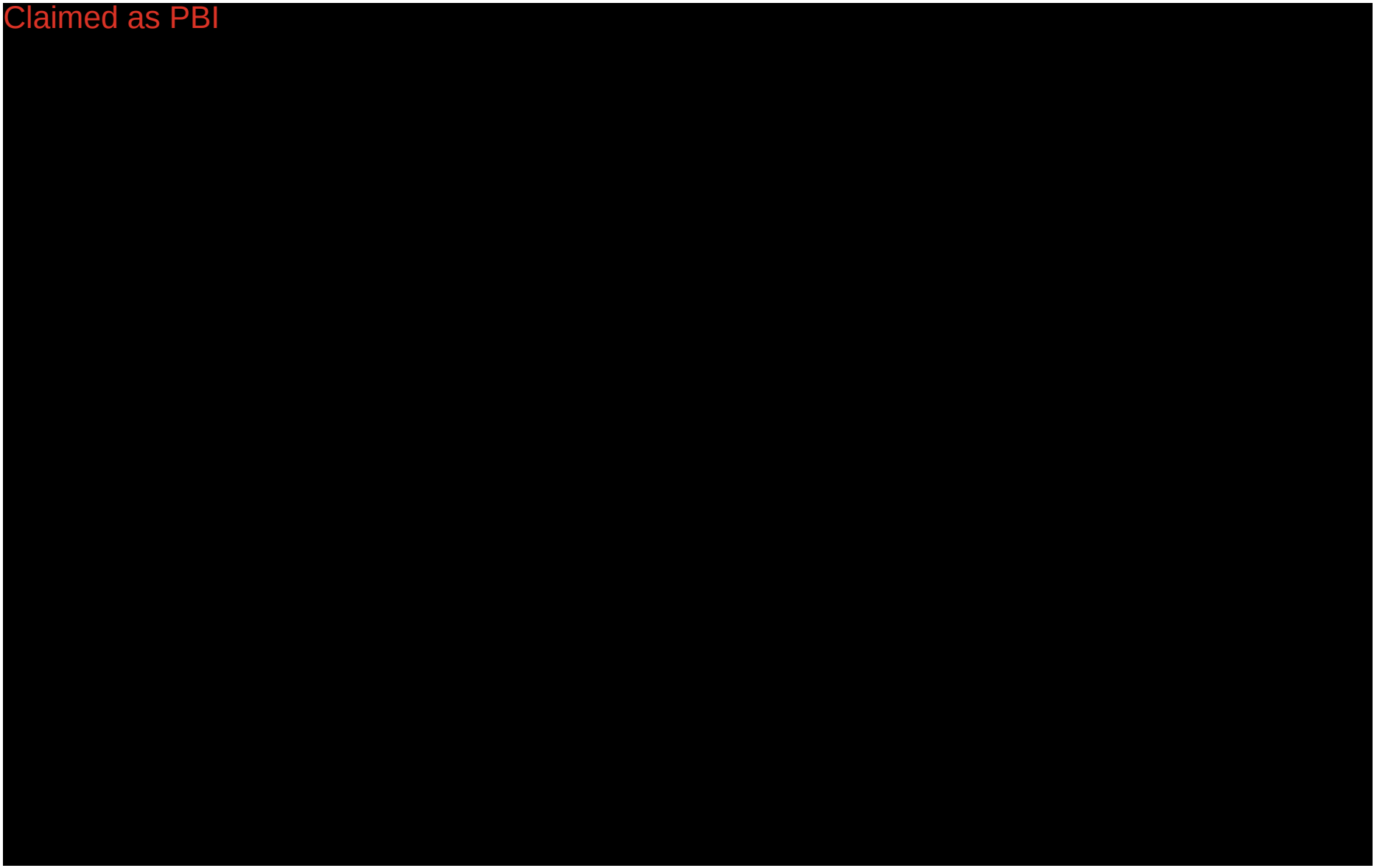

Figure 2-30: Overview depositional dip oriented cross section.

Table 2-3: Well markers in project reference well HI-12L ST (API 427083021200)

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2.4.4 Proposed Lower Confining Zone

The lower confining zone is defined by the *Siph D* shale of the Oakville Formation. Claimed as PBI

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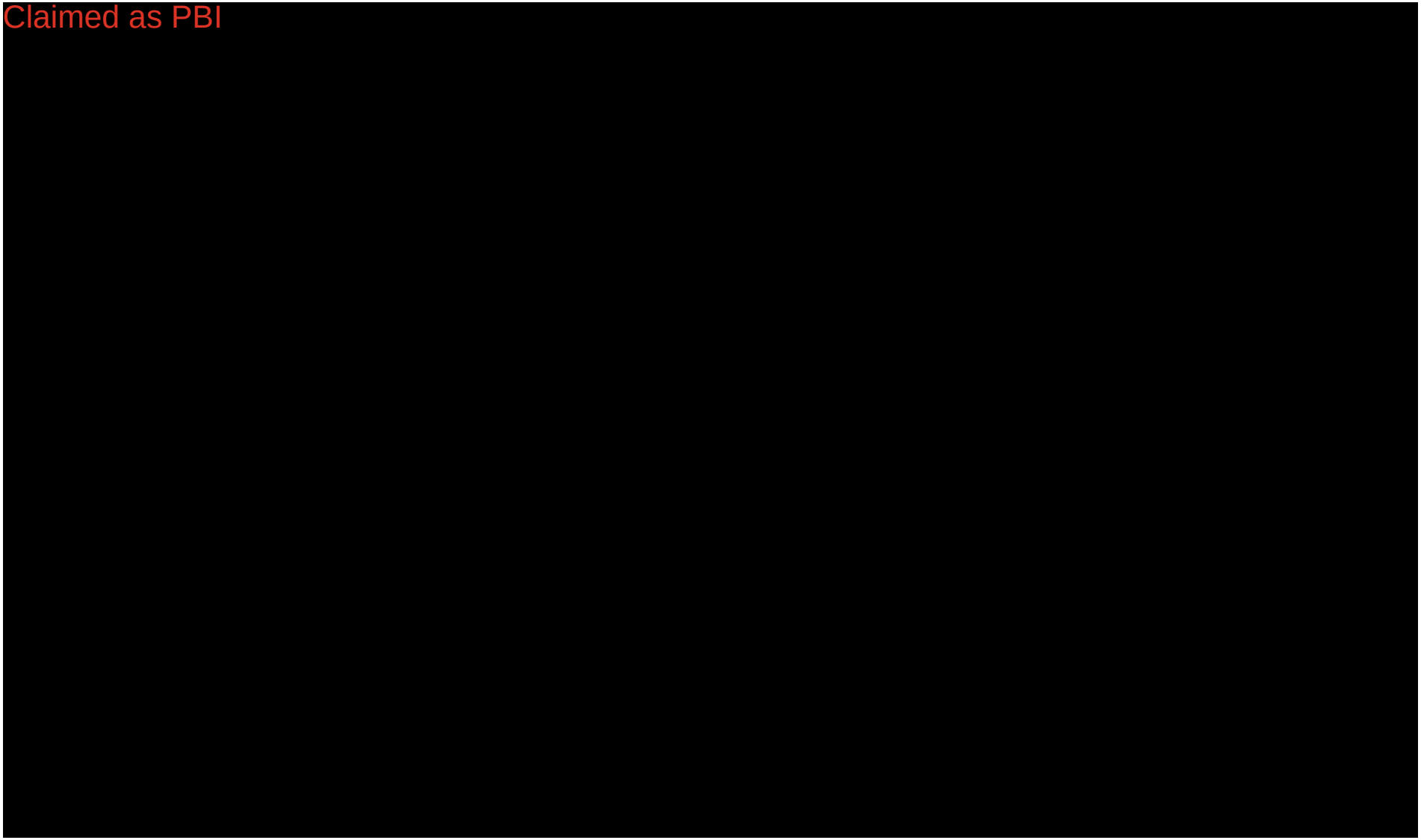

Figure 2-31: Sandstone percentage maps of regionally recognized subunits within Unit 3, between MFS9 and MFS10 (Olariu et al., 2019). The average thickness of sandstone within each subdivision ranges from 40 to 70 m. The red star marks the location of the BBE-P1 project area.

2.5 Geomechanical and Petrophysical Information [40 CFR 146.82(A)(3)(IV)]

Predictions of the stress magnitudes and orientations as well as the fracture gradient were calculated using a finite-element MEM. The MEM covered an area of approximately 50x50 kilometer around the lease area and includes identified formations from the ground surface (or seabed) until 22,000 ft true vertical depth below sea level (TVDSS).

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starting at the base of the T5 sand has been inferred from leak-off tests (LOT) data (**Table 2-4**) collected from various wells in the High Island area (**Figure 2-32**), as well as from offse Claimed as PBI

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Table 2-4: Available LOT data from offset wells.

Well	UWI	MD (ft)	TVDSS (ft)	LOT Grad (pounds per gallon [ppg])	LOT Press (psi)
HI 19 OCS G22227 001 ST00BP00	427084061200	4000	3909	14.1	2930
HI 22 OCS G05006 A001 ST00BP00	427084064300	4553	4429	14.8	3405
HI 22 OCS G32744 A001 ST00BP01	427084064301	10550	9711	17.0	8685
HI 37 OCS G20656 A004 ST00BP00	427084056700	10250	10158	17.1	9104
HI 37 OCS G20656 A004 ST00BP00	427084056700	13994	13901	18.5	13447
HI 52 OCS 00508 C003 ST00BP00	427084061400	9325	9060	17.3	8260

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Natural fractures have not been identified in the area of study, due to lack of wellbore images. Given the ductility of the formations, it is expected that natural fractures will not be very prevalent in the area of study. Large geological faults have been identified from the seismic data and they are extensively discussed in Section 2.3.



Figure 2-32: Pore pressure model (orange line) for the area of study, compared against hydrostatic pore pressure with gradient of 0.462 psi/ft (dashed blue) and calculated overburden stress (dashed grey). LOTs located above 10,000 ft TVDSS are shown as blue dots. Hydrostatic pore pressure is predicted from seafloor down to the base of the T5 sand, after which an overpressure ramp has been inferred from LOT data. Approximate top and base of the confining and injection zones at BBE-P1 are marked with a yellow dashed line.

2.5.1 Karst

No carbonates have been observed in the area of study, so the presence of karsts is not relevant for this project.

2.5.2 Local Crustal Stress Conditions

The stress regime for the BBE-P1 site was identified to be normal or extensional, with the main tectonic drive being the extension towards the GoM (Lundstern and Zoback, 2016). A second tectonic component is provided by the salt bodies, although these are localized effects expected only around and above the different diapirs found in the area, as evidenced by the orientations of the several faults identified within the area of study (**Figure 2-15**).

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2.5.3 Determination of Vertical Stress (Sv) from Density Measurements

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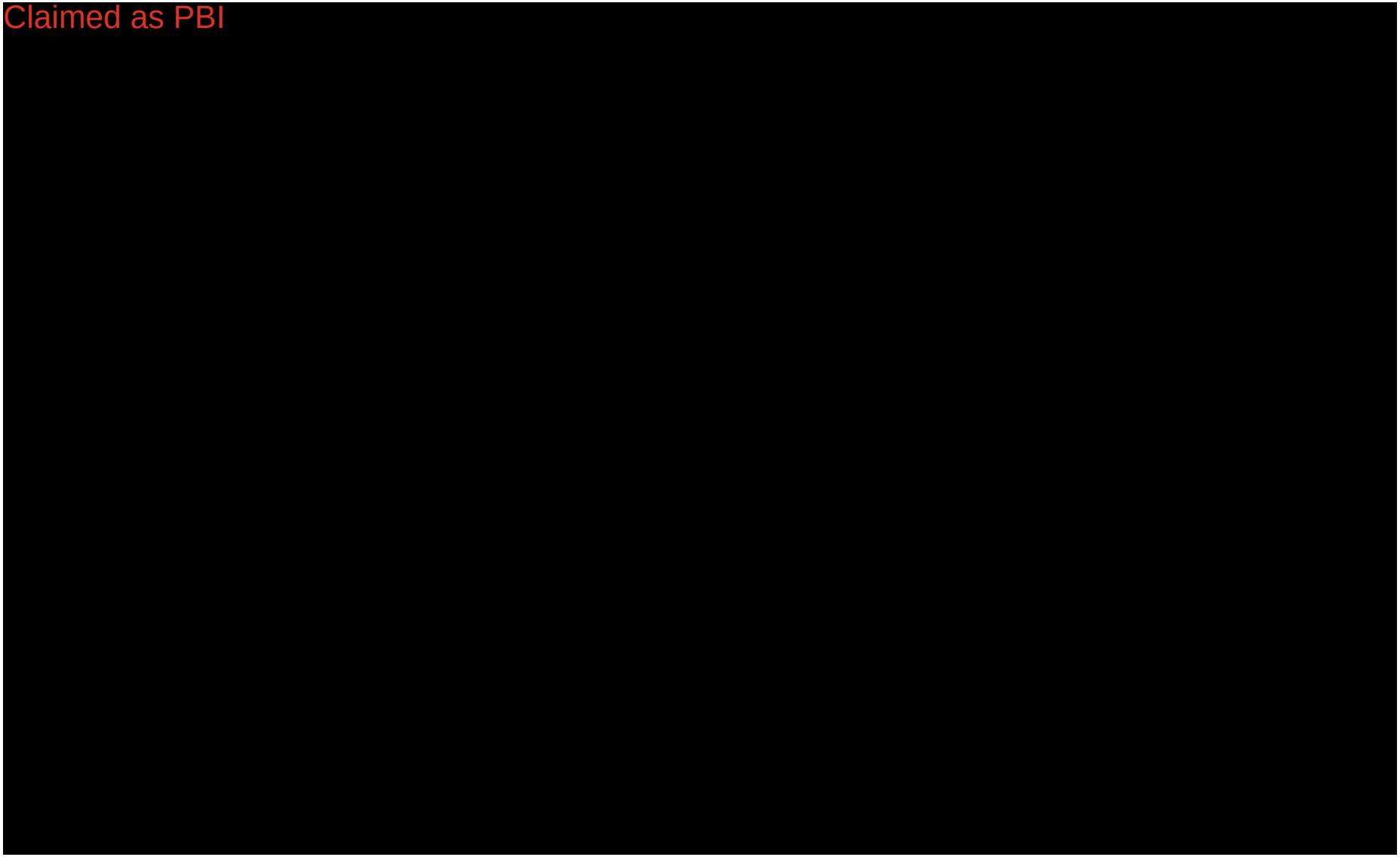

Figure 2-33: Cross plot of saturated bulk density versus sonic compressional velocity, from logs acquired on wells HI-4, HI-10, HI-10_CENERGY, HI-12 and HI-37. The blue line represents the empirical correlation between the two quantities which was used to calculate the 3D MEM density volume based on the available seismic velocities.

2.5.4 Maximum and Minimum Horizontal Stress Azimuth

Under the assumption of an extensional stress regime, it is expected that the predominant maximum horizontal stress azimuth will be approximately parallel to the shoreline (i.e., E-W to NE-SW), and the predominant minimum horizonal stress azimuth will be approximately perpendicular to it (i.e., N-S to SE-NW). Local stress rotations are expected near the salt diapirs present in the area.

2.5.5 Elastic Moduli

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Table 2-5: Wells used to calculate sonic compressional velocity.

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2.5.6 Injection Zone Fracture Pressure

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Calculating the value of this $\Delta\sigma$ is difficult as there is no valid theoretical relationship for it. Usually, the FPP is measured in-situ using a step-rate test (SRT) seen in **Figure 2-34**. And $\Delta\sigma$ is then calculated by knowing the value of S_{hmin}. Claimed as PBI

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2.5.7 Confining Zone Fracture Pressure

According to the numerical models, the mean value of minimum horizontal stress gradient in the confining

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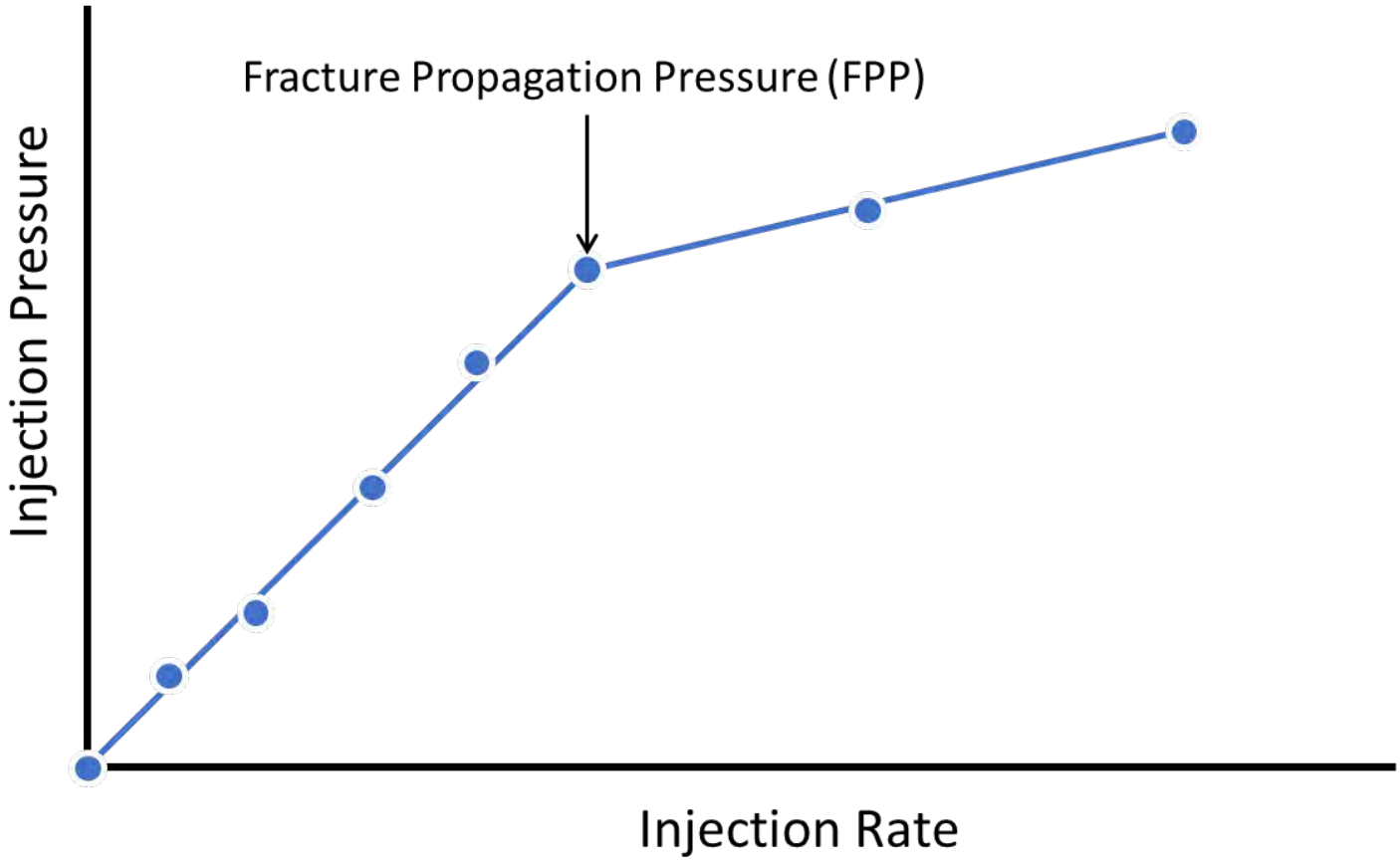

Figure 2-34: Typical pressure vs rate curve for a step-rate test (SRT). The injection rate is increased in discrete steps and at each step, the bottomhole pressure is recorded after it stabilizes. The injection rates and corresponding stabilized pressures are plotted, and they usually align with a straight line. A change of slope is usually observed at certain pressure, which corresponds to the pressure at which a fracture created at the wellbore starts propagating. This is known as the fracture propagation pressure (FPP). Once the fracture begins propagating, the subsequent points in the pressure vs rate plot align with a different straight line with a shallower slope.

2.6 Seismic History [40 CFR 146.82(a)(3)(v)]

A review of historical seismicity in southeast Texas was completed using the online monitoring databases of the United States Geological Survey (USGS) Earthquake Hazards Program and the University of Texas BEG's TexNet Earthquake Catalog (USGS, 2023 and TexNet, 2023). Data was filtered from the earliest events recorded to July 27, 2023, and encompassing a 100 mile radius around BBE. Available data (events and seismic stations) are presented in **Figure 2-35**, including the details of the nearest seismic event.

No events have been recorded within a 50-mile radius of BBE, and only one event was located within a 100-mile radius. This single Magnitude 3.8 event occurred in 1983 near Sulphur, Louisiana, at a reported depth of 8.7-miles (Stevenson and Agnew, 1988). It was recorded on the local Sweet Lake network approximately 5-miles to the southeast, an array sponsored by the U.S. Department of Energy for geothermal test sites. The event is believed to have occurred near the basement along the east-west trending Lake Arthur fault system which has a southeast dip. No substantiated damage was reported, and most public observations included minor rattling or movement of objects.

Based on recent North American stress modeling (Snee, 2020) and the available earthquake catalogs, the Gulf Coast region is characterized by low-frequency, low-magnitude seismic activity related to its extensional setting. The Gulf Coast geosyncline is comprised of "southerly dipping and thickening [Tertiary-age] beds disrupted by diapiric structures and regional systems of relatively shallow listric growth faults roughly paralleling the coast" (Stevenson and Agnew, 1988). Maximum horizontal stress (S_{Hmax}) direction follows the east-west trend of these growth faults (Snee 2020), dominated by north-south extension. While some present-day movement may occur along the faults, the poorly consolidated Tertiary sediments tend to deform plastically, and stress build-up is dissipated via continuous slippage or creep (Qu et al. 2019). Therefore, there is little potential for stress build-up along Gulf Coast faults and the risk of induced seismic is minimal for BBE-P1. This conclusion is further supported by the USGS's National Seismic Hazard Map (**Figure 2-35**) in which risk is very low (<4) along the Texas coastal plain.

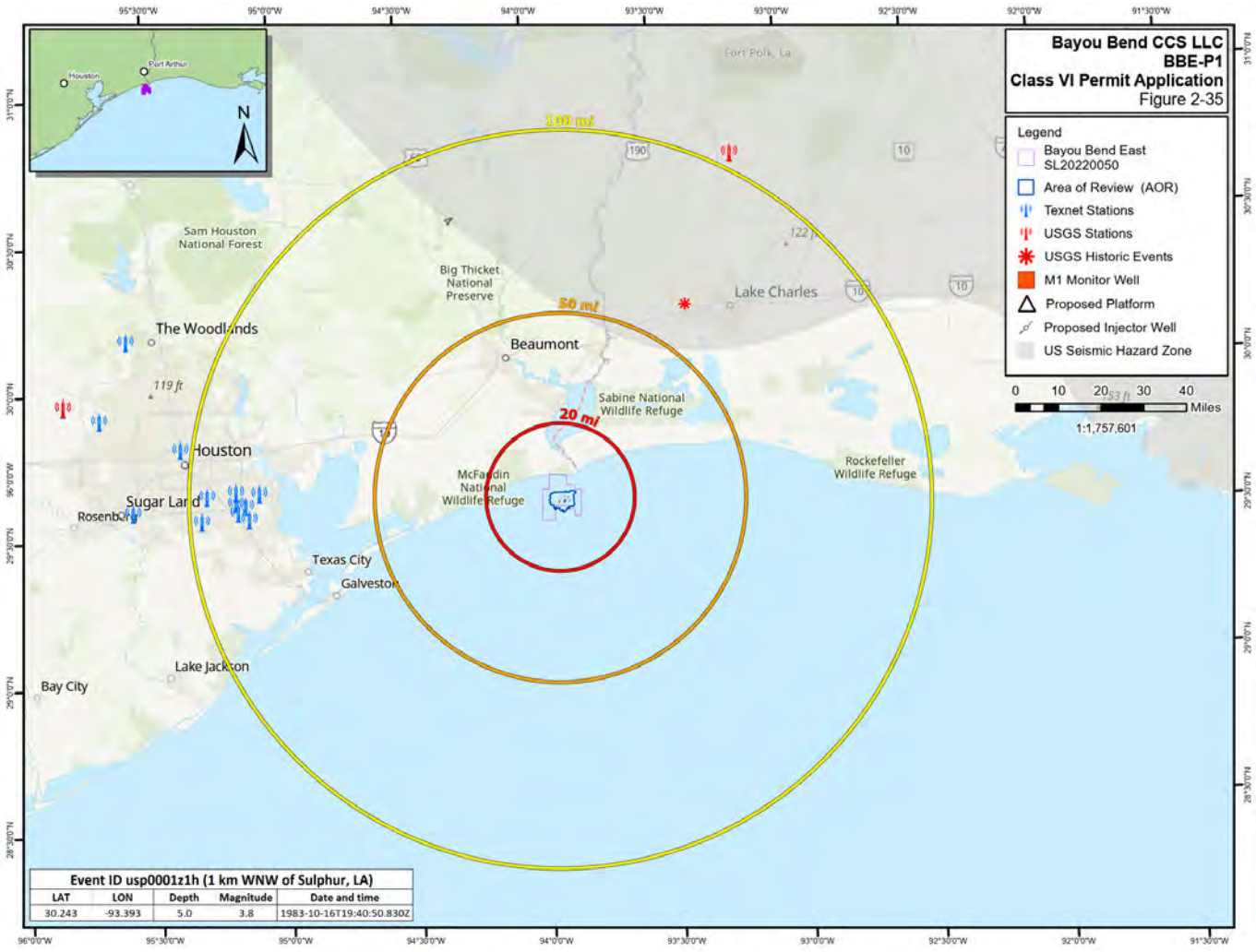

Figure 2-35: Historic seismic events recorded by the USGS and TexNet seismic arrays in southeast Texas and southern Louisiana. The closest event is marked with an asterisk and details are in the lower lefthand corner. Grey area labelled "4" is the nearest Seismic Hazard Map contour, showing a low risk of seismic activity.

2.7 Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

2.7.1 Regional Hydrogeology

The Gulf Coast aquifer system, located updip from BBE, 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, 1979; Williamson and Grubb, 2001; and Young et al., 2012). **Figure 2-11** provides a hydrostratigaphic column that includes the Lower Miocene aquifers: Jasper Aquifer and Burkeville Aquitard respectively within the Oakville and Lagarto Formations. Salt domes may locally increase groundwater salinity and overall TDS.

An underground source of drinking water (USDW) as defined in 40 CFR §146.3 is

> *...an aquifer or its portion: (i) Which supplies any public water system; or (ii) Which contains a sufficient quantity of ground water to supply a public water system; and (A) Currently supplies drinking water for human consumption; or (B) Contains fewer than 10,000 milligrams of total dissolved solids per liter...*

Within Texas State Waters, there is no identified USDW and no offshore formation containing formation fluid suitable for public water supply within or with proximity to the project site has been observed. Claimed as PBI

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In understanding the protection of the coastline and offshore resources, an upper and lower confining zone with sufficient areal extent and integrity to contain the proposed injected volume and any displaced fluids at proposed maximum pressures was identified (Sections 2.4.1 and 2.4.4) Claimed as PBI

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Figure 2-36: Map of offshore wells used for petrophysical salinity calculations at BBE-P1 site. Salinity values of the displayed offshore wells are calculated near a depth of 400 ft and shown on **Figure 2-38**. Onshore water wells in Texas and Louisiana are also shown and used to identify the nearest USDW at ~1,000 ft approximately 18 miles north (TX) and 15 miles NE (LA) of BBE-P1. Texas water wells are labeled with total depth (TD) and used as a proxy for an estimated lowest known USDW and Louisiana water wells are labeled with USDW depth.

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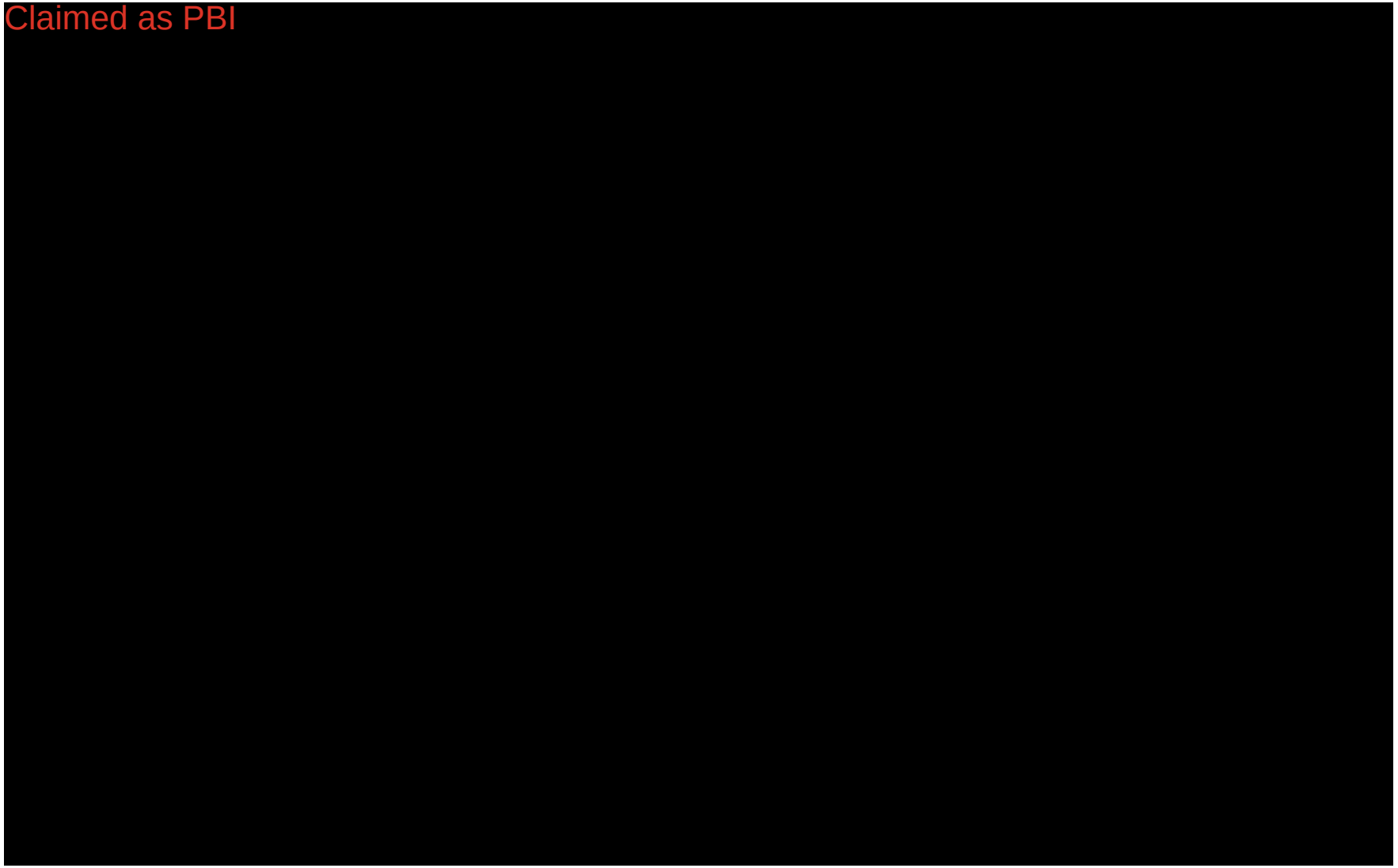

Figure 2-37: Map of offshore wells used for petrophysical salinity calculations from well logs. Salinity values (mg/L) displayed are estimated from resistivity curves at depths <1,000 ft at each well location, including the BBE SL20220050 M1 stratigraphic well. See **Figure 2-38** for the depth vs salinity trend at the most shallow petrophysical calculations.

Groundwater Flow

The Gulf Coast Aquifer dominant groundwater flow is toward the southeast direction. Faults may act as lateral barriers or vertical conduits for groundwater flow. Additionally, salt domes may also have localized effects on groundwater flow. (Baker, 1979, Young et al., 2012).

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Figure 2-38: Chart of shallow (approximately 400 ft) calculated salinity values from offshore wells near BBE-P1 site. GoM salinity (near the seafloor) is estimated at 30,000 mg/L. The nearest salinity value to our proposed injection site is at the SL20220050 M1 stratigraphic well and is calculated to be 20,000 mg/L at 700ft TVDSS.

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Figure 2-39: Cross section of shallow wells near the perimeter of the BBE-P1 site.

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Figure 2-40: Chart of calculated salinity values near BBE-P1 site from seafloor to top of proposed injection zone. The top injection zone data point marked with a star is measured from modular formation dynamics tester (MDT) fluid sampling analysis at the injection zone at the SL20220050 M1 stratigraphic well location.

2.8 Geochemistry [40 CFR 146.82(a)(6)]

The mineralogical characteristics of the proposed confining and injection zones do not indicate a potential for deleterious, geochemical reactions (Zhang et al., 2019).

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2.8.1 Other Information (Including Surface Air and/or Soil Gas Data, if Applicable)

BBE is located within a dynamic coastal environment of Texas State Waters. These waters experience freshwater inputs from rivers, runoff from upstream agricultural and farming lands, longshore currents, natural hydrocarbon seeps, algal blooms, existing pollution slicks, fishing activities, and shipping activities which result in continual variations in seawater chemistry, salinity, temperature, and sediment load. The project is immediately southwest of the Sabine Pass Ship Channel, a medium-sized port with LNG tankers comprising nearly a third of calling vessels (MarineTraffic.com, 2024).

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2.9 Site Suitability [40 CFR 146.83]

The summary below is a description of how the proposed injection site meets the suitability requirements set forth at 40 CFR 146.83. Claimed as PBI

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Construction materials for this project were selected based on the corrosive nature of the injectate. Corrosion monitoring of the injection wells will be conducted throughout the life of the BBE-P1 program. In addition, the mineralogical characteristics of the proposed confining and injection zones do not indicate a potential for deleterious, geochemical reactions. Compatibility testing of the injectate with the injection zone will be conducted following installation of the injection well(s).

3 AOR AND CORRECTIVE ACTION

An Area of Review (AOR) and Corrective Action Plan was prepared per the requirements in 40 CFR 146.82(a)(13) and 146.84(b). INTERSECT© was used for CO_2 sequestration simulation to understand CO_2 saturation and pressure front migration through time, delineate the AOR, and optimize development scenarios. A tabulation of wells within the delineated AOR that penetrate the confining zone was created and files were reviewed to determine if corrective actions are necessary [40 CFR 146.82(a)(4)]. A summary of computational modeling details is provided [40 CFR 146.84(c).

The AOR and Corrective Action Plan with associated tables, figures, appendices including well records and modeling details have been uploaded to the GSDT in support of this application.

AoR and Corrective Action GSDT Submissions
GSDT Module: AoR and Corrective Action ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]*** ☒ AoR and Corrective Action Plan ***[40 CFR 146.82(a)(13) and 146.84(b)]*** ☒ Computational modeling details ***[40 CFR 146.84(c)]***

3.1 Modeling

The AOR and Corrective Action Plan outlines the data, processes, software, and simulation results used to delineate the AOR. The AOR and Corrective Action Plan details data sourcing and analysis that was leveraged to generate a representative model that has been used to forecast pressure response and CO_2 migration through the life of the project. The document also provides a report on the wide variety of sensitivities that have been analyzed and their corresponding impacts to the AOR.

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[redacted]

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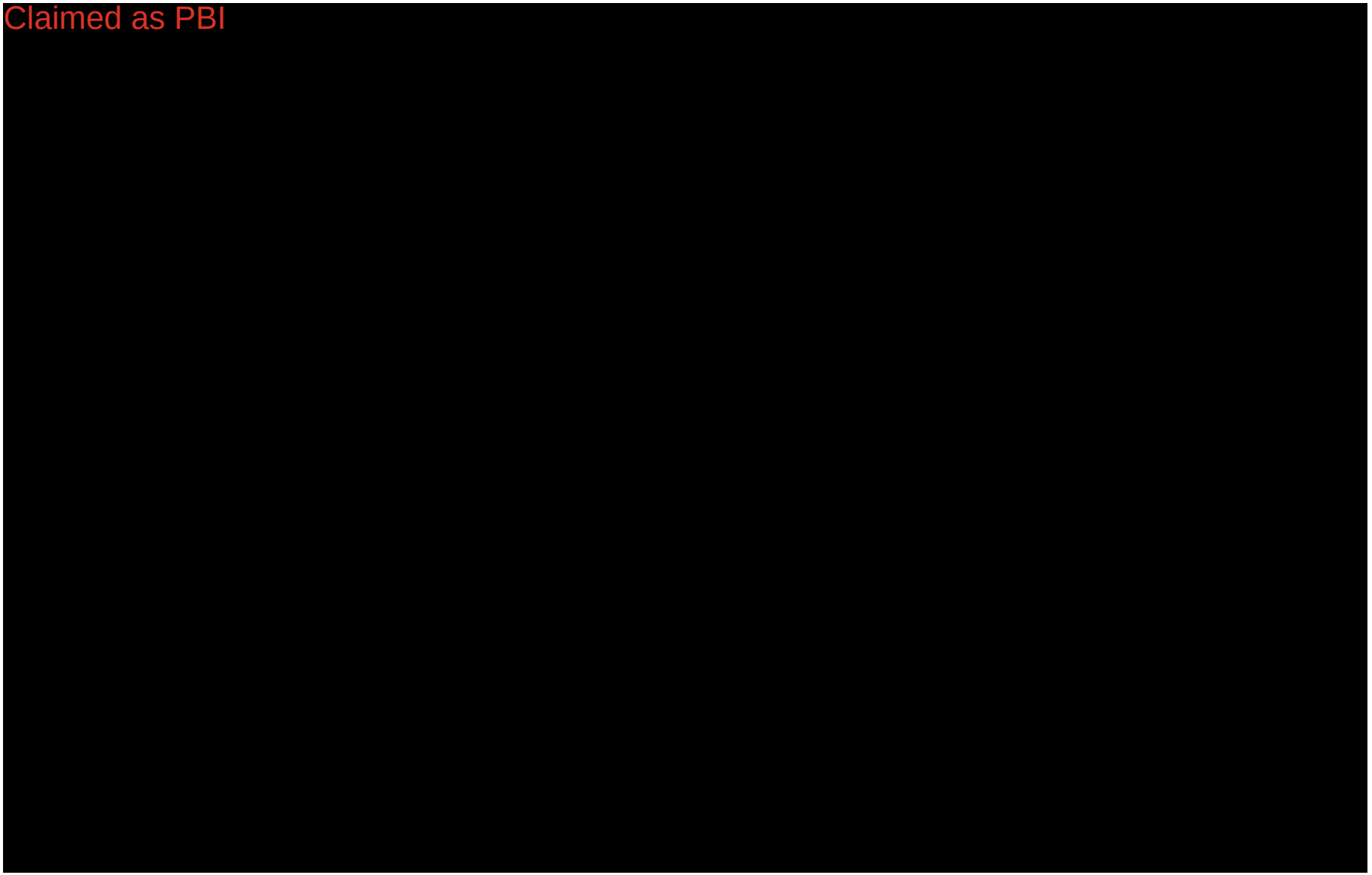

Figure 3-1: Position of injection and monitoring wells in relation to AOR, faults at the top of the T15 (confining zone) and existing penetrative wells.

3.2 AOR and Corrective Action

3.2.1 Artificial Penetration Tabulation and Well Records

Potential pathways for the migration of CO_2 are through artificial penetrations (APs) and naturally occurring faults that penetrate the injection zone. The potential for APs to provide pathways are investigated in more detail in the sections below, as well as any corrective action, if needed.

A tabulation of reviewed data including artificial penetrations within the AOR of the proposed injection wells at the site is provided in *Table 3-19* of the Class VI UIC AOR and Corrective Action Plan. Artificial Penetration Well Records and schematics are provided in *Appendix 3-2*. Reviewed responsive records regarding these wells have been provided in the Class VI UIC AOR and Corrective Action Module. Wells in *AOR Table 3-19* of the AOR and Corrective Action Plan are identified with map identification numbers (Control Nos.) keyed to **Figure 3-2**.

3.2.2 Condition of Artificial Penetrations Within the AOR

A total of 10 AP well data records were identified within the AOR (**Figure 3-2**). Each well was evaluated to determine if it will allow movement of CO_2 (considering the properties of CO_2 within the variable phases) above the confinement zone or migration to surface. Three (3) of the APs (Well ID #167, #155, and #132) were never drilled thus poses no potential pathway for fluid migration from the injection zone. One (1) of the APs (Well ID #122) is the offshore stratigraphic well and will be converted to the SL20220050 M1 monitoring well for BBE-P1. Six (6) APs are listed as dry and abandoned.

One (1) of the six AP's is conservatively classified as deficient with proposed phased corrective action. Well ID #169 poses no detrimental risk to the project at first injection due to proximity from the injectors. The corrective action plan includes monitoring during the first 5-years of injection based on CO_2 saturation migration with intent to intervene the well prior to CO_2 reaching the well path.

Water Wells Within the AOR

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. Surface bodies of water and other pertinent surface features are included in accordance with 40 CFR 146.82(a)(2) on **Figure 3-2** and **Figure 2-2**.

3.2.3 Corrective Action Plan

Claimed as PBI

[redacted]

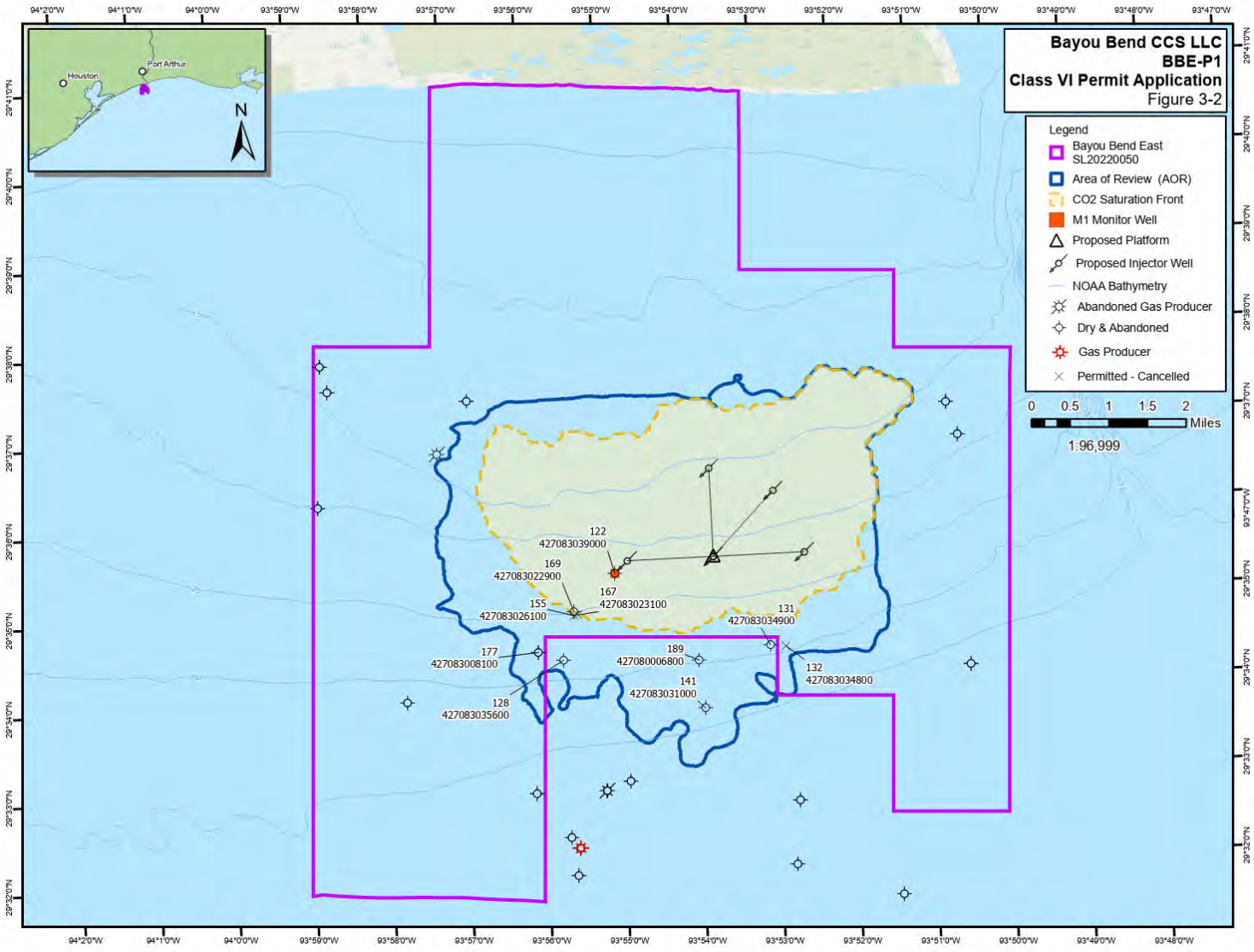

Figure 3-2: Artificial Penetrations within the AOR. Table 3-19 in the AOR and Corrective Action document provides detailed information.

4 FINANCIAL RESPONSIBILITY

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]***

5 INJECTION WELL CONSTRUCTION

Five new CO_2 injection wells are proposed targeting the Lower Miocene. These wells have been engineered with appropriate materials to meet the structural integrity requirements of 40 CFR 146.86, to meet the Operator's internal standards for well design, and to minimize corrosion throughout the life of the project.

The full well construction details for the CO_2 injectors can be found in the Well Construction documents.

5.1 Proposed Stimulation Program [40 CFR 146.82(a)(9)]

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.

5.2 Construction Procedures [40 CFR 146.82(a)(12)]

5.2.1 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.

5.2.2 Well Design

Maximum Wellhead Injection Pressure

The operating injection pressure will be dependent on the reservoir pressure, the properties of the injected fluid, the wellbore friction, and the injection rate. Claimed as PBI [redacted]

Claimed as PBI [redacted]

Given that the temperature of the injection stream fluctuates seasonally, the Operator may further refine the maximum injection pressure throughout the life of the project based on actual data pending UIC Program Director approval, never to exceed allowable downhole injection pressures. Fluid will be added to or removed from the annulus to maintain a minimum of 100psi over the operating injection pressure at the injection packer while always maintaining a minimum surface annulus pressure of 100psi, to meet the requirements of 40 CFR 146.88(c). The Operator will use pressure measurements at the downhole pressure gauge and surface pressure measurements to confirm the annulus pressure required at surface.

During well construction, to demonstrate mechanical integrity, the cemented injection casing and tubing and packer will be pressure tested to a pressure equal or greater than the estimated pressures. Once injection commences, the tubing and packer annulus will be tested following the monitoring and testing plans criteria.

Claimed as PBI [redacted]

Casing and Tubing Program

The Casing and tubing program is designed to meet the well lifecycle conditions from installation through injection and abandonment. The specifications listed in **Table 5-1** meet 40 CFR 146.86(b)(1)(iv) and to allow operation at the maximum calculated bottom hole pressures.

Claimed as PBI [redacted]

Claimed as PBI

Injection Liner and Long String (Injection Casing)

Claimed as PBI

Cementing Program

The Cementing Program is designed to meet the well lifecycle conditions. Casing strings will be cemented with industry standard Class H cement with CO_2 resistant additives planned for cement located across the injection interval as demonstrated in each wellbore schematic. Centralizers will be placed throughout the casing string to increase likelihood of full cement coverage around casing. The cement installation will be completed leveraging inner string cement operations for the surface casing and conventional cementing practices for all remaining casing strings with cement planned to be brought to surface for all casing strings, except the liner, which will have cement brought to the top of the liner Claimed as PBI

Claimed as PBI

Claimed as PBI

Tubing

Claimed as PBI the injection volumes necessary to meet the design requirements. The tubing is designed to handle the full injection lifecycle of pressure, temperature, and resultant stress changes. Claimed as PBI

Table 5-1: Casing details (Varies by well, using SL20220050 W1 (vertical well) depths)

Claimed as PBI

Table 5-2: Tubing and anchor Details (Varies by Well, using SL20220050 W1 (vertical well) depths)

Claimed as PBI

Packer

Claimed as PBI

Annular Fluid

The annular fluid will fill the space Claimed as PBI. The annular fluid density will provide a hydrostatic pressure to meet or exceed the initial reservoir pressure. Surface pressure will be added to annular system to meet or exceed the tubing injection pressures to ensure integrity of the tubing and packer system.

The treated annulus fluid will be a brine solution consisting of fresh water, salt, and corrosion inhibitors. The fluids will be tested to confirm compatibility with reservoir and injection fluids as well as casing and tubing materials. Claimed as PBI

Wellhead

Figure 5-1 describes the proposed wellhead and tree configuration. The components will follow the API Spec 6A – Specification for Wellhead and Tree Equipment. Claimed as PBI The design will vary depending on supplier selection process.

The wellhead and tree will be designed for compatibility with the injection fluid (CO_2) to minimize corrosion and pressure rated to meet full life cycle well designs. Flow wetted components that contact CO_2 will be made of corrosion-resistant alloy. The non-flow wetted components will be comprised of carbon steel material.

Well Openings to Formation

The injection wells will connect through the casing to the defined injection interval by utilizing perforations to adequately establish injection rate requirements. Claimed as PBI The final perforation interval selection will be confirmed after the drilling and evaluation phases of Well Construction. The perforating technique will be executed using tubing conveyed or wireline guns. Perforation debris clean-up techniques,

such as underbalance perforating, may be used in conjunction with the pre-operational testing 40 CFR 146.87 (e) to ensure injectivity requirements.

Schematic of the Subsurface Construction Details of the Example Well(s) – W1

A schematic of the proposed injection well construction is provided as **Figure 5-2**.

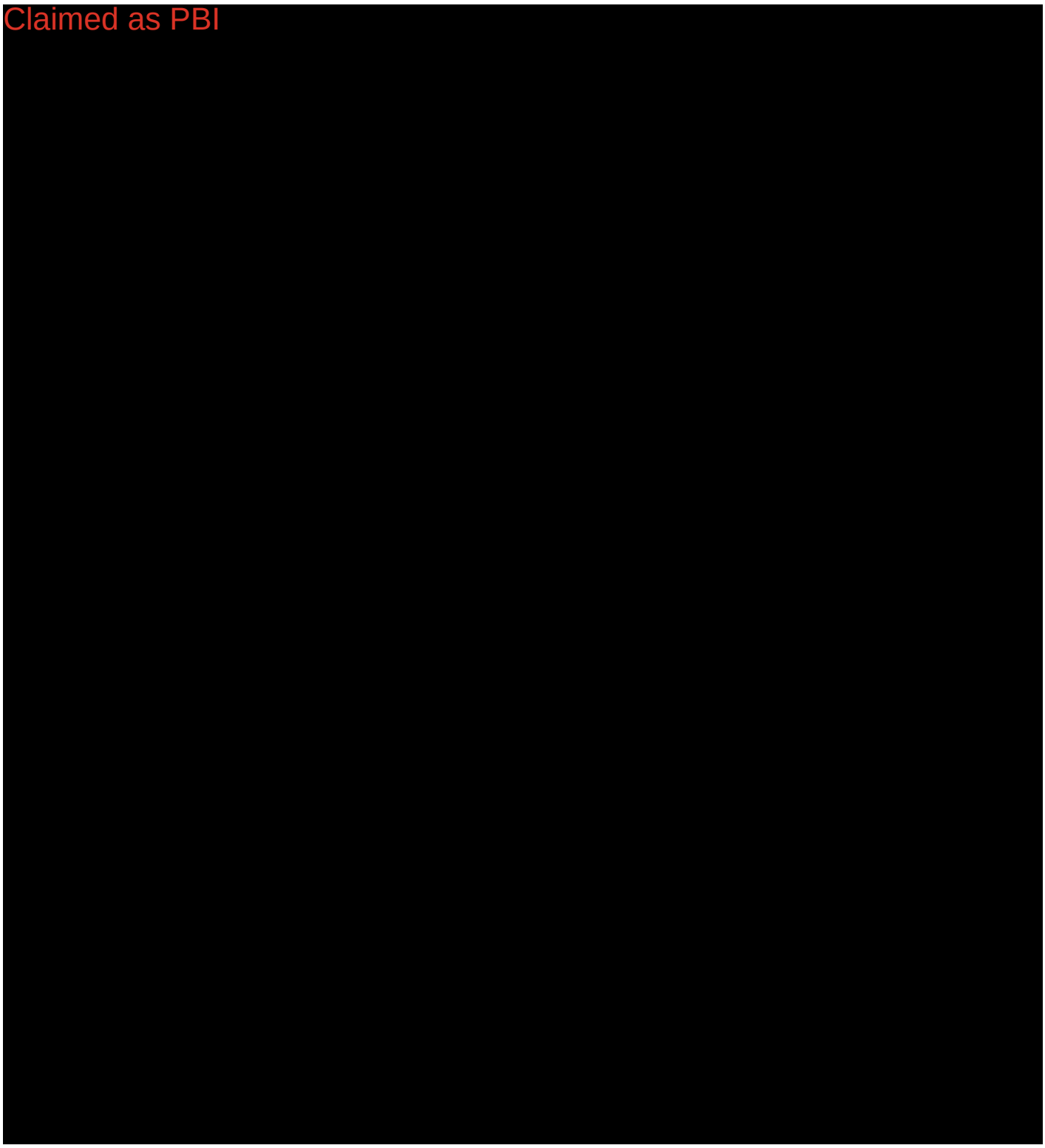

Figure 5-1: Proposed Injection Wellhead and Tree.

Claimed as PBI

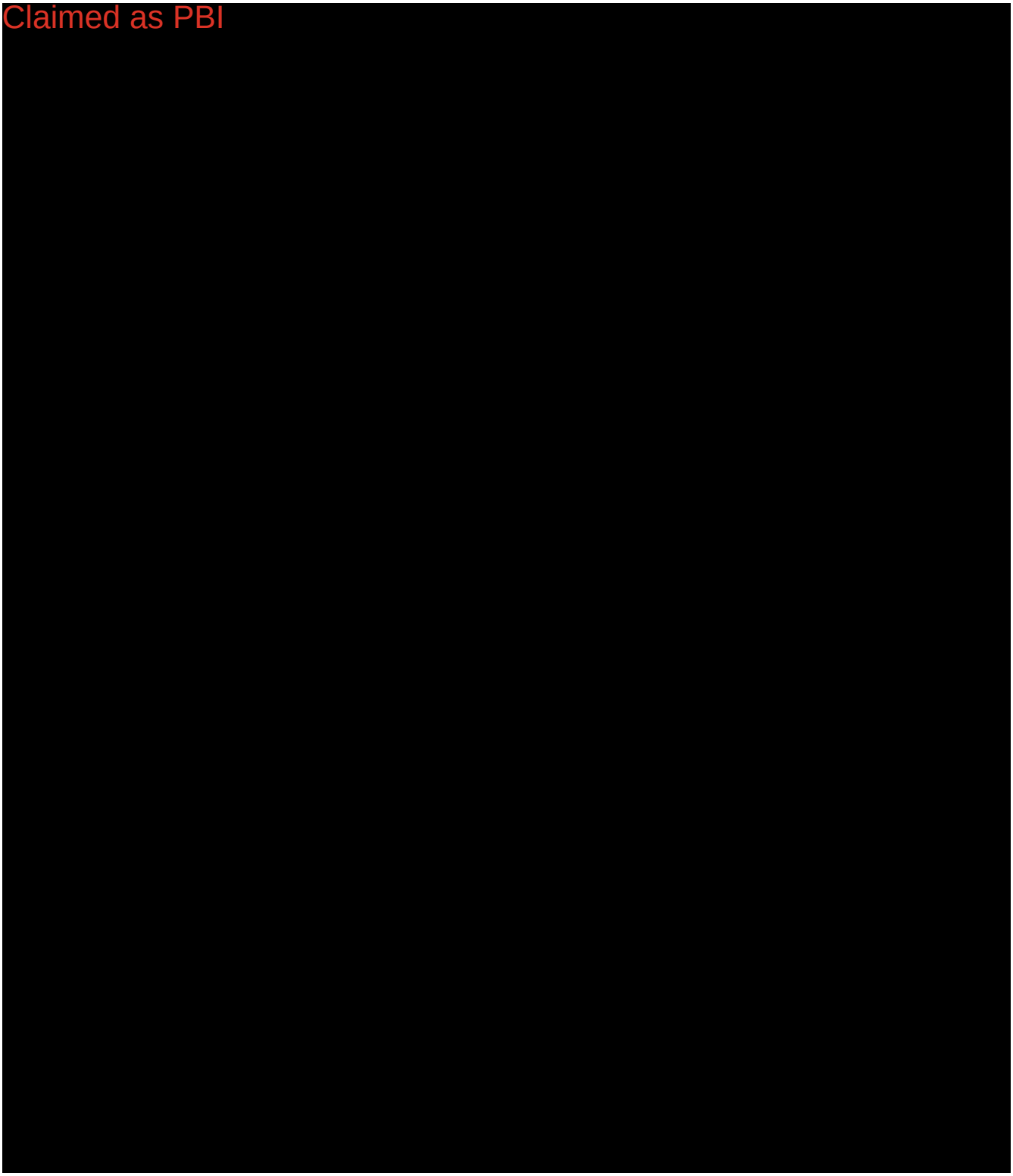

Figure 5-2: SL20220050 W1 Proposed Schematic.

6 PRE-OPERATIONAL LOGGING AND TESTING

A Pre-Operational Logging and Testing Plan was prepared per the requirements of 40 CFR 146.82(a)(8) and 146.87 as part of this application. The plan addresses pre-injection period testing to be conducted on the five proposed injection wells (SL20220050 W1, SL20220050 W2, SL20220050 W4, SL20220050 W5, and SL20220050 W6) and the proposed monitoring well (SL20220050 M1). Injection well SL20220050 W3 is not being requested at this time. The SL20220050 M1 stratigraphic characterization well (API 427083039000) will be converted to a monitoring well for BBE-P1.

The Pre-Operational Logging and Testing Plan associated tables and figures have been uploaded to the GSDT in support of this application.

Pre-Operational Logging and Testing GSDT Submissions
GSDT Module: Pre-Operational Logging and Testing ***Tab(s):*** Welcome tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

7 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.

7.1.1 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 Section 5.2.2.

Table 7-1: Proposed operational procedures.

Parameters/Conditions	Limit or Permitted Value					Unit
Well	SL20220050 W1	SL20220050 W2	SL20220050 W4	SL20220050 W5	SL20220050 W6	
Claimed as PBI [redacted]						
Average Injection Rate*	1.5 | 1.2	1.5 | 1.2	1.5 | 1.2	1.5 | 1.2	1.5 | 1.2	MTA/well
Maximum Injection Rate	2.0	2.0	2.0	2.0	2.0	MTA/well
Claimed as PBI [redacted]						

*1.5 MTA for first year of injection. 1.2 MTA for remaining 19 years of injection.

7.1.2 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].

7.1.3 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.

8 TESTING AND MONITORING

A Testing and Monitoring Plan was prepared per the requirements of 40 CFR 146.90 as part of this application. The Testing and Monitoring Plan describes how the Operator will monitor the BBE-P1 site utilizing the five proposed injector wells and one dedicated monitoring well. The Testing and Monitoring Plan will assess 1) the location of the CO_2 front, 2) the region of highest elevated reservoir pressure (near injectors), and 3) the containment of CO_2 below the confining zone. The technologies and techniques for this monitoring plan were selected based on a site-specific focus area as determined by the site characterization, reservoir modeling and simulation, and AOR sensitivity analysis.

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 geological models used to predict the distribution of the CO_2 within the injection zone to support AOR reevaluations and a non-endangerment demonstration.

The Testing and Monitoring Plan, associated tables, figures, and the Quality Assurance and Surveillance Plan have been uploaded to the GSDT in support of this application.

Testing and Monitoring GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Testing and Monitoring tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Testing and Monitoring Plan ***[40 CFR 146.82(a)(15) and 146.90]***

9 INJECTION WELL PLUGGING

Injection Well Plugging Plans were prepared per the requirements in 40 CFR 146.92 [40 CFR 146.82 (a)(16) and 146.92(b)] as part of this application. The Injection Well Plugging plan includes planned mechanical integrity testing activities, proposed plugging details and procedures, and a proposed abandonment schematic.

The costs associated with the proposed Class VI well closures are provided in the Financial Assurance Module, per 40 CFR 146.85.

The Injection Well Plugging Plan, associated tables, figures, and appendices have been uploaded to the GSDT in support of this application.

Injection Well Plugging GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Injection Well Plugging tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Injection Well Plugging Plan ***[40 CFR 146.82(a)(16) and 146.92(b)]***

10 POST-INJECTION SITE CARE (PISC) AND SITE CLOSURE

A PISC and Site Closure Plan was prepared per the requirements in 40 CFR 146.82 (a) (17) – (18) and 40 CFR 146.93 as part of this application. The PISC and Site Closure Plan describes how the Operator will monitor ground water quality and track the position of the CO_2 saturation and pressure fronts for 50 years unless an alternative timeframe duration is discussed and approved by UIC Program Director following cessation of injection pursuant to 40 CFR 146.93(b). 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.

An Alternative PISC Timeframe Demonstration is not provided as part of this application at this time.

The PISC and Site Closure Plan with associated tables and figures have been uploaded to the GSDT in support of this application.

PISC and Site Closure GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** PISC and Site Closure tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ PISC and Site Closure Plan ***[40 CFR 146.82(a)(17) and 146.93(a)]***
GSDT Module: Alternative PISC Timeframe Demonstration ***Tab(s):*** All tabs (only if an alternative PISC timeframe is requested) Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]***

11 EMERGENCY AND REMEDIAL RESPONSE

An Emergency and Remedial Response Plan was prepared per the requirements in 40 CFR 146.82 (a) (19) and 40 CFR 146.94 as part of this application. This plan has been uploaded to the GSDT in support of this application.

Emergency and Remedial Response GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Emergency and Remedial Response tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Emergency and Remedial Response Plan ***[40 CFR 146.82(a)(19) and 146.94(a)]***

12 INJECTION DEPTH WAIVER AND AQUIFER EXEMPTION EXPANSION

Neither an injection depth waiver nor aquifer exemption expansion will be requested as part of this permit application.

Injection Depth Waiver and Aquifer Exemption Expansion GSDT Submissions
GSDT Module: Injection Depth Waivers and Aquifer Exemption Expansions stite Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Injection Depth Waiver supplemental report ***[40 CFR 146.82(d) and 146.95(a)]*** ☐ Aquifer exemption expansion request and data ***[40 CFR 146.4(d) and 144.7(d)]***

13 ADDITIONAL INFORMATION

13.1 Community Engagement

The Operator identified communities through assessments including utilization of the EPA EJScreen Tool. The Operator has been actively engaging with the nearby communities.

The Beaumont and Port Arthur, Texas areas were identified as having greater than 80% of the population, compared to United States averages, having a community-level vulnerability based on the supplemental demographic index.

The Operator's community outreach and investments are aimed at strengthening nearby communities and enriching lives, at the same time fostering valuable collaborations by:

- Supporting well-run organizations and investments that align with project drivers and focus areas that meaningfully address nearby community needs.
- Maintaining and fostering relationships that position the Operator as a well-respected industry leader and partner of choice in the local community.
- Establishing strong external communications.

Community outreach efforts for BBE include social investments to the Southeast Texas Food Bank, which serves eight counties and distributes to approximately 130 nonprofit agencies within these counties. Their partner agencies offer approximately 90,000 meals to people in need each month. Additional community non-profits that BBE supports include the Port Arthur Education Foundation and the Winnie, Texas Marsh Fest which directly contributes to scholarships for students in Jefferson and Chambers County. The Operator supports four local Chamber of Commerce organizations. The Chamber serves as a unified voice and economic catalyst to ignite partnerships for the business community, local governments, legislative representatives, that will positively impact the development of the project communities and the region. BBE team members have also volunteered at local community events such as the Rotary Club of Port Arthur's service projects, Earth Day's Street Clean Up, and Port Arthur Independent School District student interviews.

13.2 Acronyms

°F	Degree Fahrenheit
Claimed as PBI	
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
Claimed as PBI	
CO_2	carbon dioxide
EoD	Environment of Deposition
FPP	fracture propagation pressure
ft	feet
Fm	Formation
GoM	Gulf of Mexico
GR	gamma ray
Claimed as PBI	
Hz	Hertz
LOT	Leak-off test
Claimed as PBI	
Claimed as PBI	
MAIP	maximum allowable injection pressure
MD	measured depth
MDT	modular formation dynamics tester
MEM	Mechanical Earth Model
MFS	maximum flooding surface
mg/L	milligram per liter
MIT	Mechanical integrity test
Claimed as PBI	

MMT	Million metric tonnes
MTA	million metric tonnes per annum
N_2	nitrogen
PAS	Process Automation System
PCS	the Process Control System
PISC	Post-injection Site Care
ppg	pounds per gallon
ppm	parts per million
psia	pound per square inch absolute
psi/ft	pounds per square inch per foot
RES	Deep resistivity

Claimed as PBI

S_{hmax}	maximum horizontal stress
S_{hmin}	minimum horizontal stress

Claimed as PBI

SGR	shale gouge ratio
SP	Spontaneous potential
SRT	step-rate test

Claimed as PBI

t/d	tonnes per day
TD	total depth
TDS	total dissolved solids
TM	transmissibility multiplier
TST	true stratigraphic thickness
TVDSS	true vertical depth below sea level
UIC	Underground Injection Control

Claimed as PBI

USDW	underground source of drinking water
USGS	United States Geologic Survey
Vclay	Clay volume
Vshale	Shale volume

13.3 References

Claimed as PBI

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Appendices

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Appendix 4: Certification Documentation

SEPARATE FILE

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
	Appendix 3-4 AOR and Corrective Action Plan Figures	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

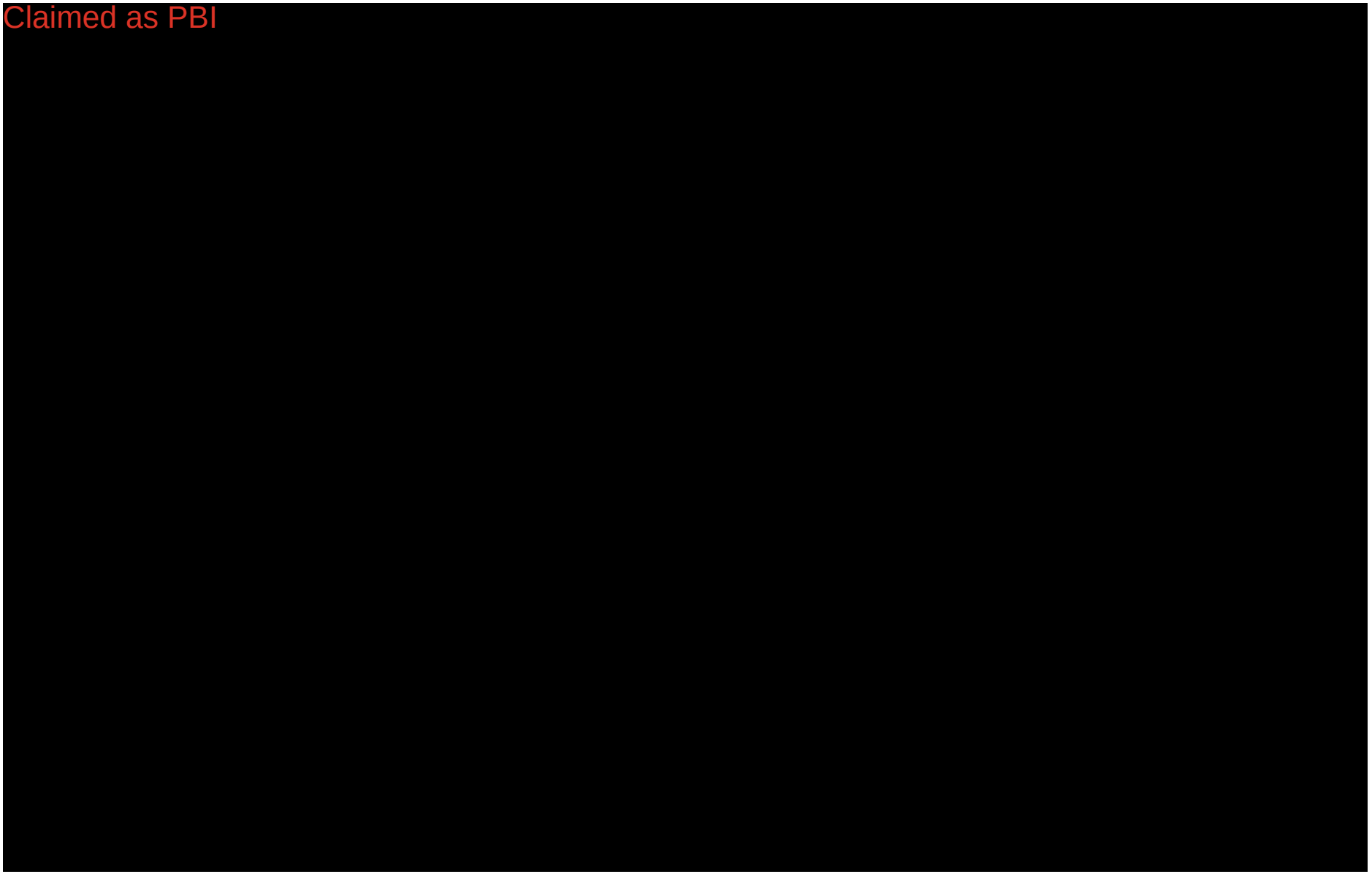
Claimed as PBI

[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



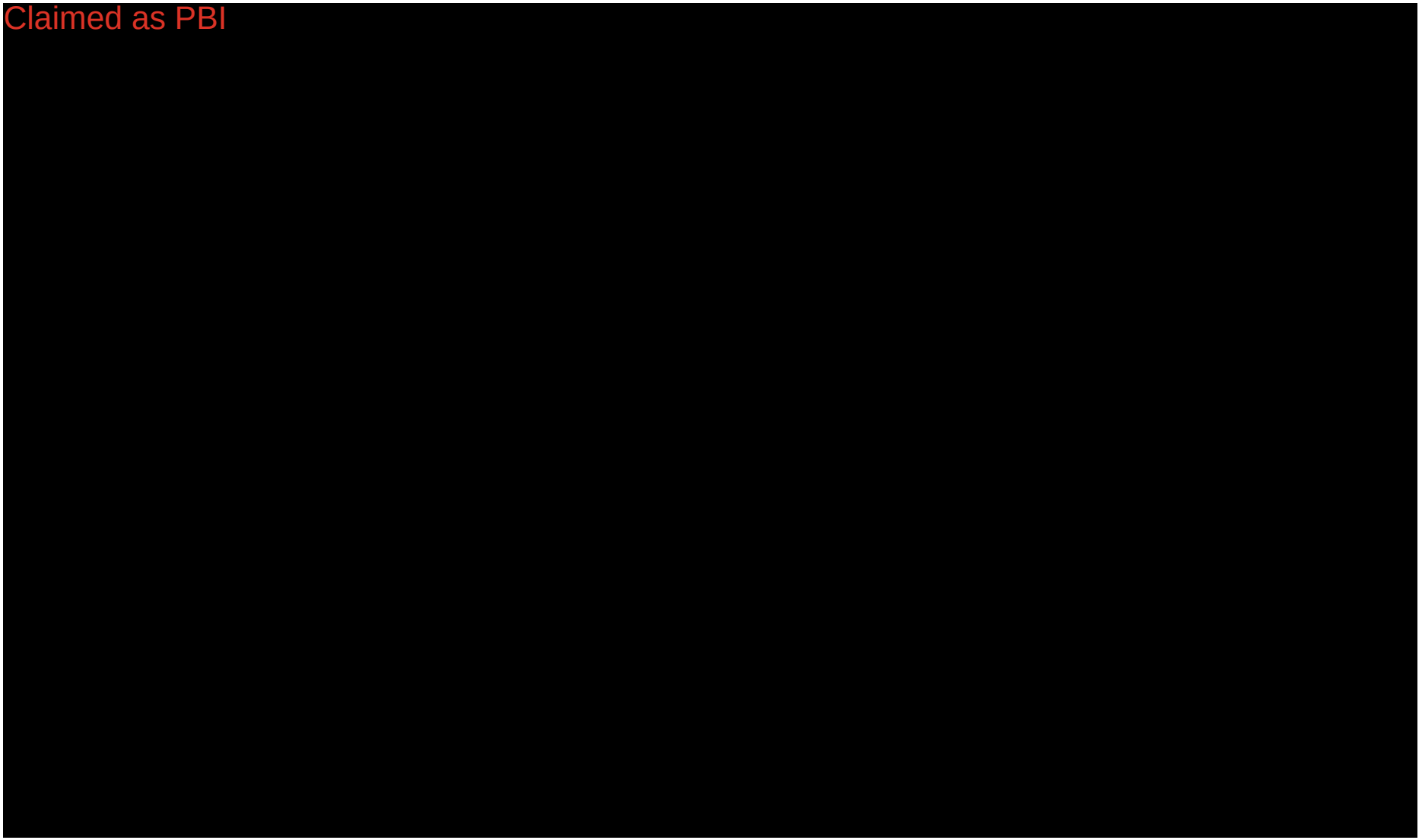
Table 3-2: Model domain information.

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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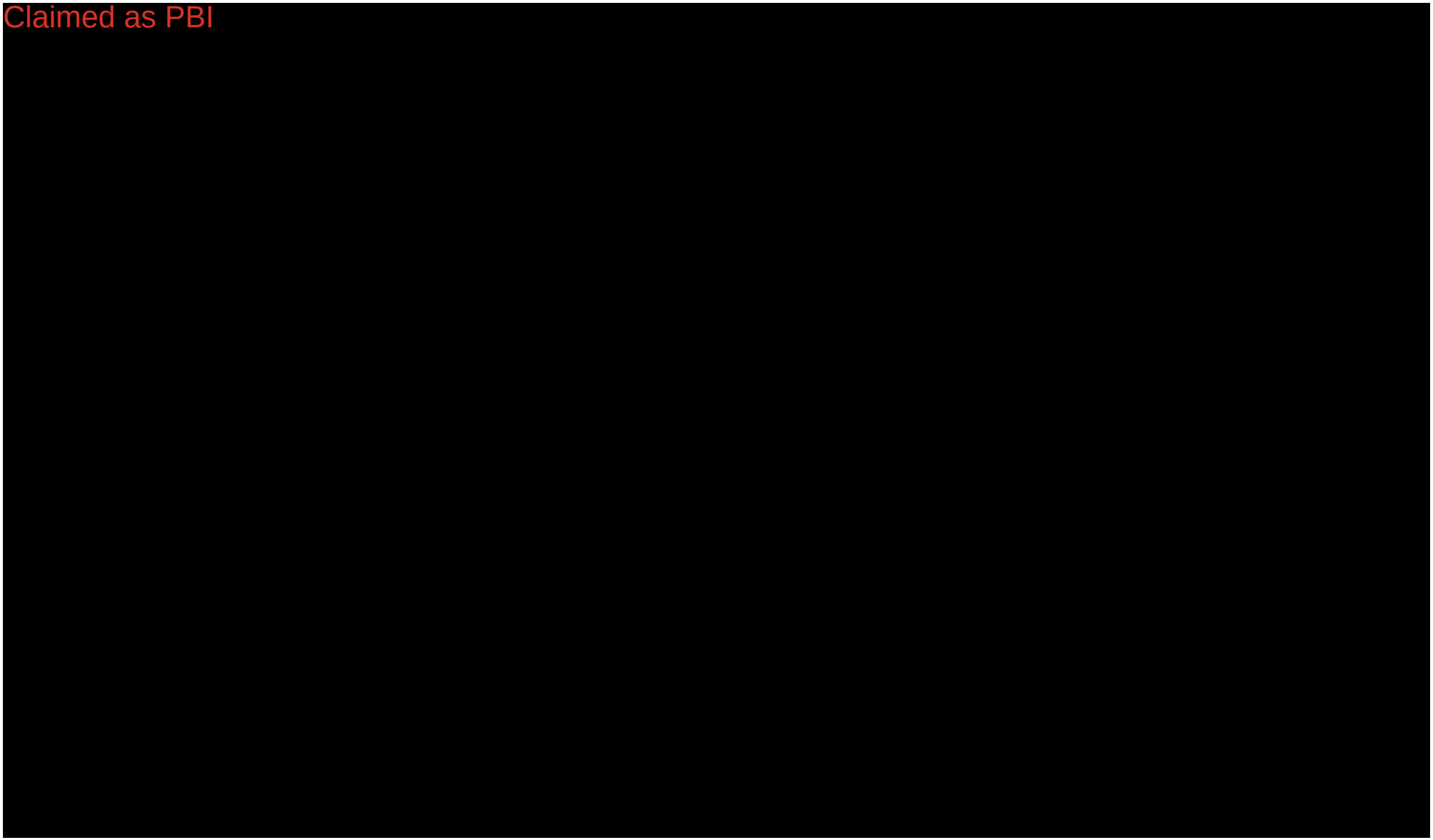


Claimed as PBI



3.2.5 Porosity and Permeability

Methodology

Claimed as PBI

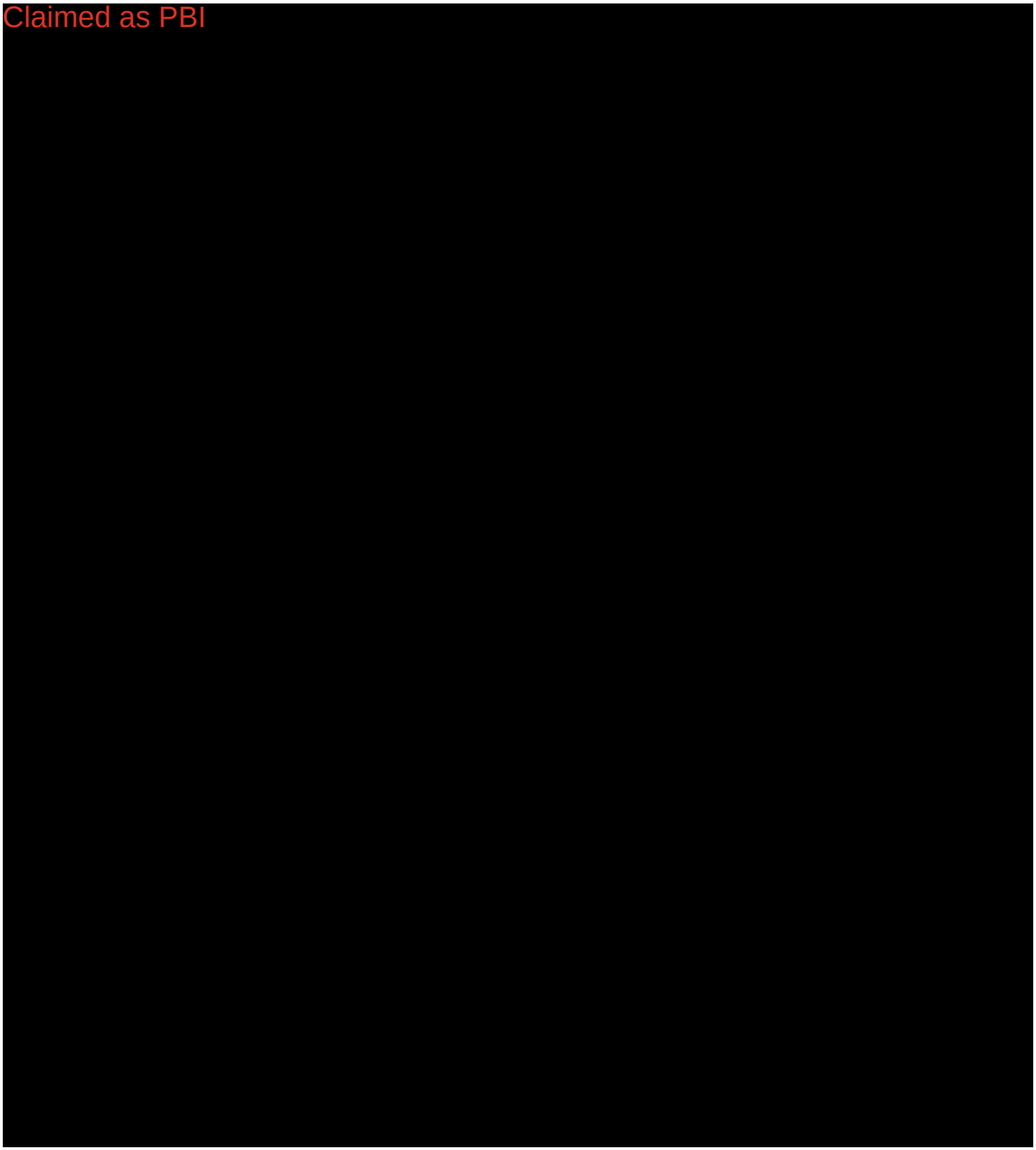


Plan revision number: 003
Plan revision date: September 2026

Claimed as PBI



Claimed as PBI



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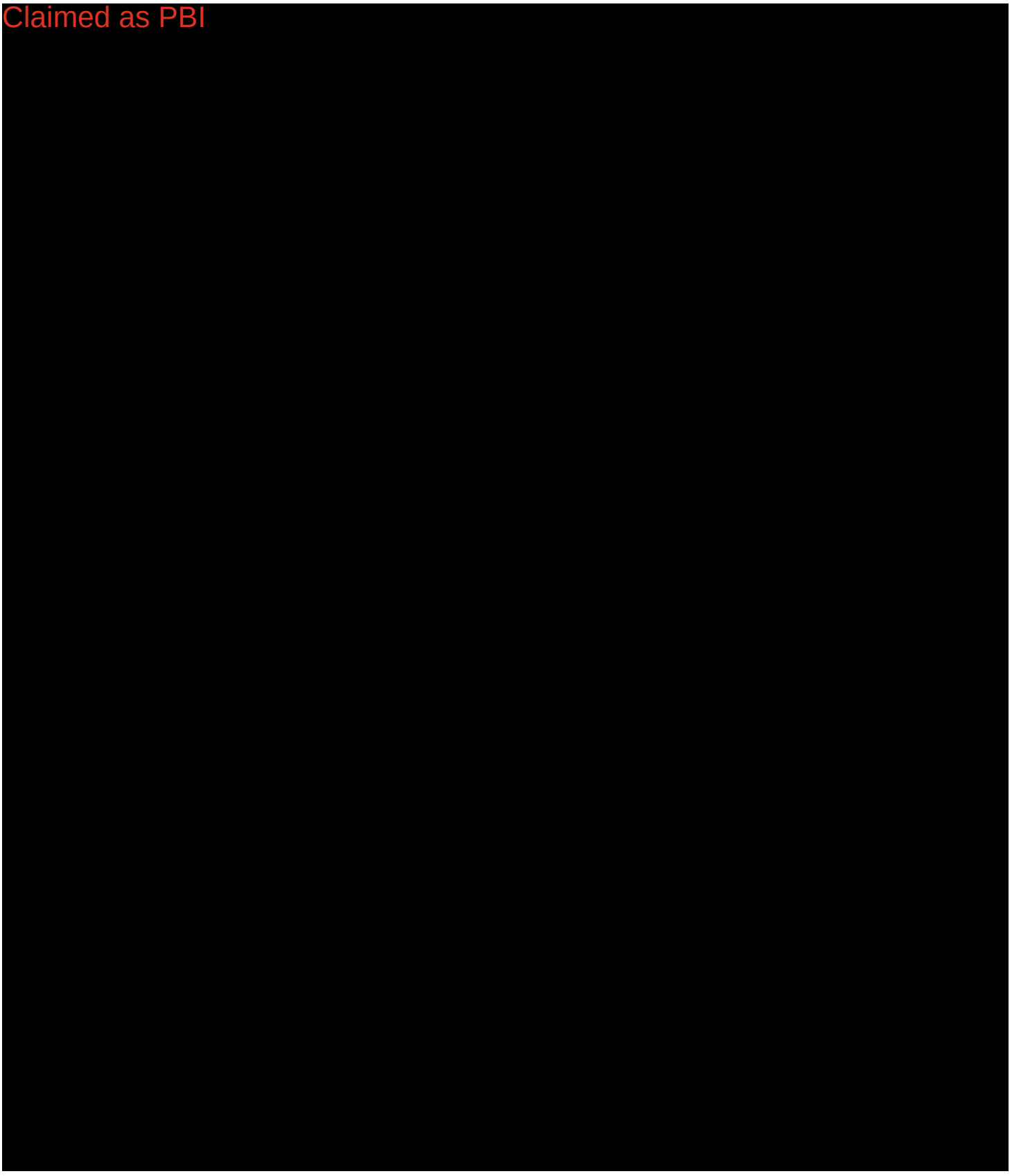

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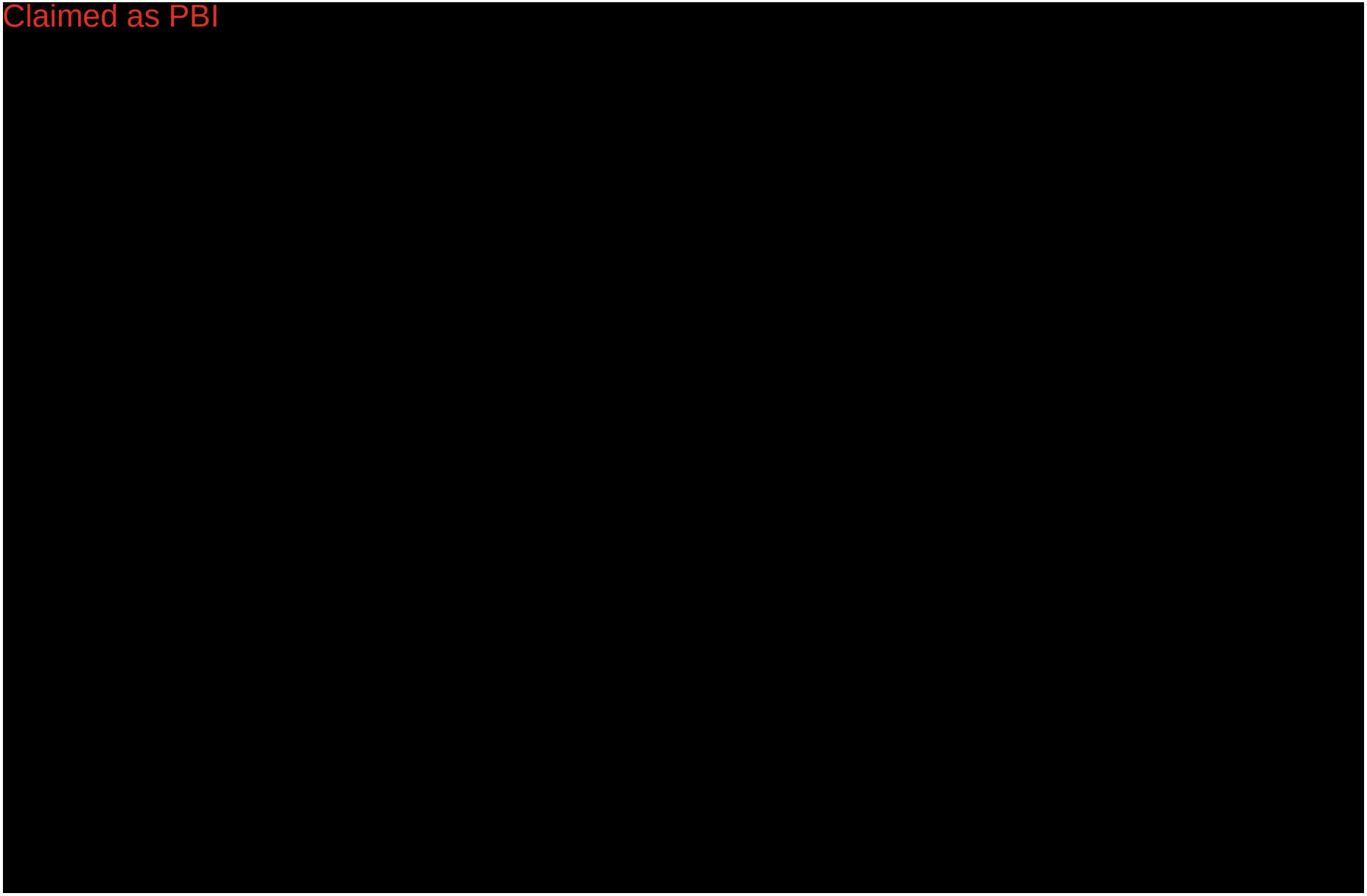

Claimed as PBI



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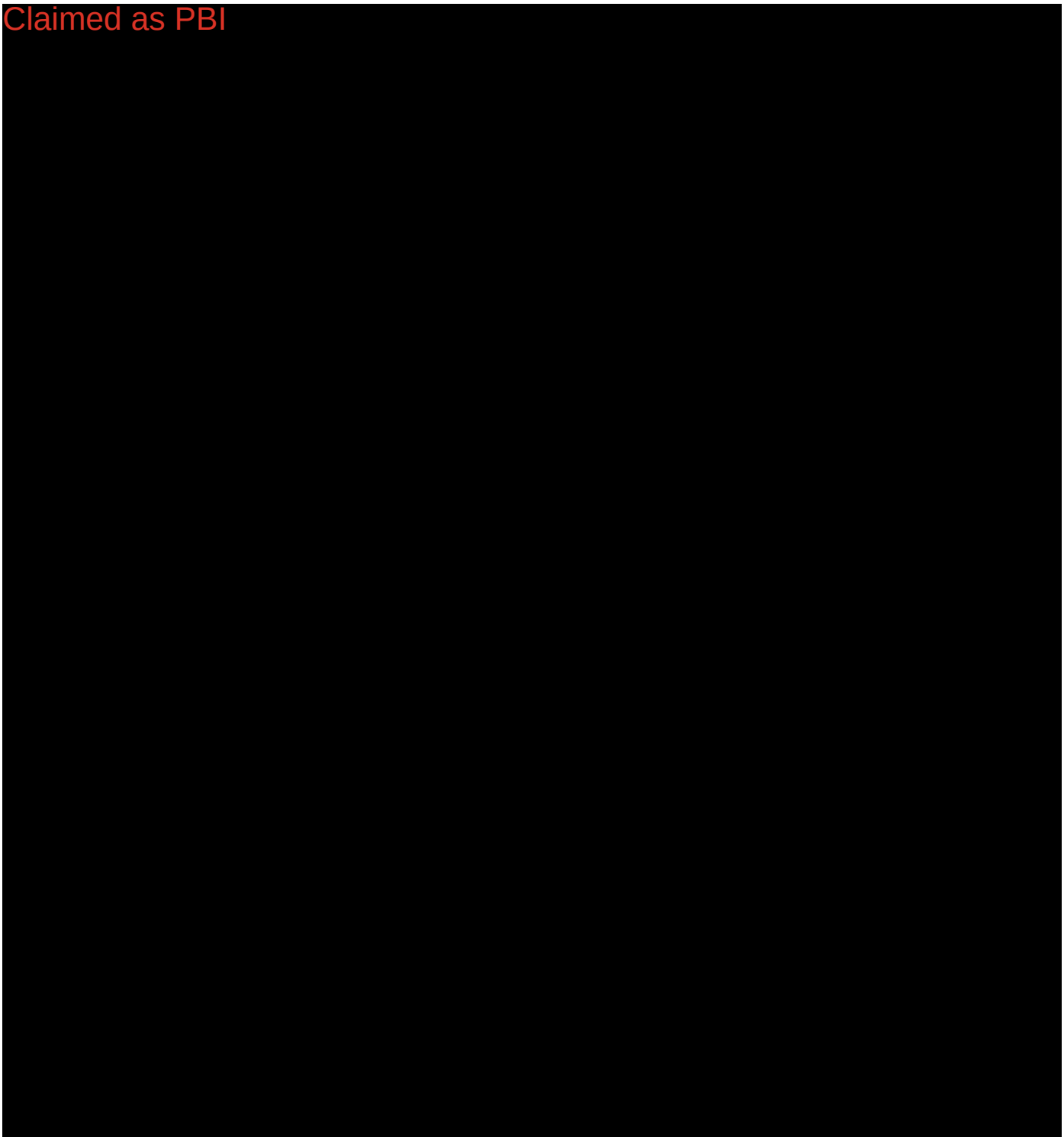

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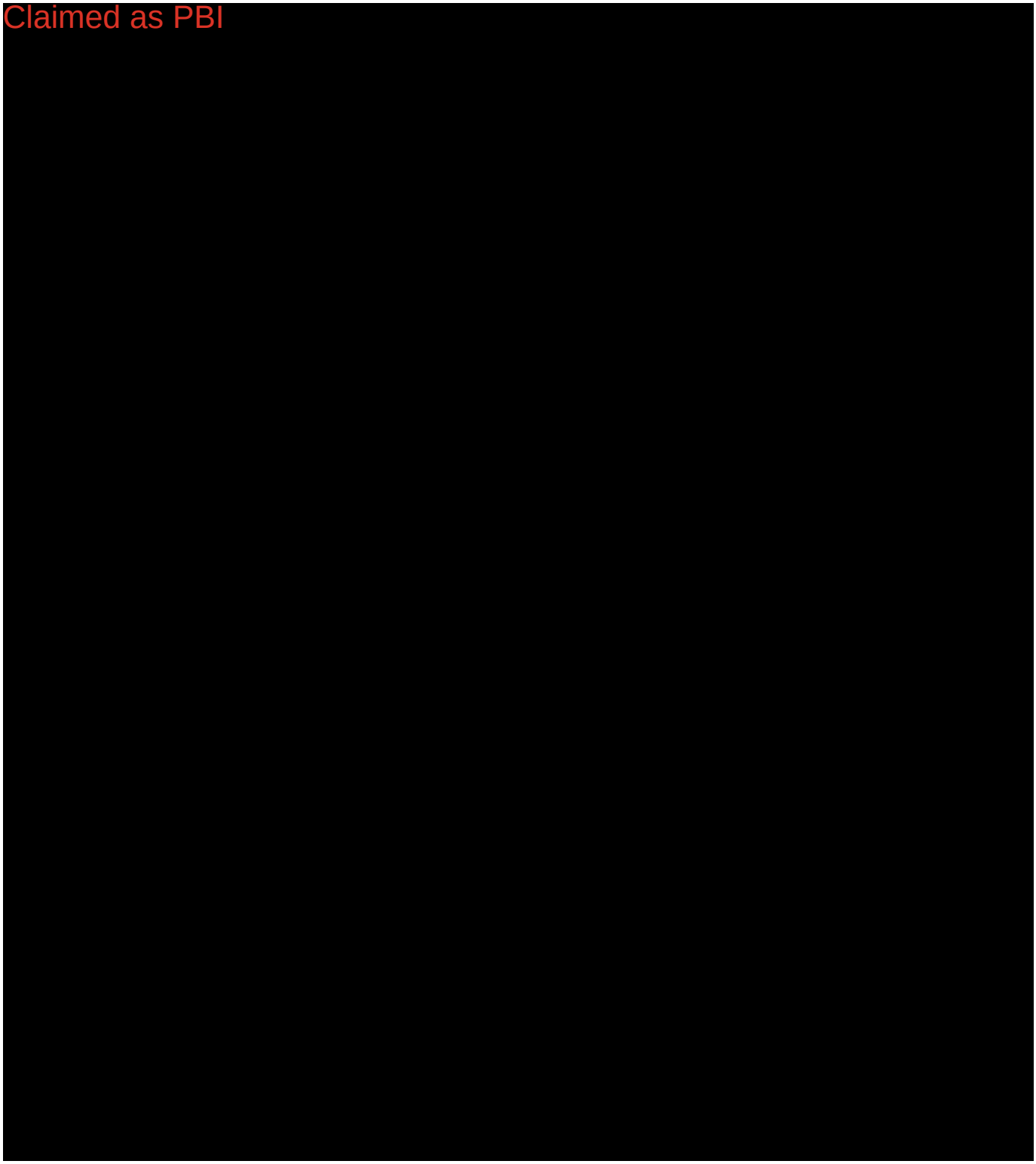

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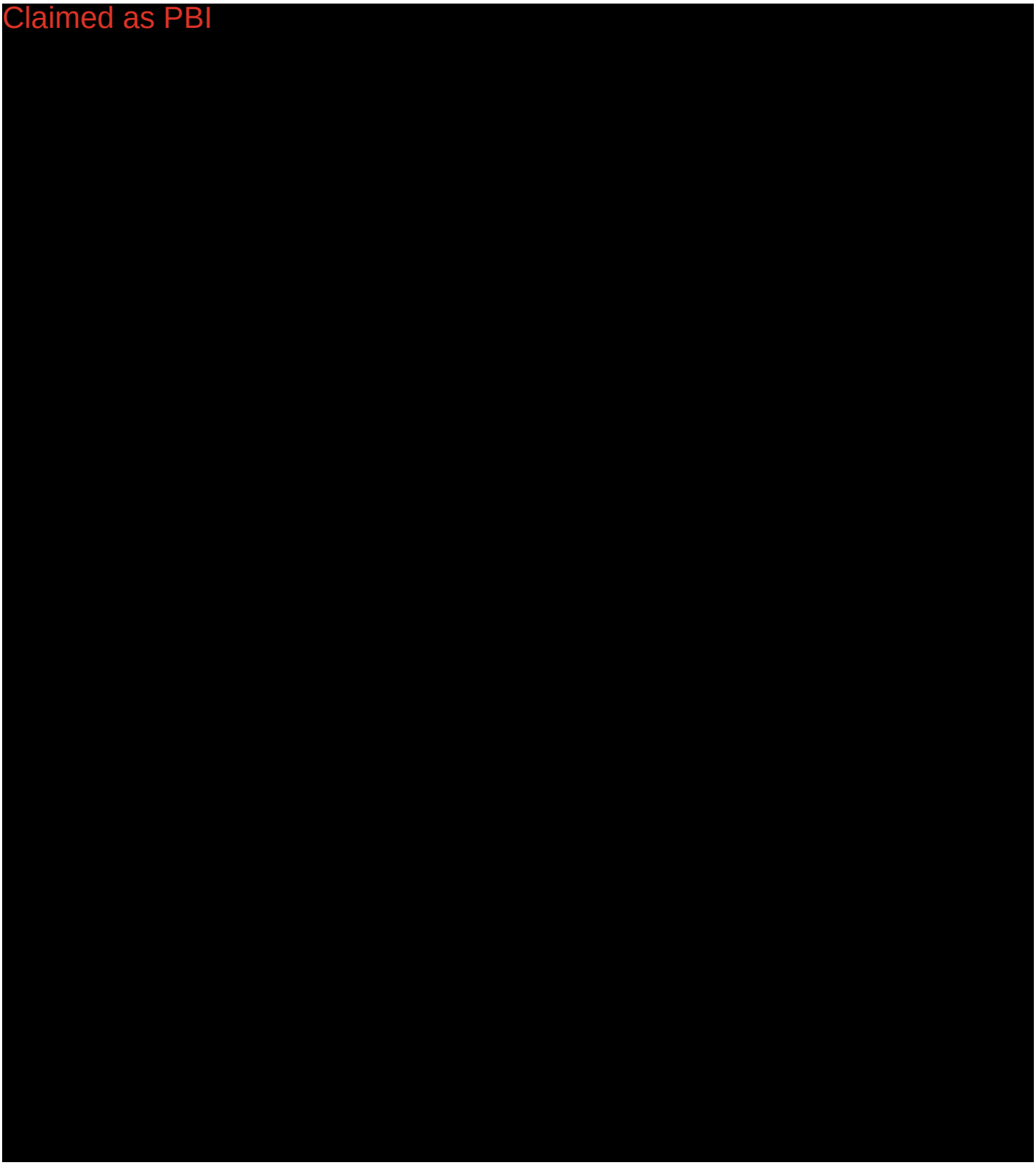

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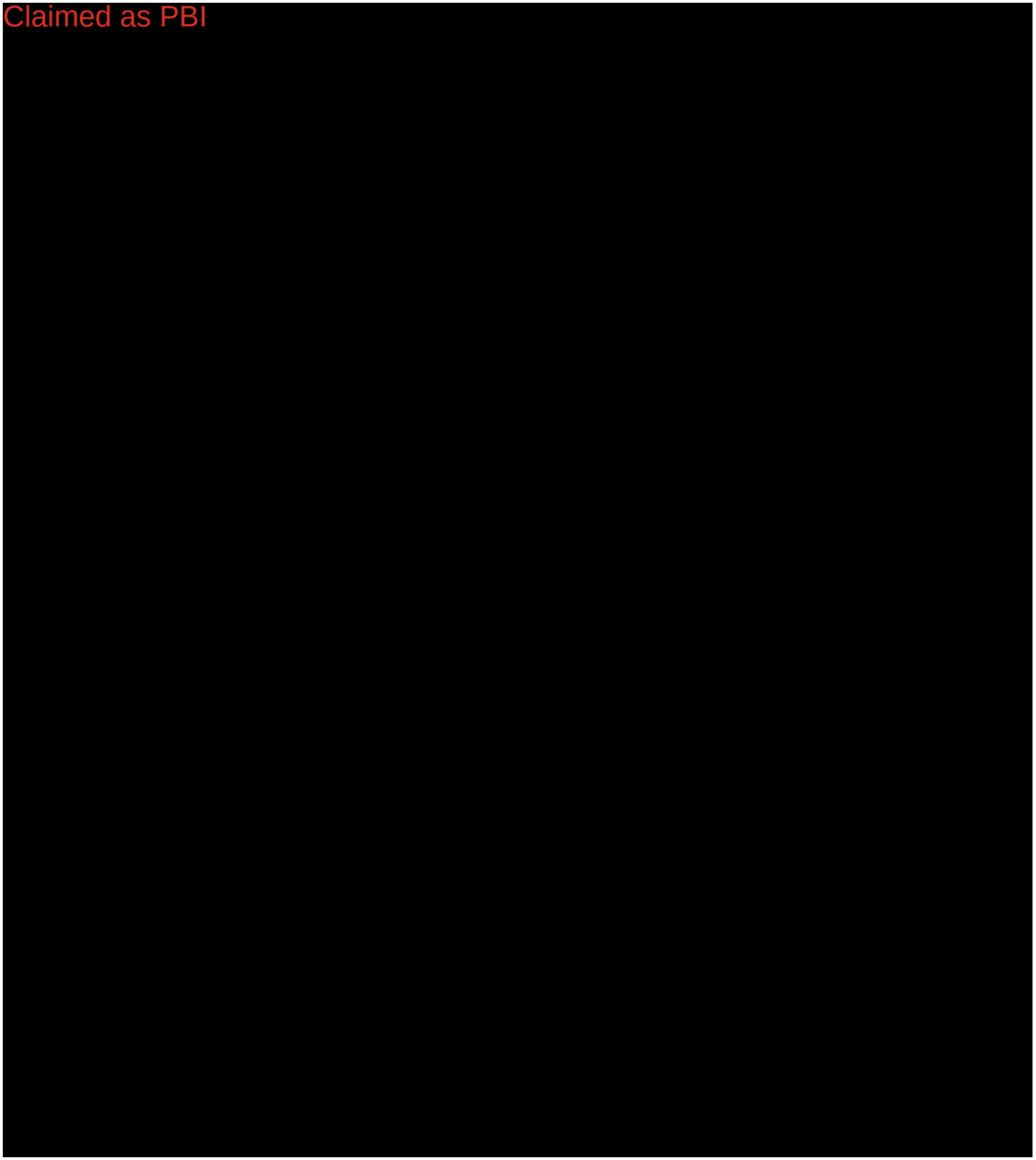

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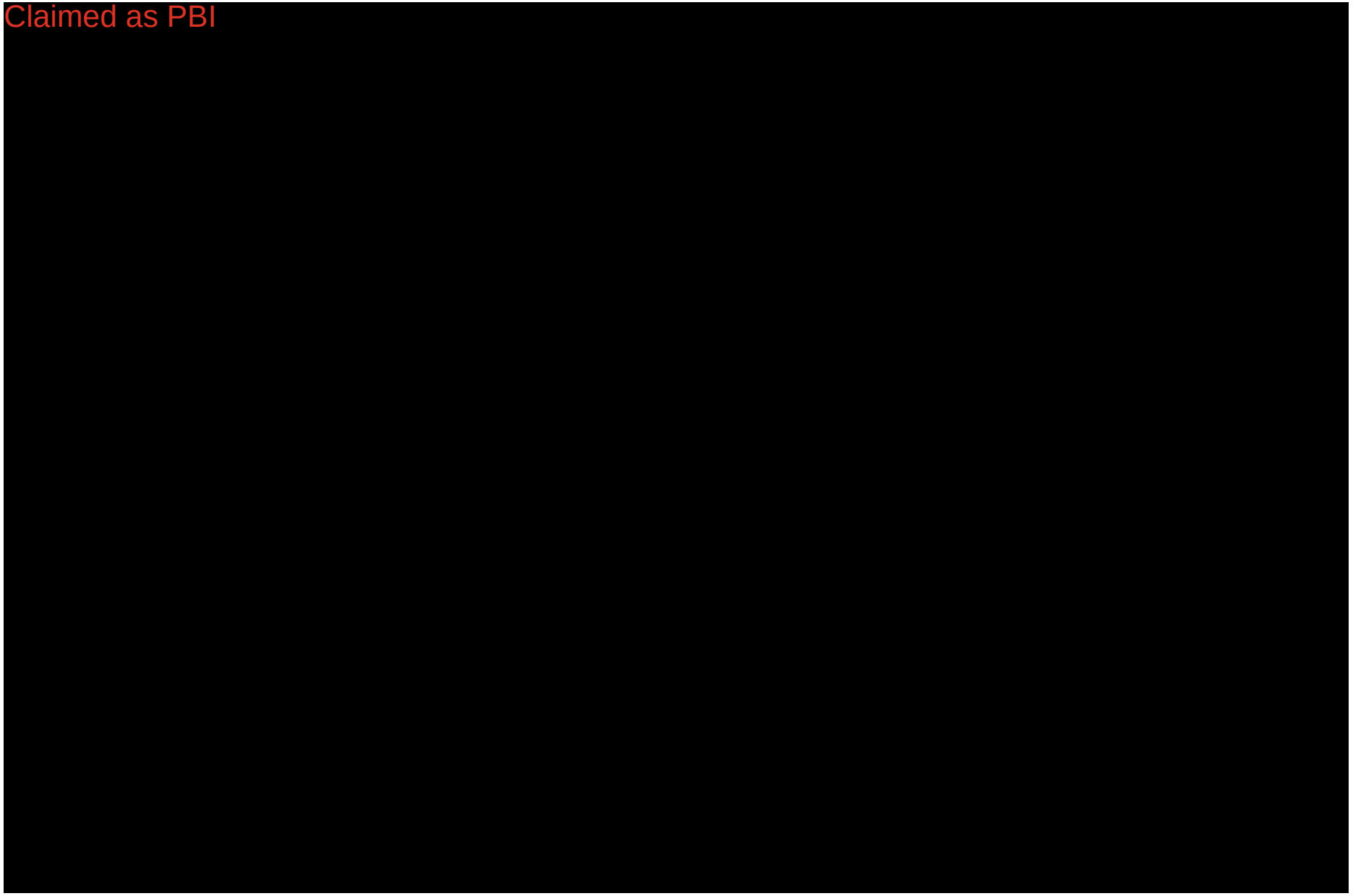

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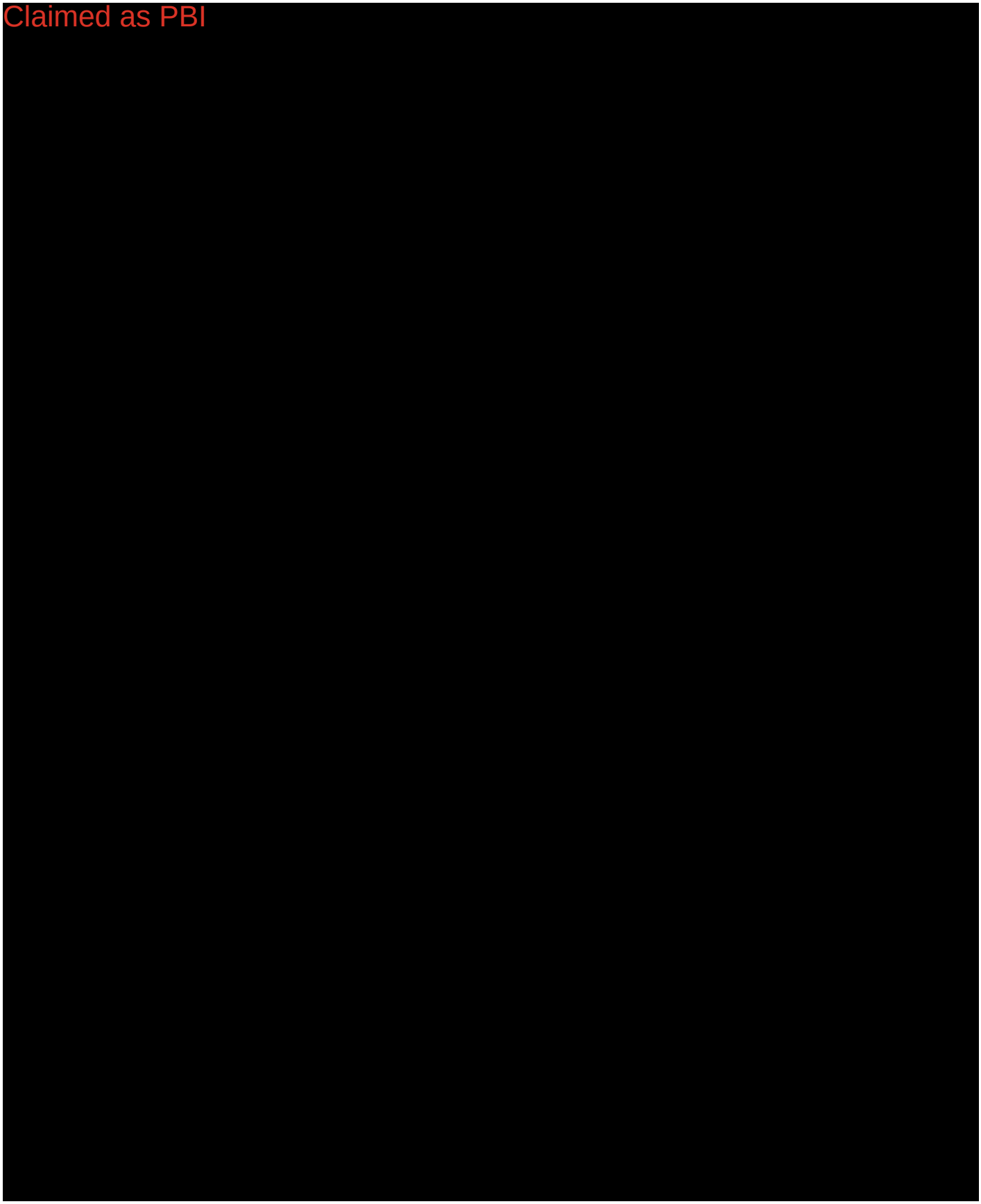


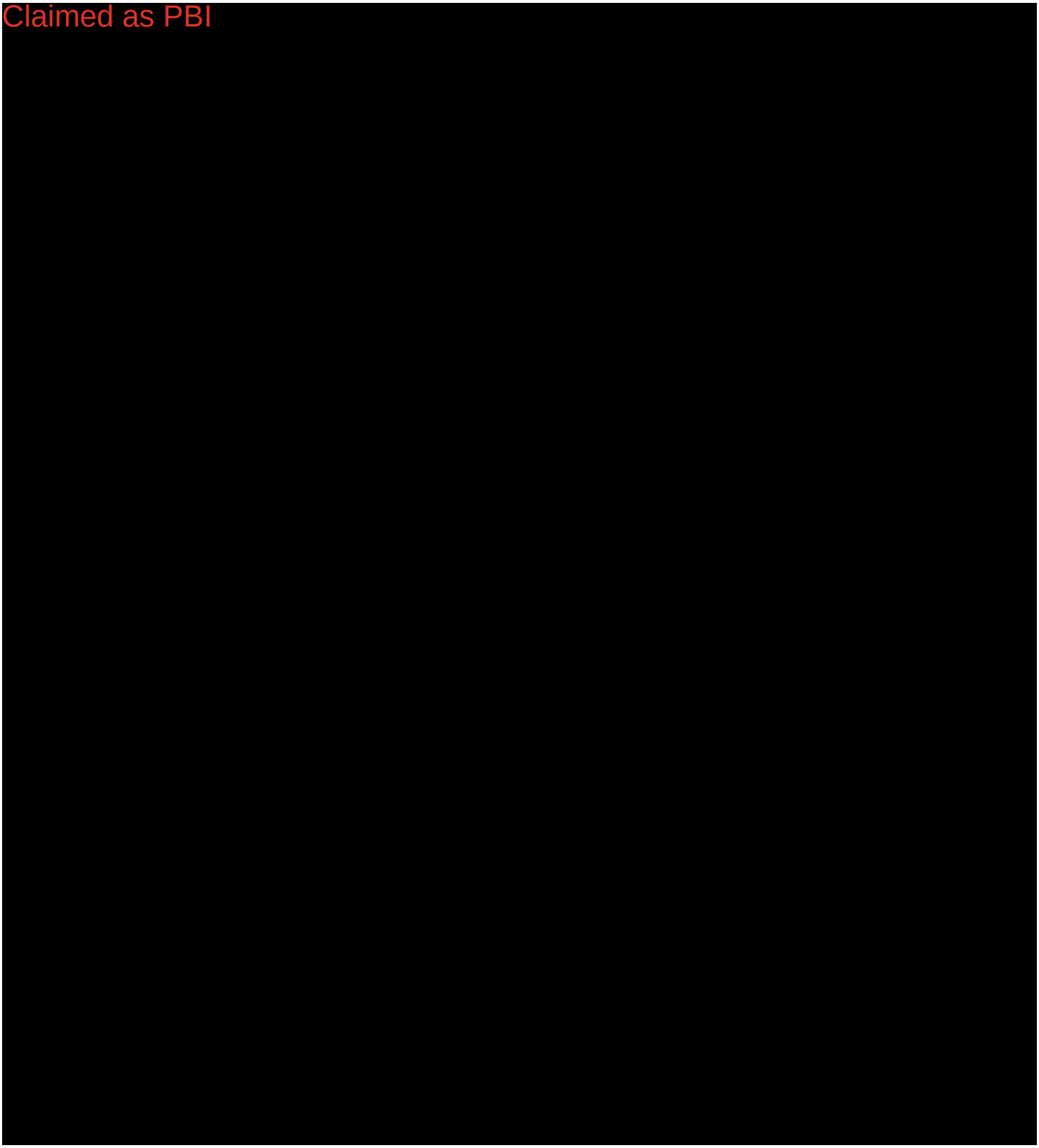
3.2.6 Constitutive Relationships and other Rock Properties

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

[redacted]

Claimed as PBI



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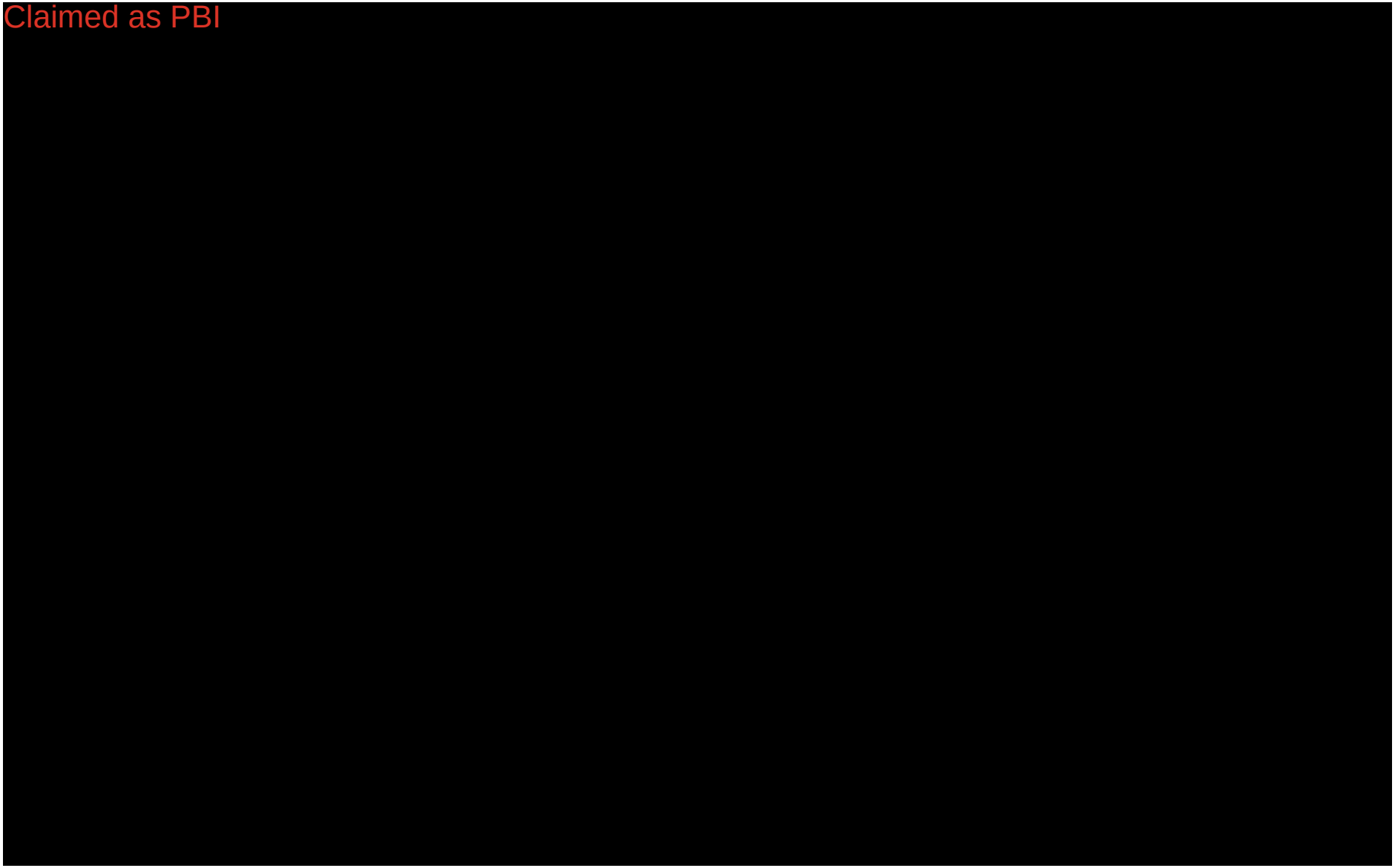

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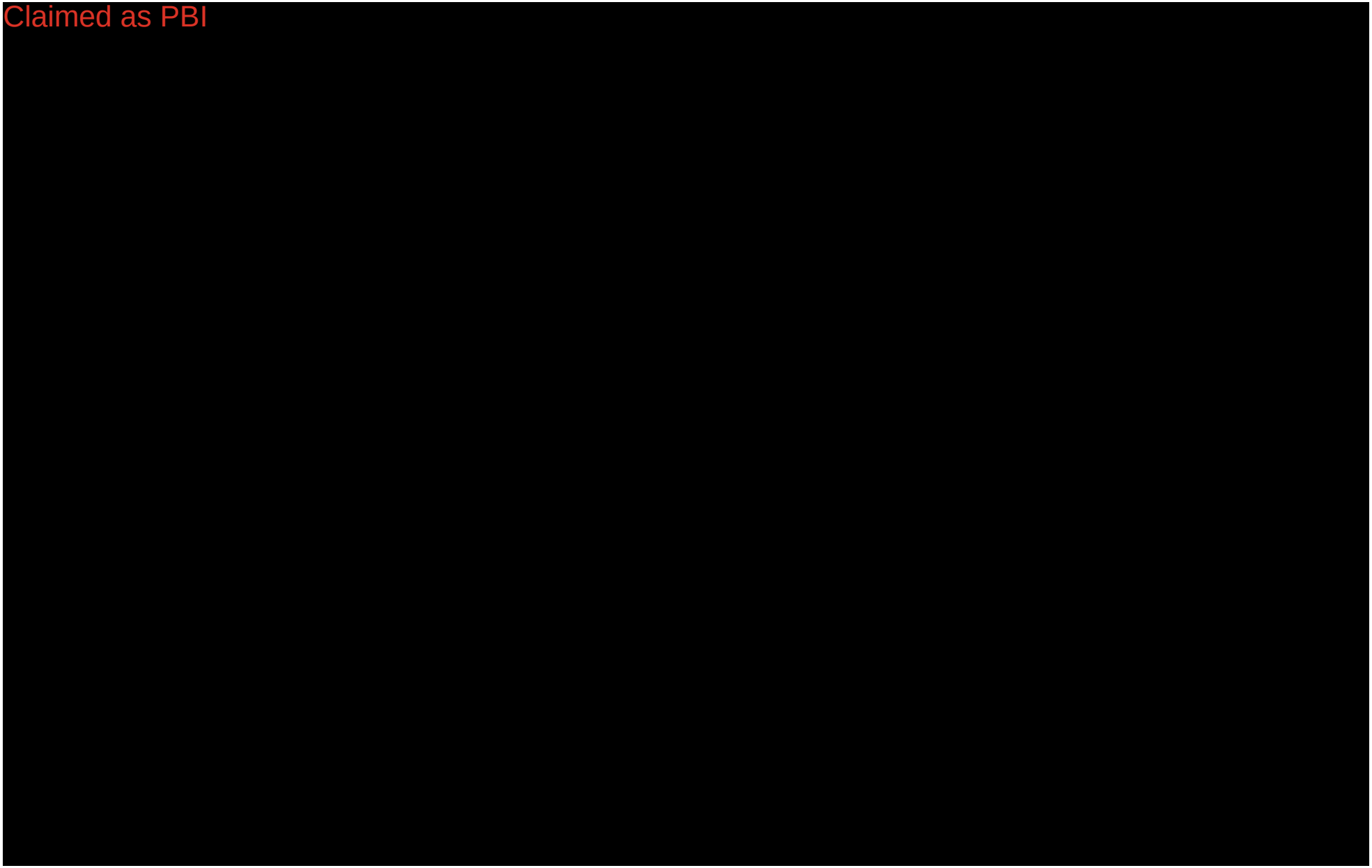

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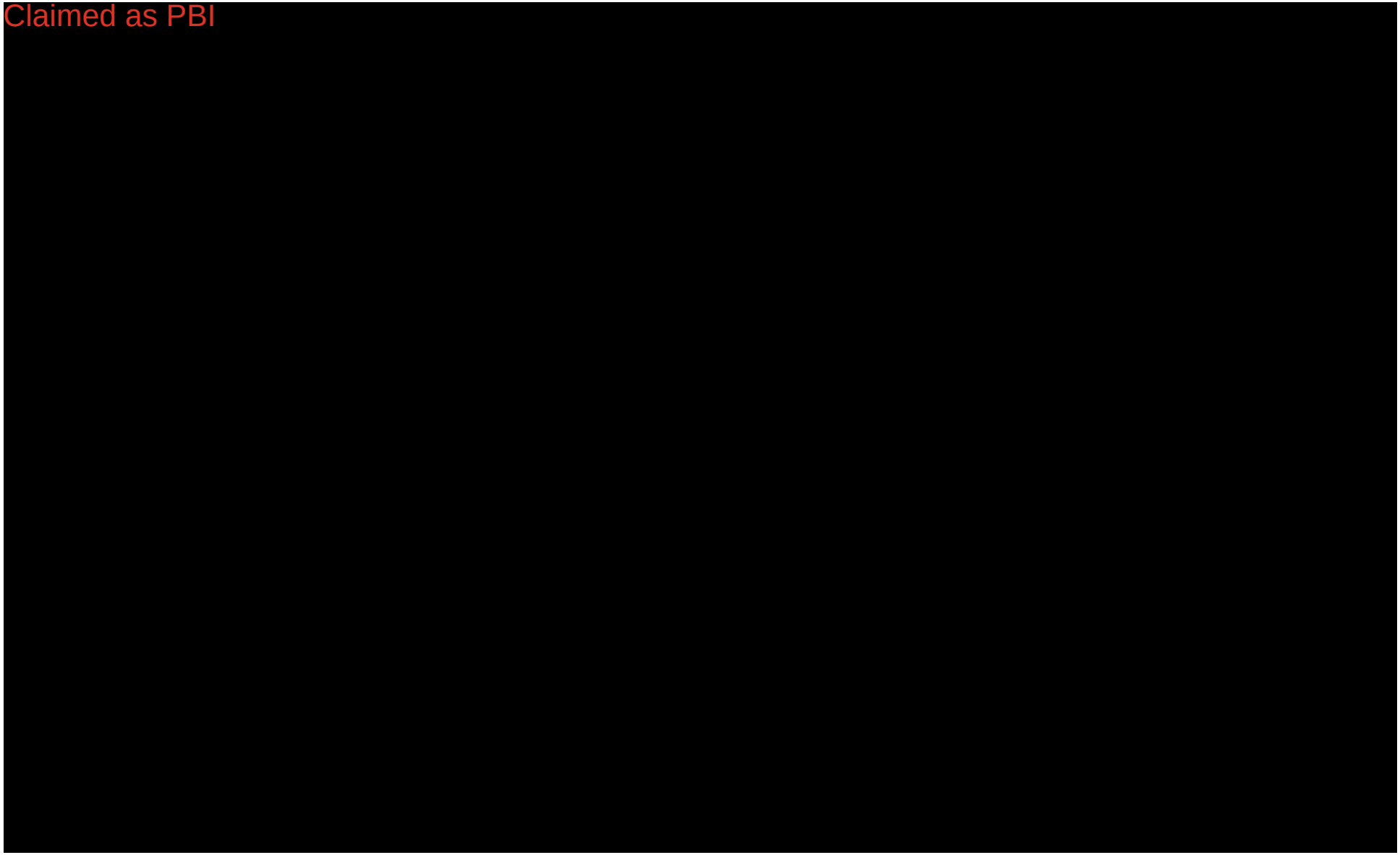
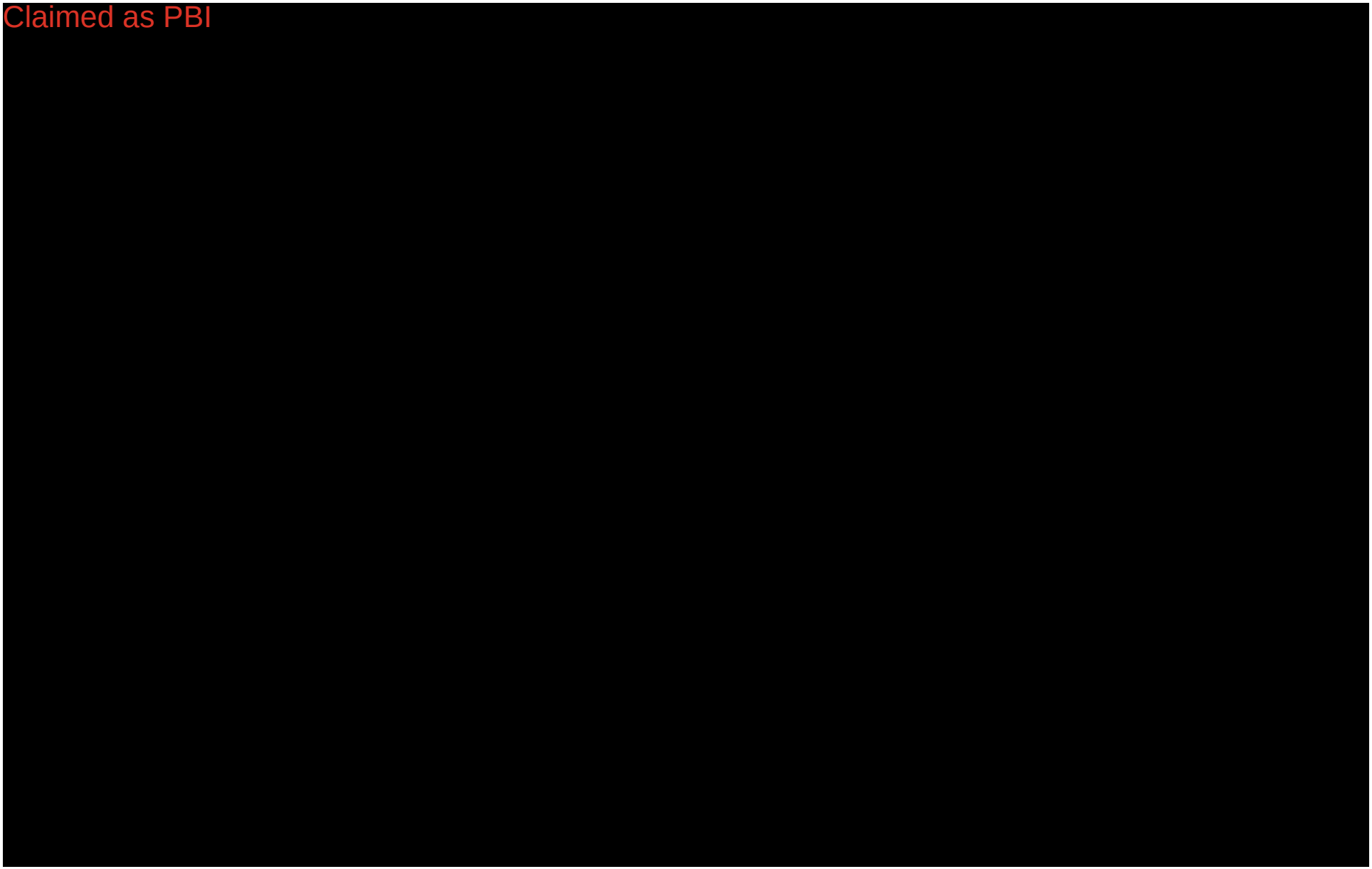


Claimed as PBI



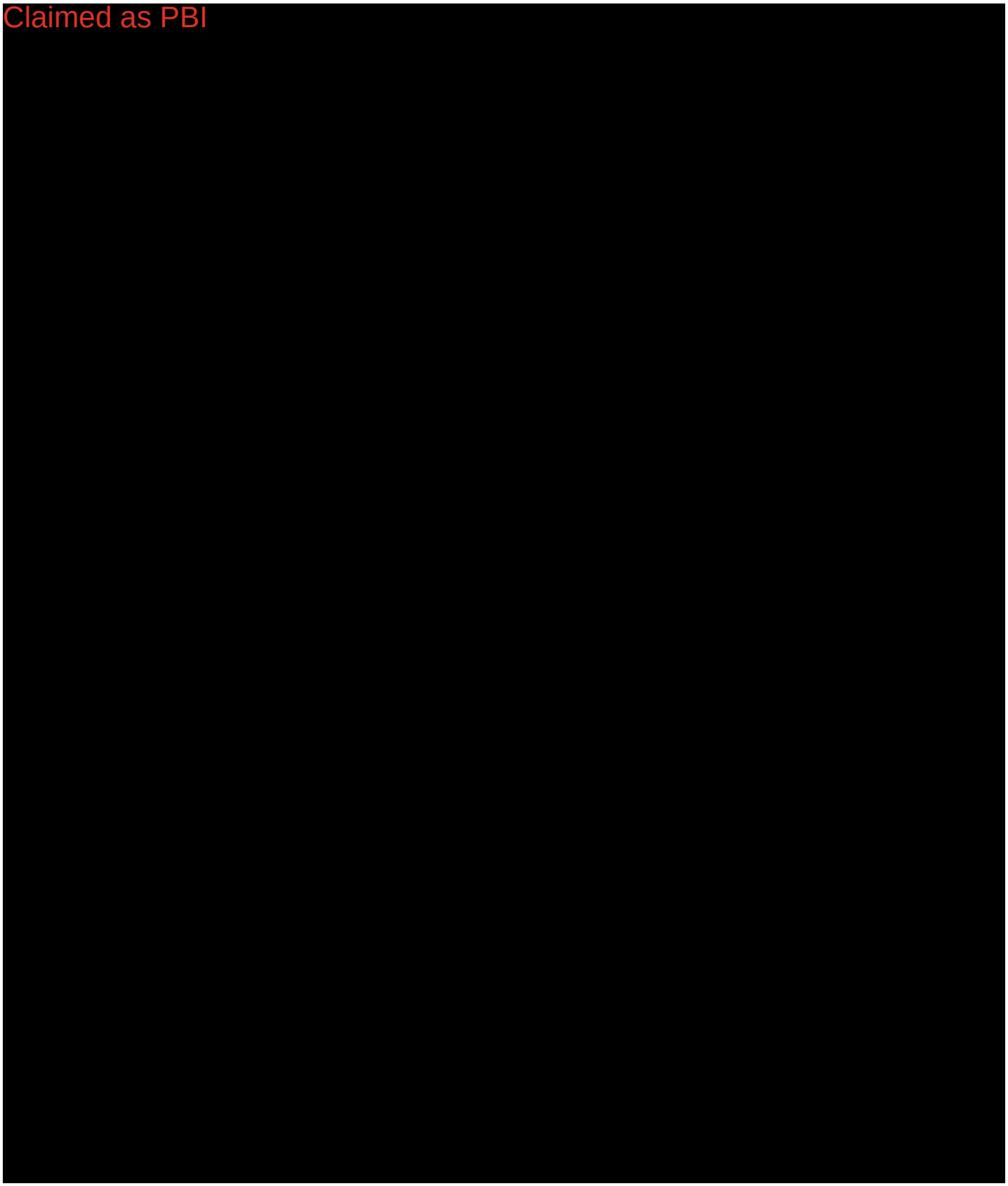
3.2.7 Compositional PVT Model

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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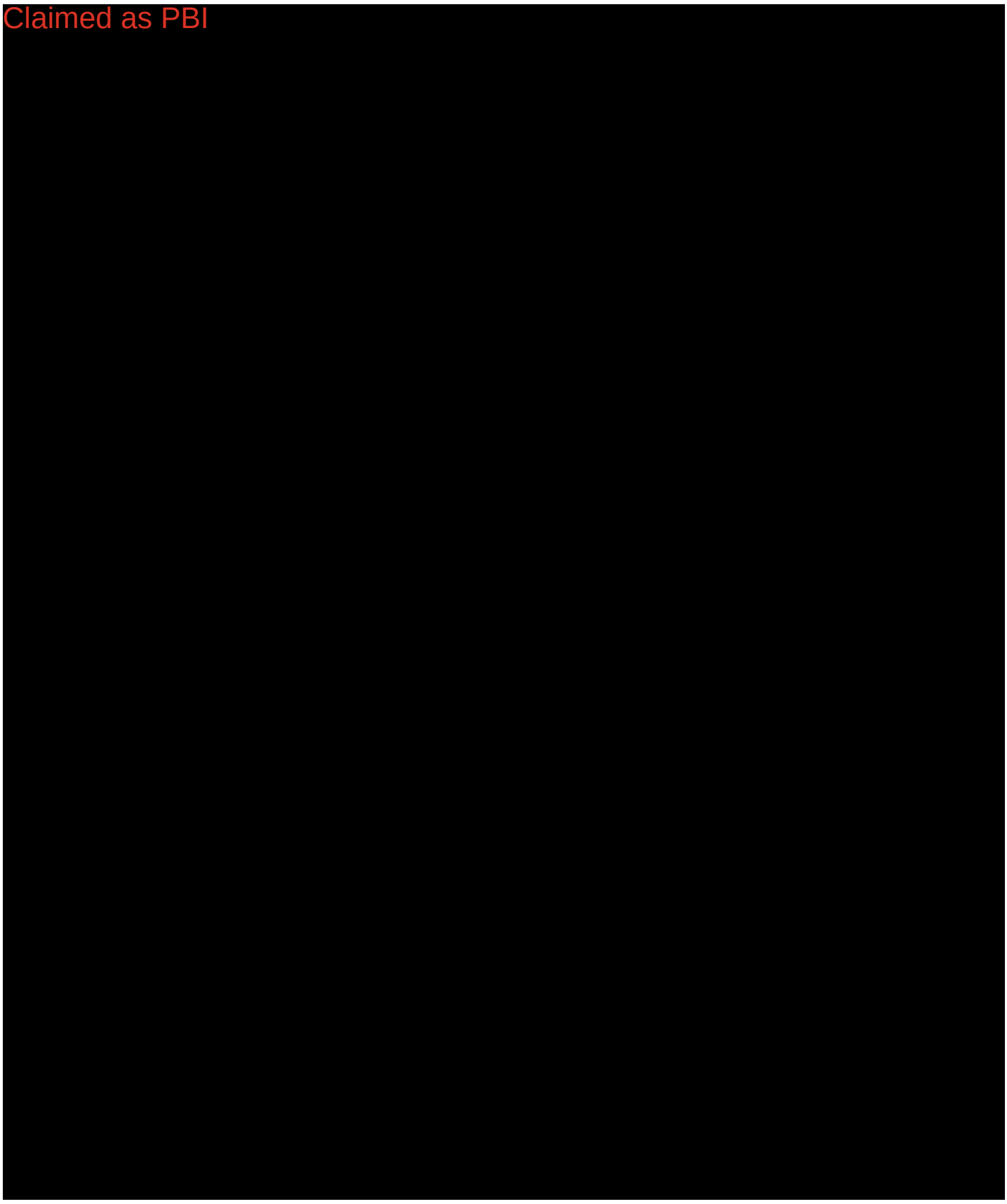

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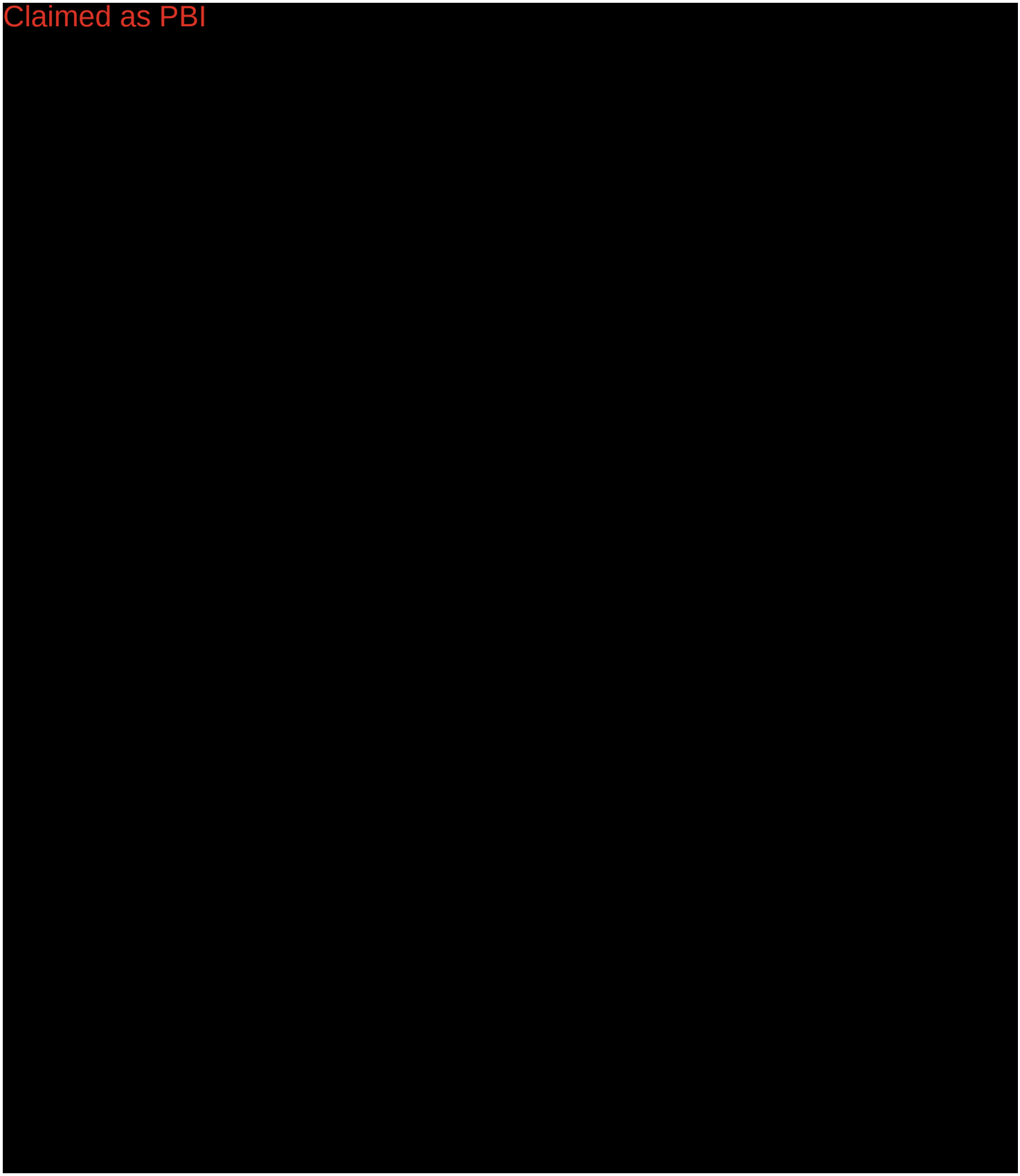

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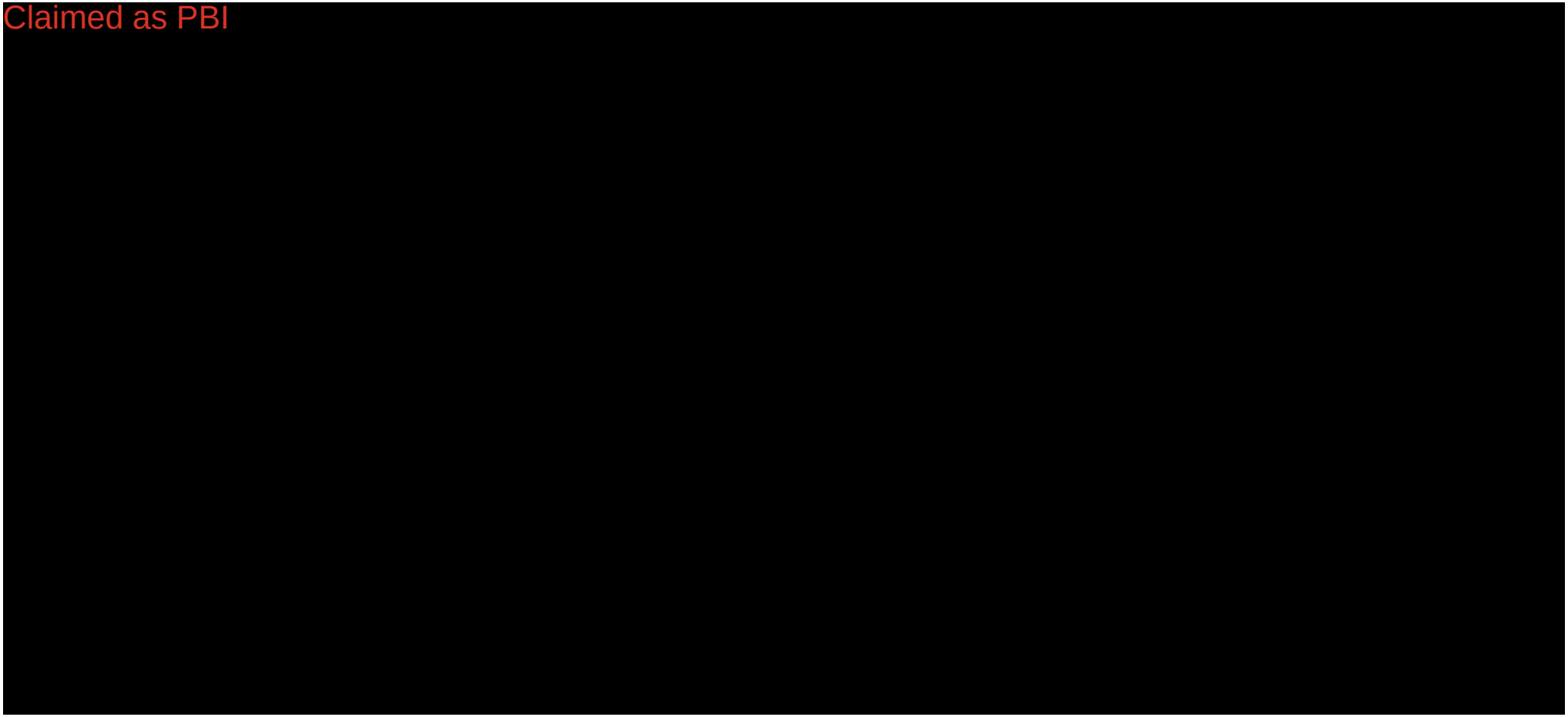


3.2.8 Shale Cut off in the model

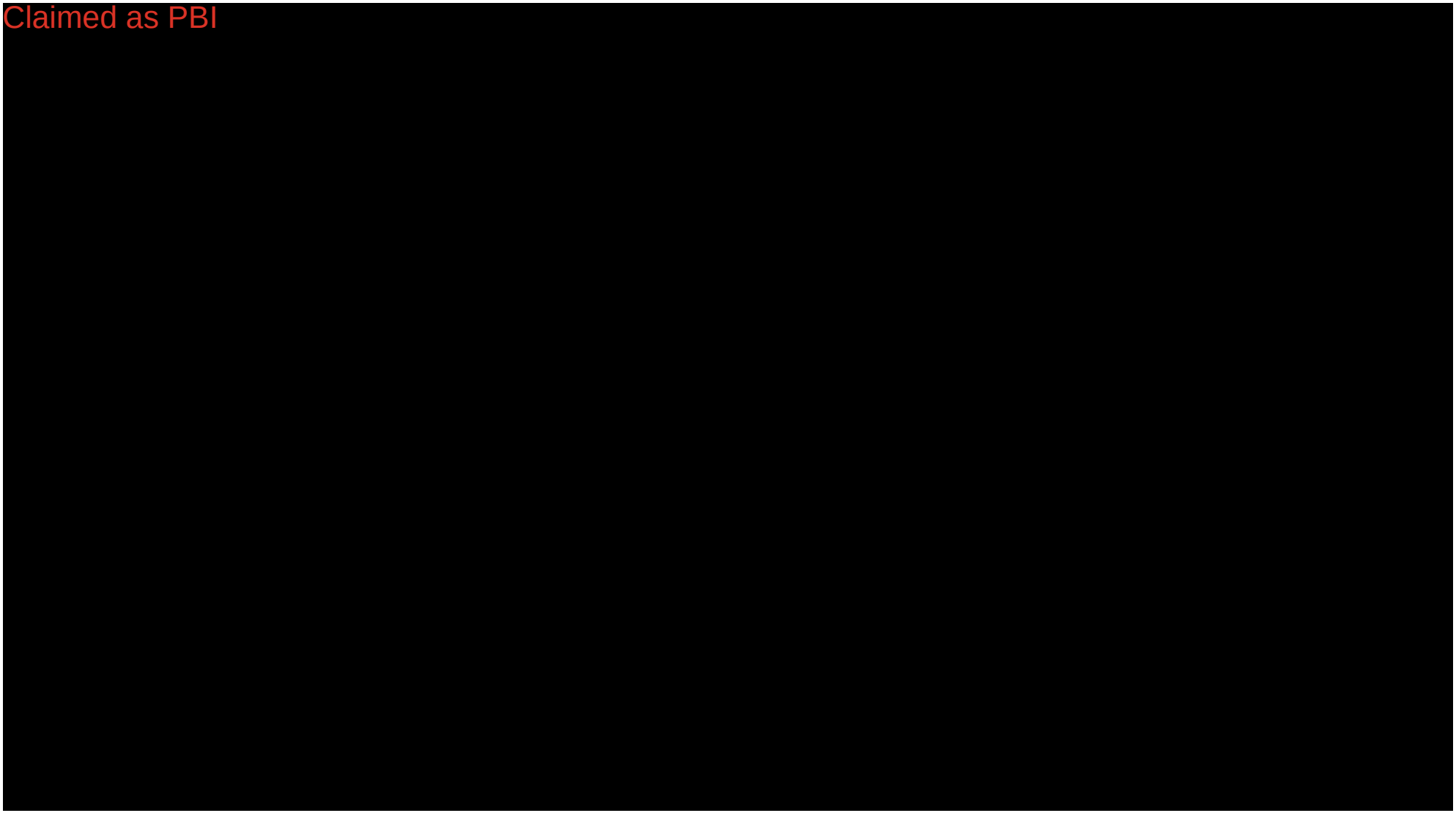
It is essential to account for appropriate rock volume (sand and shale) in the dynamic modeling of CO_2 injection. Claimed as PBI [redacted]

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



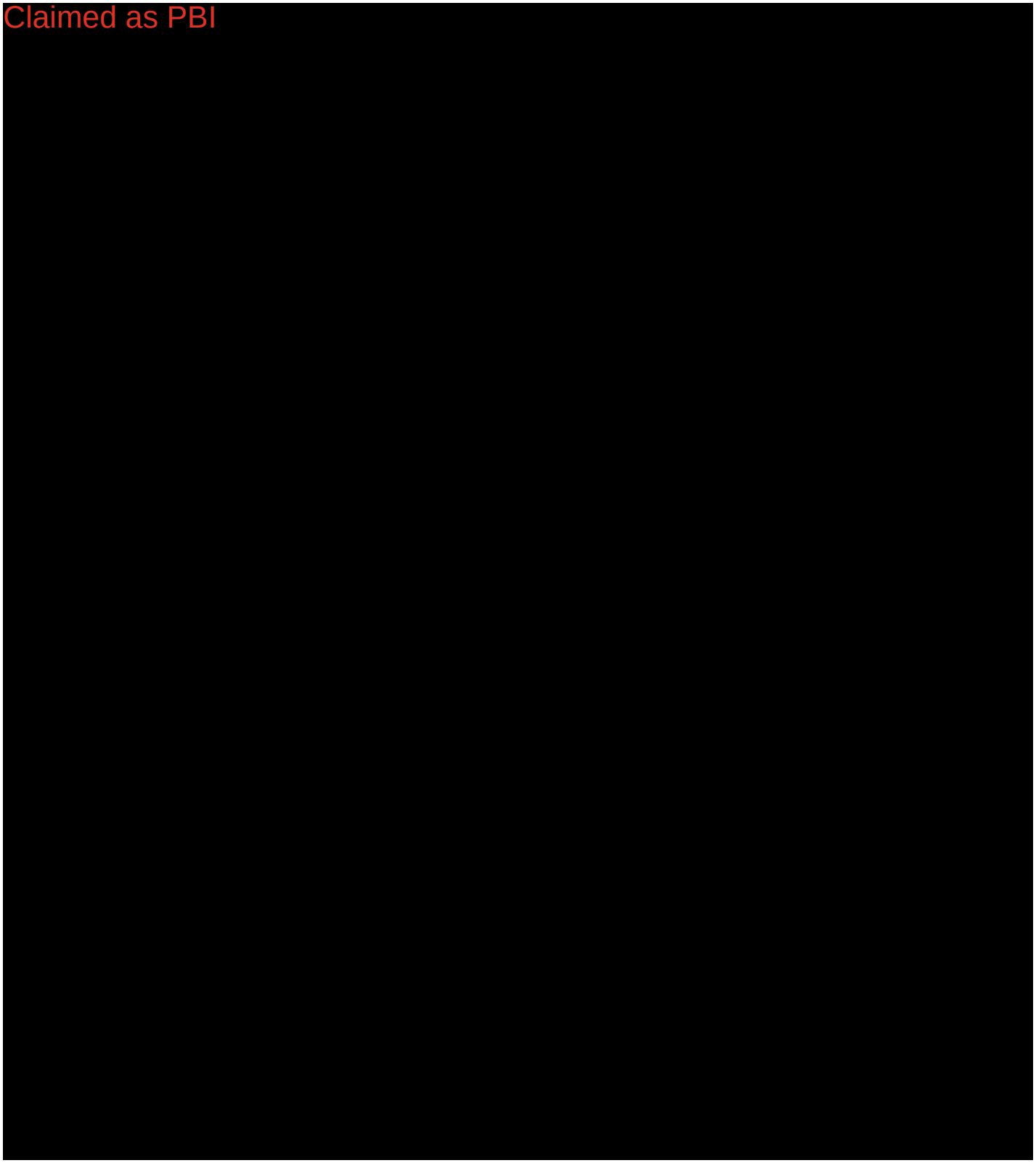
3.2.13 *Fracture Pressure and Fracture Gradient*

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

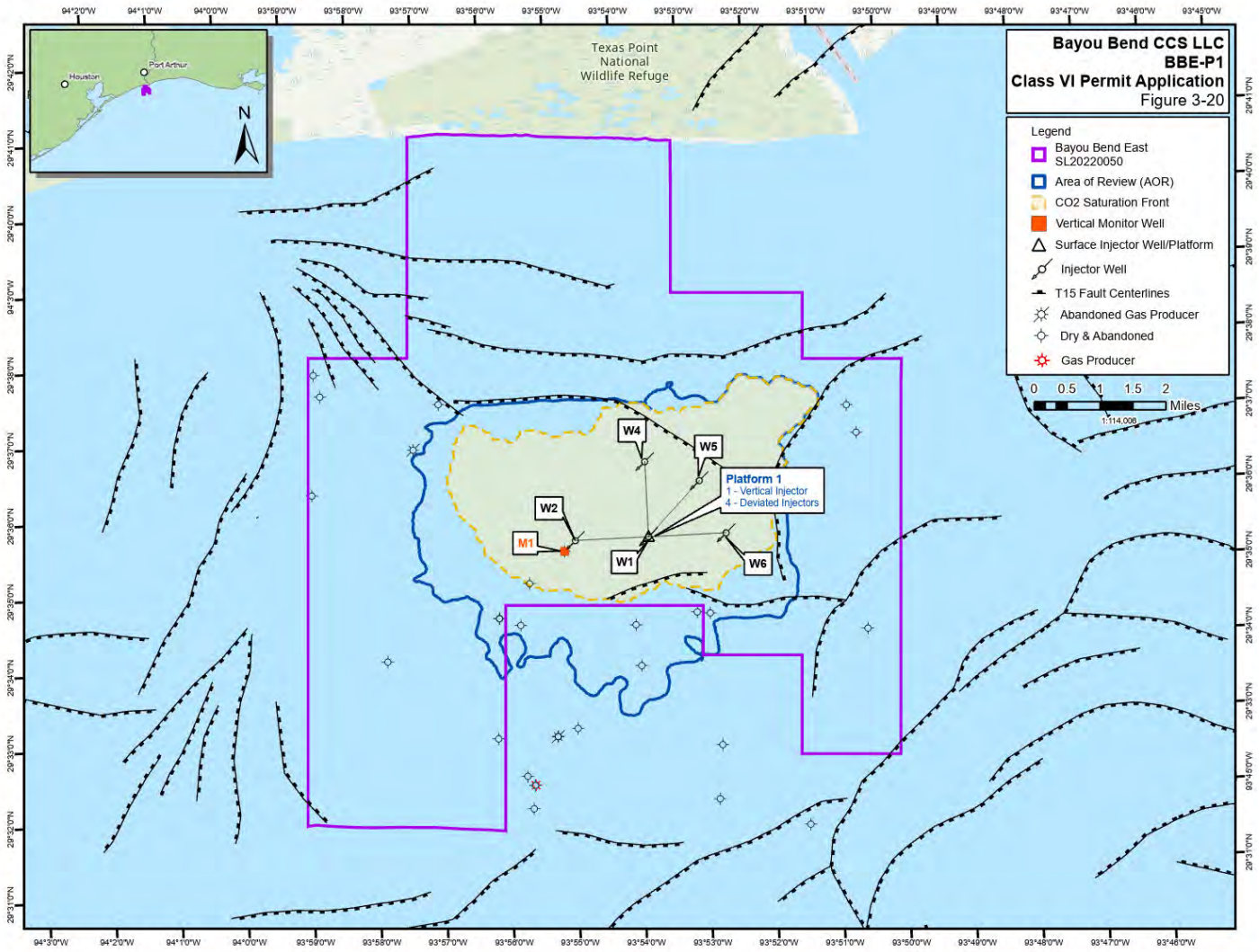
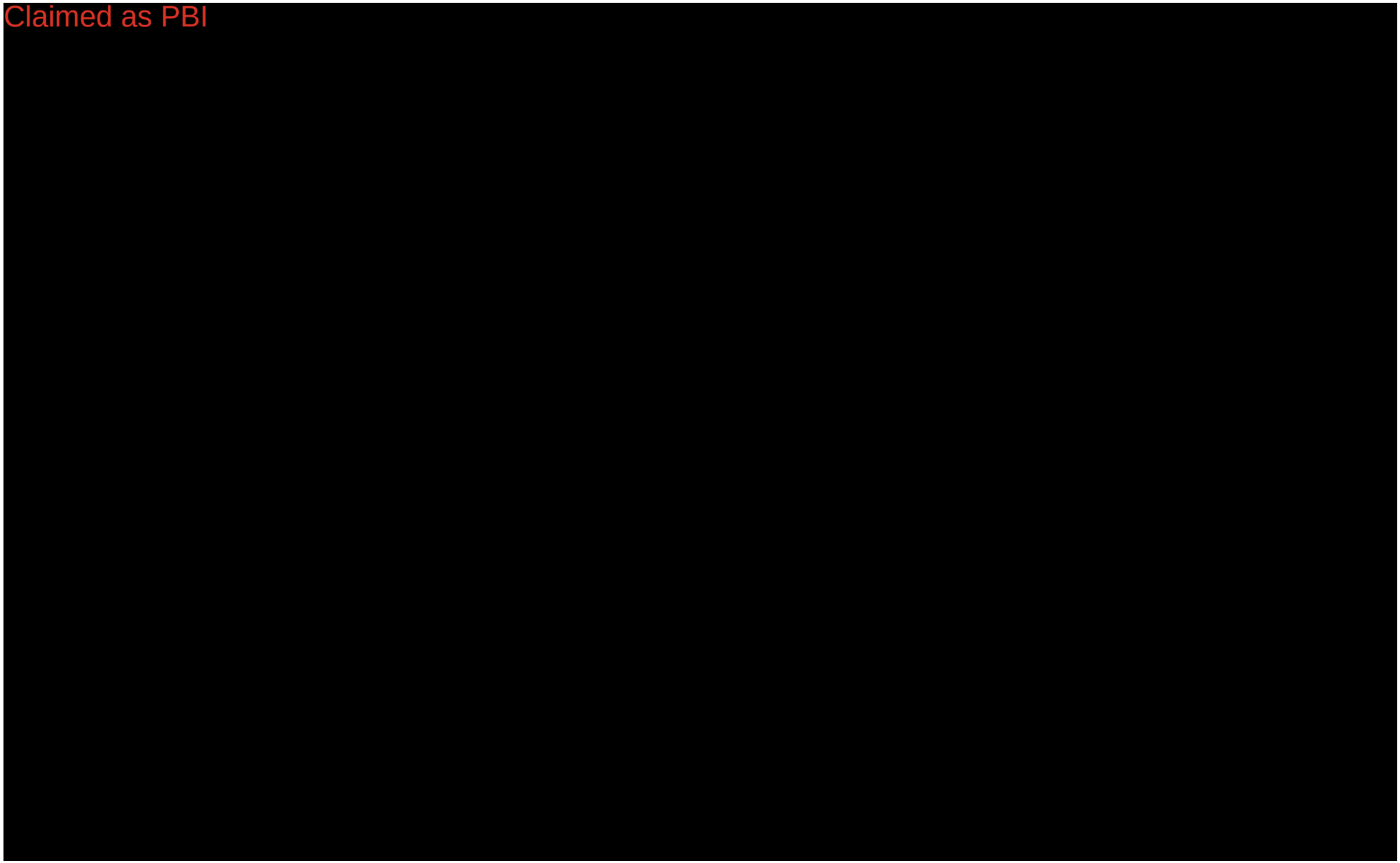


Figure 3-20: Position of injection and monitoring wells in relation to AOR, faults at the top of the T15 (confining zone) and existing penetrative wells.

Claimed as PBI



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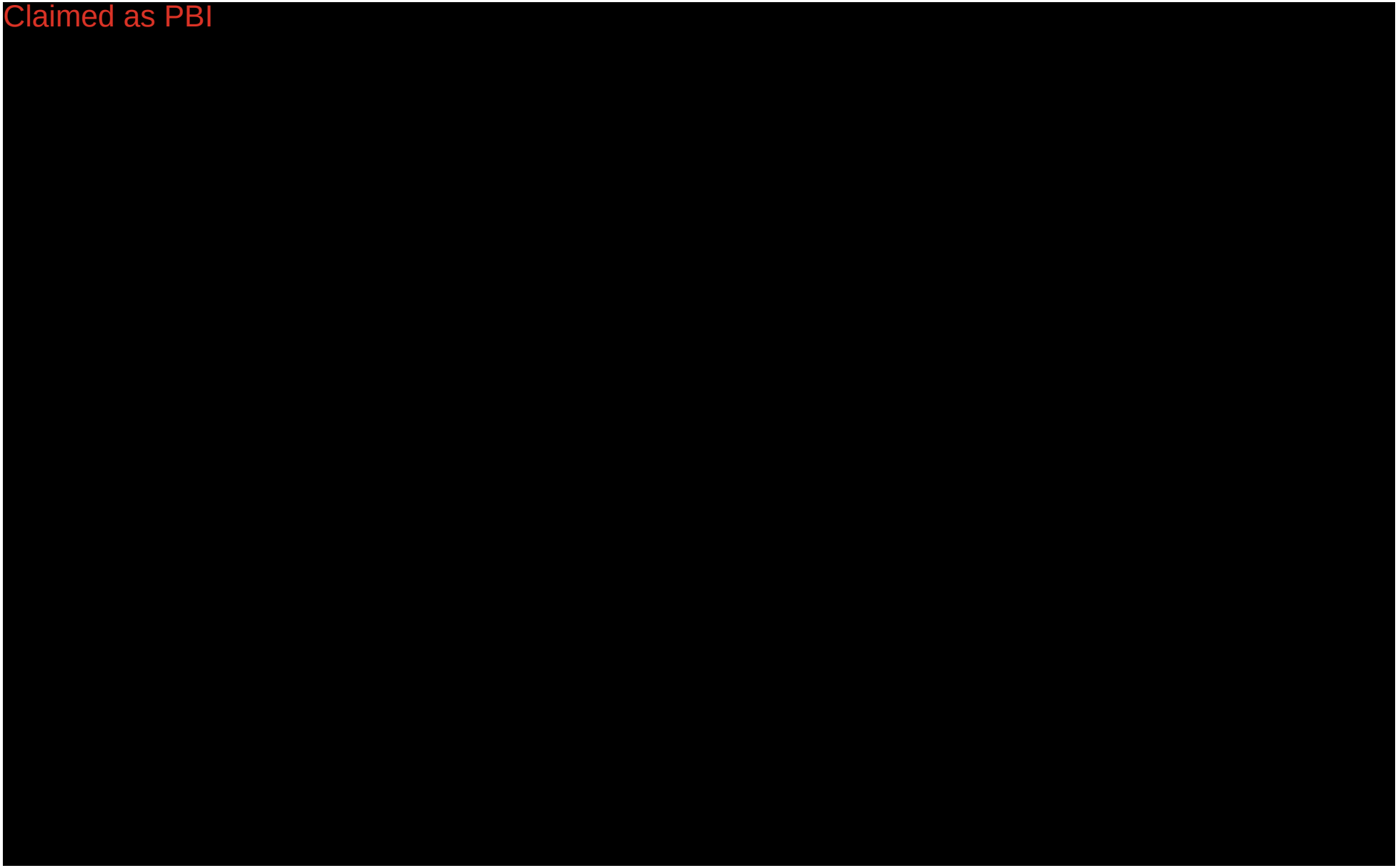

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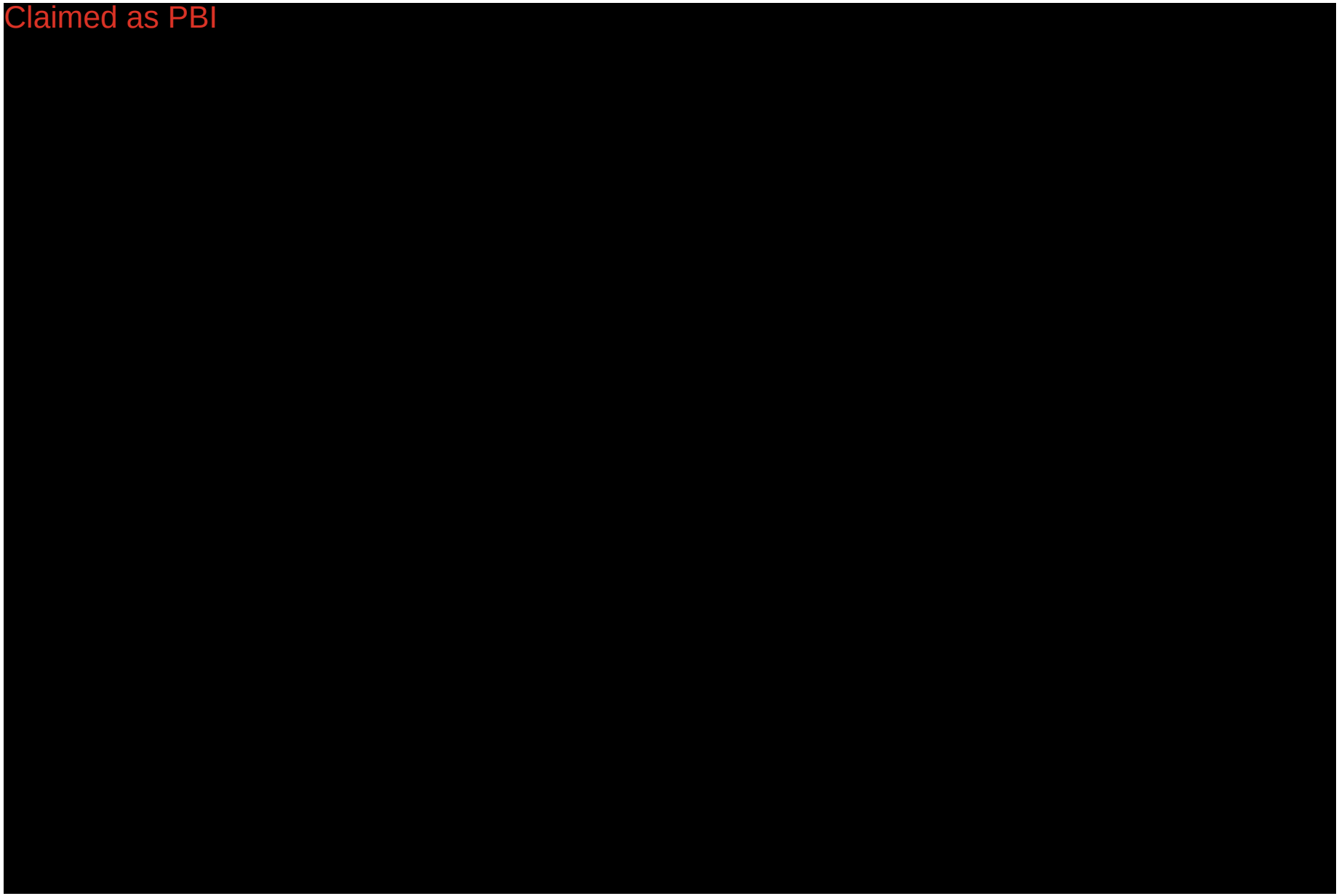

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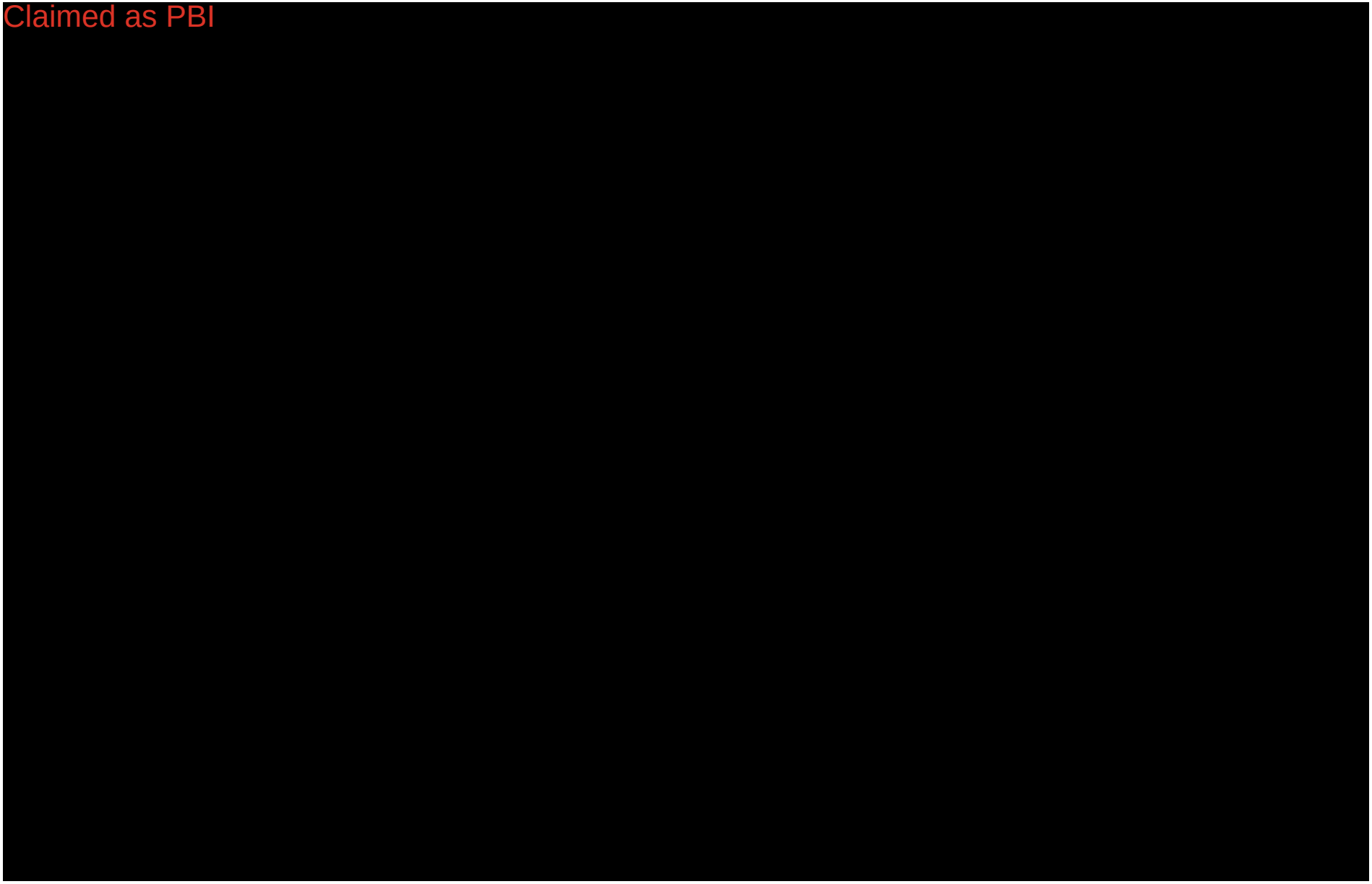

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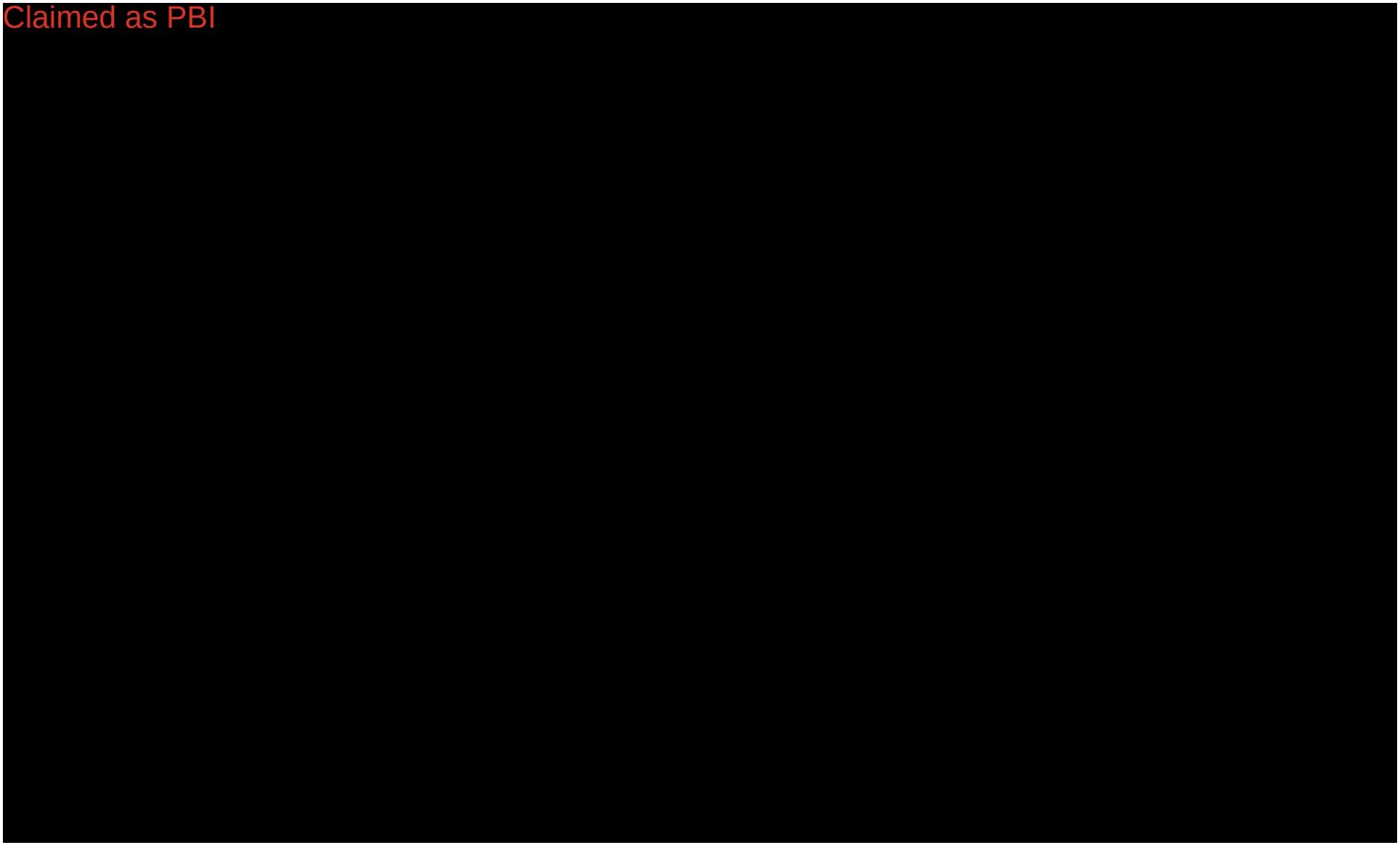

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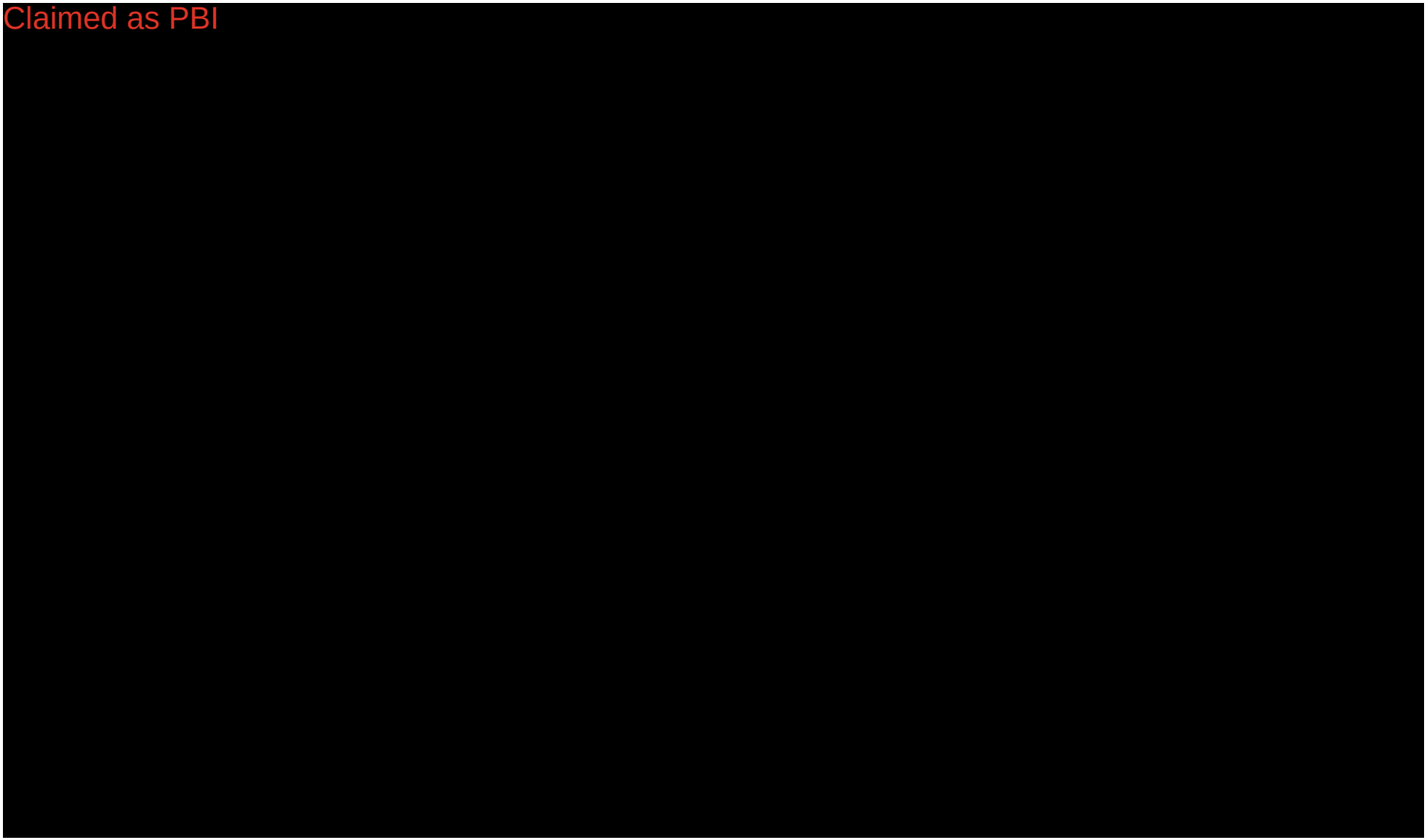

Claimed as PBI



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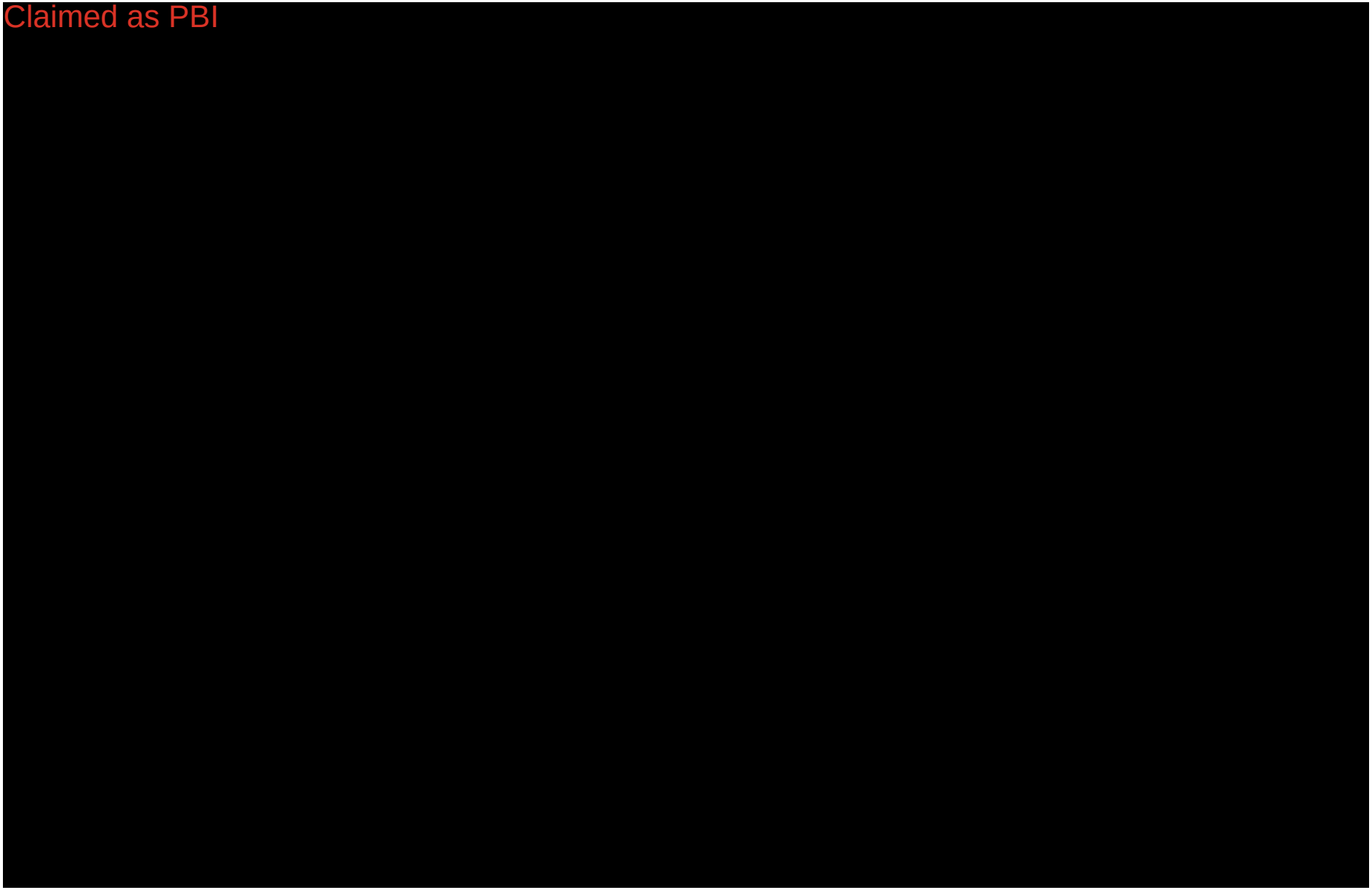

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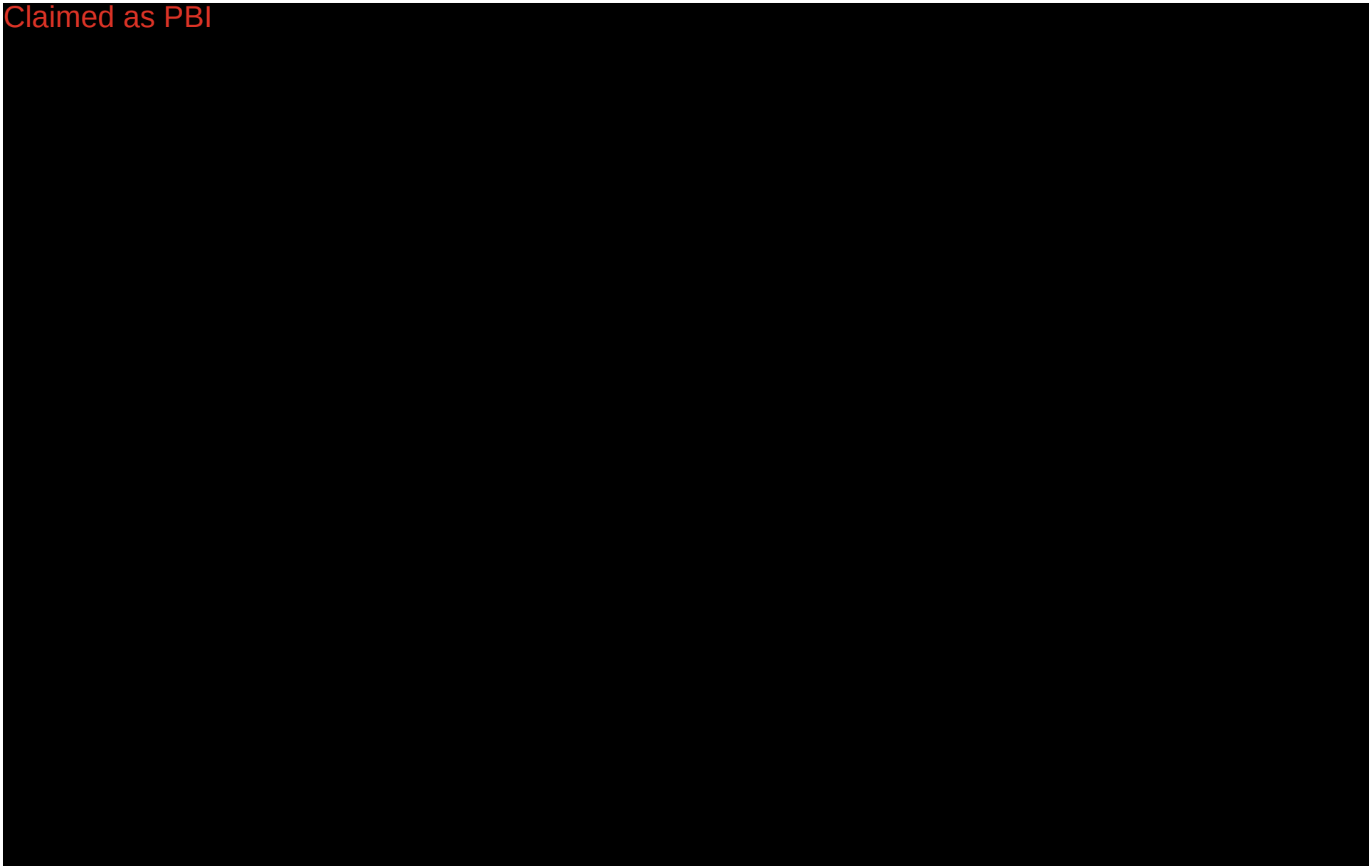

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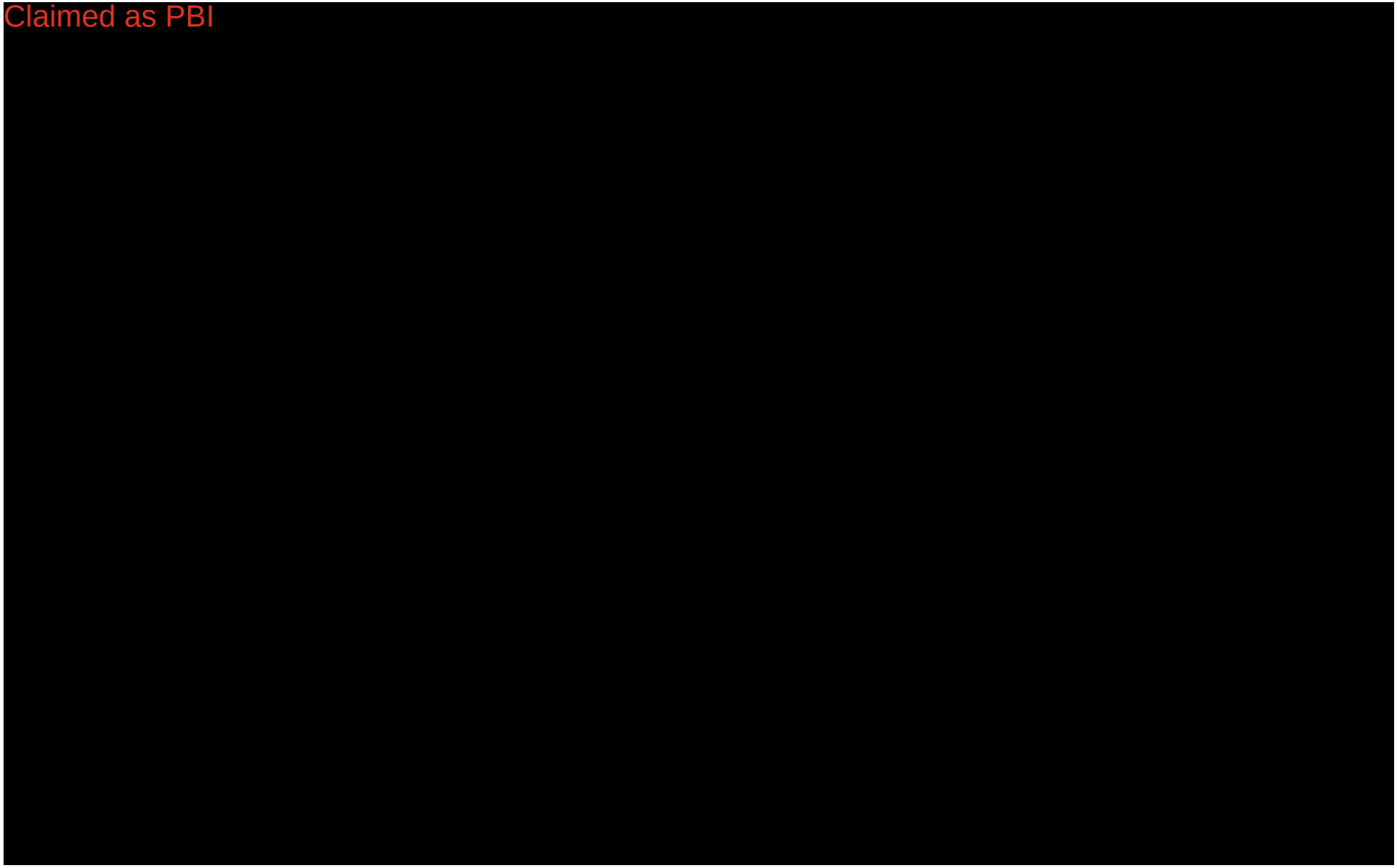

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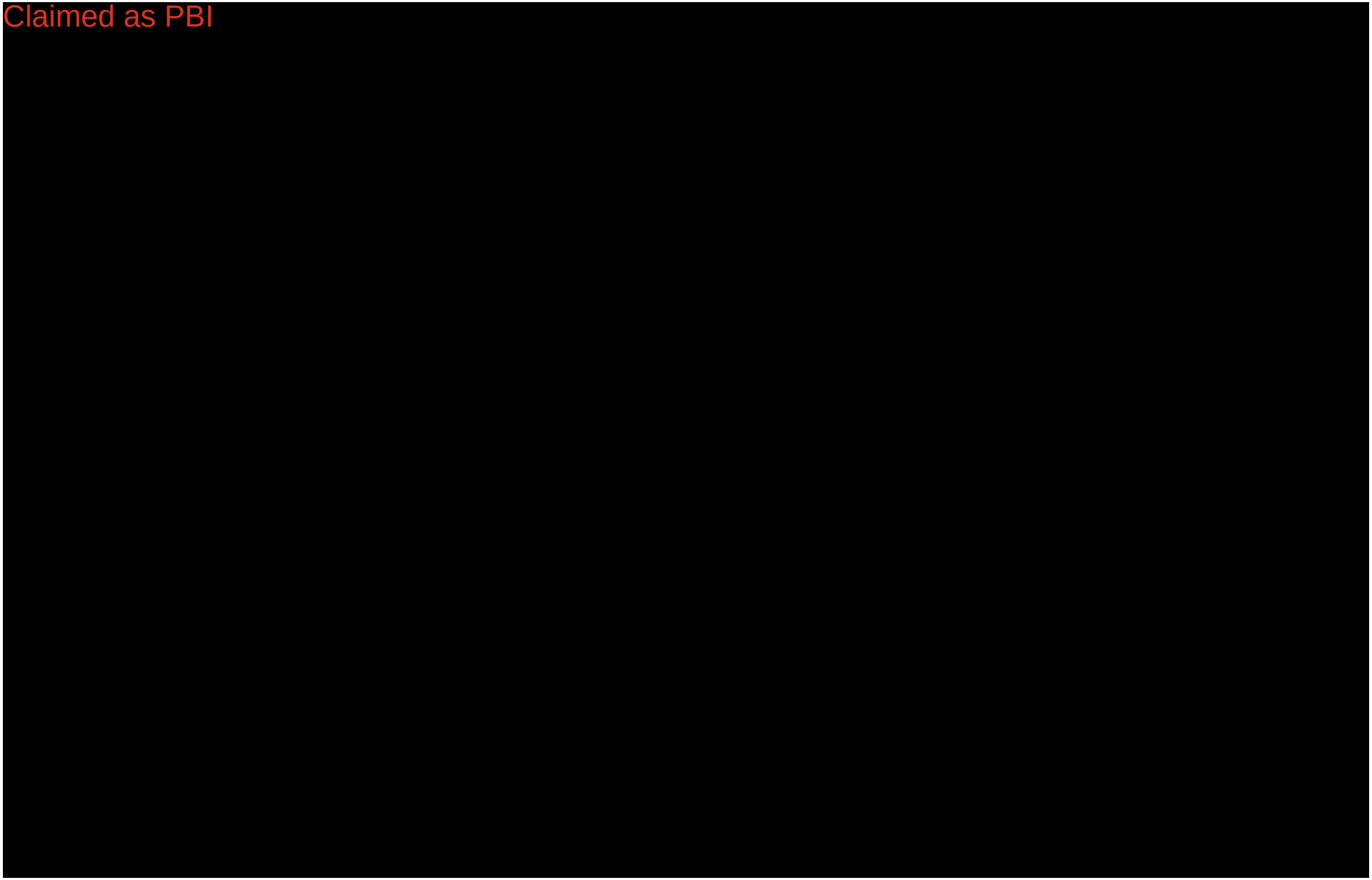

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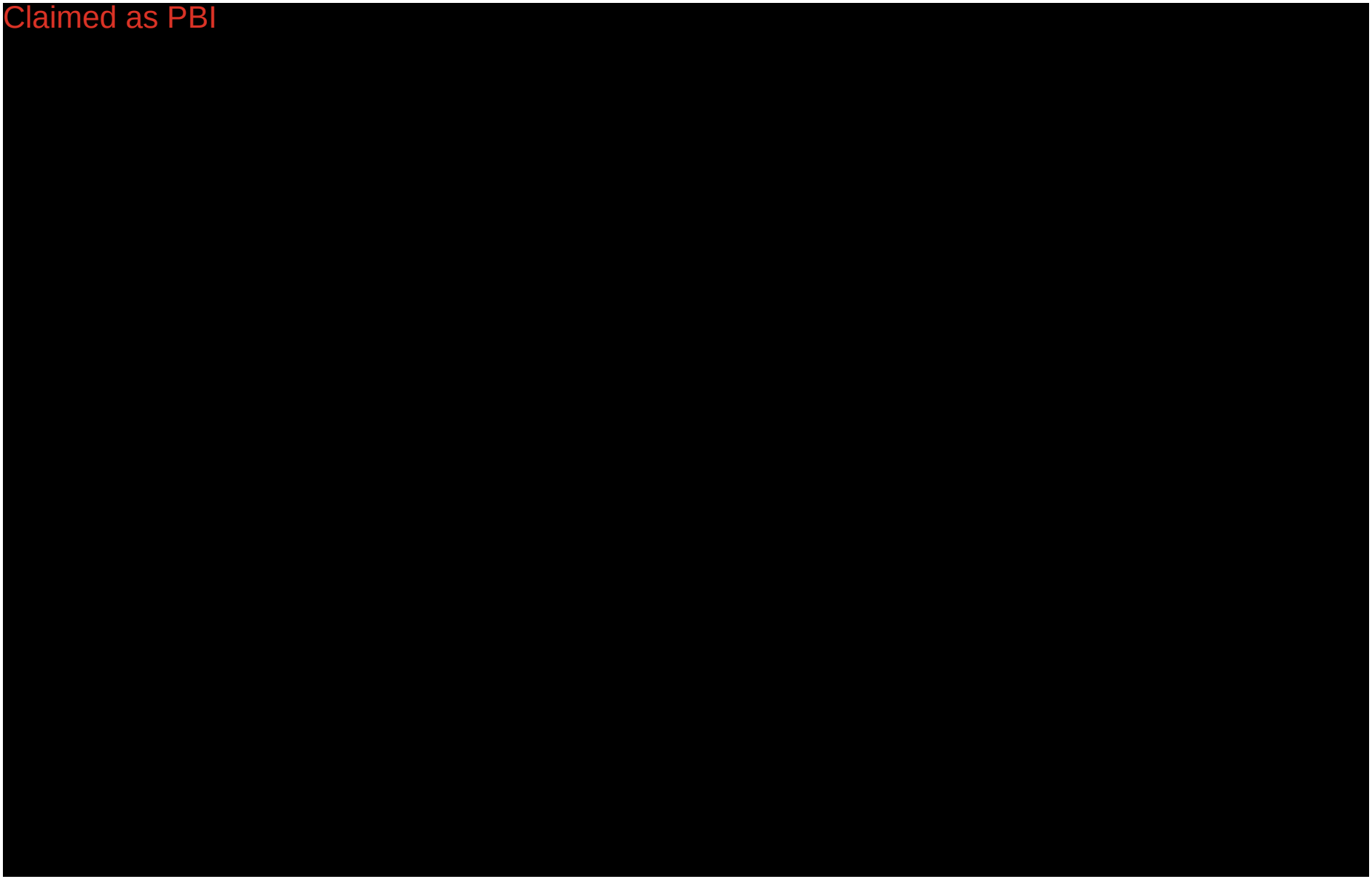

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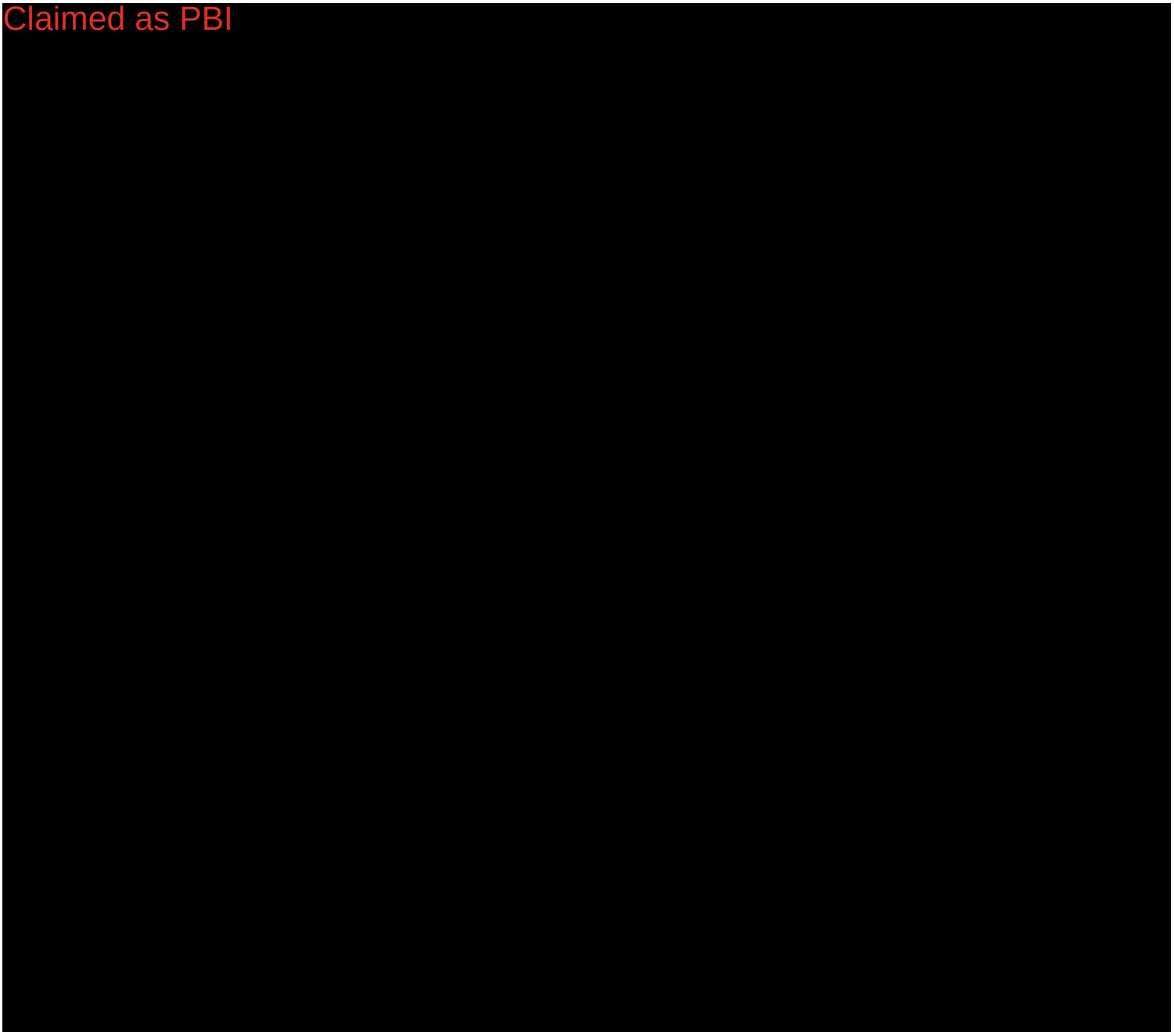

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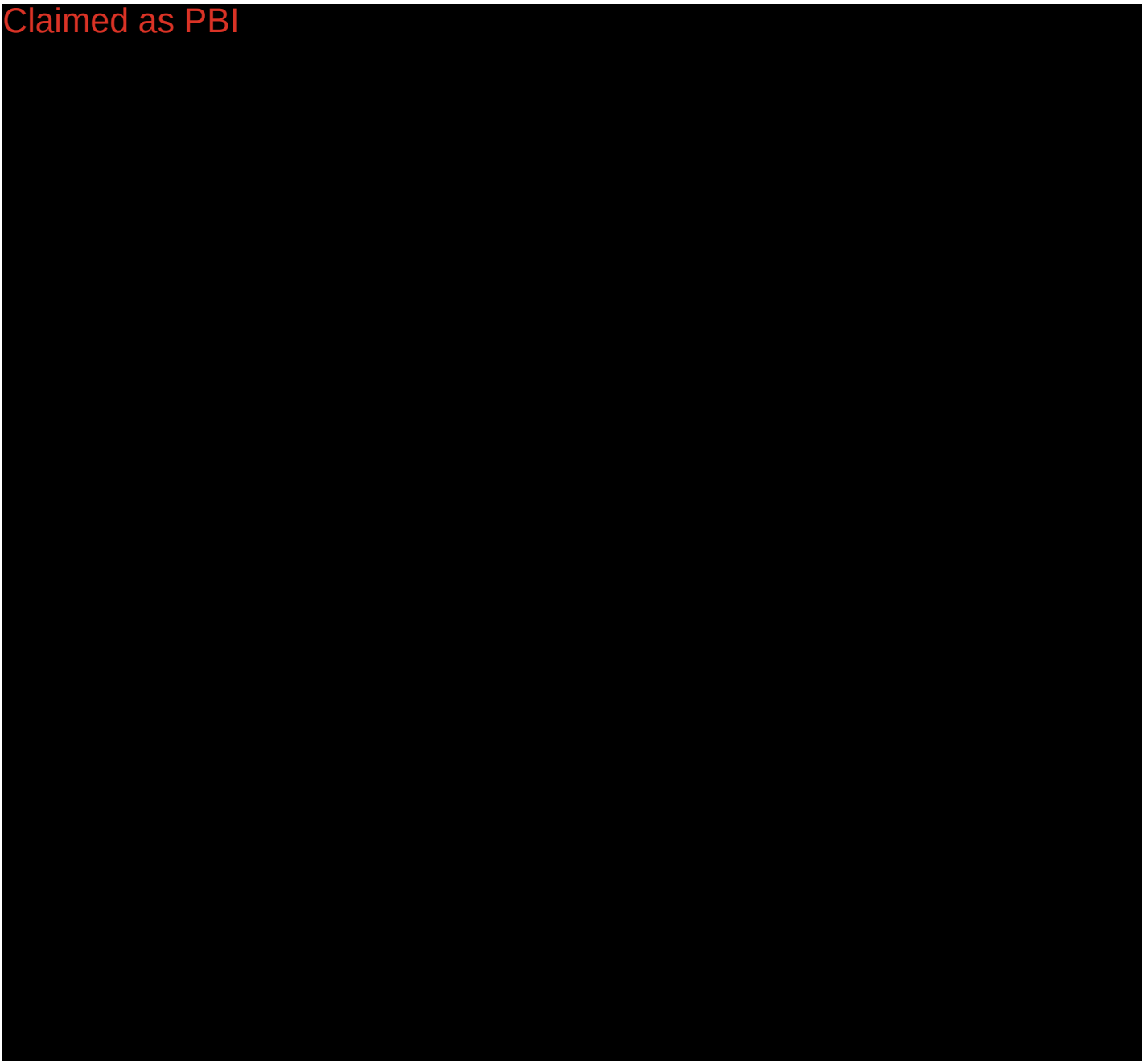

Claimed as PBI

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).

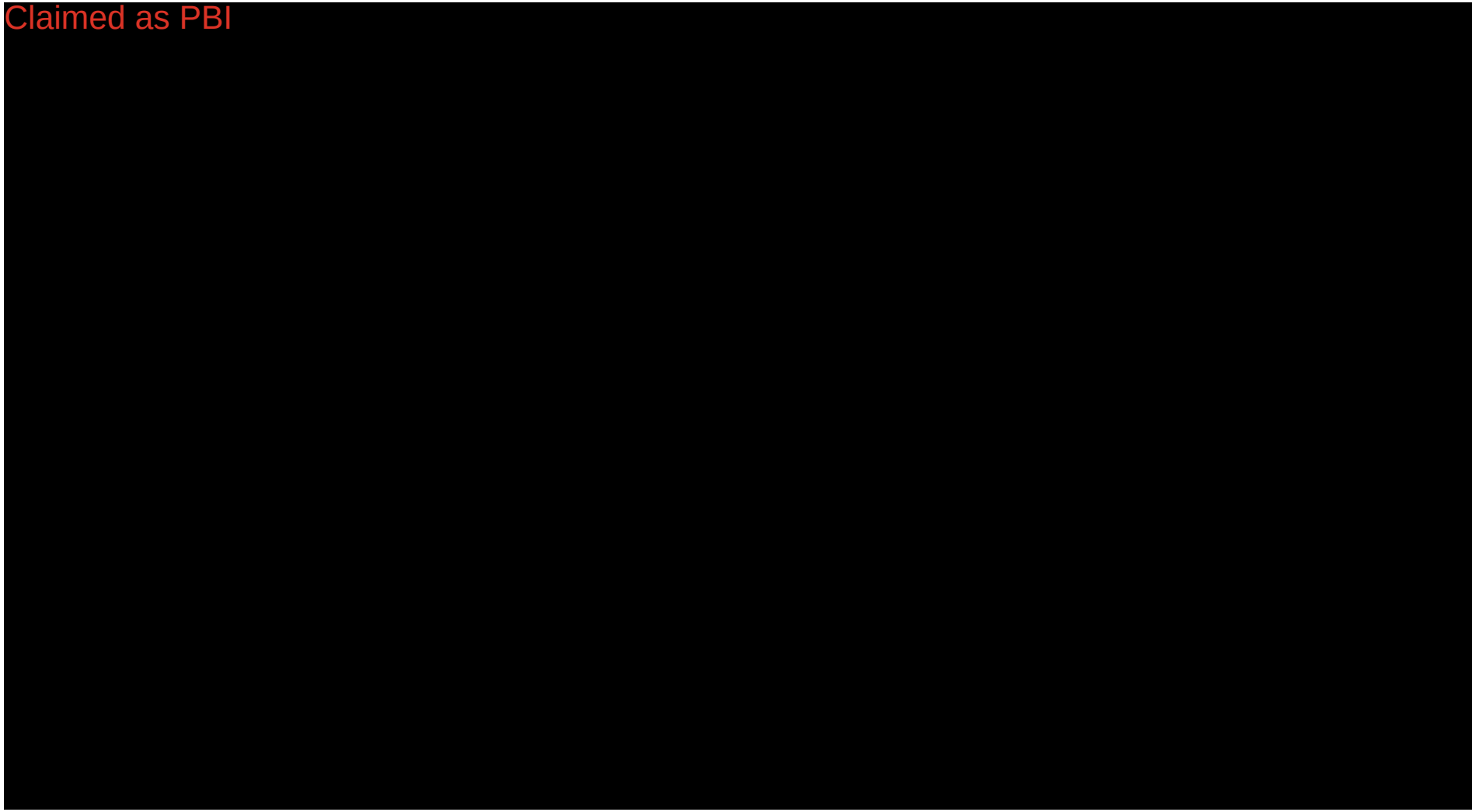
Claimed as PBI



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).

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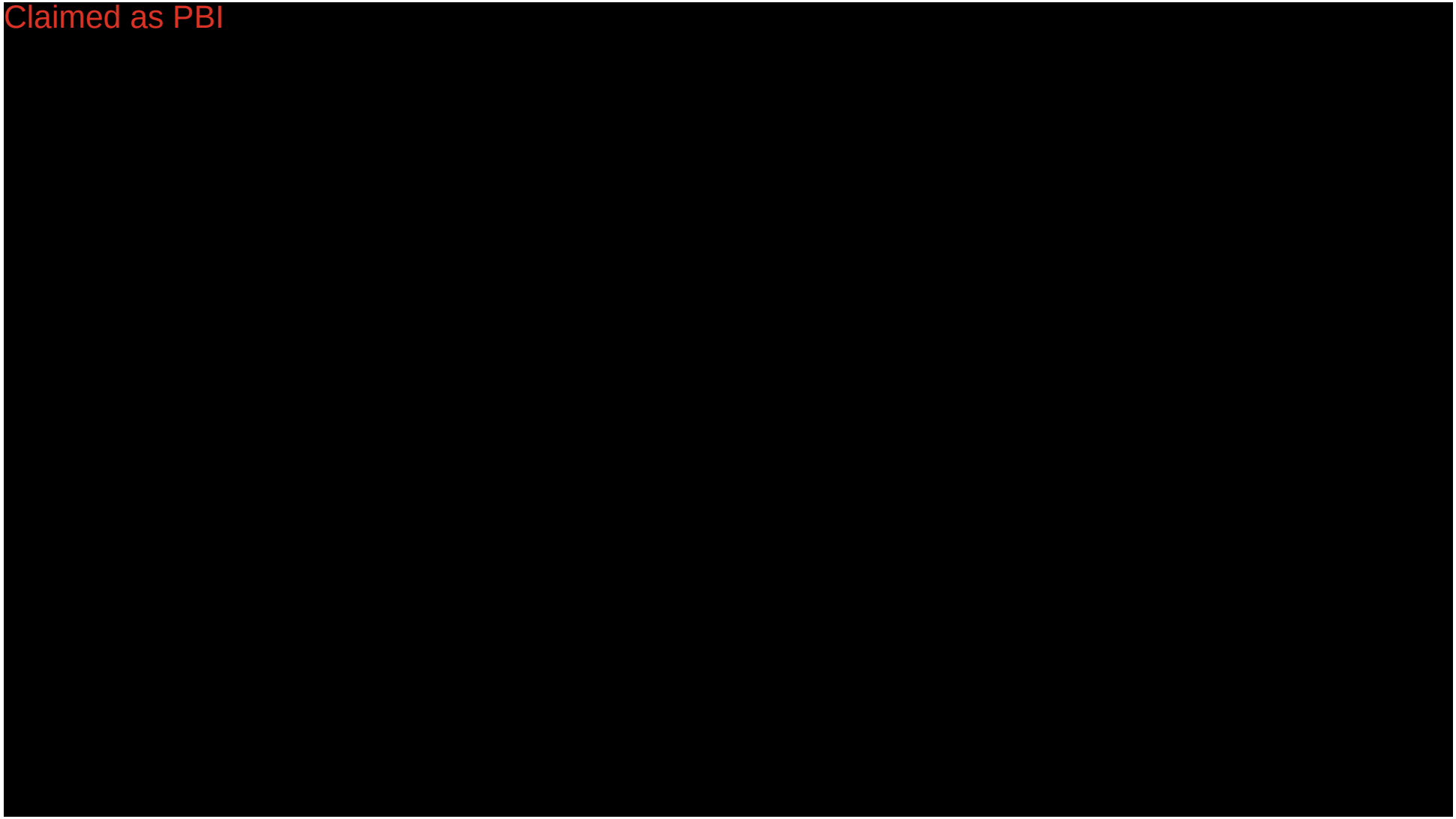
Claimed as PBI



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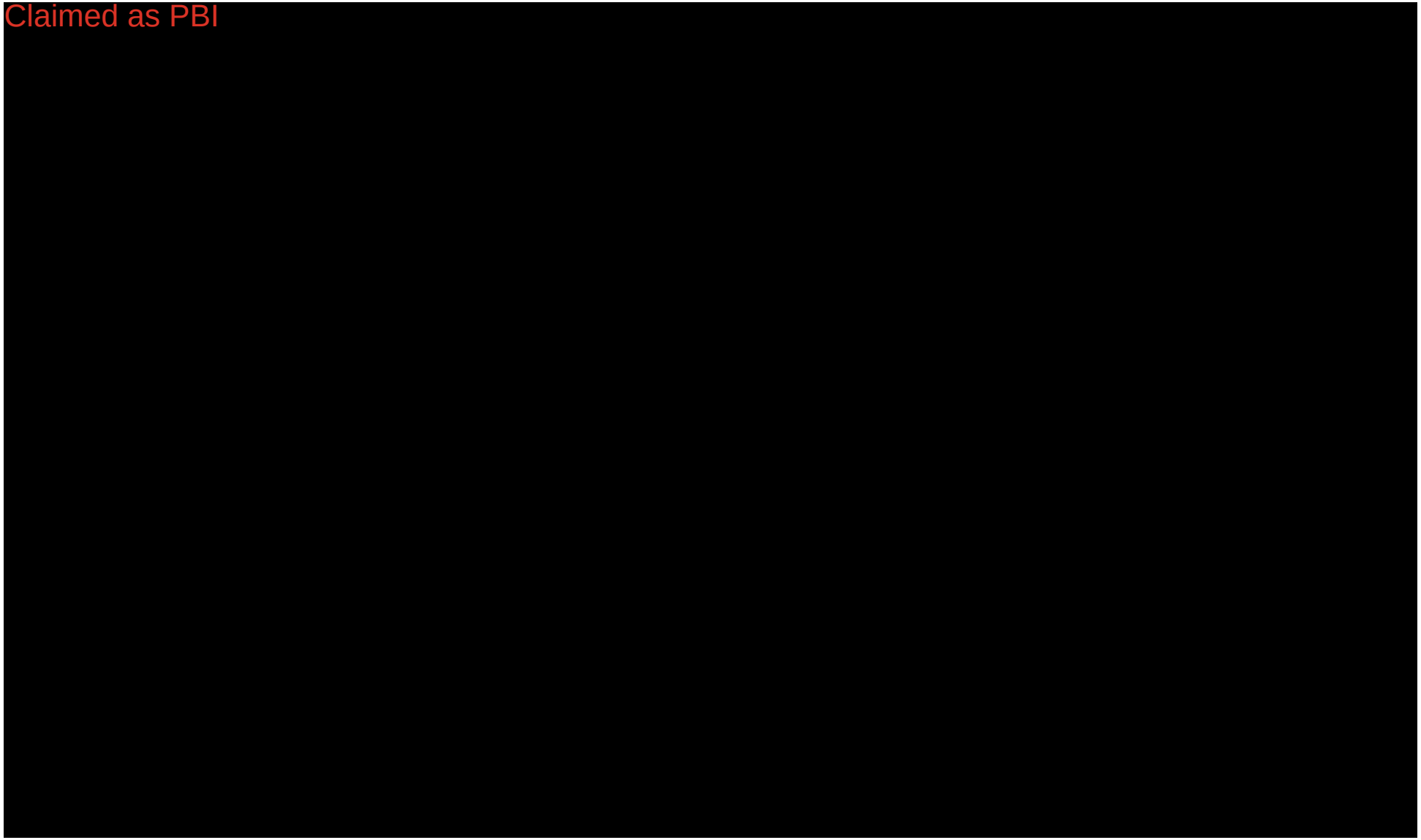


3.5 Corrective Action

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

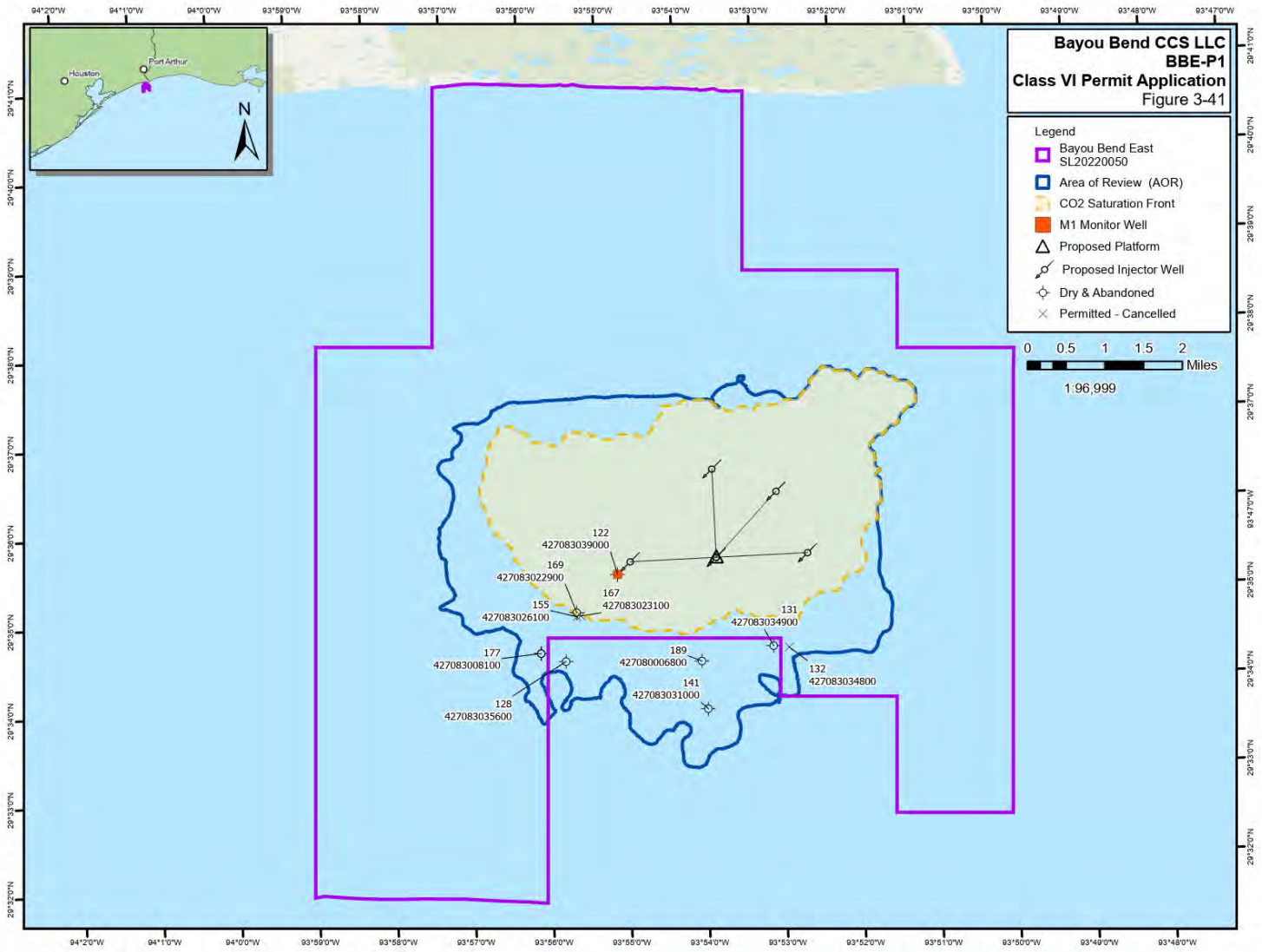


Figure 3-41: Artificial Penetrations within the AOR. Table 3-21 provides detailed information.

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.

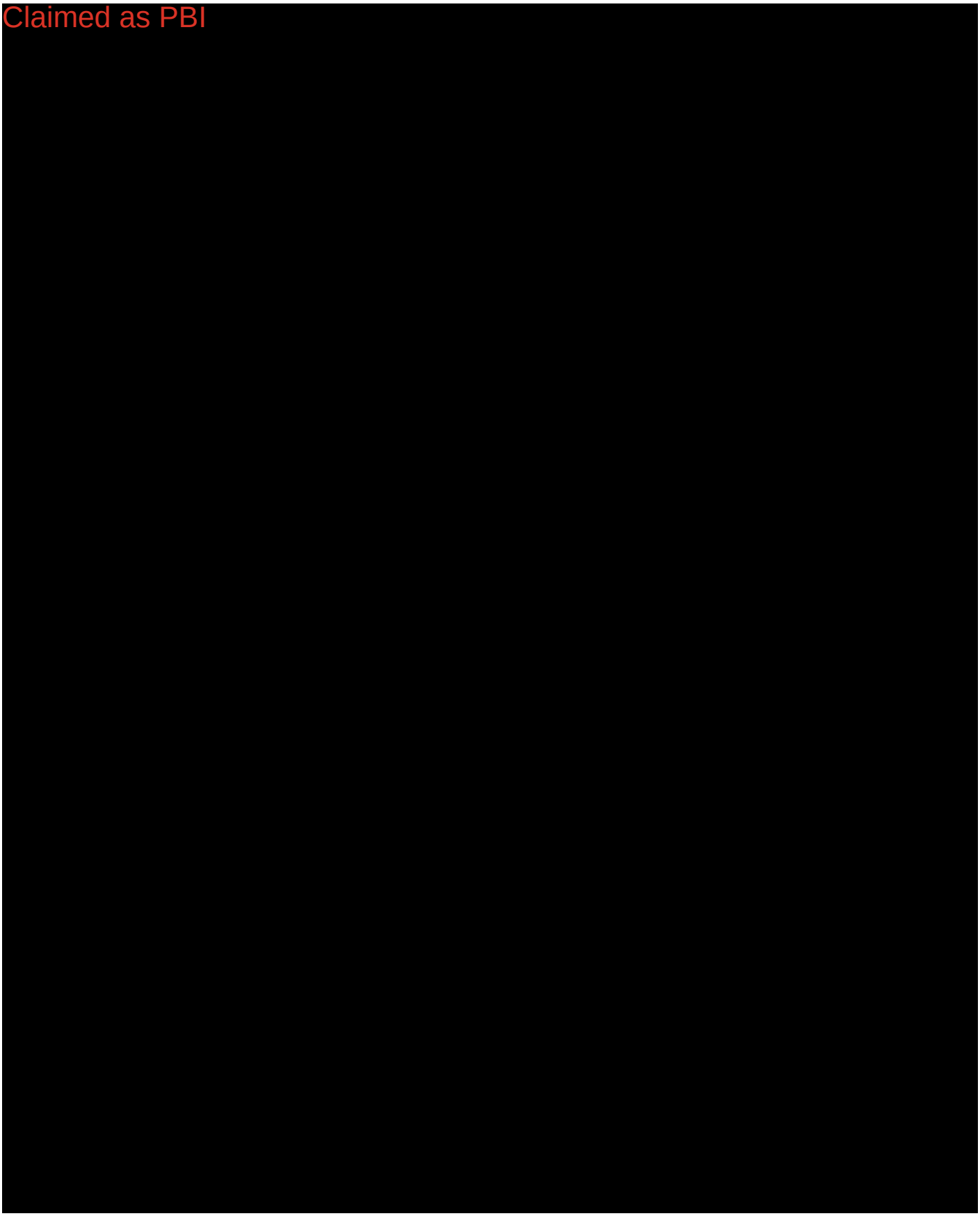
Wells Penetrating the Confining Zone

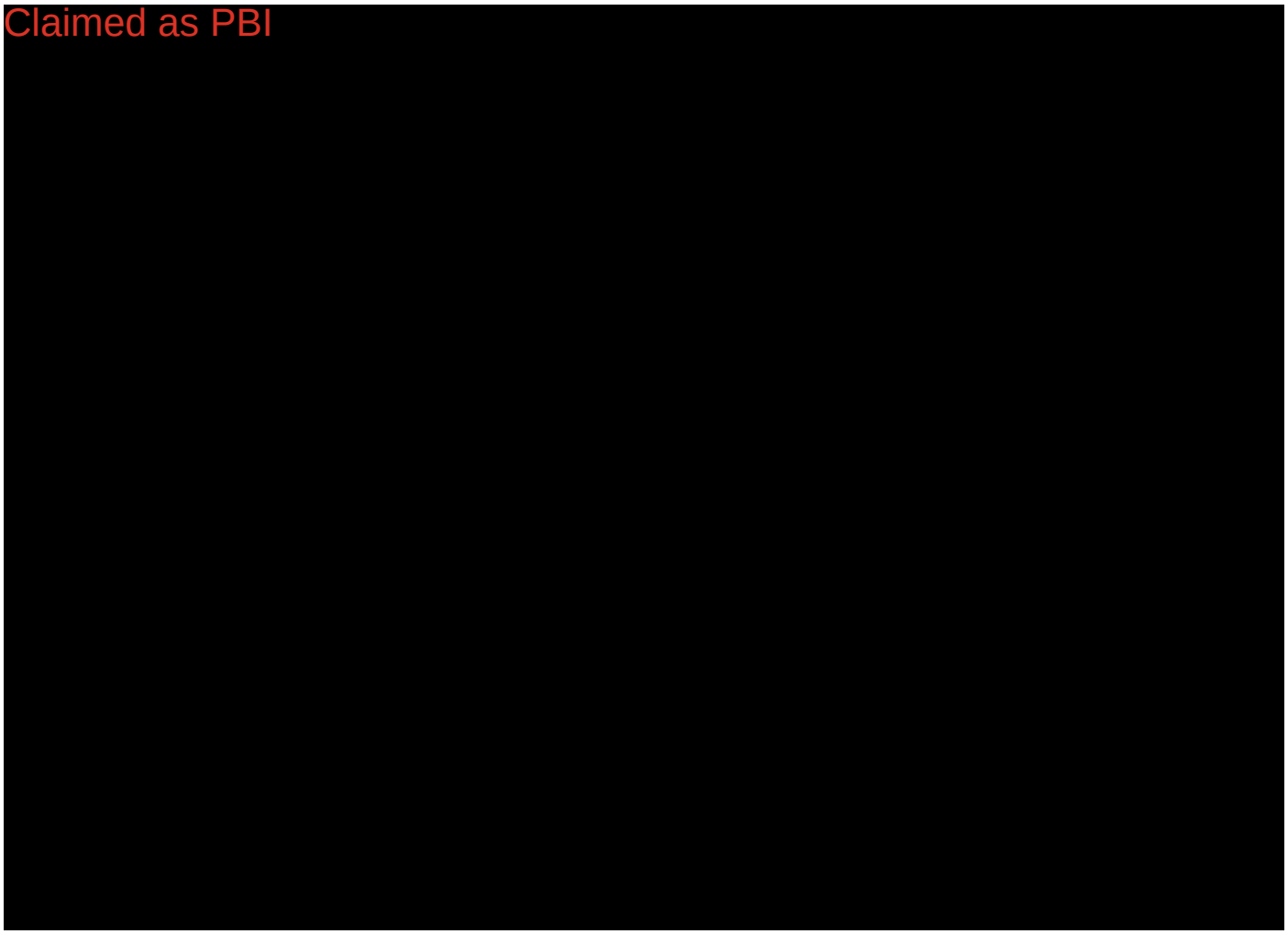
The seven (7) artificial penetrations identified in the AOR with penetration depths penetrating the confining zone were determined based on database records research. Subsurface interpretation of the top of the confining zone and top of the injection zone were documented for each well penetration. This 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

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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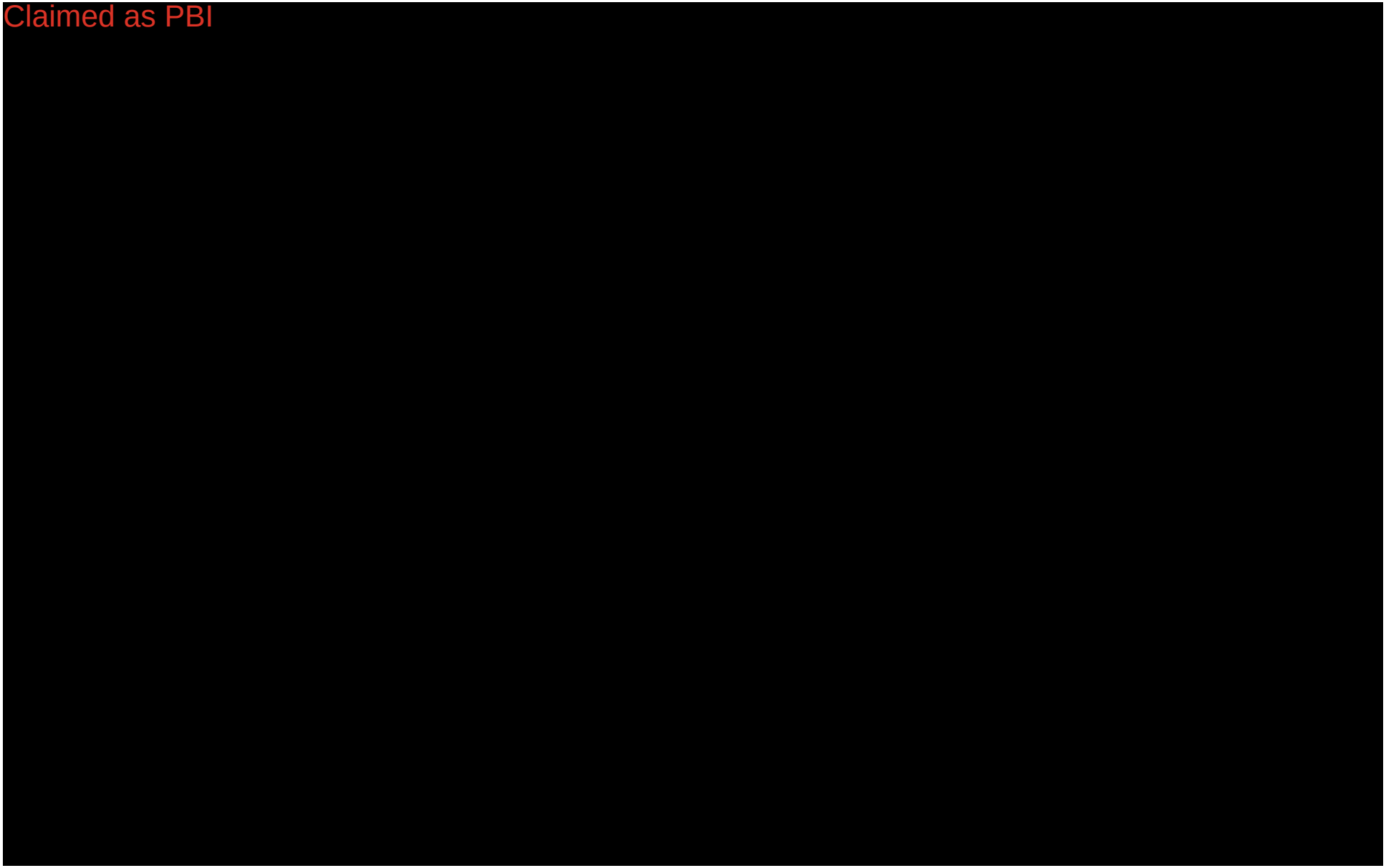
Plan revision number: 003
Plan revision date: September 2026

Claimed as PBI

Claimed as PBI

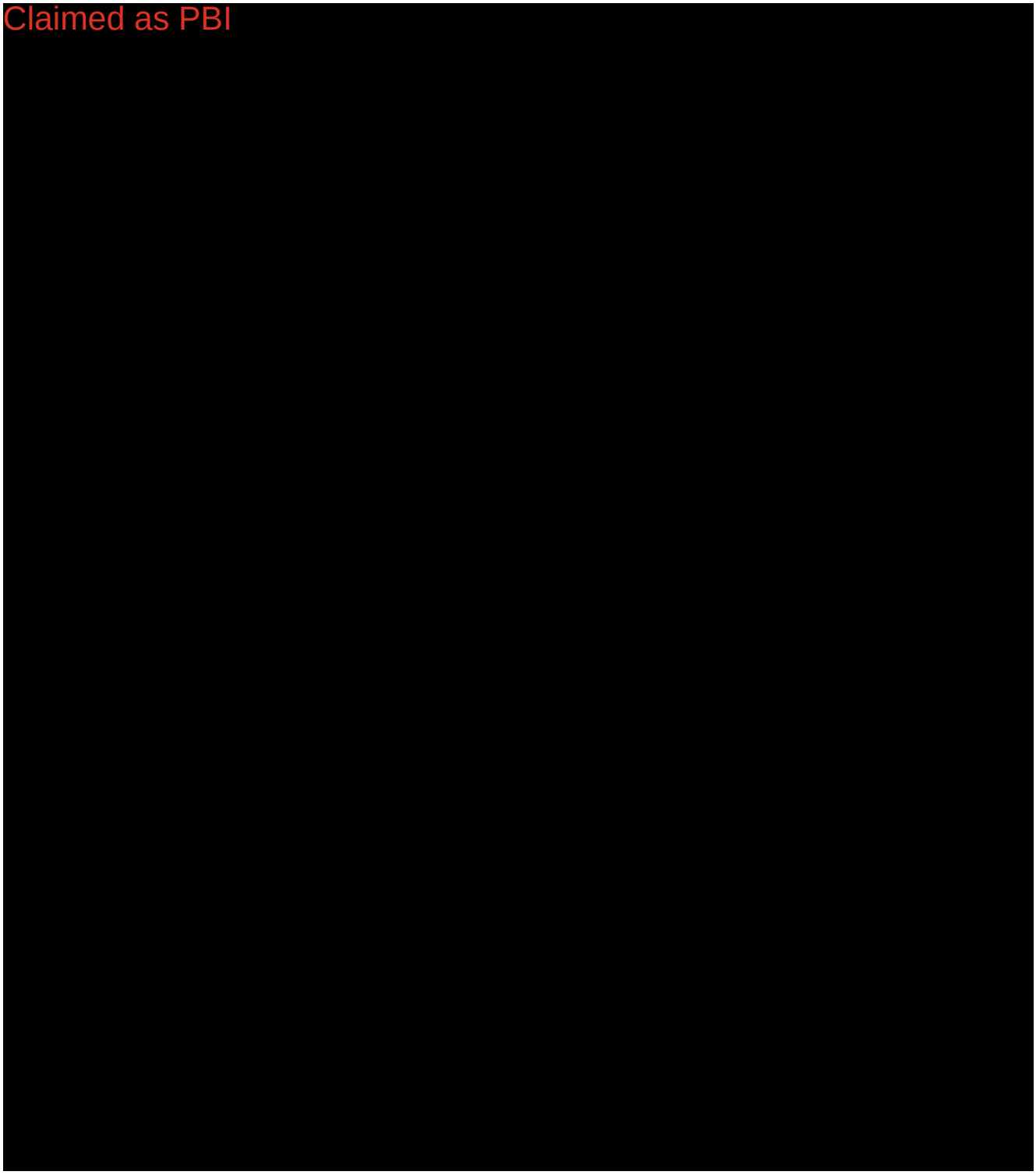


Plan revision number: 003
Plan revision date: September 2026

Claimed as PBI



Claimed as PBI



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Plan revision date: September 2026

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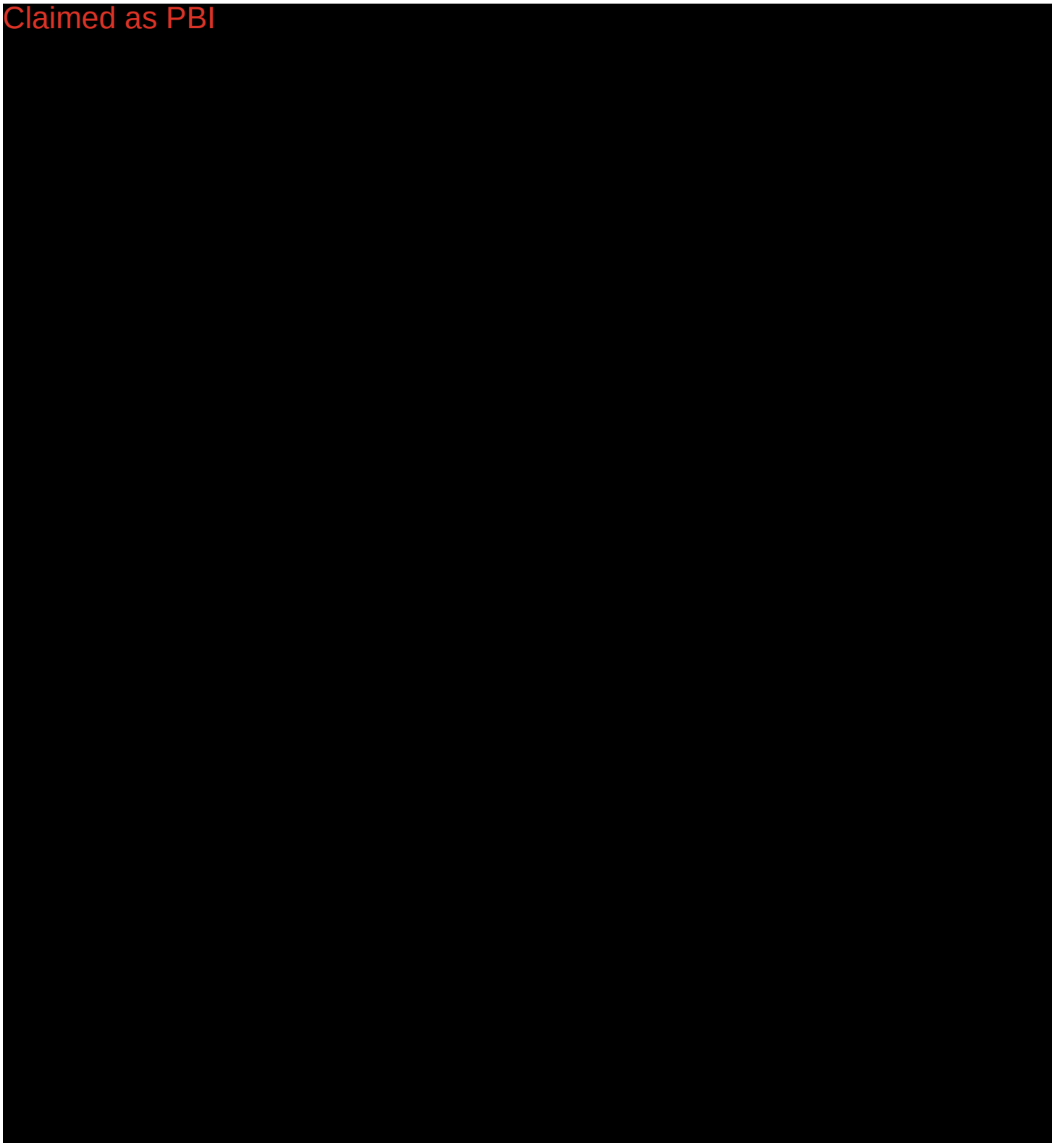

B. Well Construction Plans

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°

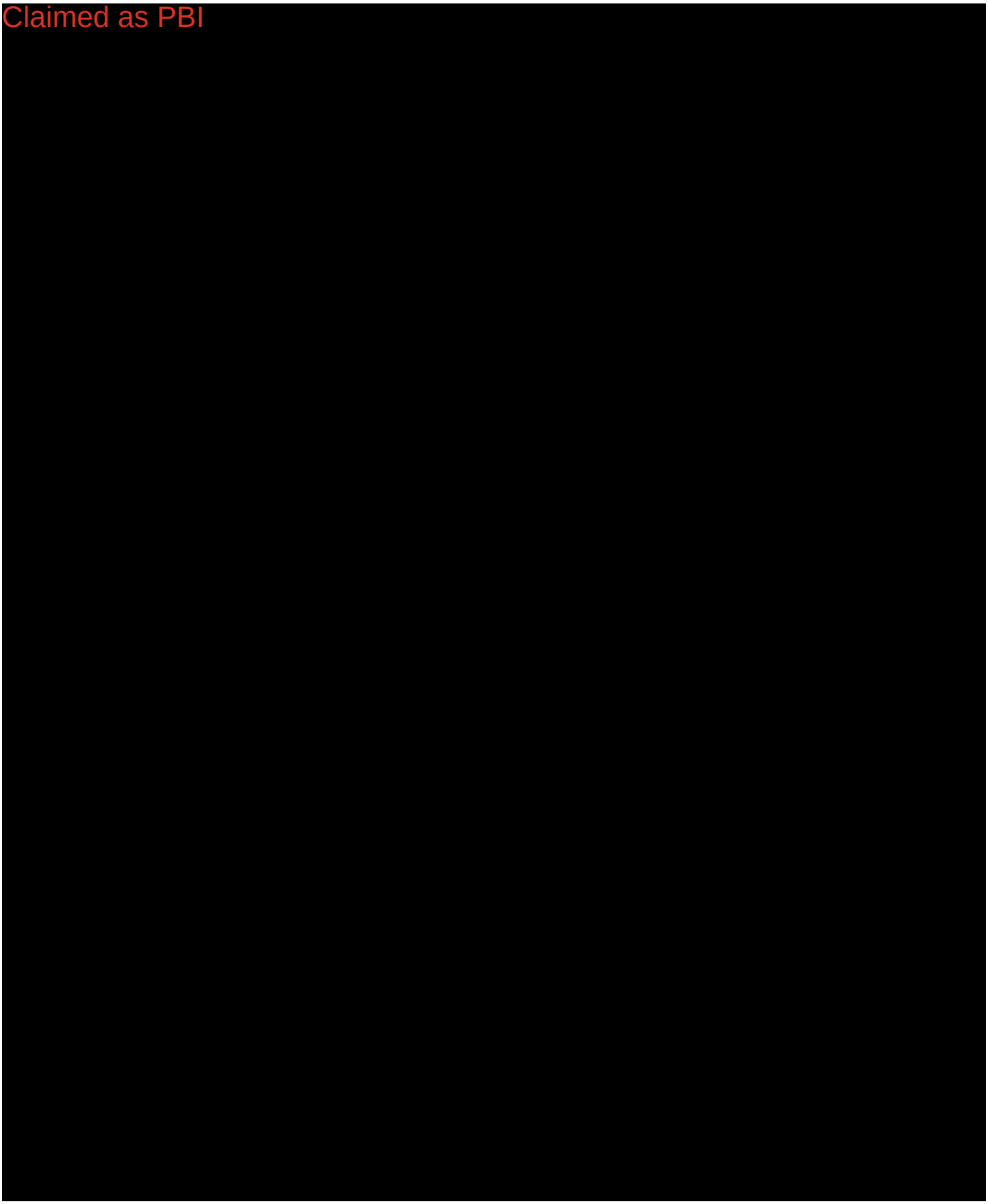
Claimed as PBI



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.

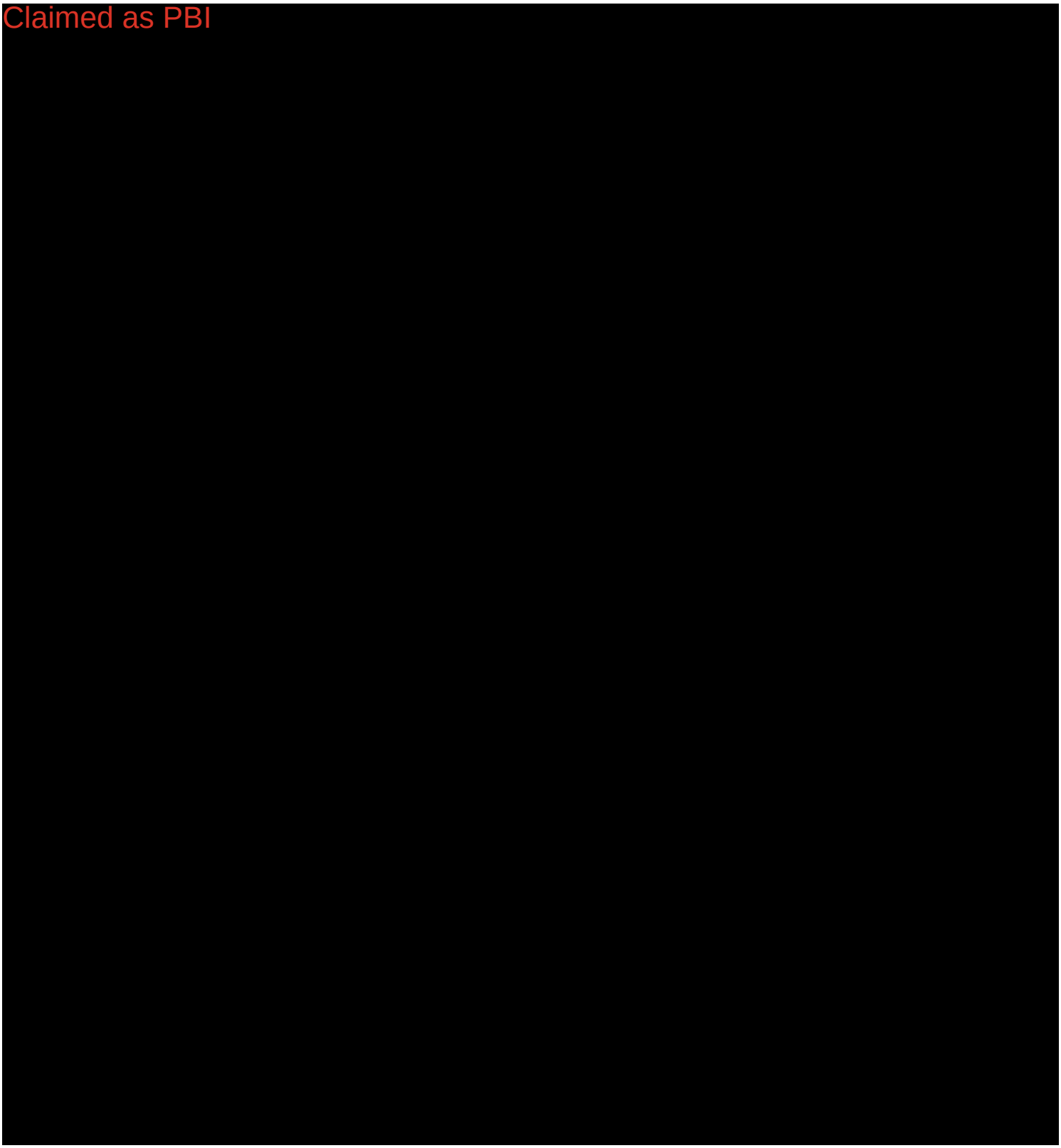
5.3 W2 - Injection Well Construction Details

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

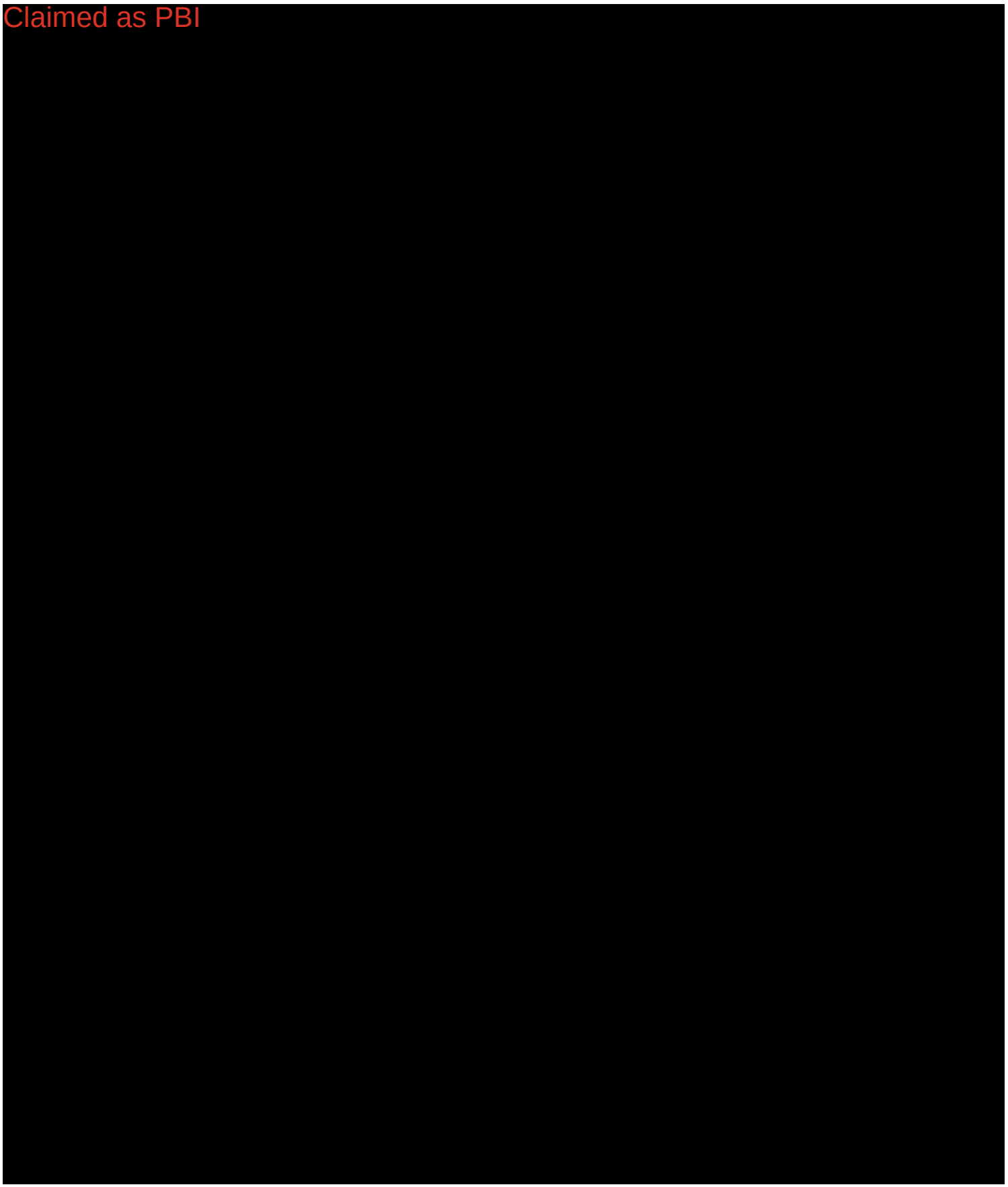


Claimed as PBI



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



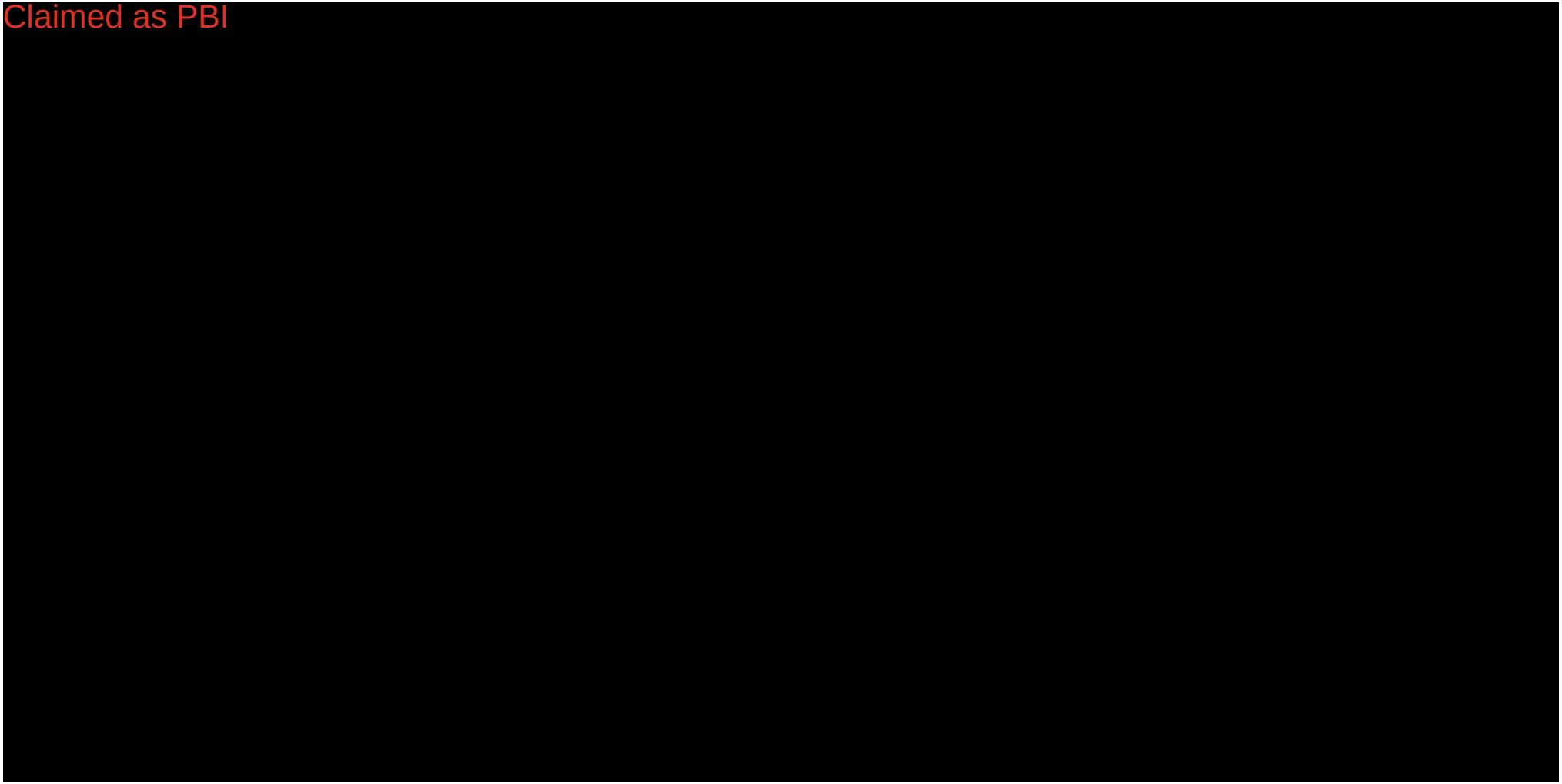
Claimed as PBI



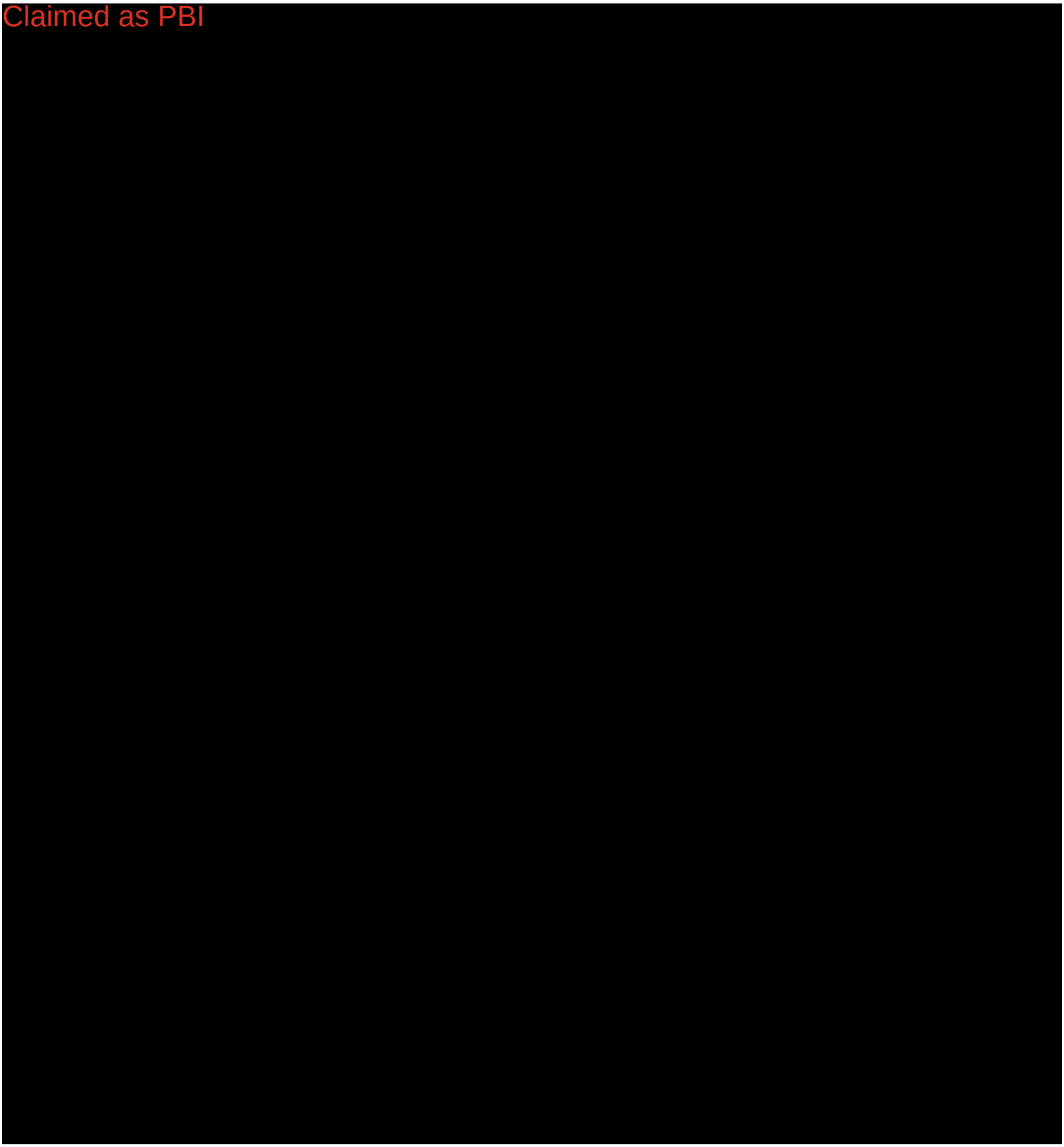
Claimed as PBI



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°

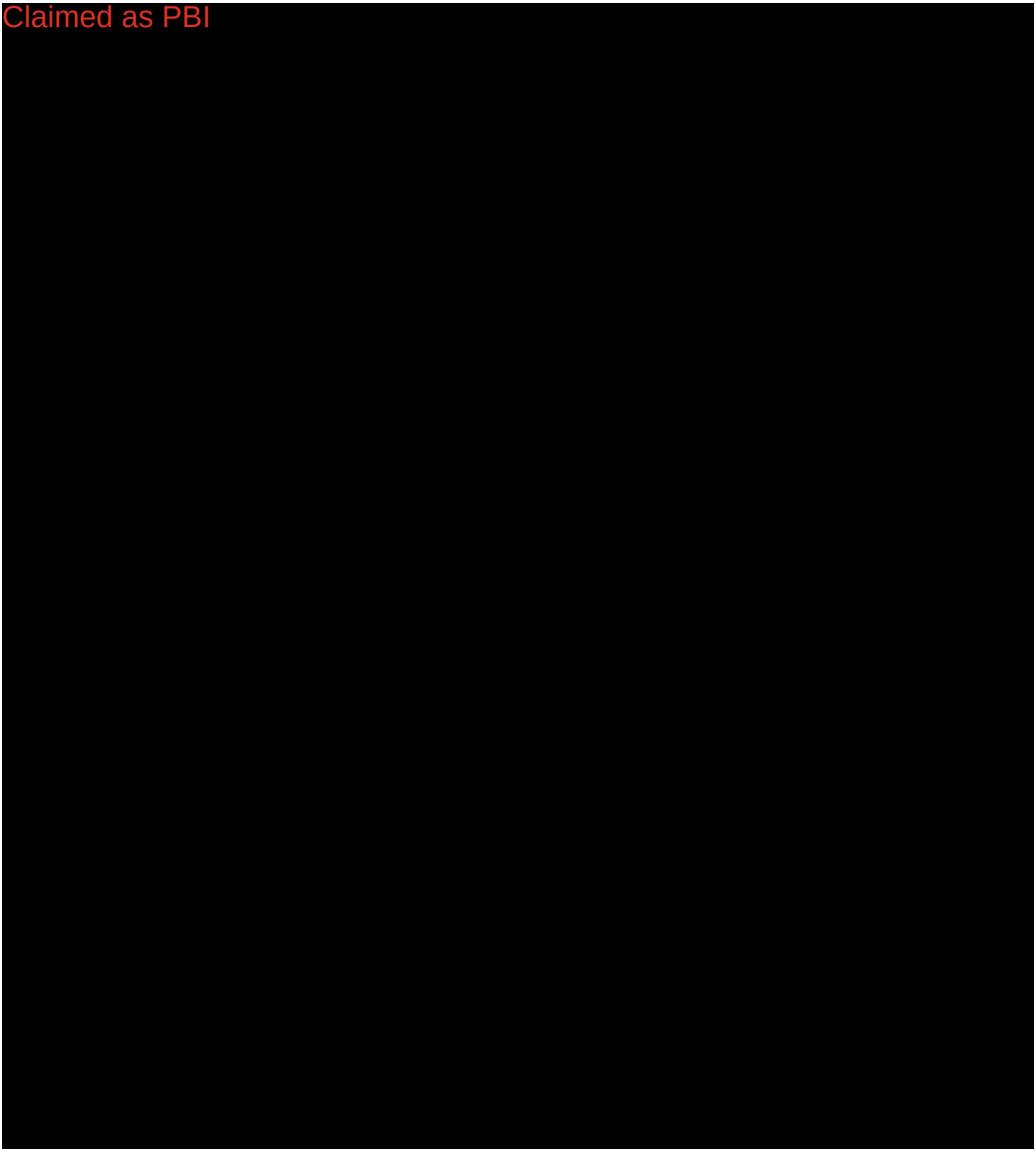
BHL Lat: 29.6039239°

BHL Long: -93.88184566°

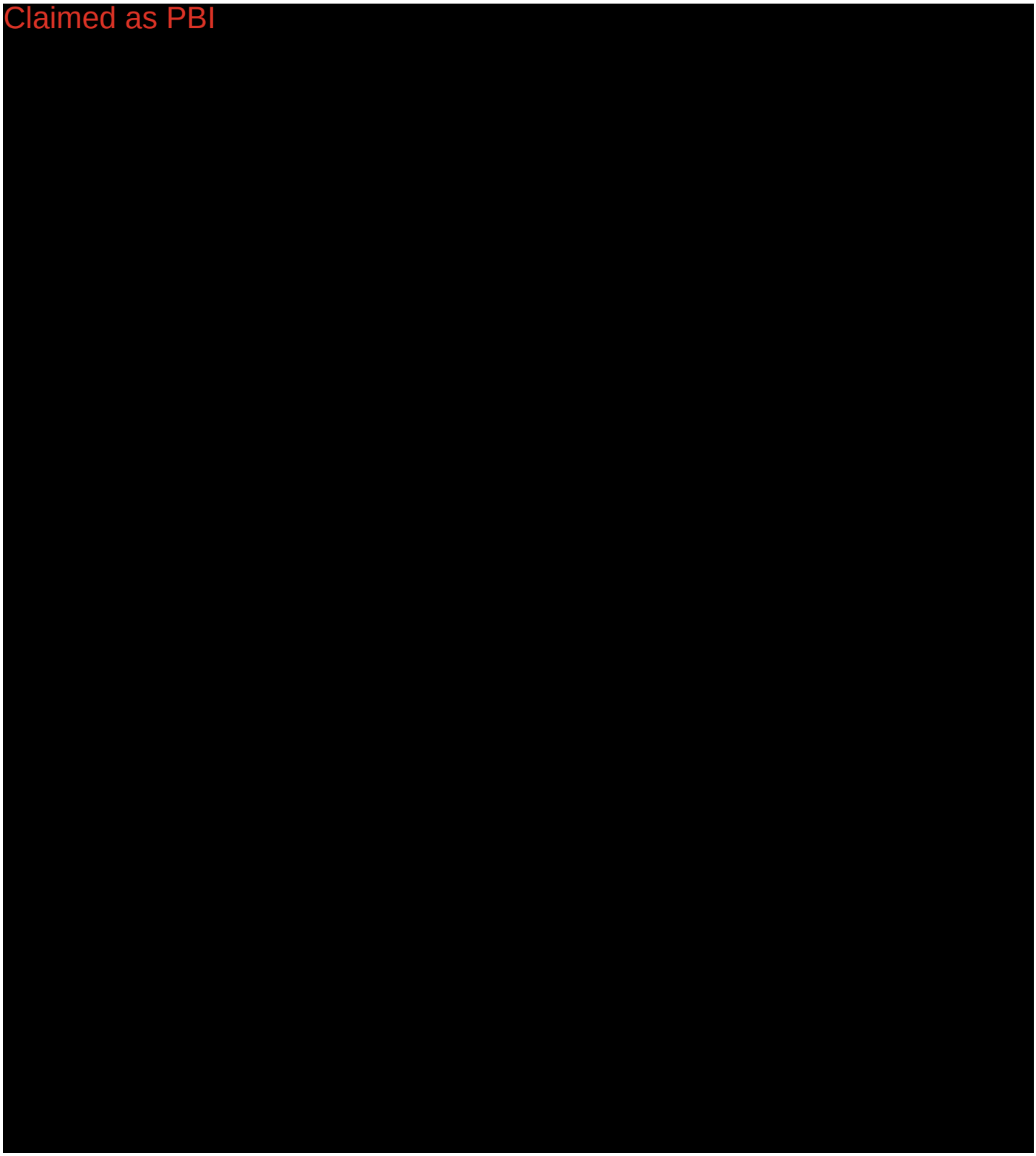
Claimed as PBI



Claimed as PBI



Claimed as PBI



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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

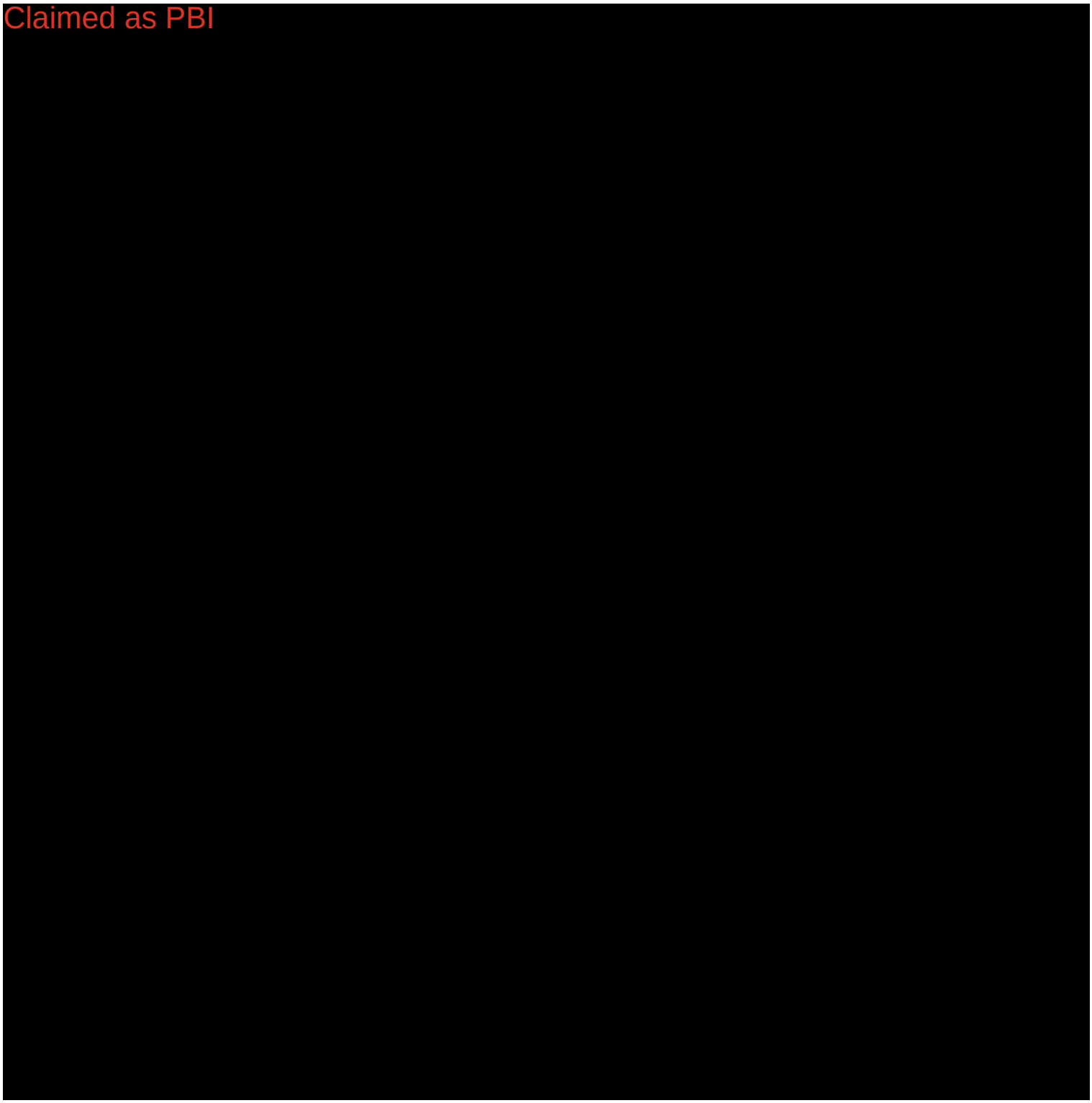
Surface X: 29.59200921°

Surface Y: -93.89523621°

BHL X: 29.59215342°

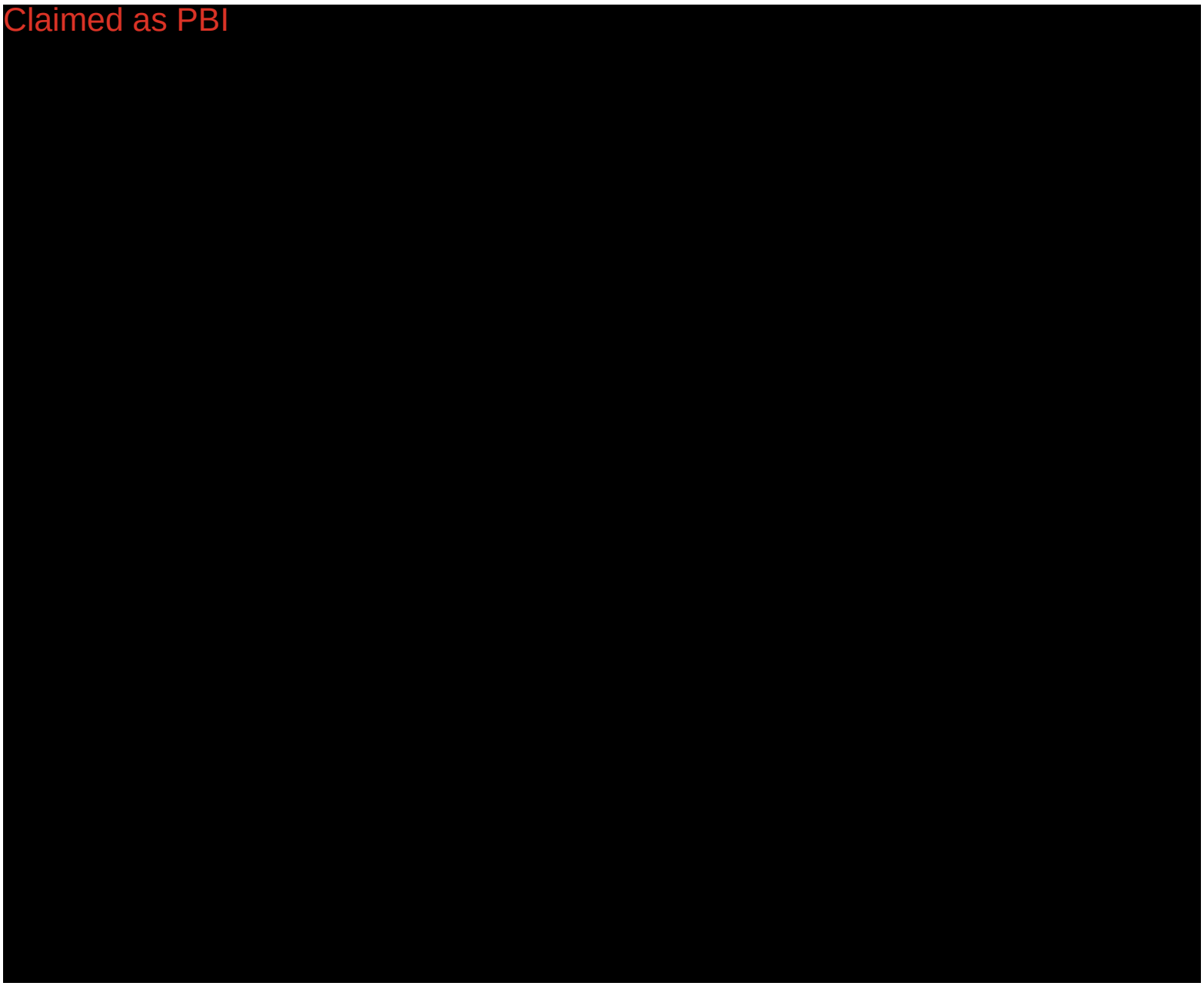
BHL Y: -93.87566908°

Claimed as PBI




Claimed as PBI

Claimed as PBI



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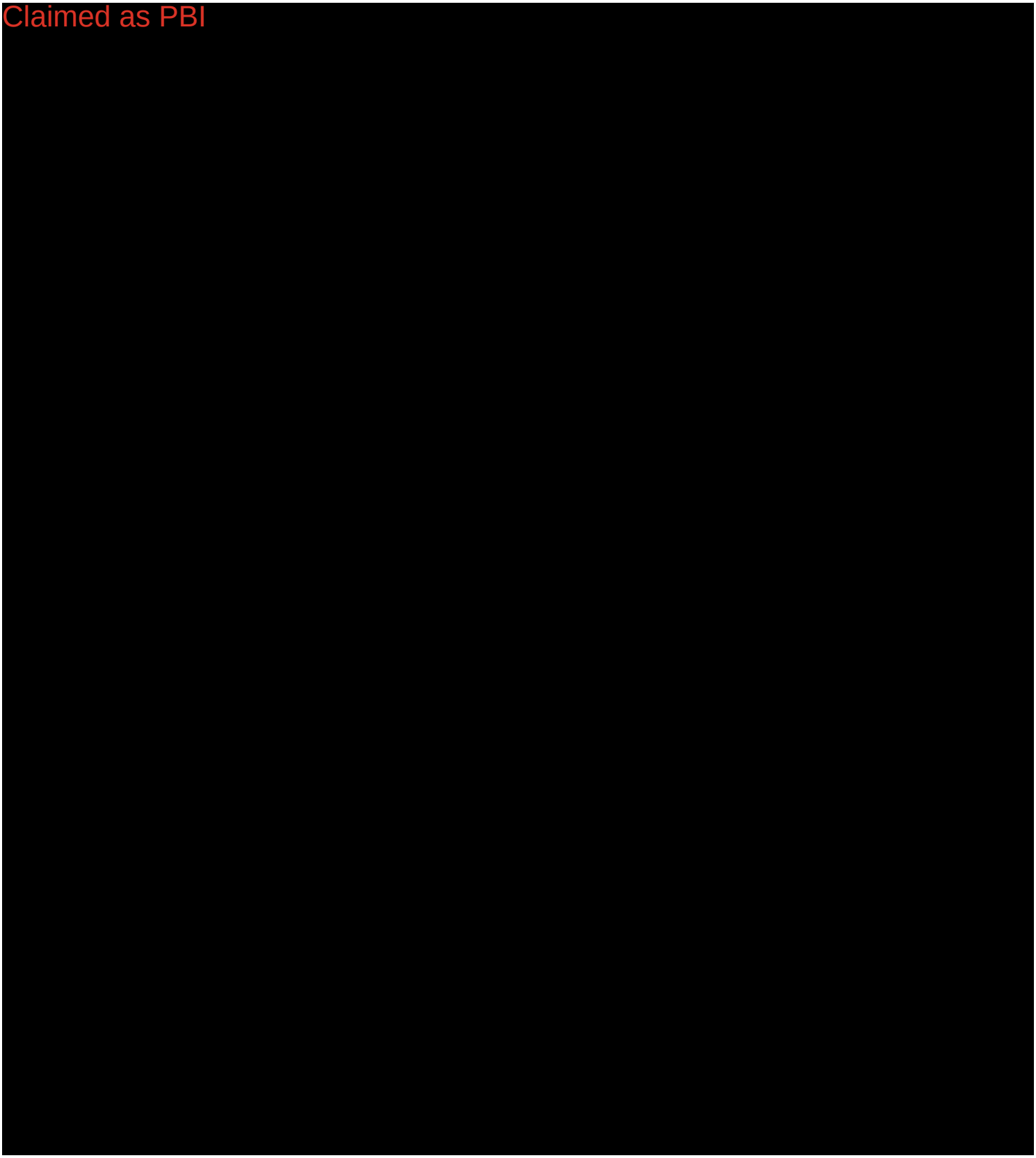

C. Stimulation Plan

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

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

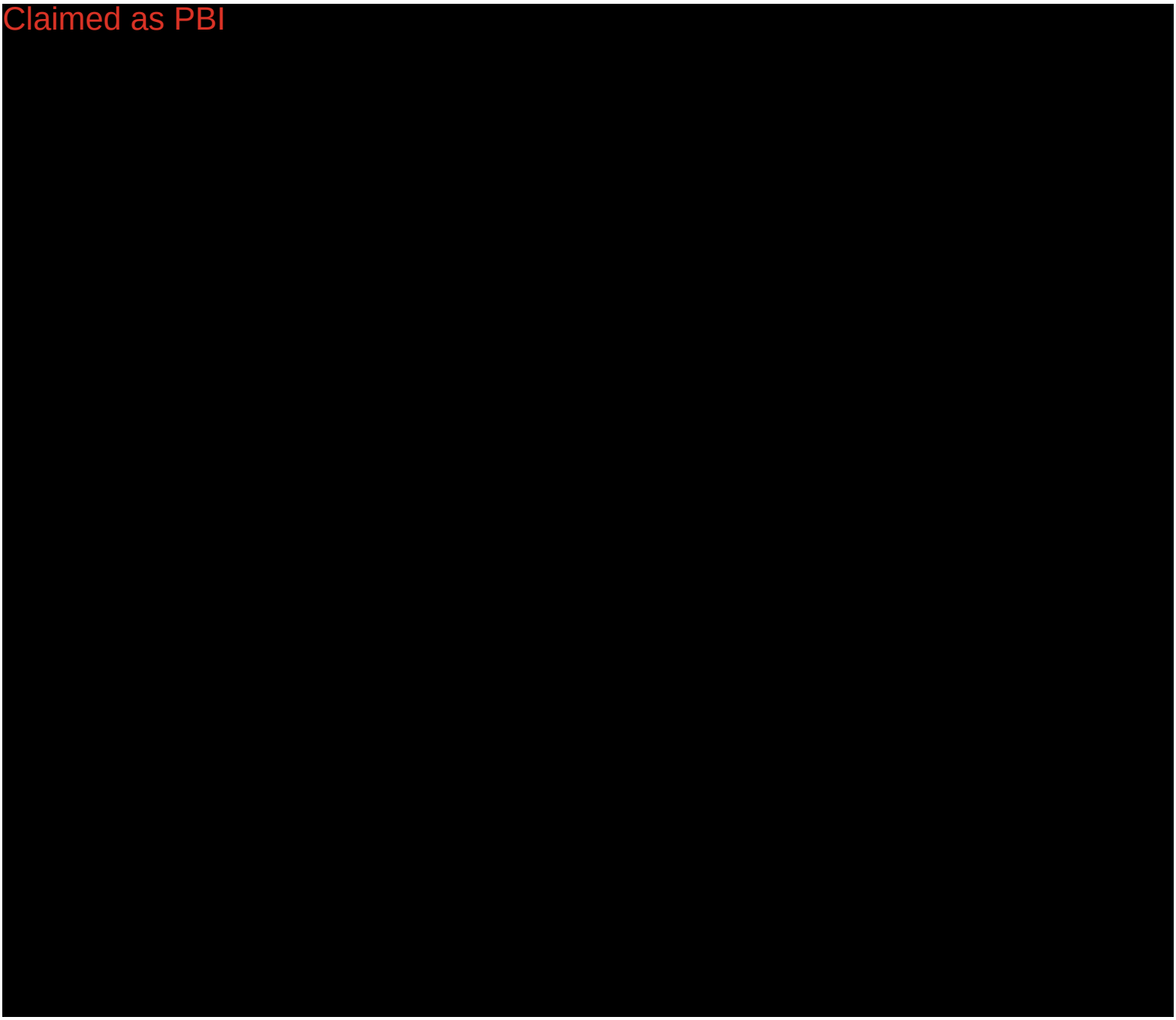
Claimed as PBI



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



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

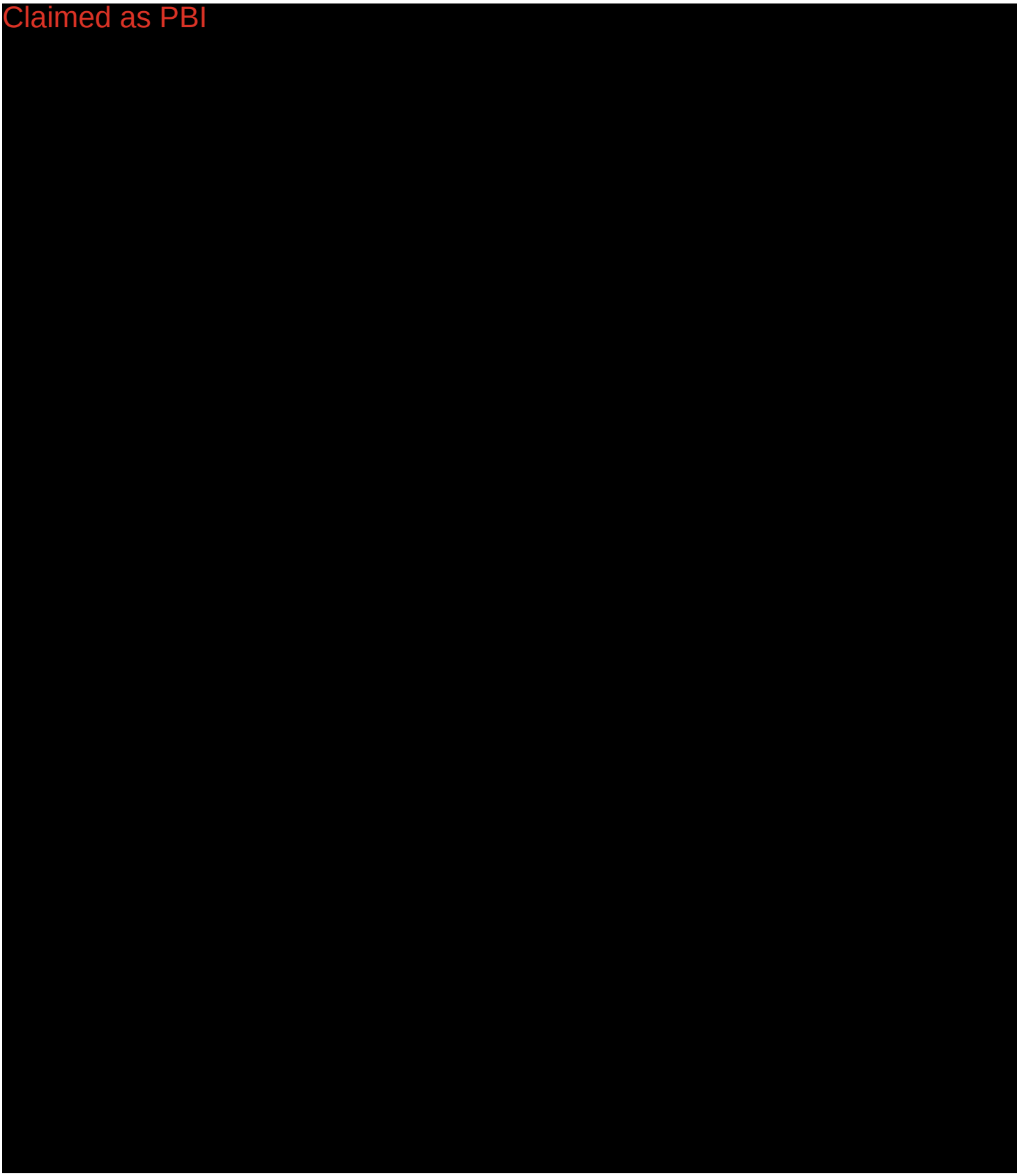
Performed during drilling

Claimed as PBI

[redacted]

Revision number: 002
Plan revision date: July 2026

Claimed as PBI



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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Figure 7-3: Proposed indirect seismic monitoring of the BBE-P1 CO_2 saturation front. A pre-injection surface seismic survey covers the core acreage. During injection 3D DAS VSP and 2D seismic lines will be acquired, extending the DAS coverage with 2D seafloor nodes (OBS). Post-injection 2D OBS will be acquired. Pre- and post-injection surveys will be compared for time-lapse responses. 21

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



Claimed as PBI

[redacted]

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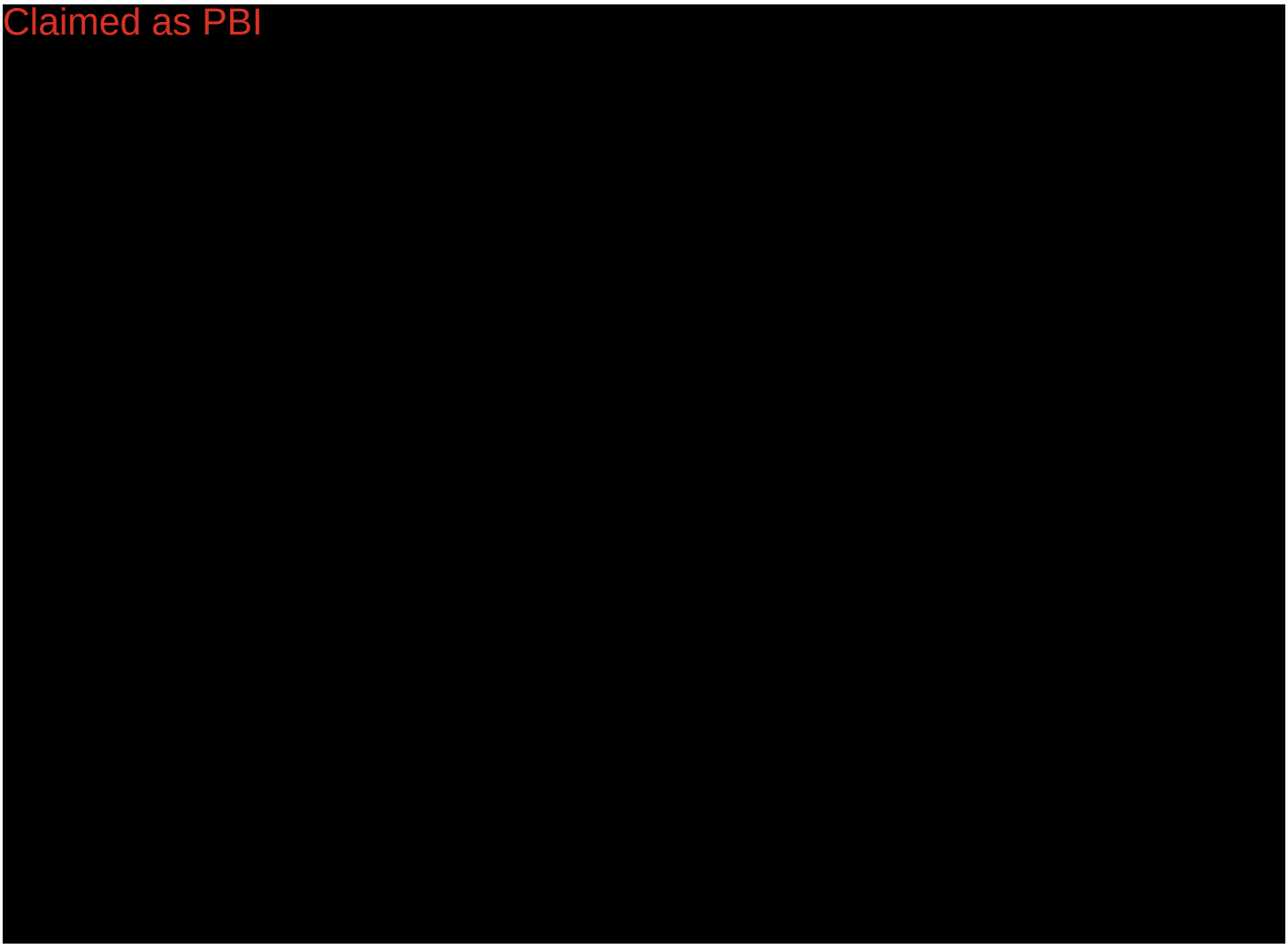


7.3.3 Monitoring Network Design and Strategy

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

Claimed as PBI

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

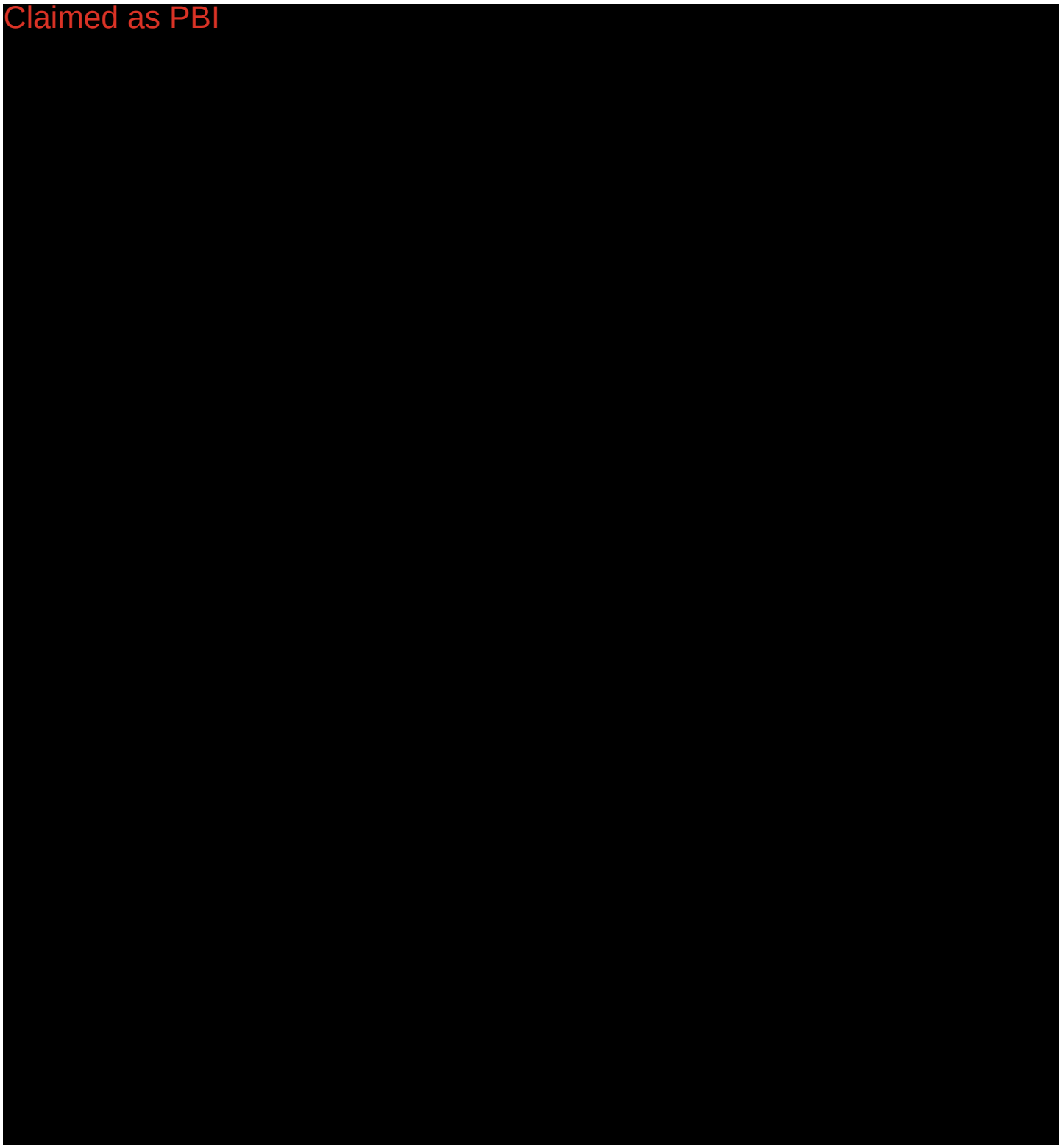
The Operator will perform the activities Claimed as PBI [redacted] operational parameters and verify internal mechanical integrity of the injection well. Monitoring will take place at the locations and frequencies shown in the table.

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]

Plan revision number: 002
Plan revision date: July 2026

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).

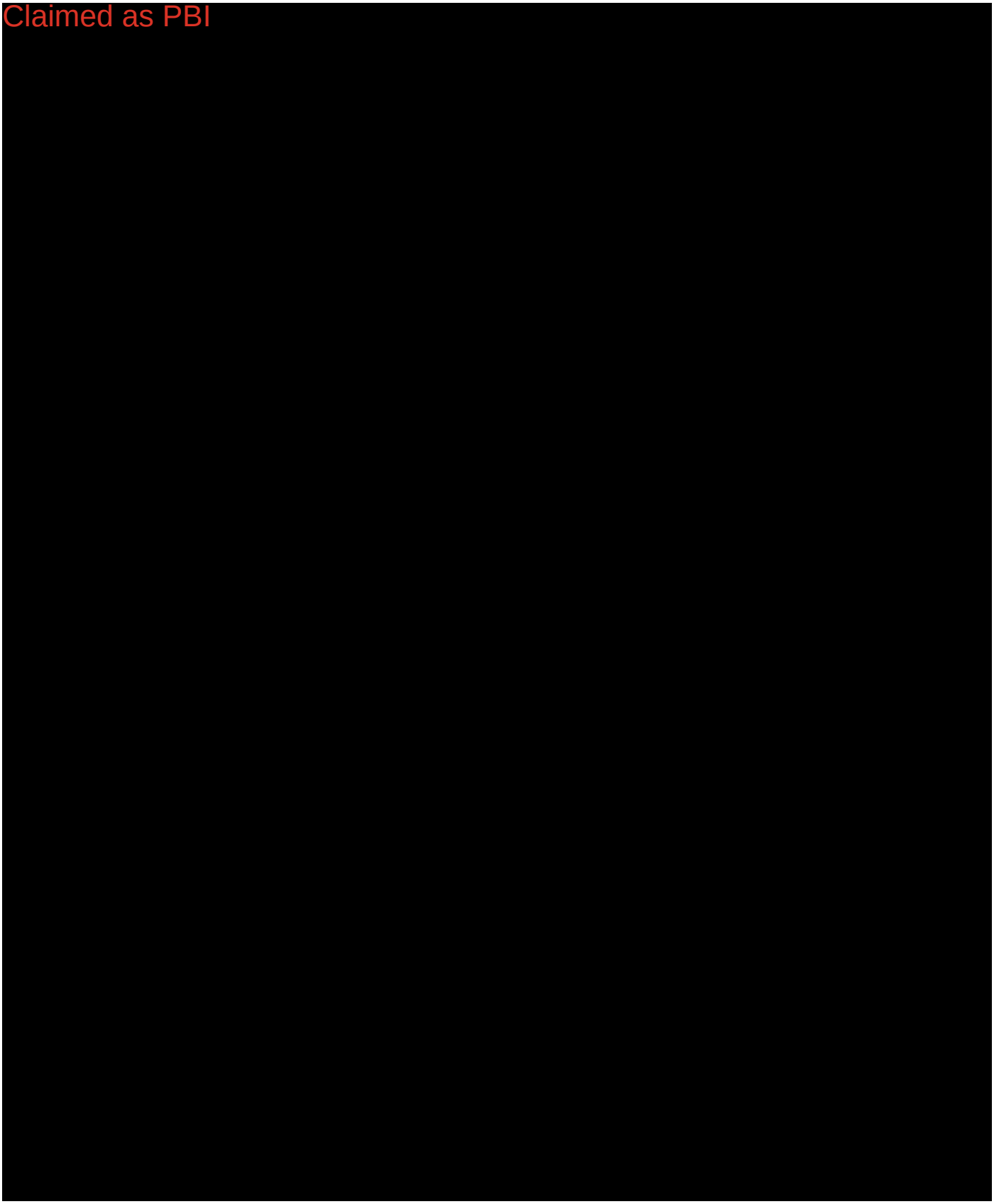
7.7.1 Monitoring location and frequency

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**).

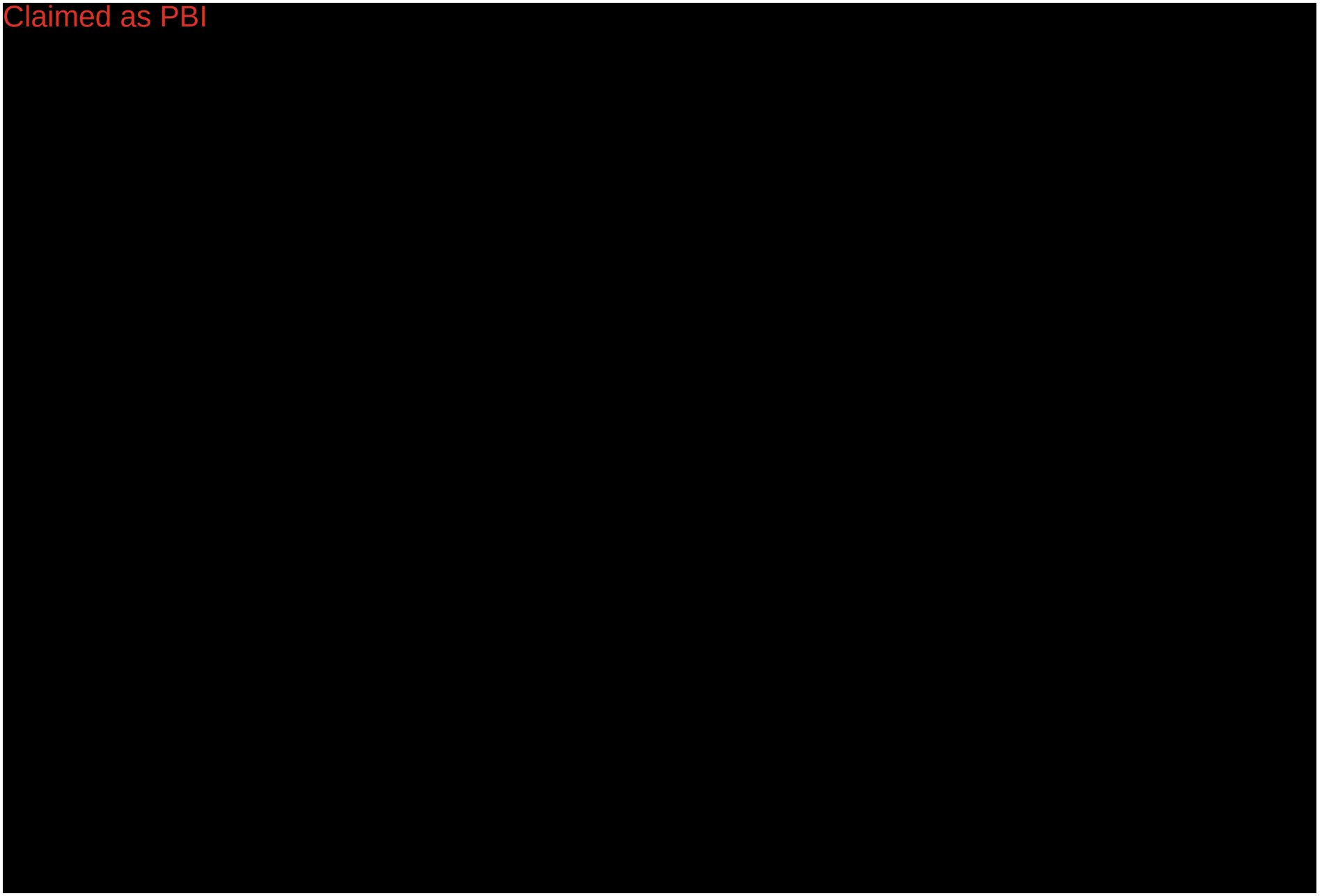
7.10.1 Saturation front monitoring location and frequency

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

[redacted]

[redacted]

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.

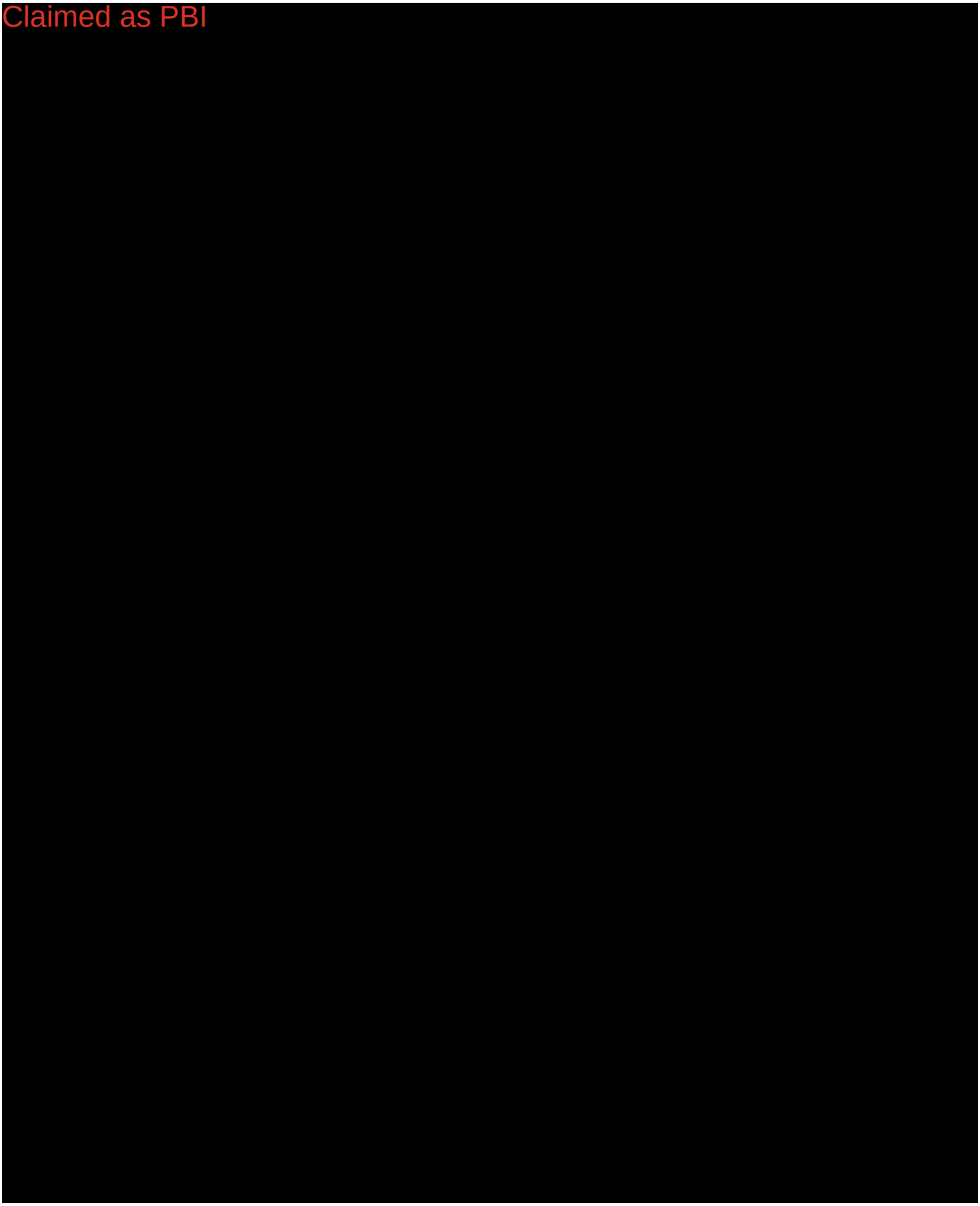
8.6.2 Plugging Procedures

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.

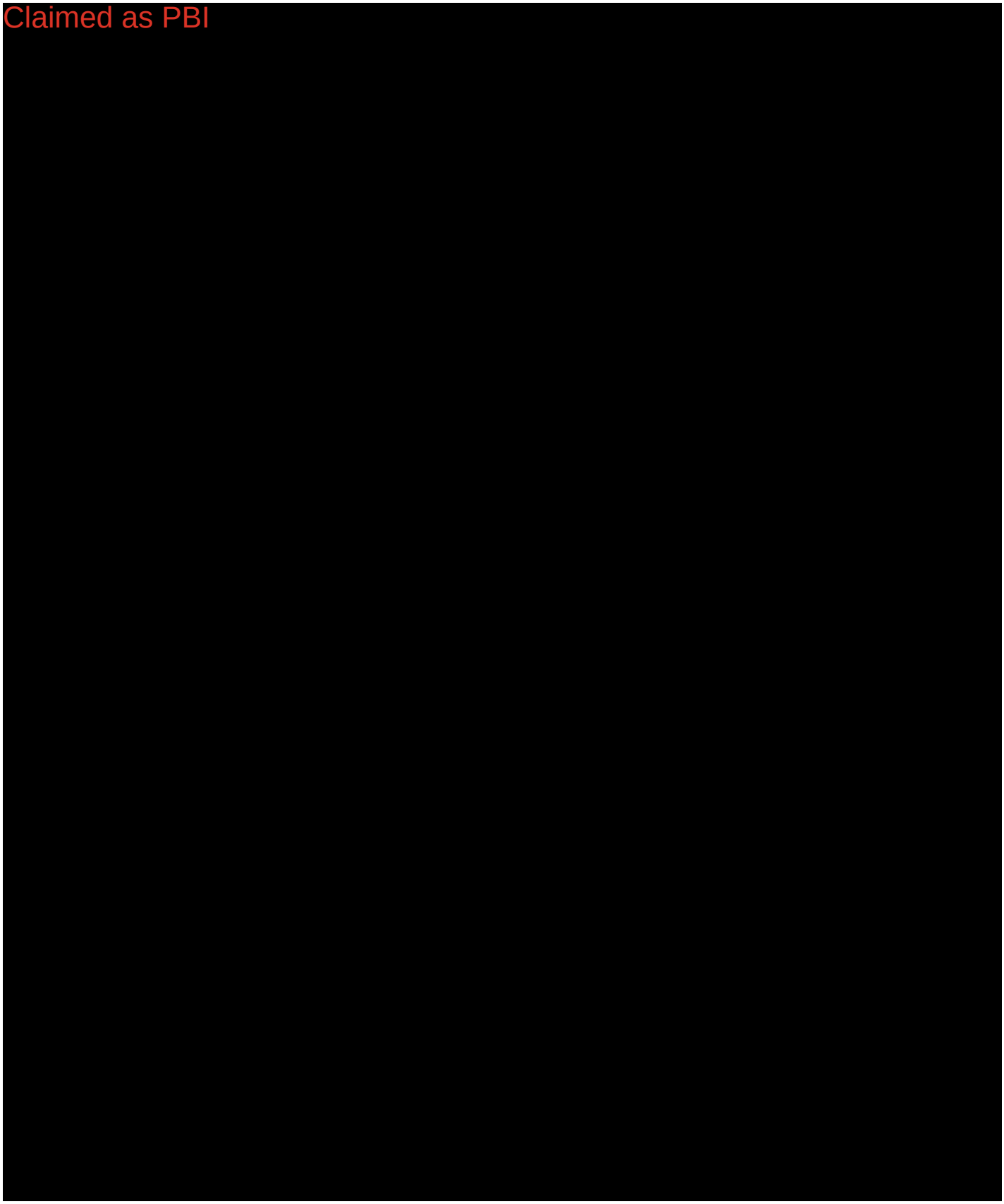
Claimed as PBI

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

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.

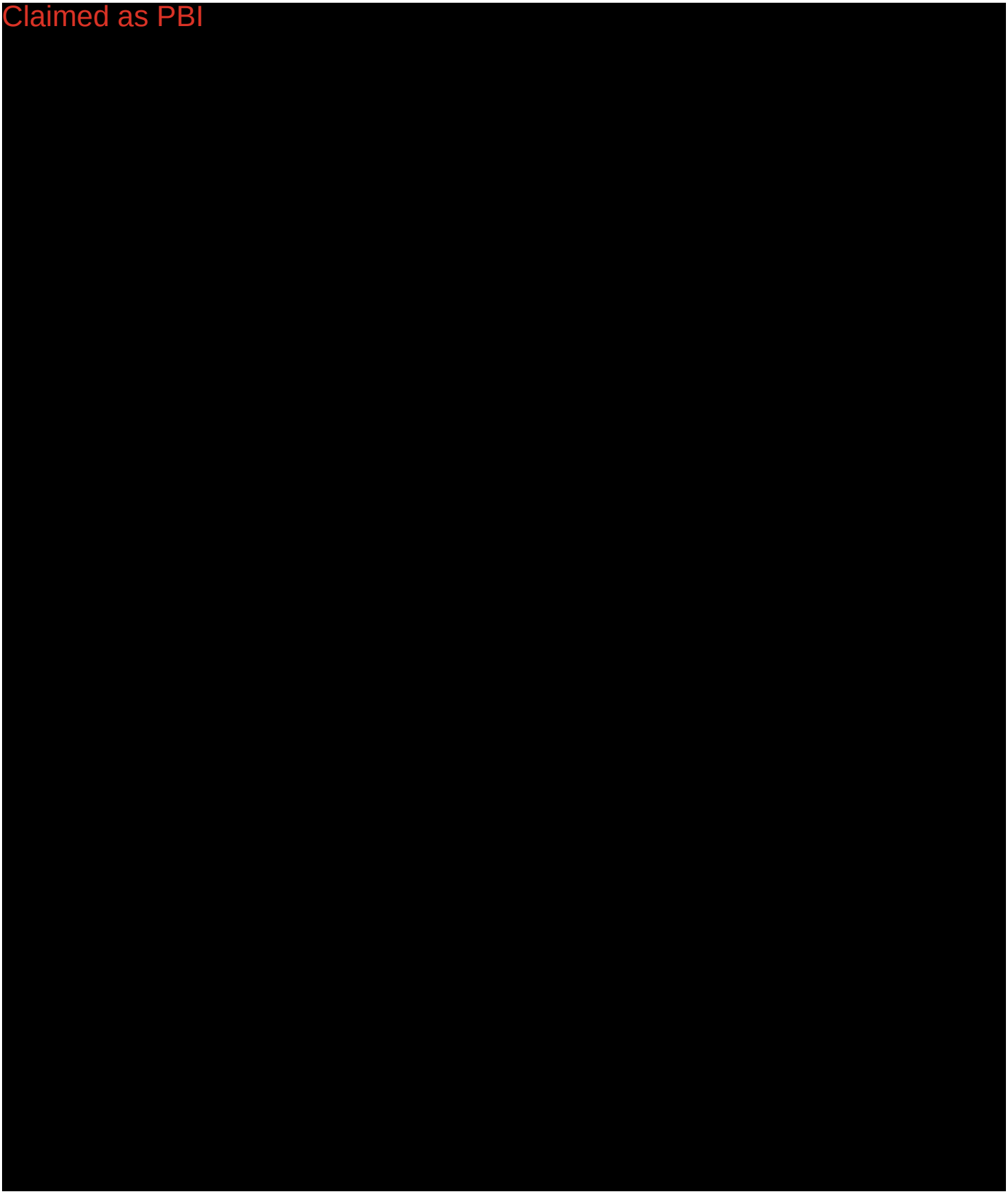
8.6.2 Plugging Procedures

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.

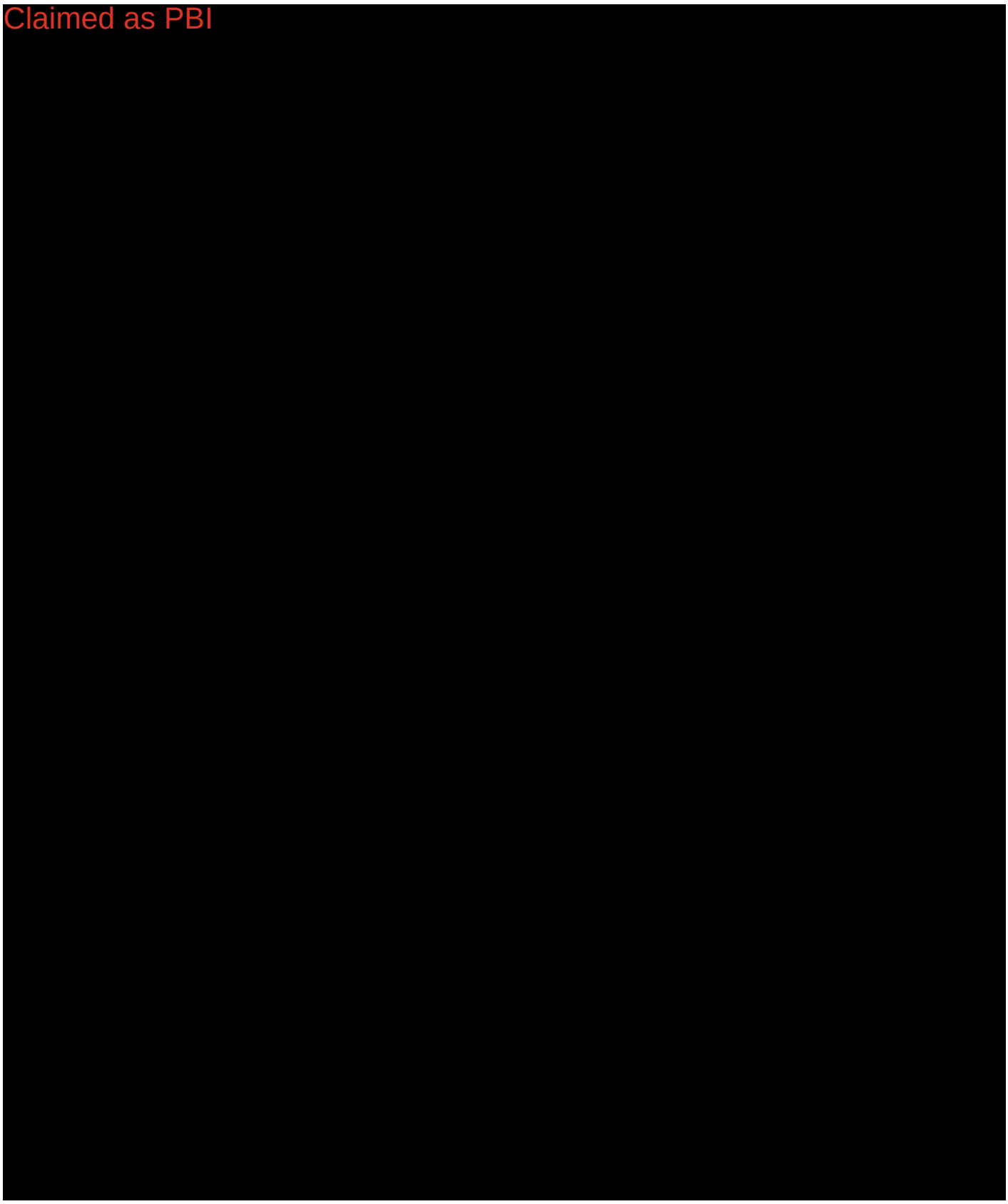
Claimed as PBI

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.

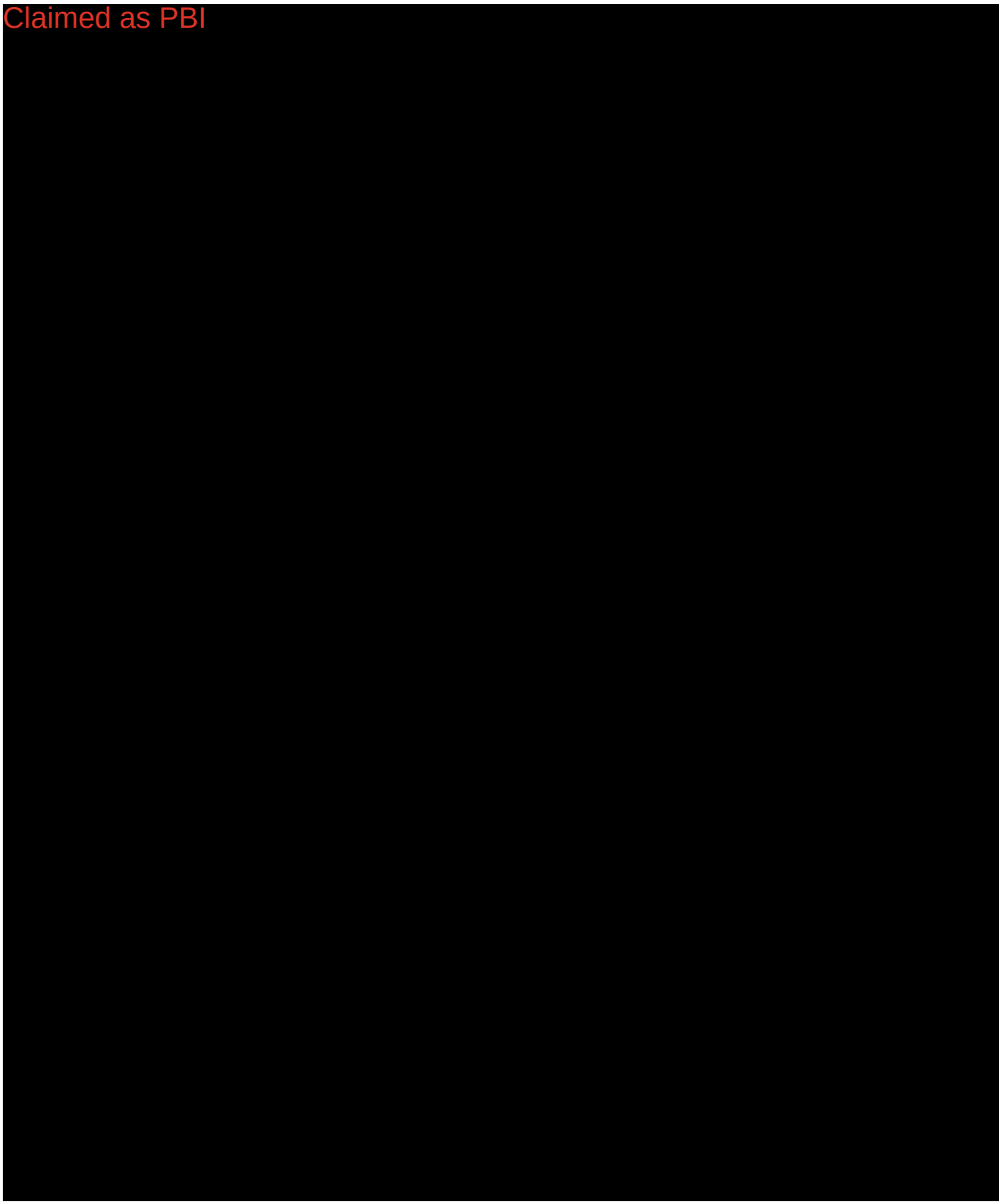
8.6.2 Plugging Procedures

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

[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 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.

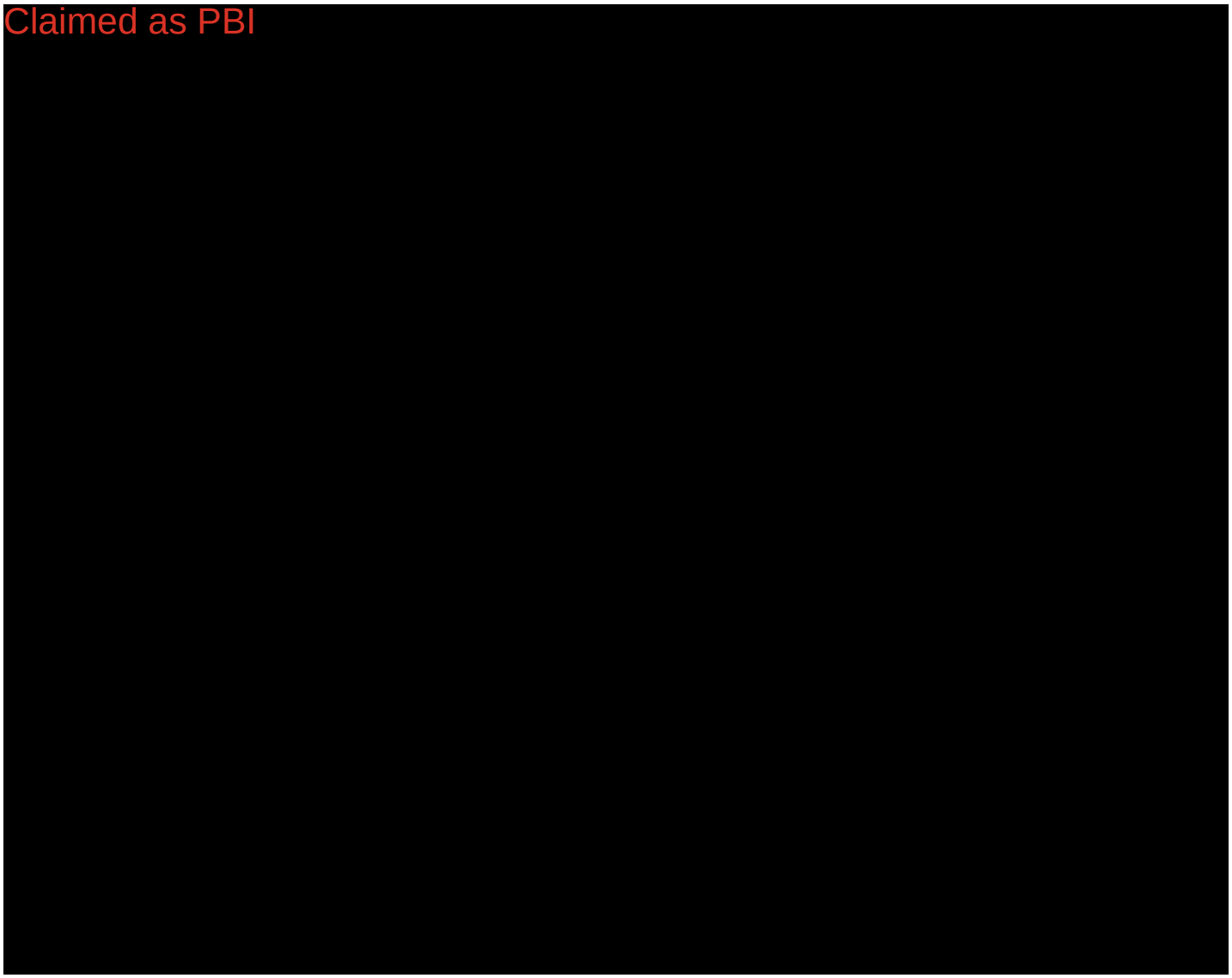
Advance notice will also be provided to the Texas General Land Office, the United States Coast Guard, and other stakeholders who might be impacted by plugging and abandonment operations.

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.

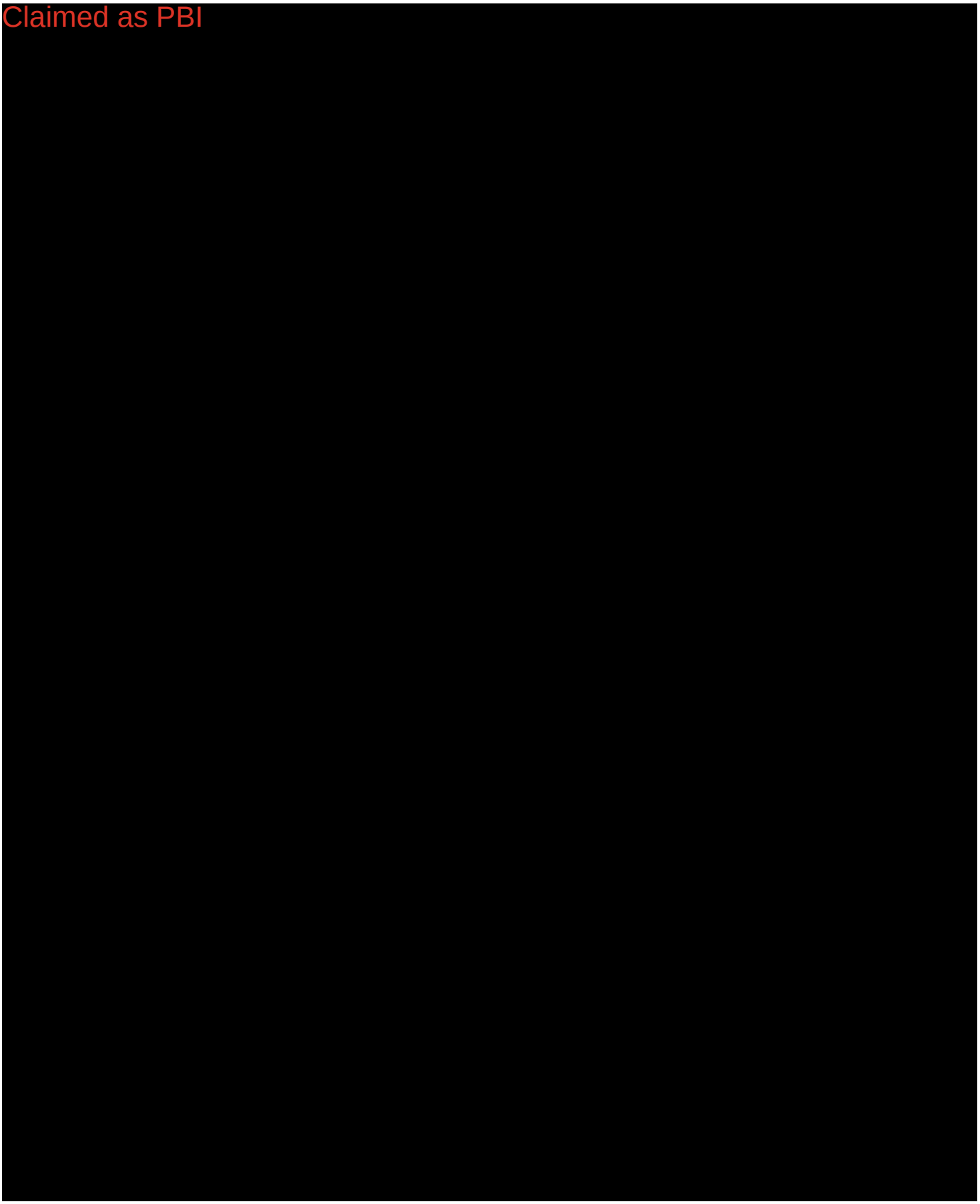
8.7.2 Plugging Procedures

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.

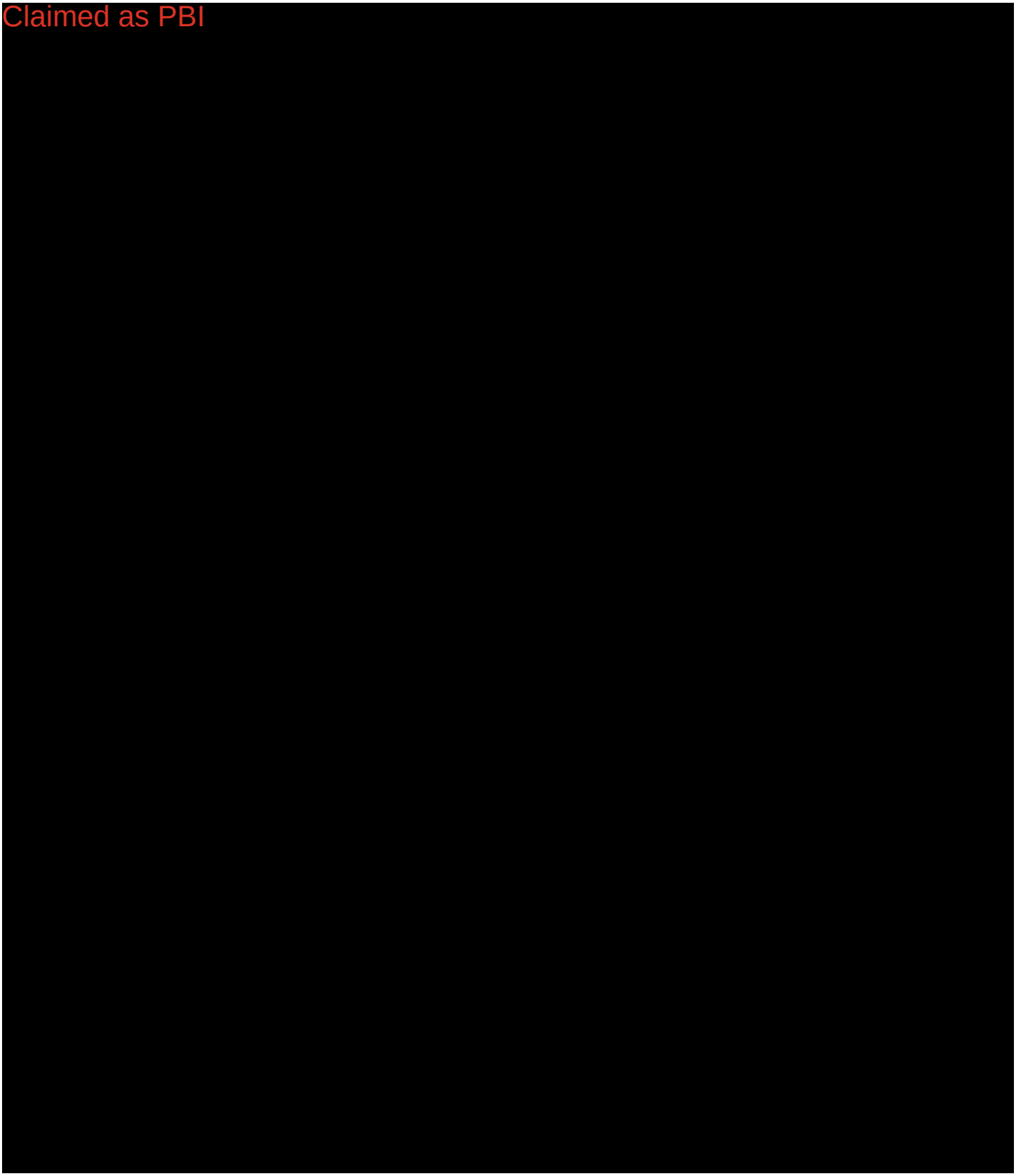
Advance notice will also be provided to the Texas General Land Office, the United States Coast Guard, and other stakeholders who might be impacted by plugging and abandonment operations.

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

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:

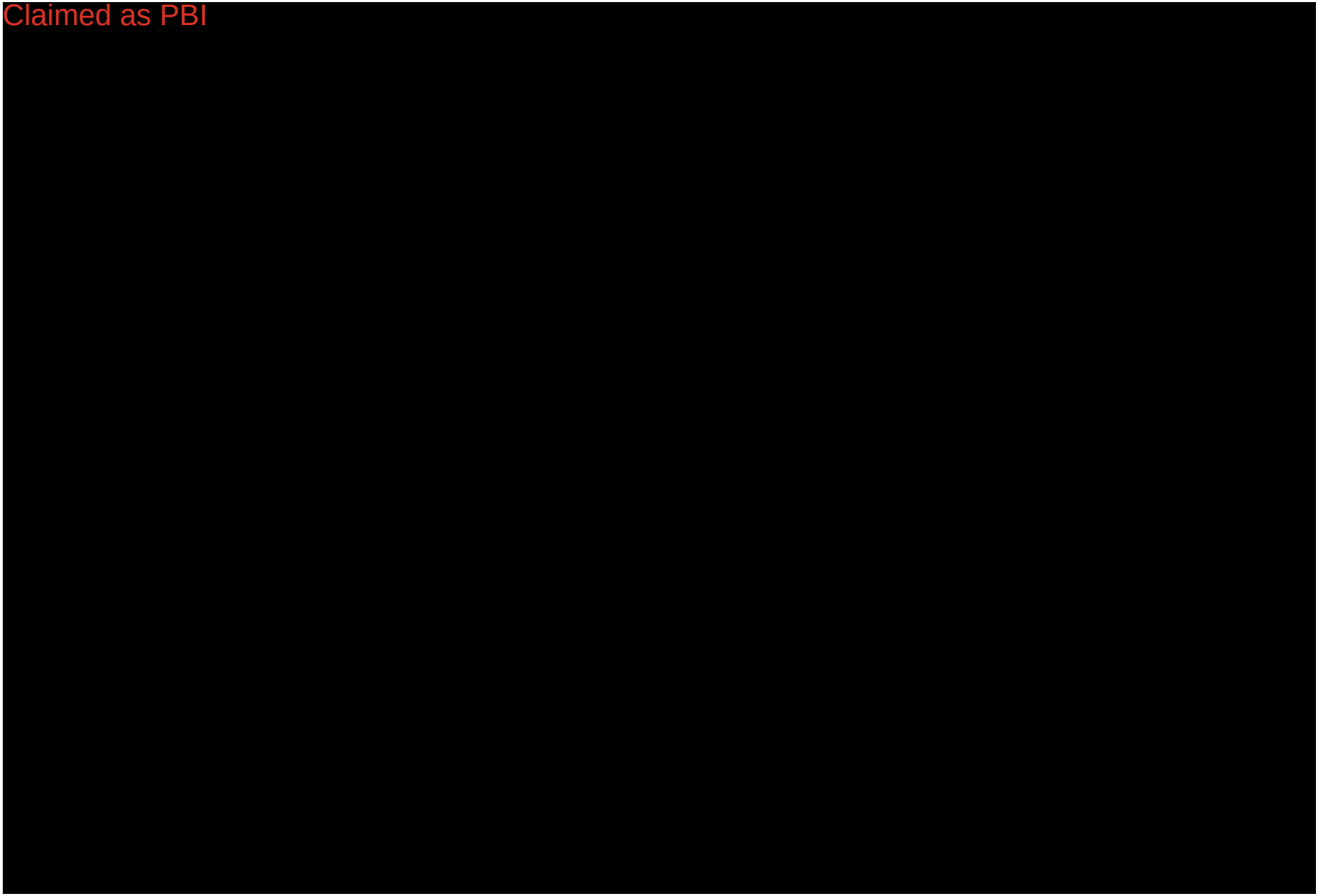
- Cultural Artifacts.
- Threatened and Endangered Species

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.

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[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

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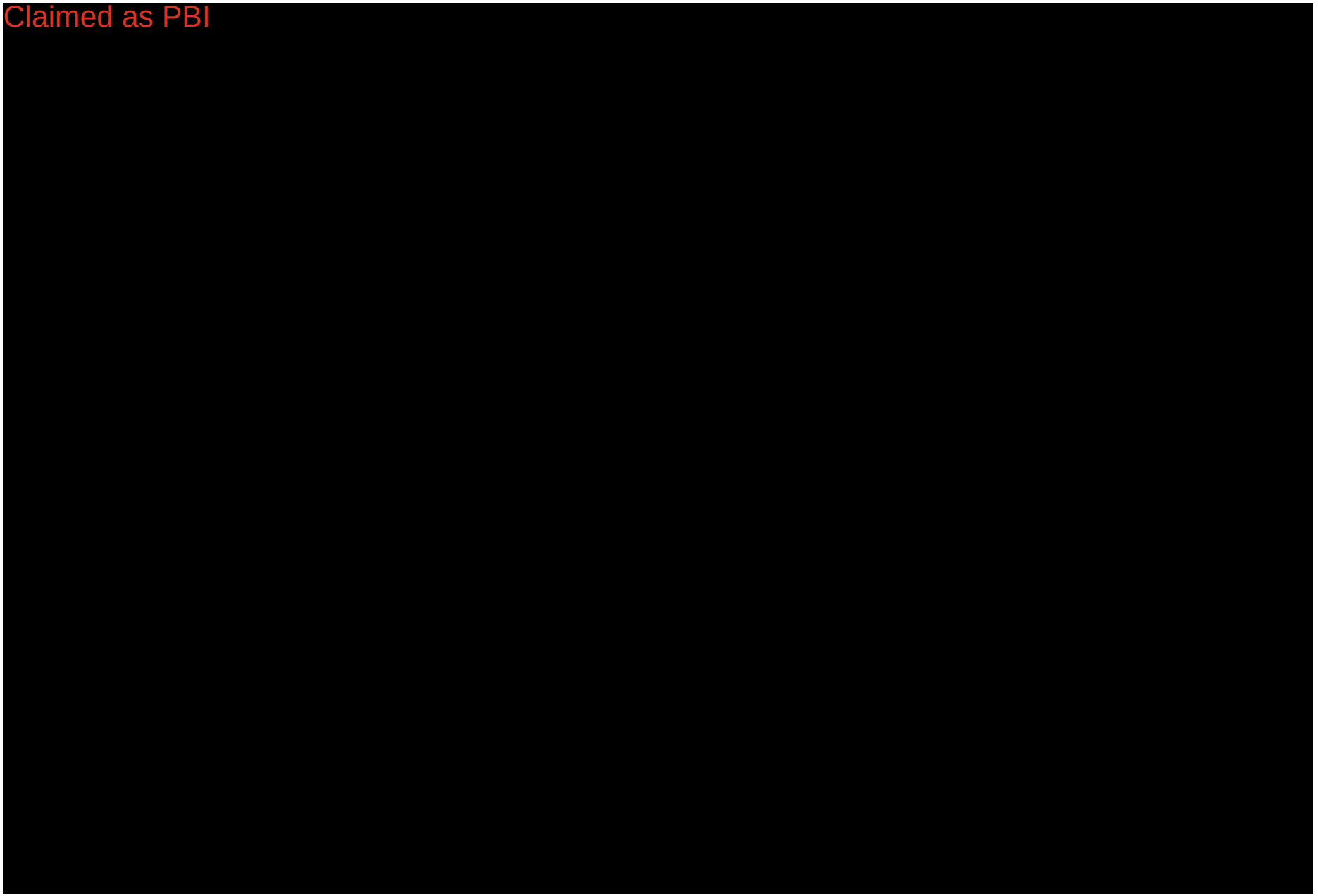

10.2.1.1 Infrastructure

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

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

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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.

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[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

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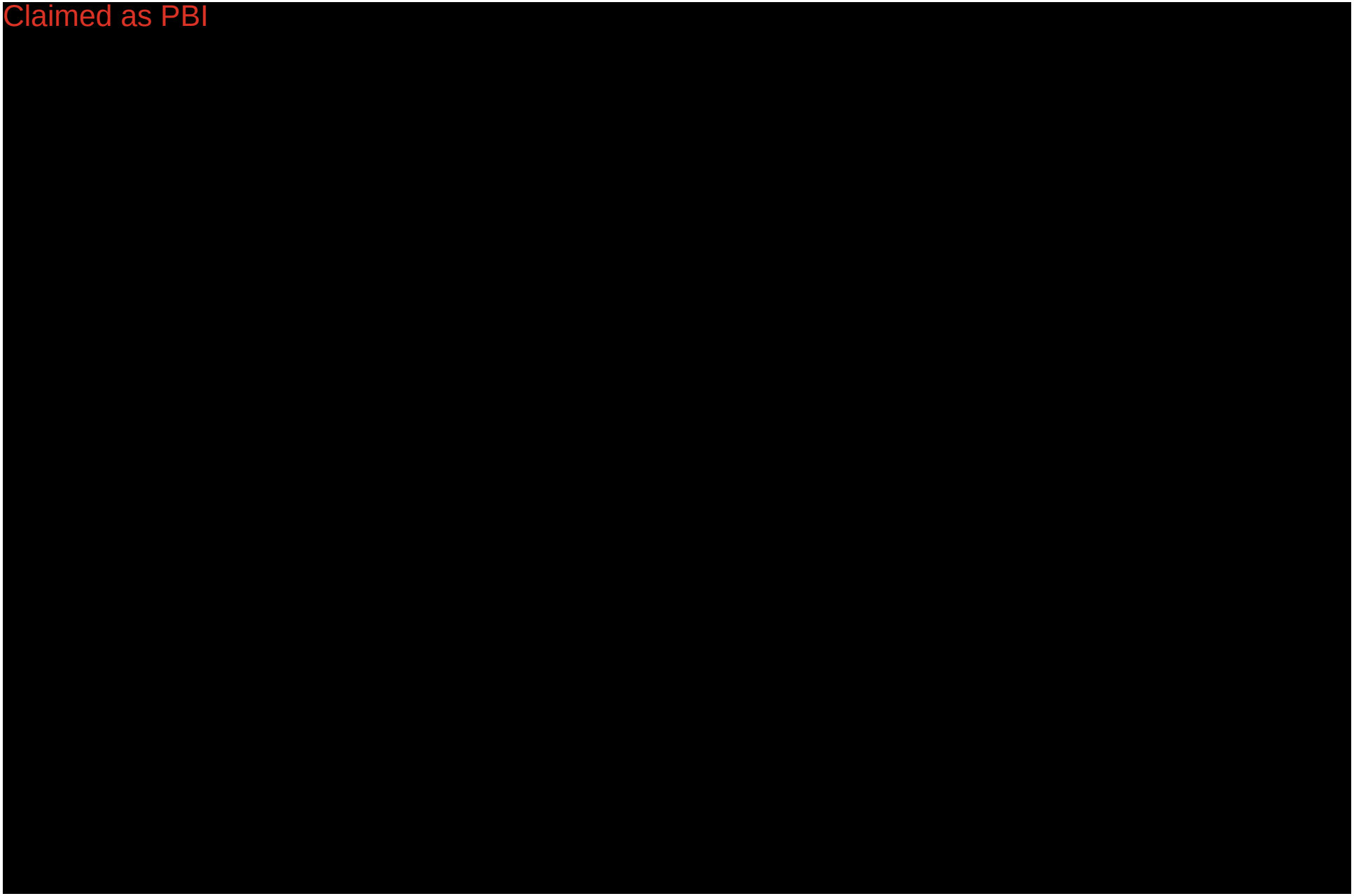

10.9.2 Acronyms

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

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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

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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

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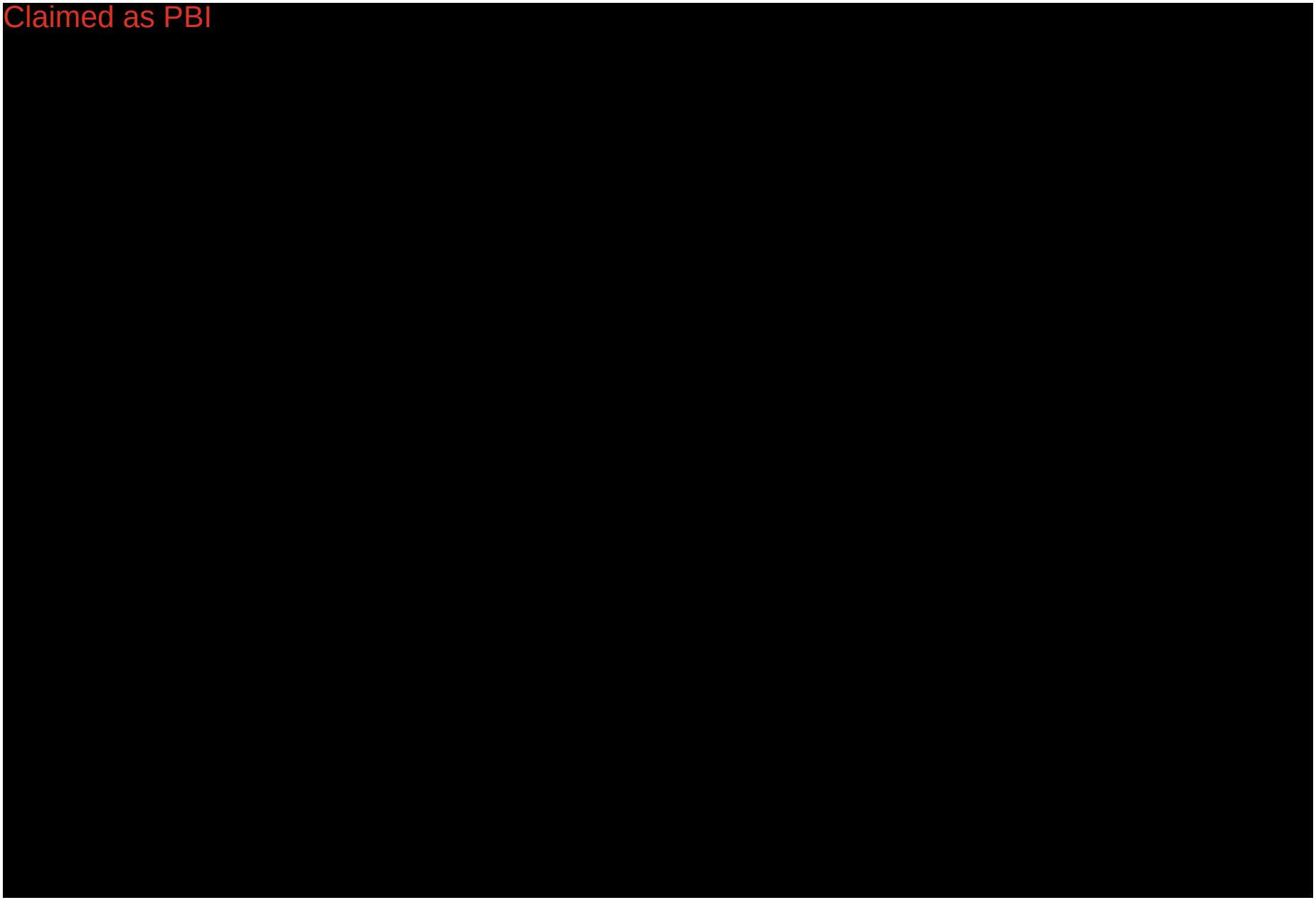

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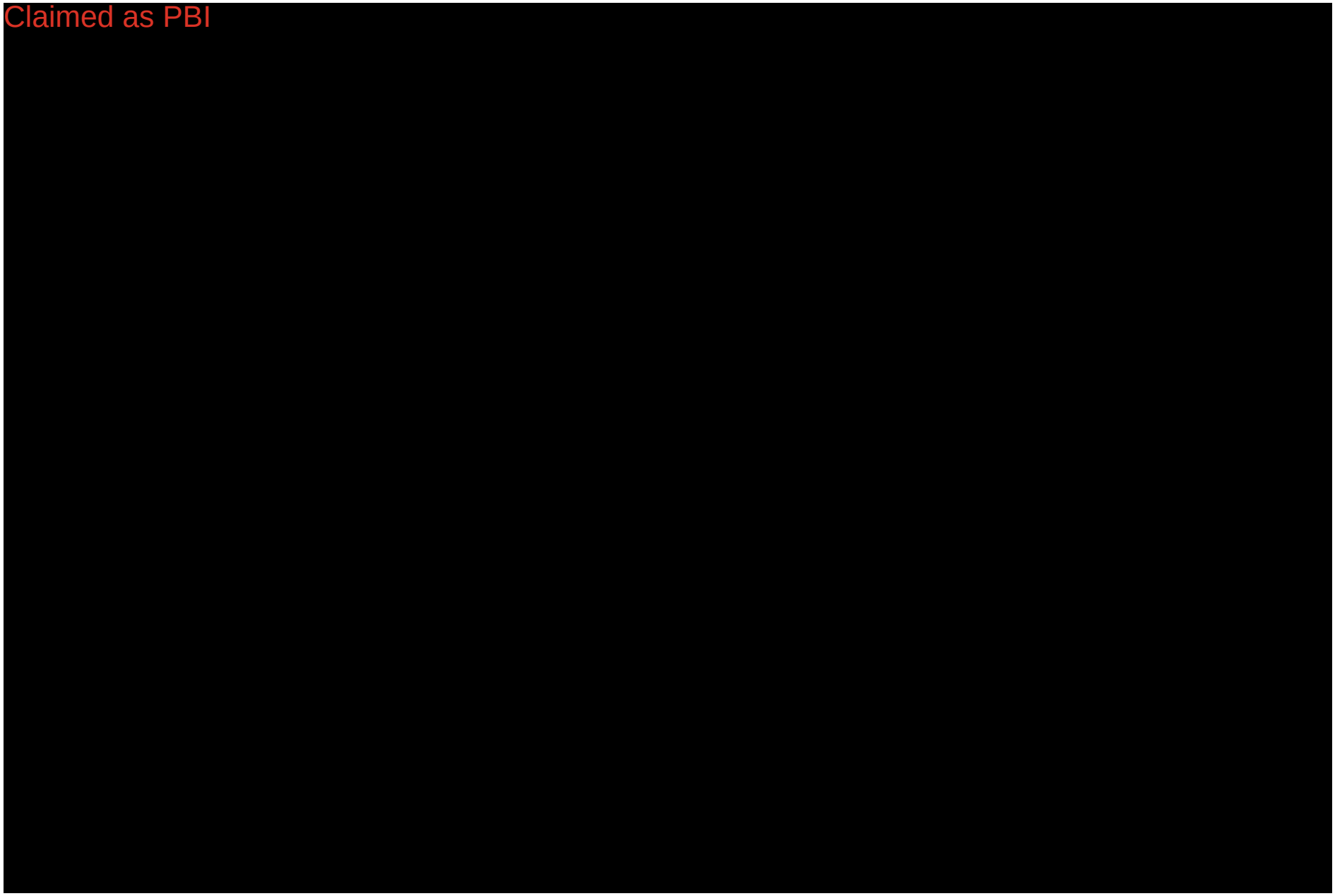
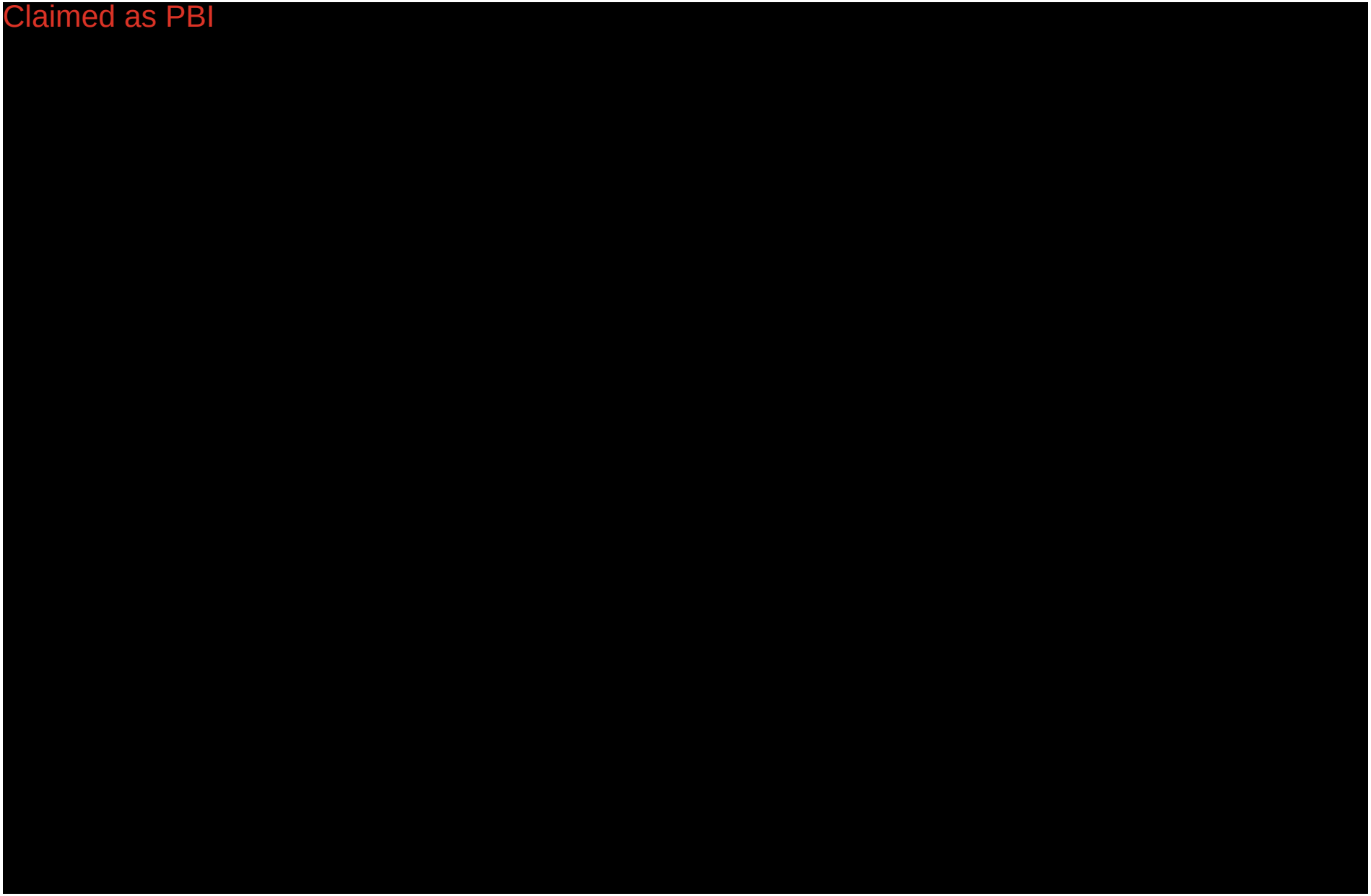
9.4 Predicted Position of the CO_2 Saturation Front and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

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.

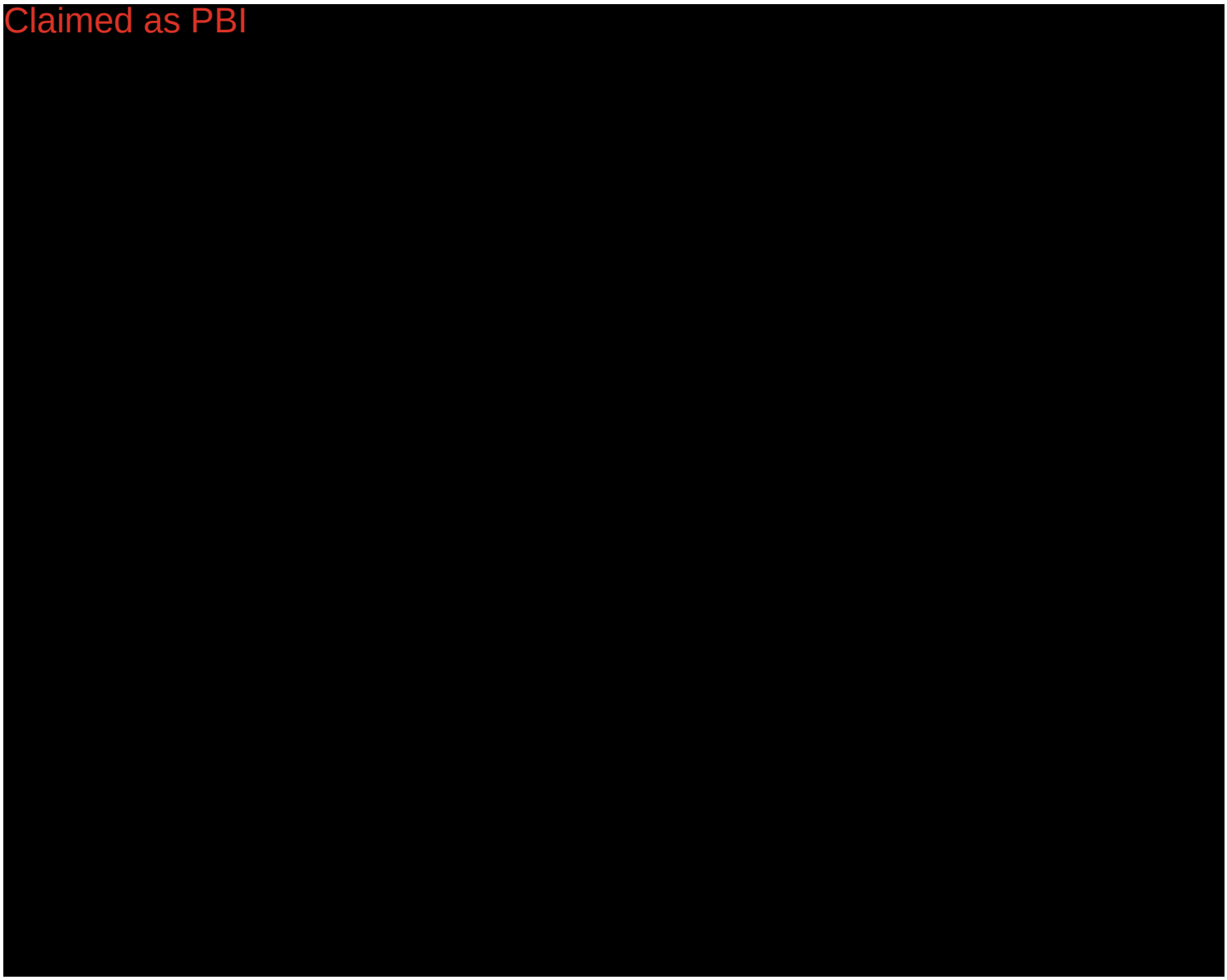
Claimed as PBI

[redacted]

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 [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
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].

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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.

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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.

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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
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
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**.

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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

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