CONFIDENTIAL BUSINESS INFORMATION

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

Claimed as PBI, Texas

Prepared for

ExxonMobil Low Carbon Solutions Onshore LLC

Spring, TX

Prepared by

Environmental Resources Management and Petrotek Corporation

Sustainability is our business

February 2024

FOREWORD

ExxonMobil Low Carbon Solutions Onshore LLC (ExxonMobil) submits this Underground Injection Control Class VI Permit Application (Application) to develop the Rose Carbon Capture and Sequestration (CCS) Project (Project) in Jefferson County, Texas. The Project will collect concentrated carbon dioxide (CO_2) streams from third-party atmospheric emission points and route them to the Project site where three injection wells will sequester the CO_2. This site is ideally suited for the sequestration of CO_2 with the proposed injection zone in the Claimed as PBI [redacted]. The selected injection intervals within these formations exhibit high porosity and permeability that are ideal for CO_2 storage and are "of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of carbon dioxide stream" [40 Code of Federal Regulations (40 CFR) 146.83(a)(2)]. The upper confining zone is a thick, muddy interval containing the regionally extensive Claimed as PBI [redacted] that is continuous across the area of review. This interval thickness and lack of permeability is sufficient for containment.

In accordance with the requirements of 40 CFR 146.82 through 146.95, ExxonMobil has gathered the necessary information and conducted the required evaluations to characterize the geology and predict how the CO_2 plume and brine pressure front will move in the injection zone, between upper and lower shale confining zones. Based on the results of the site characterization and area of review (AoR) modeling, ExxonMobil developed five plans to describe the engineering design and safety considerations for construction and operation of the injection wells, the testing and monitoring plan to track the CO_2 plume and brine pressure front. Of particular interest, the Project area contains Claimed as PBI [redacted]. Corrective actions will be conducted on Claimed as PBI [redacted]. ExxonMobil plans to close the injection wells and Project site after the CO_2 storage target of Claimed as PBI [redacted].

The post-closure site care phase of the project continues the testing and monitoring plan throughout the proposed 50-year period to provide the data necessary for demonstrating no endangerment of underground sources of drinking water (USDWs). The extent of the CO_2 plume is expected to stabilize by Claimed as PBI [redacted], at which time the rate of CO_2 plume growth was predicted to be less than Claimed as PBI [redacted]. Routine AoR reevaluations will occur during the active and post-closure phases of the Project to compare measured CO_2 plume migration rates with model-predicted migration rates.

The strength of ExxonMobil's financial assurance demonstration means funding for the Project will be secure throughout its lifecycle. In the rare event that a USDWs are threatened, an emergency and remedial response plan outlines the steps to be taken in accordance with the requirements for a timely response.

CERTIFICATION

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

CERTIFICATION

CERTIFIED BY:

Environmental Resources Management Southwest, Inc.

Claimed as PBI

On behalf of Environmental Resources Management Southwest, Inc., I, Claimed as PBI, certify that this application was prepared by Environmental Resources Management Southwest, Inc. or under its direct supervision and that the information and analyses presented herein are true and accurate to the best of its knowledge.

Environmental Resources Management Southwest, Inc.

Claimed as PBI

Date Signed: February 29, 2024

Petrotek DIWS Corporation

Claimed as PBI

On behalf of Petrotek DIWS Corporation, I, Claimed as PBI, certify that this application was prepared by Petrotek DIWS Corporation or under its direct supervision and that the information and analyses presented herein are true and accurate to the best of its knowledge.

Petrotek DIWS Corporation

Claimed as PBI

Date Signed: February 29, 2024

ACRONYMS AND ABBREVIATIONS

Note: All terms are written as used in the text.

Acronym, Abbreviation, or Term	Definition / Meaning
°F	degrees Fahrenheit
µD	microdarcy
µg/m3	micrograms per meters cubed
1D	one-dimensional
2D	two-dimensional
3D	three-dimensional
4D	four-dimensional
AMPP	Association for Materials Protection and Performance
AMSL	above mean sea level
AoR	Area of Review
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
AZMI	above-zone monitoring interval
bbl	barrel(s)
Bcf	billion cubic feet – standard unit of measurement for natural gas
BGL	measured depth below ground level
BHP	bottomhole pressure
bpm	barrels per minute
BMSL	below mean sea level
BTC	buttress-thread and coupled
CBG	Census Block Group
CBL	cement bond log
CCL	casing collar locator
CCS	carbon capture and storage
CEQ	U.S. Council on Environmental Quality
CFR	Code of Federal Regulations
CIL	casing inspection log
cm	centimeter
CO2	carbon dioxide
[redacted]	Claimed as PBI
DHPT	downhole pressure temperature
DSA	double-studded adapter
DTS	distributed temperature sensing
EEHC	Exxon Equity Holding Company
EJ	environmental justice
EMC	Exxon Mobil Corporation
EPA	U.S. Environmental Protection Agency
ERR	emergency or remedial response
ERRP	emergency and remedial response plan
ExxonMobil	ExxonMobil Low Carbon Solutions Onshore Storage LLC
F/ft	Fahrenheit per foot
ft	foot
g/cm3	gram per cubic centimeter
GPa	gigapascal

Acronym, Abbreviation, or Term	Definition / Meaning
Claimed as PBI	Claimed as PBI
GR	gamma ray
GS	geologic sequestration
GSDT	Geologic Sequestration Data Tool
GWB	Geochemist's Workbench
h	hour
H2S	hydrogen sulfide
HI	hazard index
HNBR	hydrogenated nitrile rubber
ID	inner diameter
in	inch
Claimed as PBI Claimed as PBI	Claimed as PBI Claimed as PBI
KB	Kelly Bushing
km	kilometer
Kv	vertical permeability
lb	pound
LCZ	lower confining zone
m	meter
m	cementation exponent
Mcf	unit of volume equal to 1,000 cubic feet
mD	millidarcy
mg	milligram
mg/L	milligram per liter
mi	mile(s)
MIT	mechanical integrity test
mm	millimeter
MMscf/d	million standard cubic foot per day
MMt	million metric tonne
MMta	million metric tonne per annum (year)
MMT/yr	million tonne per year
mol%	mole percent
MPa	megapascal
Mya	millions of years ago
n	exponent in the relation to water saturation
nD	nanodarcy
NEIC	National Earthquake Information Center
nm	nanometer
NTG	Net-to-Gross
O2	oxygen
OA	Oxygen Activation
OD	outer diameter
P&A	plug and abandon
P&GA	public and government affairs
PBTD	plugged back total depth

Acronym, Abbreviation, or Term	Definition / Meaning
PISC	post-injection site care
PM2.5	particulate matter 2.5
ppb	parts per billion
ppf	pound per foot
ppg	pound per gallon
ppm	part per million
ppmv	part per million volume
Project	Rose Carbon Capture and Storage Project
psi	pound per square inch
psi/ft	pound per square inch per foot
QASP	Quality Assurance Surveillance Plan
RRC	Railroad Commission of Texas
Rw	resistivity of water
SC	specific conductance
sc-CO2	supercritical CO2
sDAS	seismic distributed acoustic sensing
SGR	shale gouge ratio
SP	spontaneous potential
sq. mi	square mile
STEM	science, technology, engineering, and math
TD	total depth
TDS	total dissolved solids
TRL	Technology Readiness Level
TVD	true vertical depth
TVDSS	true vertical depth subsea
TWDB	Texas Water Development Board
UCCZ	upper composite confining zone
UIC	underground injection control
[redacted]	Claimed as PBI
USDW	underground source of drinking water
USGS	U.S. Geological Survey
VSP	vertical seismic profile
XRD	x-ray diffraction

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REQUIREMENTS MATRIX

The following requirements are for submittal of a Class VI Underground Injection Control (UIC) application to the Railroad Commission of Texas (TRRC). Additional submittals of the application to other regulatory agencies are indicated in this requirement matrix.

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.82	Required Class VI permit information		
§146.91(e)	Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	§5.203(a)(1)(A)Form and filing. Each applicant for a permit to construct and operate a geologic storage facility must file an application with the division in Austin on a form prescribed by the Commission. The applicant must file the application and all attachments with the division and with EPA Region 6 in an electronic format approved by EPA. On the same date, the applicant must file one copy with each appropriate district office and one copy with the Executive Director of the Texas Commission on Environmental Quality. §5.207(b)(2) The operator must submit all required reports, submittals, and notifications under this subchapter to the director and to the EPA in an electronic format approved by the director and the Regional Administrator, respectively.	Class VI Application

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
Section 1 - Introduction			
§146.82(a)(1)	Information required in §144.31(e)(1) through (6) of this chapter;	§5.203(a)(2) General information. (A) On the application, the applicant must include the name, mailing address, and location of the facility for which the application is being submitted and the operator's name, address, telephone number, Commission Organization Report number, and ownership of the facility. (B) When a geologic storage facility is owned by one person but is operated by another person, it is the operator's duty to file an application for a permit. (C) The application must include a listing of all required permits or construction approvals for the facility received or applied for under federal or state environmental programs; (D) A person making an application to the director for a permit under this subchapter must submit a copy of the application to the Texas Commission on Environmental Quality (TCEQ) and must submit to the director a letter of determination from TCEQ concluding that drilling and operating an anthropogenic CO2 injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by TCEQ. The letter must be submitted to the director before any permit under this subchapter may be issued.	Section 1 - Introduction

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§144.31(e)(8)	A brief description of the nature of the business.		Section 1.0 - Project Introduction
§144.31(e)(1)	The activities conducted by the applicant which require it to obtain permits under RCRA, UIC, the National Pollution Discharge Elimination system (NPDES) program under the Clean Water Act, or the Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	§5.203(a)(2)(C) General information. The application must include a listing of all required permits or construction approvals for the facility received or applied for under federal or state environmental programs;	Section 1.15 - Permits and Construction Approvals for Rose CCS Project
§146.82(a)(7)(iii)	The source(s) of the carbon dioxide stream; and	§5.203(i)(1)(C) the sources of the CO2 stream and the volume and/or mass of CO2 from each source; and	Section 1.0 - Project Introduction and 1.8 Well Operations
§146.82(a)(7)(iv)	An analysis of the chemical and physical characteristics of the carbon dioxide stream.	§5.203(i)(1)(D) an analysis of the chemical and physical characteristics of the CO2 stream prior to injection.	1.8 Well Operations
§144.31(e)(2)	Name, mailing address, and location of the facility for which the application is submitted.	§5.203(a)(2)(A) General information. On the application, the applicant must include the name, mailing address, and location of the facility for which the application is being submitted and the operator's name, address, telephone number, Commission Organization Report number, and ownership of the facility.	Section 1.2 - Contact Information
§144.31(e)(3)	Up to four SIC codes which best reflect the principal products or services provided by the facility.	Not Addressed.	Section 1.2 - Contact Information
§144.31(e)(4)	The operator's name, address, telephone number, ownership status, and status as Federal, State, private, public, or other entity.	§5.203(a)(2)(A) General information. On the application, the applicant must include the name, mailing address, and location of the facility for which the application is being submitted and the operator's name, address, telephone number, Commission Organization Report number, and ownership of the facility.	Section 1.2 - Contact Information

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§144.31(e)(5)	Whether the facility is located on Indian lands.	Refer to §5.203(a)(2)(E)and(F). §5.203(a)(2)(E) The application must indicate whether the geologic storage project is located on Indian lands. (F) The application must include a list of contacts for those States, Tribes, and Territories any portion of which is identified to be within the AOR of the geologic storage project based on the map showing the injection well and the AOR	Section 1.2 - Contact Information
§144.31(e)(1)	The activities conducted by the applicant which require it to obtain permits under RCRA, UIC, the National Pollution Discharge Elimination system (NPDES) program under the Clean Water Act, or the Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	§5.203(a)(2)(C) General information. The application must include a listing of all required permits or construction approvals for the facility received or applied for under federal or state environmental programs;	Section 1.2 - Contact Information
§144.31(e)(6)	A listing of all permits or construction approvals received or applied for under any of the following programs:	§5.203(a)(2)(C) General information. The application must include a listing of all required permits or construction approvals for the facility received or applied for under federal or state environmental programs;	Section 1.15 - Permits and Construction Approvals for Rose CCS Project
§144.31(e)(6)(i)	Hazardous Waste Management program under RCRA.		Section 1.15 - Permits and Construction Approvals for Rose CCS Project
§144.31(e)(6)(ii)	UIC program under SDWA.		Section 1.15 - Permits and Construction Approvals for Rose CCS Project
§144.31(e)(6)(iii)	NPDES program under CWA.		Section 1.15 - Permits and Construction Approvals for Rose CCS Project

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§144.31(e)(6)(iv)	Prevention of Significant Deterioration (PSD) program under the Clean Air Act.		Section 1.15 - Permits and Construction Approvals for Rose CCS Project
§144.31(e)(6)(v)	Nonattainment program under the Clean Air Act.		Section 1.15 - Permits and Construction Approvals for Rose CCS Project
§144.31(e)(6)(vi)	National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act.		Section 1.15 - Permits and Construction Approvals for Rose CCS Project
§144.31(e)(6)(vii)	Ocean dumping permits under the Marine Protection Research and Sanctuaries Act.		Section 1.15 - Permits and Construction Approvals for Rose CCS Project
§144.31(e)(6)(viii)	Dredge and fill permits under section 404 of CWA.		Section 1.15 - Permits and Construction Approvals for Rose CCS Project
§144.31(e)(6)(ix)	Other relevant environmental permits, including State permits.		Section 1.15 - Permits and Construction Approvals for Rose CCS Project

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
Section 2 - Site Characterization & Appendix B, C			
§146.82(a)(3)	Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:	§5.203(c) Geologic, geochemical, and hydrologic information. (1) The applicant must submit a descriptive report prepared by a knowledgeable person that includes an interpretation of the results of appropriate logs, surveys, sampling, and testing sufficient to determine the depth, thickness, porosity, permeability, and lithology of, and the geochemistry of any formation fluids in, all relevant geologic formations. (2) The applicant must submit information on the geologic structure and reservoir properties of the proposed storage reservoir and overlying formations, including the following information:	Section 2.5 - Site Geology Section 2.9 - Assessment of Injection Interval and Confining Zone Geochemical Reactions Section 2.10 - Hydrogeology
§146.82(a)(3)(ii)	The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;	§5.203(c)(2)(C) the location, orientation, and properties of known or suspected transmissive faults or fractures that may transect the confining zone within the AOR and a determination that such faults or fractures would not compromise containment;	Section 2.5.9.1 - Interpreted Structural Features – Faults; Section 2.5.9.3 - Interpreted Structural Features – Fractures
§146.82(a)(3)(iii)	Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	§5.203(c)(2)(B) the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of, and the geochemistry of any formation fluids in, the storage reservoir and confining zone and any other relevant geologic formations, including geology/facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and lithologic descriptions, and the analyses of logging,	Section 2.3 - Major Stratigraphic Units: Confining and Injection Zones; Section 2.9 - Assessment of Injection Interval and Confining Zone Geochemical Reactions

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		sampling, and testing results used to make such determinations;	
§146.82(a)(3)(iv)	Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	§5.203(c)(2)(E) geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone;	Section 2.6 - Geomechanics and Petrophysics
§146.82(a)(3)(v)	Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and	§5.203(c)(2)(D) the seismic history, including the presence and depth of seismic sources, and a determination that the seismicity would not compromise containment;	Section 2.11 - Seismic Risk and Fault-Slip Potential for AoR
§146.82(a)(3)(vi)	Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.	§5.203(c)(2)(A) geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the area from the ground surface to the base of the injection zone within the AOR that indicate the general vertical and lateral limits of all USDWs within the AOR, their positions relative to the storage reservoir and the direction of water movement, where known;	Section 2 Figures
§146.82(a)(5)	Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;	§5.203(c)(2)(A) geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the area from the ground surface to the base of the injection zone within the AOR that indicate the general vertical and lateral limits of all USDWs within the AOR, their positions relative to the storage reservoir and the direction of water movement, where known;	Section 2 Figures

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.82(a)(6)	Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	§5.203(c)(2)(G) baseline geochemical data for subsurface formations that will be used for monitoring purposes, including all formations containing USDWs within the AOR.	Section 2.9 - Assessment of Injection Interval and Confining Zone Geochemical Reactions
§146.83(a)	Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises:	§5.206 (b) General criteria. The director may issue a permit under this subchapter if the applicant demonstrates and the director finds that: (6) the geologic storage facility will be sited in an area with suitable geology, which at a minimum must include: (A) an injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO2 stream	Section 2.5.6. Geologic Characteristics of the Injection Zone; Section 2.12 Site Suitability
§146.83(a)(1)	An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	§5.206 (b) (6)(A) General criteria. The director may issue a permit under this subchapter if the applicant demonstrates and the director finds that: (6) the geologic storage facility will be sited in an area with suitable geology, which at a minimum must include: (A) an injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO2 stream;	Section 2.5.6. Geologic Characteristics of the Injection Zone; Section 2.12 Site Suitability
§146.83(a)(2)	Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	§5.206 (b) (6)(B) a confining zone that is laterally continuous and free of known transecting transmissive faults or fractures over an area sufficient to contain the injected CO2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without compromising the confining zone or causing the movement	Section 2.3 - Major Stratigraphic Units: Confining and Injection Zones; Section 2.9 - Assessment of Injection Interval and Confining Zone Geochemical Reactions; Section 2.5.5 -

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		of fluids that endangers USDWs	Top and Bottom Elevations of Injection and Confining Zones
§146.83(b)	The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.		Not Applicable
§146.84(c)	Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	§5.203(d) (1) Initial delineation of the AOR and initial corrective action. The applicant must delineate the AOR, identify all wells that require corrective action, and perform corrective action on those wells. Corrective action may be phased.	Section 3.9 Corrective Action Plan and Schedule

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.84(c)(1)	Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	§5.203(d)(1)(A) (i) Delineation of AOR. (i) Using computational modeling that considers the volumes and/or mass and the physical and chemical properties of the injected CO2 stream, the physical properties of the formation into which the CO2 stream is to be injected, and available data including data available from logging, testing, or operation of wells, the applicant must predict the lateral and vertical extent of migration for the CO2 plume and formation fluids and the pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface for the following time periods: (I) five years after initiation of injection; (II) from initiation of injection to the end of the injection period proposed by the applicant; and (III) from initiation of injection until the movement of the CO2 plume and associated pressure front stabilizes.	Section 2.8.1 Section 2 Figures
§146.84(c)(1)(i)	Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	§5.203(d)(1)(A) (ii) (I) and (II) (ii) The applicant must use a computational model that: (I) is based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone; (II) is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection;	Section 2.1 - Reservoir Characterization and 3D Geologic Modeling

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.84(c)(1)(ii)	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	§5.203(d)(1)(A) (ii) (III) (ii) The applicant must use a computational model that: (III) takes into account relevant geologic heterogeneities and data quality, and their possible impact on model predictions;	3.6 Model Design and Input Parameters
§146.86(b)(1)(vii)	Lithology of injection and confining zone(s);	§5.203(e)(2)(H) lithology of injection and confining zones;	Section 2.3 - Major Stratigraphic Units: Confining and Injection Zones Section 2.5 - Site Geology
§146.93(c)(1)(vii)	A characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., carbon dioxide, formation fluids) movement;	§5.203(m)(7)(G) a characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., CO2, formation fluids) movement;	Section 2.3 - Major Stratigraphic Units: Confining and Injection Zones Section 2 Figures
§146.93(c)(1)(x)	The distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	§5.203(m)(7)(J) the distance between the injection zone and the nearest USDWs above and/or below the injection zone; and	Section 2.10 - Hydrogeology

Section 3 - AoR and Corrective Action			
§146.84(a)	The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization,	§5.102(5) Area of review (AOR)--The subsurface three dimensional extent of the CO2 stream plume and the associated pressure front, as well as the overlying formations, any underground sources of drinking water overlying an injection zone along with any intervening formations, and the surface area above that delineated region.	Sections 3.3, 3.4, 3.5, 3.6, and 3.7

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	monitoring, and operational data.		
§146.84(c)	Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	§5.203(d) (1) Initial delineation of the AOR and initial corrective action. The applicant must delineate the AOR, identify all wells that require corrective action, and perform corrective action on those wells. Corrective action may be phased.	Section 3.7, 3.9
§146.84(c)(1)	Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	§5.203(d)(1)(A) (i) Delineation of AOR. (i) Using computational modeling that considers the volumes and/or mass and the physical and chemical properties of the injected CO2 stream, the physical properties of the formation into which the CO2 stream is to be injected, and available data including data available from logging, testing, or operation of wells, the applicant must predict the lateral and vertical extent of migration for the CO2 plume and formation fluids and the pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface for the following time periods: (I) five years after initiation of injection; (II) from initiation of injection to the end of the injection period proposed by the applicant; and (III) from initiation of injection until the movement of the CO2 plume and associated pressure front stabilizes.	Section 3.7 - AoR Delineation Based on Model Results Section 3.10 - AoR Reevaluation Plan and Schedule

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.84(c)(1)(i)	Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	§5.203(d)(1)(A) (ii) (I) and (II) (ii) The applicant must use a computational model that: (I) is based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone; (II) is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection;	Sections 3.3, 3.4, 3.5, 3.6, and 3.7
§146.84(c)(1)(ii)	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	§5.203(d)(1)(A) (ii) (III) (ii) The applicant must use a computational model that: (III) takes into account relevant geologic heterogeneities and data quality, and their possible impact on model predictions;	3.8 Model Calibration and Validation
§146.93(c)(1)(iii)	The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;	§5.203(m)(7)(C) the predicted rate of CO2 plume migration within the injection zone, and the predicted timeframe for the stabilization of the CO2 plume and associated pressure front;	Section 3.7 - AoR Delineation Based on Model Results
§146.93(c)(1)(iv)	A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	§5.203(m)(7)(D) a description of the site-specific processes that will result in CO2 trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	3.6 Model Design and Input Parameters
§146.93(c)(1)(v)	The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	§5.203(m)(7)(E) the predicted rate of CO2 trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	3.6 Model Design and Input Parameters
§146.82(a)(7)(ii)	Average and maximum injection pressure;	§5.203(i)(1)(B) the average and maximum surface injection pressure;	Section 3.6.3 - Fluid Injection Rates

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.82(a)(1)	Information required in § 144.31(e)(1) through (6) of this chapter;	§5.203(a)(2) General information. (A) On the application, the applicant must include the name, mailing address, and location of the facility for which the application is being submitted and the operator's name, address, telephone number, Commission Organization Report number, and ownership of the facility. (B) When a geologic storage facility is owned by one person but is operated by another person, it is the operator's duty to file an application for a permit. (C) The application must include a listing of all required permits or construction approvals for the facility received or applied for under federal or state environmental programs; (D) A person making an application to the director for a permit under this subchapter must submit a copy of the application to the Texas Commission on Environmental Quality (TCEQ) and must submit to the director a letter of determination from TCEQ concluding that drilling and operating an anthropogenic CO2 injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by TCEQ. The letter must be submitted to the director before any permit under this subchapter may be issued. (E) The application must indicate whether the geologic storage project is located on Indian lands. (F) The	Section 1 - Introduction

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		application must include a list of contacts for those States, Tribes, and Territories any portion of which is identified to be within the AOR of the geologic storage project based on the map showing the injection well and the AOR.	
§146.82(a)(2)	A map showing the injection well for which a permit is sought and the applicable area of review consistent with § 146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;	§5.203 (b) Surface map and information. Only information of public record is required to be included on this map. (1) The applicant must file with the director a surface map delineating the proposed location and geographic coordinates of any injection wells, any proposed monitoring wells, and the boundary of the geologic storage facility for which a permit is sought and the applicable AOR. The applicant must indicate the coordinate system used. (2) The applicant must show within the AOR on the map the number or name and the location of: (A) all known artificial penetrations through the confining zone, including stratigraphic boreholes, injection wells, producing wells, inactive wells, plugged wells, or dry holes; (B) the locations of cathodic protection holes, subsurface cleanup sites, bodies of surface water, springs, surface and subsurface mines, quarries, and water wells; and (C) other pertinent surface features, including pipelines, roads, and structures intended for human occupancy. (3) The applicant must identify on the map any known or suspected faults expressed at the surface.	Appendix B - Site Characterization Files
§146.82(a)(3)(i)	Maps and cross sections of the area of review;	§5.203(c)(2)(A) geologic and topographic maps and cross sections illustrating regional	Appendix B - Site Characterization Files

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		geology, hydrogeology, and the geologic structure of the area from the ground surface to the base of the injection zone within the AOR that indicate the general vertical and lateral limits of all USDWs within the AOR, their positions relative to the storage reservoir and the direction of water movement, where known;	
§146.82(a)(4)	A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;	§5.203(d)(1)(B) Identification and table of penetrations. The applicant must identify, compile, and submit a table listing all penetrations, including active, inactive, plugged, and unplugged wells and underground mines in the AOR that may penetrate the confining zone, that are known or reasonably discoverable through specialized knowledge or experience. The applicant must provide a description of each penetration's type, construction, date drilled or excavated, location, depth, and record of plugging and/or completion or closure. Examples of specialized knowledge or experience may include reviews of federal, state, and local government records, interviews with past and present owners, operators, and occupants, reviews of historical information (including aerial photographs, chain of title documents, and land use records), and visual inspections of the facility and adjoining properties	Section 3.9 - Corrective Action Plan and Schedule

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.82(a)(13)	Proposed area of review and corrective action plan that meets the requirements under § 146.84;	§5.203(d)(2) AOR and corrective action plan. As part of an application, the applicant must submit an AOR and corrective action plan that includes the following information: (A) the method for delineating the AOR, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based; (B) for the AOR, a description of: (i) the minimum fixed frequency, not to exceed five years, at which the applicant proposes to reevaluate the AOR during the life of the geologic storage facility; (ii) how monitoring and operational data will be used to re-evaluate the AOR; and (iii) the monitoring and operational conditions that would warrant a re-evaluation of the AOR prior to the next scheduled re-evaluation; and (C) a corrective action plan that describes: (i) how the corrective action will be conducted; (ii) how corrective action will be adjusted if there are changes in the AOR; (iii) if a phased corrective action is planned, how the phasing will be determined; and (iv) how site access will be secured for future corrective action.	Section 3.9 - Corrective Action Plan and Schedule
§146.82(a)(20)	A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and		Section 1 - Introduction

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.84(a)	The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.	§5.102(5) Area of review (AOR)--The subsurface three dimensional extent of the CO2 stream plume and the associated pressure front, as well as the overlying formations, any underground sources of drinking water overlying an injection zone along with any intervening formations, and the surface area above that delineated region.	Sections 3.3, 3.4, 3.5, 3.6, and 3.7
§146.84(b)	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the Director, the owner or operator must submit an area of review and corrective action plan that includes the following information:	§5.203(d) AOR and corrective action. This subsection describes the standards for the information regarding the delineation of the AOR, the identification of penetrations, and corrective action that an applicant must include in an application. (1) Initial delineation of the AOR and initial corrective action. The applicant must delineate the AOR, identify all wells that require corrective action, and perform corrective action on those wells. Corrective action may be phased. (A) Delineation of AOR. (i) Using computational modeling that considers the volumes and/or mass and the physical and chemical properties of the injected CO2 stream, the physical properties of the formation into which the CO2 stream is to be injected, and available data including data available from logging, testing, or operation of wells, the applicant must predict the lateral and vertical extent of migration for the CO2 plume and formation fluids and the pressure differentials required to cause movement of	Sections 3.3, 3.4, 3.5, 3.6, 3.7, and 3.9

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		injected fluids or formation fluids into a USDW in the subsurface for the following time periods: (I) five years after initiation of injection; (II) from initiation of injection to the end of the injection period proposed by the applicant; and (III) from initiation of injection until the movement of the CO2 plume and associated pressure front stabilizes. (ii) The applicant must use a computational model that: (I) is based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone; (II) is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection; (III) takes into account relevant geologic heterogeneities and data quality, and their possible impact on model predictions; (IV) considers the physical and chemical properties of injected and formation fluids; and (V) considers potential migration through known faults, fractures, and artificial penetrations and beyond lateral spill points. (iii) The applicant must provide the name and a description of the model, software, the assumptions used to determine the AOR, and the equations solved.	

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.84(b)(1)	The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	§5.203(d)(2) (A) AOR and corrective action plan. As part of an application, the applicant must submit an AOR and corrective action plan that includes the following information: (A) the method for delineating the AOR, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	Sections 3.3, 3.4, 3.5, 3.6, and 3.7
§146.84(b)(2)	A description of:	§5.203(d)(2)(B) for the AOR, a description of:	See Below
§146.84(b)(2)(i)	The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review;	§5.203(d)(2)(B)(i) the minimum fixed frequency, not to exceed five years, at which the applicant proposes to reevaluate the AOR during the life of the geologic storage facility;	Section 3.10 - AoR Reevaluation Plan and Schedule
§146.84(b)(2)(ii)	The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in paragraph (b)(2)(i) of this section.	§5.203(d)(2)(B)(iii) the monitoring and operational conditions that would warrant a re-evaluation of the AOR prior to the next scheduled re-evaluation; and	Section 3.10 - AoR Reevaluation Plan and Schedule
§146.84(b)(2)(iii)	How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	§5.203(d)(2)(B)(ii) how monitoring and operational data will be used to re-evaluate the AOR;	Section 3.10 - AoR Reevaluation Plan and Schedule
§146.84(b)(2)(iv)	How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are	§5.203(d)(2)(C) a corrective action plan that describes: (i) how the corrective action will be conducted; (ii) how corrective action will be adjusted if there are changes in the AOR; (iii) if a phased corrective action is planned, how the phasing will be determined; and	Section 3.9 - Corrective Action Plan and Schedule Section 3.10 - AoR Reevaluation Plan and Schedule

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	changes in the area of review; and how site access will be guaranteed for future corrective action.	(iv) how site access will be secured for future corrective action.	
§146.84(c)	Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	§5.203(d)(1) Initial delineation of the AOR and initial corrective action. The applicant must delineate the AOR, identify all wells that require corrective action, and perform corrective action on those wells. Corrective action may be phased.	See Below
§146.84(c)(1)	Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	§5.203(d)(1)(A) (i) Delineation of AOR. (i) Using computational modeling that considers the volumes and/or mass and the physical and chemical properties of the injected CO2 stream, the physical properties of the formation into which the CO2 stream is to be injected, and available data including data available from logging, testing, or operation of wells, the applicant must predict the lateral and vertical extent of migration for the CO2 plume and formation fluids and the pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface for the following time periods: (I) five years after initiation of injection; (II) from initiation of injection to the end of the injection period proposed by the applicant; and (III) from initiation of injection until the movement of the CO2 plume and associated pressure front stabilizes.	Section 3.7 - AoR Delineation Based on Model Results Section 2 Figures

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.84(c)(1)(i)	Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	§5.203(d)(1)(A) (ii) (I) and (II) (ii) The applicant must use a computational model that: (I) is based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone; (II) is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection;	Sections 3.3, 3.4, 3.5, 3.6, and 3.7
§146.84(c)(1)(ii)	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	§5.203(d)(1)(A) (ii) (III) (ii) The applicant must use a computational model that: (III) takes into account relevant geologic heterogeneities and data quality, and their possible impact on model predictions;	3.6 Model Design and Input Parameters
§146.84(c)(1)(iii)	Consider potential migration through faults, fractures, and artificial penetrations	§5.203(d)(1)(A) (ii) (V) (V) considers potential migration through known faults, fractures, and artificial penetrations and beyond lateral spill points.	Section 3.6.4 - Fracture Pressure and Fracture Gradient Section 3.9 - Corrective Action Plan and Schedule
§146.84(c)(2)	Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require; and	§5.203(d)(1)(B) Identification and table of penetrations. The applicant must identify, compile, and submit a table listing all penetrations, including active, inactive, plugged, and unplugged wells and underground mines in the AOR that may penetrate the confining zone, that are known or reasonably discoverable through specialized knowledge or experience. The applicant must provide a description of each penetration's	Section 3.9 - Corrective Action Plan and Schedule

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		type, construction, date drilled or excavated, location, depth, and record of plugging and/or completion or closure. Examples of specialized knowledge or experience may include reviews of federal, state, and local government records, interviews with past and present owners, operators, and occupants, reviews of historical information (including aerial photographs, chain of title documents, and land use records), and visual inspections of the facility and adjoining properties.	
§146.84(c)(3)	Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.	§5.203(d)(1)(C) Corrective action. The applicant must demonstrate whether each of the wells on the table of penetrations has or has not been plugged and whether each of the underground mines (if any) on the table of penetrations has or has not been closed in a manner that prevents the movement of injected fluids or displaced formation fluids that may endanger USDWs or allow the injected fluids or formation fluids to escape the permitted injection zone. The demonstration shall include evidence that the materials used are compatible with the carbon dioxide stream. The applicant must perform corrective action on all wells and underground mines in the AOR that are determined to need corrective action. The operator must perform corrective action using materials suitable for use with the CO2 stream. Corrective action may be phased	Section 3.9 - Corrective Action Plan and Schedule

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.84(d)	Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.	§5.203(d)(1)(C) Corrective action. The applicant must demonstrate whether each of the wells on the table of penetrations has or has not been plugged and whether each of the underground mines (if any) on the table of penetrations has or has not been closed in a manner that prevents the movement of injected fluids or displaced formation fluids that may endanger USDWs or allow the injected fluids or formation fluids to escape the permitted injection zone. The demonstration shall include evidence that the materials used are compatible with the carbon dioxide stream. The applicant must perform corrective action on all wells and underground mines in the AOR that are determined to need corrective action. The operator must perform corrective action using materials suitable for use with the CO2 stream. Corrective action may be phased	Section 3.9 - Corrective Action Plan and Schedule
§146.84(e)	At the minimum fixed frequency, not to exceed five years, as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must:	§5.206(g) Permit conditions for AOR and corrective action. At the frequency specified in the approved AOR and corrective action plan or permit, and whenever warranted by a material change in the monitoring and/or operational data or in the evaluation of the monitoring and operational data by the operator, but no less frequently than every five years, the operator of a geologic storage facility also must:	See Below
§146.84(e)(1)	Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section;	§5.206(g) (1) perform a re-evaluation of the AOR by performing all of the actions specified in §5.203(d)(1)(A) - (C) of this title to delineate	3.10 - AoR Reevaluation Plan and Schedule

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		the AOR and identify all wells that require corrective action;	
§146.84(e)(2)	Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section;	§5.206(g) (2) identify all wells in the re-evaluated AOR that require corrective action;	3.10 - AoR Reevaluation Plan and Schedule
§146.84(e)(3)	Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in paragraph (d) of this section; and	§5.206(g)(3) perform corrective action on wells requiring corrective action in the re-evaluated AOR in the same manner specified in §5.203(d)(1)(C) of this title;	3.10 - AoR Reevaluation Plan and Schedule
§146.84(e)(4)	Submit an amended area of review and corrective action plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	§5.206(g)(4) submit an amended AOR and corrective action plan or demonstrate to the director through monitoring data and modeling results that no change to the AOR and corrective action plan is needed. Any amendments to the AOR and corrective action plan must be approved by the director, must be incorporated into the permit, and are subject to the permit modification requirements at §5.202 of this title (relating to Permit Required, and Draft Permit and Fact Sheet), as applicable; and	3.10 - AoR Reevaluation Plan and Schedule
§146.84(g)	All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.	§5.207 (e) (5) Record retention. The operator must retain all documentation of good faith claim to necessary and sufficient property rights to operate the geologic storage facility until the director issues the final certificate of closure in accordance with §5.206(k)(7) of this title.	3.10 - AoR Reevaluation Plan and Schedule

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
Section 4 - Engineering Design and Operations & Appendix D			
§146.82(c)(5)	Final injection well construction procedures that meet the requirements of § 146.86;	§5.206(c) Permit conditions for injection well construction. (1) Construction of anthropogenic CO2 injection wells must meet the criteria in §5.203(e) of this title. (2) Within 30 days after the completion or conversion of an injection well subject to this subchapter, the operator must file with the division a complete record of the well on Commission Form W-2, Oil Well Potential Test, Completion or Recompletion Report and Log showing the current completion. (3) Except in the case of an emergency repair, the operator of a geologic storage facility must notify the director in writing at least 30 days prior to conducting any well workover that involves running tubing and setting packers, beginning any workover or remedial operation, or conducting any required pressure tests or surveys. Such activities shall not commence before the end of the 30 days unless authorized by the director. In the case of an emergency repair, the operator must notify the director of such emergency repair as soon as reasonably practical	Section 4.0 - Engineering Design and Operating Strategy
§146.86	Injection well construction requirements.	§5.203(e)Injection well construction.	Section 4.0 - Engineering Design and Operating Strategy
§146.86(a)	General. The owner or operator must ensure that all Class VI wells are constructed and completed to:	§5.203(e)(1)(A) General. The operator of a geologic storage facility must ensure that all anthropogenic CO2 injection wells are constructed and completed in a manner that	See Below

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		will:	
§146.86(a)(1)	Prevent the movement of fluids into or between USDWs or into any unauthorized zones;	§5.203(e)(1)(A)(i) prevent the movement of injected CO2 or displaced formation fluids into any unauthorized zones or into any areas where they could endanger USDWs;	Section 4.1 - Objectives, Section 4.2 - Engineering Design
§146.86(a)(2)	Permit the use of appropriate testing devices and workover tools; and	§5.203(e)(1)(A)(ii) allow the use of appropriate testing devices and workover tools; and	Section 4.1 - Objectives, Section 4.2 - Engineering Design
§146.86(a)(3)	Permit continuous monitoring of the annulus space between the injection tubing and long string casing.	§5.203(e)(1)(A)(iii)allow continuous monitoring of the annulus space between the injection tubing and long string casing	Section 4.1 - Objectives, Section 4.2 - Engineering Design
§146.86(b)	Casing and cementing of Class VI wells.	§5.203(e)(1)(B) Casing and cementing of anthropogenic CO2 injection wells.	See Below

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.86(b)(1)	Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information:	§5.203(e)(1)(B)(i) The operator must ensure that injection wells are cased and the casing cemented in compliance with§3.13 of this title (relating to Casing, Cementing, Drilling, Well Control, and Completion Requirements), in addition to the requirements of this section.§5.203(e)(1)(B)(ii) Casing, cement, cement additives, and/or other materials used in the construction of each injection well must have sufficient structural strength and must be of sufficient quality and quantity to maintain integrity over the design life of the injection well. All well materials must be suitable for use with fluids with which the well materials may be expected to come into contact and must meet or exceed test standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards as approved by the director§5.203(e)(2)Construction information. The applicant must provide the following information for each well to allow the director to determine whether the proposed well construction and completion design will meet the general performance criteria in paragraph (1) of this subsection:	Section 4.1 - Objectives Section 4.2 - Engineering Design
§146.86(b)(1)(i)	Depth to the injection zone(s);	§5.203(e)(2)(A) depth to the injection zone;	Section 4.3.4 - Injection Well Completion Stage and Injection Interval, Appendix D

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.86(b)(1)(ii)	Injection pressure, external pressure, internal pressure, and axial loading;	§5.203(e)(2)(D) proposed injection rate (intermittent or continuous), maximum proposed surface injection pressure, external pressure, internal pressure, axial loading, and maximum proposed volume and/or mass of the CO2 stream to be injected;	Section 4.3.4 - Injection Well Completion Stage and Injection Interval, Appendix D
§146.86(b)(1)(iii)	Hole size;	§5.203(e)(2)(B) hole size;	Section 4.3.4 - Injection Well Completion Stage and Injection Interval, Appendix D
§146.86(b)(1)(iv)	Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);	§5.203(e)(2)(C) size and grade of all casing and tubing strings (e.g., wall thickness, external diameter, nominal weight, length, joint specification and construction material, tubing tensile, burst, and collapse strengths);	Section 4.3.4 - Injection Well Completion Stage and Injection Interval, Appendix D
§146.86(b)(1)(v)	Corrosiveness of the carbon dioxide stream and formation fluids;	§5.203(e)(2)(F) a description of the capability of the materials to withstand corrosion when exposed to a combination of the CO2 stream and formation fluids;	Appendix E
§146.86(b)(1)(vi)	Down-hole temperatures;	§5.203(e)(2)(G) down-hole temperatures and pressures;	4.4.4 Fracture Pressure, Fluid Characteristics, and Downhole Conditions
§146.86(b)(1)(vii)	Lithology of injection and confining zone(s);	§5.203(e)(2)(H) lithology of injection and confining zones;	Section 4.4 - Pre-Operational Testing Plan
§146.86(b)(1)(viii)	Type or grade of cement and cement additives; and	§5.203(e)(2)(I) type or grade of cement and additives;	4.2.2 Production Casing Design and Completion
§146.86(b)(1)(ix)	Quantity, chemical composition, and temperature of the carbon dioxide stream.	§5.203(e)(2)(J) chemical composition and temperature of the CO2 stream;	Section 1 - Introduction Section 4.5.5 - CO2 Stream Characteristics
§146.86(b)(2)	Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or	§5.203(e)(1)(B)(iii) Surface casing must extend through the base of the lowermost USDW above the injection zone and must be	Section 4.2.2 - Production Casing Design and Completion,

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	multiple strings of casing and cement.	cemented to the surface.	Appendix D
§146.86(b)(3)	At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.	§5.203(e)(1)(B)(v) At least one long string casing, using a sufficient number of centralizers, must extend from the surface to the injection zone and must be cemented by circulating cement to the surface in one or more stages. The long string casing must isolate the injection zone and other intervals as necessary for the protection of USDWs and to ensure confinement of the injected and formation fluids to the permitted injection zone using cement and/or other isolation techniques. If the long string casing does not extend through the injection zone, another well string or liner must be cemented through the injection zone (for example, a chrome liner).	Section 4.2.2 - Production Casing Design and Completion, Appendix D
§146.86(b)(4)	Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.	§5.203(e)(1)(B)(iv) Circulation of cement may be accomplished by staging. The director may approve an alternative method of cementing in cases where the cement cannot be circulated to the surface, provided the applicant can demonstrate by using logs that the cement does not allow fluid movement between the casing and the well bore.	Section 4.2.2 - Production Casing Design and Completion, Appendix D

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.86(b)(5)	Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	§5.203(e)(1)(B)(ii) Casing, cement, cement additives, and/or other materials used in the construction of each injection well must have sufficient structural strength and must be of sufficient quality and quantity to maintain integrity over the design life of the injection well. All well materials must be suitable for use with fluids with which the well materials may be expected to come into contact and must meet or exceed test standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards as approved by the director. §5.203(e)(1)(B)(vi) The applicant must verify the integrity and location of the cement using technology capable of radial evaluation of cement quality and identification of the location of channels to ensure that USDWs will not be endangered.	Section 4.1 - Objectives Section 4.2 - Engineering Design
§146.86(c)	Tubing and packer.		Section 4.2.3 - Injection Tubing Design and Completion Section 4.2.6 - Injection Tubing Packer Design and Completion

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.86(c)(1)	Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.	§5.203(e)(1)(B)(ii)Casing, cement, cement additives, and/or other materials used in the construction of each injection well must have sufficient structural strength and must be of sufficient quality and quantity to maintain integrity over the design life of the injection well. All well materials must be suitable for use with fluids with which the well materials may be expected to come into contact and must meet or exceed test standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards as approved by the director.	Section 4.1 - Objectives Section 4.2.3 - Injection Tubing Design and Completion Section 4.2.6 - Injection Tubing Packer Design and Completion
§146.86(c)(2)	All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director	§5.203(e)(1)(C)(i)Tubing and packer. All injection wells must inject fluids through tubing set on a packer. Packers must be set no higher than 100 feet above the top of the permitted injection interval or at a location approved by the director.	Section 4.2.3 - Injection Tubing Design and Completion
§146.86(c)(3)	In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:	§5.203(e)(2)Construction information. The applicant must provide the following information for each well to allow the director to determine whether the proposed well construction and completion design will meet the general performance criteria in paragraph (1) of this subsection:	See Below
§146.86(c)(3)(i)	Depth of setting;	§5.203(e)(2)(E) type of packer and packer setting depth;	Section 4.2.3 - Injection Tubing Design and Completion, Appendix D

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.86(c)(3)(ii)	Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;	§5.203(e)(2)(F) a description of the capability of the materials to withstand corrosion when exposed to a combination of the CO2 stream and formation fluids; §5.203(e)(2)(J) chemical composition and temperature of the CO2 stream; and	Section 1 - Introduction Section 4.5.5 - CO2 Stream Characteristics
§146.86(c)(3)(iii)	Maximum proposed injection pressure;	§5.203(e)(2)(D) proposed injection rate (intermittent or continuous), maximum proposed surface injection pressure, external pressure, internal pressure, axial loading, and maximum proposed volume and/or mass of the CO2 stream to be injected;	Section 4.2.3 - Injection Tubing Design and Completion
§146.86(c)(3)(iv)	Maximum proposed annular pressure;		Section 4.5.3 - Annulus Pressure
§146.86(c)(3)(v)	Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;	§5.203(e)(2)(D) proposed injection rate (intermittent or continuous), maximum proposed surface injection pressure, external pressure, internal pressure, axial loading, and maximum proposed volume and/or mass of the CO2 stream to be injected;	Section 4.2.3 - Injection Tubing Design and Completion
§146.86(c)(3)(vi)	Size of tubing and casing; and	§5.203(e)(2)(C) size and grade of all casing and tubing strings (e.g., wall thickness, external diameter, nominal weight, length, joint specification and construction material, tubing tensile, burst, and collapse strengths	Section 4.2.2 - Production Casing Desing and Completion Section 4.2.3 - Injection Tubing Design and Completion

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.86(c)(3)(vii)	Tubing tensile, burst, and collapse strengths.	§5.203(e)(2)(C) size and grade of all casing and tubing strings (e.g., wall thickness, external diameter, nominal weight, length, joint specification and construction material, tubing tensile, burst, and collapse strengths	Section 4.2.2 - Production Casing Desing and Completion Section 4.2.3 - Injection Tubing Design and Completion Section 4.2.5 - Surface Casing Design and Completion
§146.82(a)(7)	Proposed operating data for the proposed geologic sequestration site:	§5.203(i) Operating information. (1) Operating plan. The applicant must submit a plan for operating the injection wells and the geologic storage facility that complies with the criteria set forth in §5.206(d) of this title, and that outlines the steps necessary to conduct injection operations. The applicant must include the following proposed operating data in the plan:	See Below
§146.82(a)(7)(i)	Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	§5.203(i)(1)(A) the average and maximum daily injection rates, temperature, and volumes and/or mass of the CO2 stream;	Section 4.5.2 - CO2 Volume
§146.82(a)(7)(ii)	Average and maximum injection pressure;	§5.203(i)(1)(B) the average and maximum surface injection pressure;	Section 4.5.1 - Injection Rate and Pressure
§146.82(a)(8)	Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at § 146.87;	§5.203(c)(2)(F) a description of the formation testing program used and the analytical results used to determine the chemical and physical characteristics of the injection zone and the confining zone; and	Section 4.4 - Pre-Operational Testing Plan
§146.82(a)(9)	Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;	§5.203(e)(4) Well stimulation plan. The applicant must submit a description of the proposed well stimulation program, including a description of the stimulation fluids, and a determination that well stimulation will not	Section 4.5.4 - Well Stimulation Procedures

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		compromise containment.	
§146.82(a)(10)	Proposed procedure to outline steps necessary to conduct injection operation;	§5.203(i) Operating information. (1) Operating plan. The applicant must submit a plan for operating the injection wells and the geologic storage facility that complies with the criteria set forth in §5.206(d) of this title, and that outlines the steps necessary to conduct injection operations. The applicant must include the following proposed operating data in the plan:	Section 4.5 - Injection Well Operating Strategy
§146.82(a)(11)	Schematics or other appropriate drawings of the surface and subsurface construction details of the well;	§5.203(e)(2) Construction information. The applicant must provide the following information for each well to allow the director to determine whether the proposed well construction and completion design will meet the general performance criteria in paragraph (1) of this subsection: (K) schematic drawings of the surface and subsurface construction details.	Appendix D
§146.82(a)(12)	Injection well construction procedures that meet the requirements of § 146.86;	§5.203(e) Injection well construction. (1) Criteria for construction of anthropogenic CO2 injection wells. This paragraph establishes the criteria for the information about the construction and casing and cementing of, and special equipment for, anthropogenic CO2 injection wells that an applicant must include in an application.	Section 4.7 - Injection Well Construction and Operation Summary Appendix D

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.87(a)	During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under § 146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:	§5.203(f) Plan for logging, sampling, and testing of injection wells before injection. The applicant must submit a plan for logging, sampling, and testing of each injection well prior to injection well operation. The plan need not include identical logging, sampling, and testing procedures for all wells provided there is a reasonable basis for different procedures. Such plan is not necessary for existing wells being converted to anthropogenic CO2 injection wells in accordance with this subchapter, to the extent such activities already have taken place. The plan must describe the logs, surveys, and tests to be conducted to verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in, the formations that are to be used for monitoring, storage, and confinement to assure conformance with the injection well construction requirements set forth in subsection (e) of this section, and to establish accurate baseline data against which future measurements may be compared. The plan must meet the following criteria and must include the following information.	Appendix D

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.87(a)(1)	Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and	§5.203(f)(1)(A) During the drilling of any hole that is constructed by drilling a pilot hole that is enlarged by reaming or another method, the operator must perform deviation checks at sufficiently frequent intervals to determine the location of the borehole and to assure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling.	Appendix D
§146.87(a)(2)	Before and upon installation of the surface casing:	§5.203(f)(1)(B) Before surface casing is installed, the operator must run appropriate logs, such as resistivity, spontaneous potential, and caliper logs.	See Below
§146.87(a)(2)(i)	Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	§5.203(f)(1)(B) Before surface casing is installed, the operator must run appropriate logs, such as resistivity, spontaneous potential, and caliper logs.	Section 4.4.2 - Injection and Confining Zone Core Sampling
§146.87(a)(2)(ii)	A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.	§5.203(f)(1)(C) After each casing string is set and cemented, the operator must run logs, such as a cement bond log, variable density log, and a temperature log, to ensure proper cementing.	Section 4.3 Well Drilling and Completion Design
§146.87(a)(3)	Before and upon installation of the long string casing:	§5.203(f)(1)(D) Before long string casing is installed, the operator must run logs appropriate to the geology, such as resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs, to gather data necessary to verify the characterization of the geology and hydrology.	See Below

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.87(a)(3)(i)	Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and	§5.203(f)(1)(D) Before long string casing is installed, the operator must run logs appropriate to the geology, such as resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs, to gather data necessary to verify the characterization of the geology and hydrology.	Section 4.4.2 - Injection and Confining Zone Core Sampling
§146.87(a)(3)(ii)	A cement bond and variable density log, and a temperature log after the casing is set and cemented.	§5.203(e)(1)(B)(vi) The applicant must verify the integrity and location of the cement using technology capable of radial evaluation of cement quality and identification of the location of channels to ensure that USDWs will not be endangered	Section 4.3 Well Drilling and Completion Design
§146.87(a)(4)	A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	§5.203(h) (2) Mechanical integrity testing plan. The applicant must prepare and submit a mechanical integrity testing plan as part of a permit application. The performance tests must be designed to demonstrate the internal and external mechanical integrity of each injection well. These tests may include:	Section 4.2 - Engineering Design Appendix D
§146.87(a)(4)(i)	A pressure test with liquid or gas;	§5.203(h)(2)(A) a pressure test with liquid or inert gas;	Section 4.4 - Pre-Operational Testing Plan
§146.87(a)(4)(ii)	A tracer survey such as oxygen-activation logging;	§5.203(h)(2)(B) a tracer survey such as oxygen-activation logging;	Section 4.3 Well Drilling and Completion Design
§146.87(a)(4)(iii)	A temperature or noise log;	§5.203(h)(2)(C) a temperature or noise log;	Section 4.4.1 and 4.4.2
§146.87(a)(4)(iv)	A casing inspection log; and	§5.203(h)(2)(D) a casing inspection log; and/or	Section 4.4.1 - Tests During Well Drilling and Construction

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.87(a)(5)	Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	§5.203(h)(2)(E) any alternative method approved by the director, and if necessary by the Administrator of EPA under 40 CFR §146.89(e), that provides equivalent or better information approved by the director.	Not Applicable
§146.87(b)	The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: Well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.	§5.203(f)(3)(B) The operator must take whole cores or sidewall cores representative of the injection zone and confining zone and formation fluid samples from the injection zone. The director may require the operator to core other formations in the borehole. The director may accept data from cores and formation fluid samples from nearby wells or other data if the operator can demonstrate to the director that such data are representative of conditions at the proposed injection well. The operator must submit to the director a detailed report prepared by a log analyst that includes well log analyses (including well logs), core analyses, and formation fluid sample information.	Section 4.4.2 - Injection and Confining Zone Core Sampling
§146.87(c)	The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	§5.203(f)(3)(A) The operator must record and submit the formation fluid temperature, pH, and conductivity, the reservoir pressure, and the static fluid level of the injection zone.	Section 4.4.3 - Injection Zone Characterization Appendix D
§146.87(d)	At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):	§5.203(f)(2)(C) The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure does not exceed the fracture pressure of the injection zone.	See Below

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.87(d)(1)	Fracture pressure;	§5.203(f)(2)(C) The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure does not exceed the fracture pressure of the injection zone.	Section 4.4.4 - Fracture Pressure, Fluid Characteristics, and Downhole Conditions
§146.87(d)(2)	Other physical and chemical characteristics of the injection and confining zone(s); and	§5.203(c)(2)(B) the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of, and the geochemistry of any formation fluids in, the storage reservoir and confining zone and any other relevant geologic formations, including geology/facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and lithologic descriptions, and the analyses of logging, sampling, and testing results used to make such determinations;	Section 4.4.4 - Fracture Pressure, Fluid Characteristics, and Downhole Conditions
§146.87(d)(3)	Physical and chemical characteristics of the formation fluids in the injection zone(s).	§5.203(c)(2)(B) the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of, and the geochemistry of any formation fluids in, the storage reservoir and confining zone and any other relevant geologic formations, including geology/facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and lithologic descriptions, and the analyses of logging, sampling, and testing results used to make such determinations;	Section 4.4.4 - Fracture Pressure, Fluid Characteristics, and Downhole Conditions

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.87(e)	Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	§5.203 (f)(2) Testing and determination of hydrogeologic characteristics of injection and confining zone.(A) Prior to operation, the operator must conduct tests to verify hydrogeologic characteristics of the injection zone.	See Below
§146.87(e)(1)	A pressure fall-off test; and,	§5.203(f)(2)(B)The operator must perform an initial pressure fall-off or other test and submit to the director a written report of the results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing log, to verify permeability, injectivity, and initial pressure using water or CO2.	Section 4.4.5 - Injection and Confining Zone Formation Testing
§146.87(e)(2)	A pump test; or		
§146.87(e)(3)	Injectivity tests.		
§146.87(f)	The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.	§5.206(i) Permit conditions for Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	Section 4.5.4 - Well Stimulation Procedures Appendix D
§146.88	Injection well operating requirements		See Below
§146.88(a)	Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to	§5.206(d)(2)(C) The operator must comply with a maximum surface injection pressure limit approved by the director and specified in the permit. In approving a maximum surface	Section 4.5.1 - Injection Rate and Pressure

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.	injection pressure limit, the director must consider the results of well tests and, where appropriate, geomechanical or other studies that assess the risks of tensile failure and shear failure. The director must approve limits that, with a reasonable degree of certainty, will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults or fractures transecting the confining zone to become transmissive. In no case may injection pressure cause movement of injection fluids or formation fluids in a manner that endangers USDWs. The Commission shall include in any permit it might issue a limit of 90 percent of the fracture pressure to ensure that the injection pressure does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. The director may approve a plan for controlled artificial fracturing of the injection zone.§5.203(f)(2)(C) The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure does not exceed the fracture pressure of the injection zone.	
§146.88(b)	Injection between the outermost casing protecting USDWs and the well bore is	§5.206(d)(2)(A) Injection between the outermost casing protecting USDWs and the	4.2.2 Production Casing Design and Completion

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	prohibited.	well bore is prohibited.	
§146.88(c)	The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	§5.206(d)(2)(D)The operator must fill the annulus between the tubing and the long string casing with a corrosion inhibiting fluid approved by the director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the director determines that such requirement might harm the integrity of the well or endanger USDWs.	Section 4.2.6 - Injection Tubing and Packer Design and Completion Section 4.3 - Well Drilling and Completion Design
§146.88(d)	Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	§5.203(h)(1)(A) Other than during periods of well workover in which the sealed tubing-casing annulus is of necessity disassembled for maintenance or corrective procedures, the operator must maintain mechanical integrity of the injection well at all times.	4.2.2 - Production Casing Design and Completion and Appendix D.1, D.2, and D.3

Section 5 - Testing and Monitoring & Appendix E, F			
§146.87(e)	Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	§5.203(f)(2) Testing and determination of hydrogeologic characteristics of injection and confining zone.(A) Prior to operation, the operator must conduct tests to verify hydrogeologic characteristics of the injection zone.	Section 5 – Testing and Monitoring Plan
§146.87(e)(1)	A pressure fall-off test; and,	§5.203(f)(2)(B)The operator must perform an initial pressure fall-off or other test and submit to the director a written report of the results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing	Section 5.7 - Pressure Fall-Off Testing

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		log, to verify permeability, injectivity, and initial pressure using water or CO2.	
§146.87(e)(2)	A pump test; or		Not Applicable
§146.87(e)(3)	Injectivity tests.		4.4.5 Injection and Confining Zone Formation Testing
§146.90	The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:	§5.206(e)(1)The operator of an anthropogenic CO2 injection well must maintain and comply with the approved monitoring, sampling, and testing plan to verify that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone. §5.206(a) (1) Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit. §5.203(j) Plan for monitoring, sampling, and testing after initiation of operation. (1) The applicant must submit a monitoring, sampling, and testing plan for verifying that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone. (2) The plan must include the following:	Section 5.0 - Testing and Monitoring Plan Section 5.1 - Objectives

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.90(a)	Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	§5.203(j)(2)(A) the analysis of the CO2 stream prior to injection with sufficient frequency to yield data representative of its chemical and physical characteristics;	Section 5.8 - Monitoring of CO2 Stream Section 5.12 - Testing Plan Review and Updates
§146.90(b)	Installation and use, except during well workovers as defined in § 146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;	§5.203(j)(2)(B) the installation and use of continuous recording devices to monitor injection pressure, rate, temperature, and volume and/or mass, and the pressure on the annulus between the tubing and the long string casing, except during workovers;	Section 5.5 - Continuous Recording of Operational Parameters During Injection, 5.5.1 - Continuous Monitoring of Injection Rate and Volume, 5.5.2 - Continuous Monitoring of Injection Temperature and Pressure at Injection Well, 5.5.3 - Continuous Monitoring Injection Temperature and Pressure in Reservoir, 5.12 - Testing Plan Review and Updates
§146.90(c)	Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in § 146.86(b), by:	§5.203(j)(2)(C) after initiation of injection, the performance on a quarterly basis of corrosion monitoring of the well materials 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 set forth in subsection (e)(1)(A) of this section. The operator must report the results of such monitoring semi-annually. Corrosion monitoring may be accomplished by:	Section 5.6 - Corrosion Monitoring, 5.6.2 - Monitoring Location and Frequency, 5.12 - Testing Plan Review Updates

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.90(c)(1)	Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	§5.203(j)(2)(C)(i) analyzing coupons of the well construction materials in contact with the CO2 stream;	Section 5.6.1 - Monitoring Location and Frequency
§146.90(c)(2)	Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	§5.203(j)(2)(C)(ii) routing the CO2 stream through a loop constructed with the materials used in the well and inspecting the materials in the loop; or	Section 5.6.1 - Monitoring Location and Frequency
§146.90(c)(3)	Using an alternative method approved by the Director;	§5.203(j)(2)(C)(iii) using an alternative method, materials, or time period approved by the director;	Not Applicable
§146.90(d)	Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:	§5.203(j)(2)(D) monitoring of geochemical and geophysical changes, including: (i) periodic sampling of the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the injection zone and monitoring for pressure changes, and for changes in geochemistry, in a permeable and porous formation near to and above the top confining zone; (ii) periodic monitoring of the quality and geochemistry of a USDW within the AOR and the formation fluid in a permeable and porous formation near to and above the top confining zone to detect any movement of the injected CO2 through the confining zone into that monitored formation;	Section 5.2 - Overall Strategy and Approach for Testing and Monitoring Plan, 5.10 - CO2 Plume Tracking Using Groundwater Monitoring Data, 5.10.3 - USDW Monitoring Well Network, 5.12 - Testing Plan Review and Updates
§146.90(d)(1)	The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and	§5.203(j)(2)(D)(iii)the location and number of monitoring wells justified on the basis of the AOR, injection rate and volume, geology, and the presence of artificial penetrations and other factors specific to the geologic storage facility; and	Section 5.10.2 - Design of the Monitoring Well Network

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.90(d)(2)	The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under § 146.82(a)(6) and on any modeling results in the area of review evaluation required by § 146.84(c).	§5.203(j)(2)(D)(iv) the monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data collected under subsection (c)(2) of this section and any modeling results in the AOR evaluation;	Section 5.10.2 - Design of the Monitoring Well Network
§146.90(e)	A demonstration of external mechanical integrity pursuant to § 146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at § 146.89(d) at a frequency established in the testing and monitoring plan;	§5.203(h)(1)(D) At least once per year until the injection well is plugged, the operator must confirm the absence of significant fluid movement into a USDW through channels adjacent to the injection wellbore (external integrity) using a method approved by the director (e.g., diagnostic surveys such as oxygen-activation logging or temperature or noise logs).§5.203(h)(2) Mechanical integrity testing plan. The applicant must prepare and submit a mechanical integrity testing plan as part of a permit application. The performance tests must be designed to demonstrate the internal and external mechanical integrity of each injection well. These tests may include:((D) a casing inspection log; and/or	Section 5.4.2 - External Mechanical Integrity Testing Section 5.12 - Testing Plan Review and Updates
§146.90(f)	A pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information;	§5.203(j)(2)(G) a pressure fall-off test at least once every five years unless more frequent testing is required by the director based on site-specific information; and	Section 5.7 - Pressure Fall-Off Testing Section 5.12 - Testing Plan Review and Updates
§146.90(g)	Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:	§5.203(j)(2)(E) tracking the extent of the CO2 plume and the position of the pressure front by using indirect, geophysical techniques, which may include seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO2 detection tools;	Section 5.9 - CO2 Plume and Pressure Front Tracking

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.90(g)(1)	Direct methods in the injection zone(s); and,		Section 5.2 - Overall Strategy and Approach for Testing and Monitoring Plan Section 5.12 - Testing Plan Review and Updates
§146.90(g)(2)	Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate;	§5.203(j)(2)(E) tracking the extent of the CO2 plume and the position of the pressure front by using indirect, geophysical techniques, which may include seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO2 detection tools;	Section 5.2 - Overall Strategy and Approach for Testing and Monitoring Plan, 5.9.2 - Plume and Pressure Front Tracking Using Indirect Geophysical Techniques, 5.12 - Testing Plan Review and Updates
§146.90(h)	The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.	§5.203(j)(2)(G) additional monitoring as the director may determine to be necessary to support, upgrade, and improve computational modeling of the AOR evaluation and to determine compliance with the requirements that the injection activity not allow the movement of fluid containing any contaminant into USDWs and that the injected fluid remain within the permitted interval.	Section 5.10.5 - Construction of In-Zone Monitoring Well
§146.90(h)(1)	Design of Class VI surface air and/or soil gas monitoring must be based on potential risks to USDWs within the area of review;		Section 5.3 - Use of Phased and/or Triggered Approach
§146.90(h)(2)	The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must		Section 5.3 - Use of Phased and/or Triggered Approach

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under §3603.D;		
§146.90(h)(3)	If an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 et seq.) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and meets the requirements pursuant to § 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under §§ 98.440 to 98.449 of this chapter. Compliance with §§ 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit;		Section 5.3 - Use of Phased and/or Triggered Approach
§146.90(i)	Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under § 146.84(c) and to determine compliance with standards under § 144.12 of this chapter;	§5.203(j)(2)(G) additional monitoring as the director may determine to be necessary to support, upgrade, and improve computational modeling of the AOR evaluation and to determine compliance with the requirements that the injection activity not allow the movement of fluid containing any contaminant into USDWs and that the injected fluid remain within the permitted interval.	Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.90(j)	The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under § 146.88, and the most recent area of review reevaluation performed under § 146.84(e). In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:	§ 5.207(a)(2)(E) Annual updates. The operator must maintain and update required plans in accordance with the provisions of this subchapter. (i) Operators must submit an annual statement, signed by an appropriate company official, confirming that the operator has: (I) reviewed the monitoring and operational data that are relevant to a decision on whether to reevaluate the AOR and the monitoring and operational data that are relevant to a decision on whether to update an approved plan required by §5.203 or §5.206 of this title; and (II) determined whether any updates were warranted by material change in the monitoring and operational data or in the evaluation of the monitoring and operational data by the operator. (ii) Operators must submit either the updated plan or a summary of the modifications for each plan for which an update the operator determined to be warranted pursuant to subclause (I) of this clause. The director may require submission of copies of any updated plans and/or additional information regarding whether or not updates of any particular plans are warranted.	Section 5.12 - Testing Plan Review and Updates
§146.90(j)(1)	Within one year of an area of review reevaluation;	§ 5.207(a)(2)(E) Annual updates. The operator must maintain and update required plans in accordance with the provisions of this subchapter.	Section 5.12 - Testing Plan Review and Updates

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.90(j)(2)	Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the Director; or	§ 5.207(a)(3) The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or whenever the director determines that such a revision is necessary to comply with the requirements of this subchapter.	Section 5.10.5 - Construction of In-Zone Monitoring Well
§146.90(j)(3)	When required by the Director.	§ 5.207(a)(3) The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or whenever the director determines that such a revision is necessary to comply with the requirements of this subchapter.	Section 5.10.5 - Construction of In-Zone Monitoring Well
§146.90(k)	A quality assurance and surveillance plan for all testing and monitoring requirements.	§5.203(a)(4) Reports. An applicant must ensure that all descriptive reports are prepared by a qualified and knowledgeable person and include an interpretation of the results of all logs, surveys, sampling, and tests required in this subchapter. The applicant must include in the application a quality assurance and surveillance plan for all testing and monitoring, which includes, at a minimum, validation of the analytical laboratory data, calibration of field instruments, and an explanation of the sampling and data acquisition techniques.	Section 5.7.3 - Quality Assurance/Quality Control
§146.89(a)	A Class VI well has mechanical integrity if:	§5.102(36)(A) An anthropogenic CO2 injection well has mechanical integrity if:	Section 5.4 - Mechanical Integrity Test Methods

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.89(a)(1)	There is no significant leak in the casing, tubing, or packer; and	§5.102(36)(A)(i) there is no significant leak in the casing, tubing, or packer; and	Section 5.4 - Mechanical Integrity Test Methods
§146.89(a)(2)	There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.	§5.102(36)(A)(ii)there is no significant fluid movement into a stratum containing an underground source of drinking water through channels adjacent to the injection well bore as a result of operation of the injection well.	Section 5.4 - Mechanical Integrity Test Methods
§146.89(b)	To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	§5.203(h)(1)(C) Following an initial annulus pressure test, the operator must continuously monitor injection pressure, rate, temperature, injected volumes and mass, and pressure on the annulus between tubing and long string casing to confirm that the injected fluids are confined to the injection zone. If mass is determined using volume, the operator must provide calculations.	Section 5.5 - Continuous Recording of Operational Parameters During Injection
§146.89(b)	To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	§5.203(h)(1)(C) Following an initial annulus pressure test, the operator must continuously monitor injection pressure, rate, temperature, injected volumes and mass, and pressure on the annulus between tubing and long string casing to confirm that the injected fluids are confined to the injection zone. If mass is determined using volume, the operator must provide calculations.	Section 5.5 - Continuous Recording of Operational Parameters During Injection
§146.89(c)	At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (a)(2) of this section:	(D) At least once per year until the injection well is plugged, the operator must confirm the absence of significant fluid movement into a USDW through channels adjacent to the injection wellbore (external integrity) using a method approved by the director (e.g., diagnostic surveys such as oxygen-activation	Section 5.4.2 - External Mechanical Integrity Testing

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		logging or temperature or noise logs).	
§146.89(c)(1)	An approved tracer survey such as an oxygen-activation log; or	§5.203(h)(2)(B) a tracer survey such as oxygen-activation logging;	Section 5.4.2 - External Mechanical Integrity Testing
§146.89(c)(2)	A temperature or noise log.	§5.203(h)(2)(C) a temperature or noise log;	Section 5.4.2 - External Mechanical Integrity Testing
§146.89(d)	If required by the Director, at a frequency specified in the testing and monitoring plan required at § 146.90, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long-string casing.	§5.203(h)(2)(D) a casing inspection log; and/or	Section 5.6.3 - Cement Evaluation and Casing Inspection Logs

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.89(e)	The Director may require any other test to evaluate mechanical integrity under paragraphs (a)(1) or (a)(2) of this section. Also, the Director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator. To obtain approval for a new mechanical integrity test, the Director must submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use. The Administrator may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator will be published in the Federal Register and may be used in all States in accordance with applicable State law unless its use is restricted at the time of approval by the Administrator.	§5.203(h)(2)(E) any alternative method approved by the director, and if necessary by the Administrator of EPA under 40 CFR §146.89(e), that provides equivalent or better information approved by the director.	Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.89(f)	In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he/she shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director must review monitoring and other test data submitted since the previous evaluation.	§5.207 Reporting and Record-Keeping(a) Reporting requirements. The operator of a geologic storage facility must provide, at a minimum, the following reports to the director and retain the following information.(1) Test records. The operator must file a complete record of all tests in duplicate with the district office within 30 days after the testing. In conducting and evaluating the tests enumerated in this subchapter or others to be allowed by the director, the operator and the director must apply methods and standards generally accepted in the industry. When the operator reports the results of mechanical integrity tests to the director, the operator must include a description of any tests and methods used. In making this evaluation, the director must review monitoring and other test data submitted since the previous evaluation.	Section 5.11 - Reporting Requirements
§146.89(g)	The Director may require additional or alternative tests if the results presented by the owner or operator under paragraphs (a) through (d) of this section are not satisfactory to the Director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in paragraphs (a)(1) and (2) of this section.	§5.206(f)(5) The director may require additional or alternative tests if the results presented by the operator do not demonstrate to the director that there is no significant leak in the casing, tubing, or packer or movement of fluid into or between formations containing USDWs resulting from the injection activity.	Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.91	The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well:	§5.207 (a) Reporting requirements. The operator of a geologic storage facility must provide, at a minimum, the following reports to the director and retain the following information.	
§146.91(a)	Semi-annual reports containing:	§5.207(a)(2)(C) Semi-annual report. The operator must report:	
§146.91(a)(1)	Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	§5.207(a)(2)(C)(ii) changes to the source as well as the physical, chemical, and other relevant characteristics of the CO2 stream from the proposed operating data;	Section 5.11 - Reporting Requirements
§146.91(a)(2)	Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	§5.207(a)(2)(C)(iii) monthly average, maximum and minimum values for injection pressure, flow rate, temperature, and volume and/or mass, and annular pressure	Section 5.11 - Reporting Requirements
§146.91(a)(3)	A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	§5.207(a)(2)(C)(v) a description of any event that significantly exceeds operating parameters for annulus pressure or injection pressure as specified in the permit;	Section 5.11 - Reporting Requirements
§146.91(a)(4)	A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken;	§5.207(a)(2)(C)(vi) a description of any event that triggers a shutdown device and the response taken; and	Section 5.11 - Reporting Requirements
§146.91(a)(5)	The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;	§5.207(a)(2)(C)(iii) monthly average, maximum and minimum values for injection pressure, flow rate, temperature, and volume and/or mass, and annular pressure	Section 5.11 - Reporting Requirements
§146.91(a)(6)	Monthly annulus fluid volume added; and	§5.207(a)(2)(C)(iv) monthly annulus fluid volume added;	Section 5.11 - Reporting Requirements
§146.91(a)(7)	The results of monitoring prescribed under § 146.90.	§5.207(a)(2)(C)(vii) the results of monitoring prescribed under	Section 5.11 - Reporting Requirements

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		§5.206(e) of this title (relating to Permit Standards).	
§146.91(b)	Report, within 30 days, the results of:	§5.207(a)(2)(B) Report within 30 days. The operator must report:	See Below
§146.91(b)(1)	Periodic tests of mechanical integrity;	§5.207(a)(2)(B)(i) the results of periodic tests for mechanical integrity;	Section 5.4.3 - Reporting Results of MIT
§146.91(b)(2)	Any well workover; and,	§5.207(a)(2)(B)(iii) a description of any well workover.	Section 5.11 - Reporting Requirements
§146.91(b)(3)	Any other test of the injection well conducted by the permittee if required by the Director.	§5.207(a)(2)(B)(ii) the results of any other test of the injection well conducted by the operator if required by the director; and	Not Applicable
§146.91(c)	Report, within 24 hours:	§5.207(a)(2)(A) Report within 24 hours. The operator must report the items listed in clauses (i) through (v) of this subparagraph to the director and the appropriate district office orally as soon as practicable, but within 24 hours of discovery, and in writing within five working days of discovery. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue, and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The operator shall report the following items:	Section 5.11 - Reporting Requirements
§146.91(c)(1)	Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;	§5.207(a)(2)(A)(ii) any evidence that the injected CO2 stream or associated pressure front may cause an endangerment to a USDW;	Section 5.11 - Reporting Requirements

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.91(c)(2)	Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	§5.207(a)(2)(A)(iii) any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	Section 5.11 - Reporting Requirements
§146.91(c)(3)	Any triggering of a shut-off system (i.e., down-hole or at the surface);	§5.206(d)(2)(F)(ii) If an automatic shutdown is triggered or a loss of mechanical integrity is discovered, the operator must immediately investigate and identify as expeditiously as possible the cause. If, upon investigation, the well appears to be lacking mechanical integrity, or if monitoring otherwise indicates that the well may be lacking mechanical integrity, the operator must: (III) notify the director as soon as practicable, but within 24 hours;	Section 5.11 - Reporting Requirements
§146.91(c)(4)	Any failure to maintain mechanical integrity; or.	§5.206(d)(2)(F)(ii) If an automatic shutdown is triggered or a loss of mechanical integrity is discovered, the operator must immediately investigate and identify as expeditiously as possible the cause. If, upon investigation, the well appears to be lacking mechanical integrity, or if monitoring otherwise indicates that the well may be lacking mechanical integrity, the operator must:(III) notify the director as soon as practicable, but within 24 hours;	Section 5.11 - Reporting Requirements
§146.91(c)(5)	Pursuant to compliance with the requirement at § 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere.		Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.91(d)	Owners or operators must notify the Director in writing 30 days in advance of:	§5.206(i) Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	See Below
§146.91(d)(1)	Any planned well workover;	§5.207(a)(2)(B)(iii) a description of any well workover. §5.206(i) Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	Section 5.11 - Reporting Requirements

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.91(d)(2)	Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and	§5.206(i) Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	
§146.91(d)(3)	Any other planned test of the injection well conducted by the permittee.	§5.207(a)(2)(B)(i) the results of periodic tests for mechanical integrity; (ii) the results of any other test of the injection well conducted by the operator if required by the director; and §5.206(i) Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	Section 5.4 - Mechanical Integrity Test Methods

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.91(e)	Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	§5.203 (a)(1)(A) Form and filing. Each applicant for a permit to construct and operate a geologic storage facility must file an application with the division in Austin on a form prescribed by the Commission. The applicant must file the application and all attachments with the division and with EPA Region 6 in an electronic format approved by EPA. On the same date, the applicant must file one copy with each appropriate district office and one copy with the Executive Director of the Texas Commission on Environmental Quality. §5.207(b)(2) The operator must submit all required reports, submittals, and notifications under this subchapter to the director and to the EPA in an electronic format approved by the director and the Regional Administrator, respectively.	Section 5.11 - Reporting Requirements
§146.91(f)	Records shall be retained by the owner or operator as follows:	§5.206(m) (2)The permittee shall retain records as follows:	Section 5.11 - Reporting Requirements
§146.91(f)(1)	All data collected under § 146.82 for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for 10 years following site closure.	§5.206(m) (2) (A) All data collected under §5.203 of this title for Class VI permit applications shall be retained throughout the life of the geologic storage project and for 10 years following site closure.	Section 5.11 - Reporting Requirements
§146.91(f)(2)	Data on the nature and composition of all injected fluids collected pursuant to § 146.90(a) shall be retained until 10 years after site closure. The Director may require the owner or operator to deliver the records to the Director at the conclusion of the retention	§5.206(m) (2) (B) Data on the nature and composition of all injected fluids collected pursuant to §5.203(i)(1)(D) of this title shall be retained until 10 years following site closure. The director may require the operator to submit the records to the director at the	Section 5.11 - Reporting Requirements

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	period.	conclusion of the retention period.	
§146.91(f)(3)	Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected.	§5.206(m) (2) (C) Monitoring data collected pursuant to §5.203(j)(2) of this title shall be retained for 10 years after it is collected.	Section 5.11 - Reporting Requirements
§146.91(f)(4)	Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at §§ 146.93(f) and (h) shall be retained for 10 years following site closure.	§5.206(m) (2) (D) Well plugging reports, post-injection site care data, including data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements of subsection (k)(6) of this section and paragraph (4) of this subsection shall be retained for 10 years following site closure.	Section 5.11 - Reporting Requirements
§146.91(f)(5)	The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.	§5.206(m) (2) (E)The director has authority to require the operator to retain any records required in this subchapter for longer than 10 years following site closure.	Section 5.11 - Reporting Requirements
§146.88(e)(1)	Continuous recording devices to monitor: The injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and	§5.206(d)(2)(E) The operator must install and use continuous recording devices to monitor the injection pressure, and the rate, volume, and temperature of the CO2 stream. The operator must monitor the pressure on the annulus between the tubing and the long string casing. The operator must continuously record, continuously monitor, or control by a preset high-low pressure sensor switch the wellhead pressure of each injection well.	Section 5.5 - Continuous Recording of Operational Parameters During Injection, 5.9 - CO2 Plume and Pressure Front Tracking 5.11 - Reporting Requirements Table 5-10

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
Section 6 - Plugging Plan & Appendix H			
§146.92(a)	Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	§5.203(k) Well plugging plan. The applicant must submit a well plugging plan for all injection wells and monitoring wells that includes the following: (2) proposals for activities to be undertaken prior to plugging an injection well, specifically: (A) flushing each injection well with a buffer fluid; (B) performing tests or measures to determine bottomhole reservoir pressure; (C) performing final tests to assess mechanical integrity; and	Section 6.2.1 - Flushing Well with Buffer Fluid, 6.2.4 - Planned External MITs, 6.3.2 - Final P&A
§146.92(b)	Well plugging plan. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information:	§5.206 (a)(1)Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit.§5.206(j) Permit conditions for well plugging. The operator of a geologic storage facility must maintain and comply with the approved well plugging plan required by§5.203(k) of this title.§5.203(k)Well plugging plan. The applicant must submit a well plugging plan for all injection wells and monitoring wells that includes the following:	Section 6.1 - Objectives Section 6.3 - Injection Well Zonal Isolation and Final P&A
§146.92(b)(1)	Appropriate tests or measures for determining bottomhole reservoir pressure;	§5.203(k)(2)(B)performing tests or measures to determine bottomhole reservoir pressure;	Section 6.1 - Objectives Section 6.2.3 - Planned Tests or Measures to

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
			Determine Bottomhole Pressure
§146.92(b)(2)	Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89;	§5.203(k)(2)(C) performing final tests to assess mechanical integrity; and	Section 6.1 - Objectives Section 6.3.2 - Final P&A; Section 6.4 - Notification and Record Keeping
§146.92(b)(3)	The type and number of plugs to be used;	§5.203(k)(1)(A)the type and number of plugs to be used;	Section 6.1 - Objectives Section 6.2.5; Section 6.4 - Notification and Record Keeping; Tables 6-4, 6-5, and 6-6
§146.92(b)(4)	The placement of each plug, including the elevation of the top and bottom of each plug;	§5.203(k)(1)(B)the placement of each plug, including the elevation of the top and bottom of each plug;	Tables 6-4, 6-5, and 6-6
§146.92(b)(5)	The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	§5.203(k)(1)(C) the type, grade, and quantity of material to be used in plugging and information to demonstrate that the material is compatible with the CO2 stream; and	Section 6.2.5 - CO2-Compatible Materials, Tables 6-4, 6-5, and 6-6
§146.92(b)(6)	The method of placement of the plugs.	§5.203(k)(1)(D)the method of placement of the plugs;	Section 6.2.5 - CO2 – Compatible Materials, Tables 6-4, 6-5, and 6-6

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.92(c)	Notice of intent to plug. The owner or operator must notify the Director in writing pursuant to § 146.91(e), at least 60 days before plugging of a well. At this time, if any changes have been made to the original well plugging plan, the owner or operator must also provide the revised well plugging plan. The Director may allow for a shorter notice period. Any amendments to the injection well plugging plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	§5.203(k)(3) a proposal for giving notice of intent to plug monitoring wells that penetrate the base of usable quality water and all injection wells. The applicant's plan must ensure that: (A) the operator notifies the director at least 60 days before plugging a well. At this time, if any changes have been made to the original well plugging plan, the operator must also provide a revised well plugging plan. At the discretion of the director, an operator may be allowed to proceed with well plugging on a shorter notice period; and (B) the operator will file a notice of intention to plug and abandon (Form W-3A) a well with the appropriate Commission district office and the division in Austin at least five days prior to the beginning of plugging operations;	Section 6.3.2 - Final P&A; Section 6.6 - Amendments to the P&A Plan

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.92(d)	Plugging report. Within 60 days after plugging, the owner or operator must submit, pursuant to § 146.91(e), a plugging report to the Director. The report must be certified as accurate by the owner or operator and by the person who performed the plugging operation (if other than the owner or operator.) The owner or operator shall retain the well plugging report for 10 years following site closure.	§5.203(k)(4) a plugging report for monitoring wells that penetrate the base of usable quality water and all injection wells. The applicant's plan must ensure that within 30 days after plugging the operator will file a complete well plugging record (Form W-3) in duplicate with the appropriate district office. The operator and the person who performed the plugging operation (if other than the operator) must certify the report as accurate;§5.206(m)(6)The operator must retain for 10 years following storage facility closure records collected to prepare the permit application, data on the nature and composition of all injected fluids, and records collected during the post-injection storage facility care period. The operator must submit the records to the director at the conclusion of the retention period, and the records must thereafter be retained at the Austin headquarters of the Commission.	Section 6.3.2 - Final P&A;
§146.82(a)(16)	Proposed injection well plugging plan required by § 146.92(b);	§5.203(k) Well plugging plan. The applicant must submit a well plugging plan for all injection wells and monitoring wells that includes the following:	Section 6.1 - Objectives Section 6.3 - Injection Well Zonal Isolation and Final P&A

Section 7 - Post Injection Site Care and Closure Plan			
§146.82(a)(17)	Proposed post-injection site care and site closure plan required by § 146.93(a);	§5.203 (m) Post-injection storage facility care and closure plan. The applicant must submit a post-injection storage facility care and closure plan. The plan must include:	Section 7 - Post-Injection Site Care and Site Closure Plan

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.82(a)(18)	At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by § 146.93(c);	(8) information submitted to support the demonstration in paragraph (1) of this subsection, which shall meet the following criteria: (A) all analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards; (B) estimation techniques must be appropriate and EPA-certified test protocols must be used where available; (C) predictive models must be appropriate and tailored to the site conditions, composition of the CO2 stream, and injection and site conditions over the life of the geologic storage project; (D) predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available; (E) reasonably conservative values and modeling assumptions must be used and disclosed to the director whenever values are estimated on the basis of known, historical information instead of site-specific measurements; (F) an analysis must be performed to identify and assess aspects of the alternative post-injection storage facility care timeframe demonstration that contribute significantly to uncertainty. The operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration; (G) an approved quality assurance and quality control plan must address all aspects of the demonstration; and	Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		(H) any additional criteria required by the director.	
§146.93(a)	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of paragraph (a)(2) of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	§5.203(k) (1) (A) Post-injection storage facility care and closure plan. (A)The operator of an injection well must maintain and comply with the approved post-injection storage facility care and closure plan. §5.206 (a) (1) Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit.	Section 7 - Post-Injection Site Care and Site Closure Plan
§146.93(a)(1)	The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the Director.	§5.203(m) Post-injection storage facility care and closure plan.	Section 7 - Post-Injection Site Care and Site Closure Plan
§146.93(a)(2)	The post-injection site care and site closure plan must include the following information:	§5.203(m) Post-injection storage facility care and closure plan. The applicant must submit a post-injection storage facility care and closure plan. The plan must include:	See Below
§146.93(a)(2)(i)	The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	§5.203(m)(2)the pressure differential between pre-injection and predicted post-injection pressures in the injection zone;	Section 7.1 - Objectives; Section 7.2 – Calculation of Pre- and Post-Injection Pressure Differentials; Table 7-1: Maximum Pressure Differential by Year for Injection Wells No. 01,

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
			No. 02, and No. 03
§146.93(c)	Demonstration of alternative post-injection site care timeframe. At the Director's discretion, the Director may approve, in consultation with EPA, an alternative post-injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to §§ 146.82 and 146.83, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe.		Not Applicable
§146.93(c)(1)	A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:	§5.203(m) Post-injection storage facility care and closure plan. The applicant must submit a post-injection storage facility care and closure plan. The plan must include: (7) consideration and documentation of:	Not Applicable
§146.93(c)(1)(i)	The results of computational modeling performed pursuant to delineation of the area of review under § 146.84;	§5.203(m)(7)(A) the results of computational modeling performed pursuant to delineation of the AOR under subsection (d) of this section;	Not Applicable
§146.93(c)(1)(ii)	The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures;	§5.203(m)(7)(B) the predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs, and/or the timeframe for pressure decline to pre-	Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		injection pressures;	
§146.93(c)(1)(ix)	A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;	§5.203(m)(7)(I) a description of the well construction and an assessment of the quality of plugs of all abandoned wells within the AOR;	Not Applicable
§146.93(c)(1)(viii)	The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure;	§5.203(m)(7)(H) the presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic storage project or any other projects in proximity to the predicted/modeled, final extent of the CO2 plume and area of elevated pressure;	Not Applicable
§146.93(c)(2)	Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria:	§5.203(m)(8) information submitted to support the demonstration in paragraph (1) of this subsection, which shall meet the following criteria:	Not Applicable
§146.93(c)(2)(i)	All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	§5.203(m)(8)(A) all analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	Not Applicable
§146.93(c)(2)(ii)	Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	§5.203(m)(8)(B)estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	Not Applicable
§146.93(c)(2)(iii)	Predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project;	§5.203(m)(8)(C)predictive models must be appropriate and tailored to the site conditions, composition of the CO2 stream, and injection and site conditions over the life of the geologic storage project;	Not Applicable
§146.93(c)(2)(iv)	Predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites)	§5.203(m)(8)(D)predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental	Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	where sufficient data are available;	technology well sites) where sufficient data are available;	
§146.93(c)(2)(v)	Reasonably conservative values and modeling assumptions must be used and disclosed to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;	§5.203(m)(8)(E) reasonably conservative values and modeling assumptions must be used and disclosed to the director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;	Not Applicable
§146.93(c)(2)(vi)	An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration.	§5.203(m)(8)(F) an analysis must be performed to identify and assess aspects of the alternative post-injection storage facility care timeframe demonstration that contribute significantly to uncertainty. The operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration;	Not Applicable
§146.93(c)(2)(vii)	An approved quality assurance and quality control plan must address all aspects of the demonstration; and,	§5.203(m)(8)(G) an approved quality assurance and quality control plan must address all aspects of the demonstration; and	Not Applicable
§146.93(c)(2)(viii)	Any additional criteria required by the Director.	§5.203(m)(8)(H) any additional criteria required by the director.	Not Applicable
§146.93(a)(2)(ii)	The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under § 146.84(c)(1);	§5.203(m)(3)the predicted position of the CO2 plume and associated pressure front at closure as demonstrated in the AOR evaluation required under subsection (d) of this section;	Section 7.3 - Predicted Position of the CO2 Plume and Pressure Front at Site Closure; Section
§146.93(a)(2)(iii)	A description of post-injection monitoring location, methods, and proposed frequency;	§5.203(m)(4) a description of the proposed post-injection monitoring location, methods, and frequency;	Section 7.3 - Predicted Position of the CO2 Plume and Pressure Front at Site Closure; Section; 7.3.2 -

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
			Monitoring Above the UCCZ and USDW; Section 7.3.3 - In-Zone CO2 Plume and Pressure Front Tracking;
§146.93(a)(2)(iv)	A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,	§5.203(m)(5) a proposed schedule for submitting post- injection storage facility care monitoring results to the director;	7.3.4 - Submitting PISC Monitoring Results
§146.93(a)(2)(v)	The duration of the post-injection site care timeframe and, if approved by the Director, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.		Section 7.1 – Objectives; Section 7.3.3 – In-Zone CO2 Plume and Pressure Front Tracking
§146.93(a)(3)	Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the post-injection site care and site closure plan must be approved by the Director, be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	§5.206(k)(1)(C) Upon cessation of injection, the operator of a geologic storage facility must either submit an amended plan or demonstrate to the director through monitoring data and modeling results that no amendment to the plan is needed.§5.206(k)(1)(B) The operator must update the plan in accordance with §5.207(a)(2)(D)(vi) of this title. At any time during the life of the geologic sequestration project, the operator may modify and resubmit the post- injection site care and site closure plan for the director's approval within 30 days of such change. Any amendments to the post-injection site care and site closure plan must be approved by the director, be incorporated into the permit, and are subject to the permit modification requirements in §5.202 of this title, as appropriate.	Section 7.3.1 - PISC and Site Closure Plan Reviews and Amendments

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.93(a)(4)	At any time during the life of the geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the Director's approval within 30 days of such change.	§5.206(k)(1)(B) The operator must update the plan in accordance with §5.207(a)(2)(D)(vi) of this title. At any time during the life of the geologic sequestration project, the operator may modify and resubmit the post- injection site care and site closure plan for the director's approval within 30 days of such change. Any amendments to the post-injection site care and site closure plan must be approved by the director, be incorporated into the permit, and are subject to the permit modification requirements in §5.202 of this title, as appropriate.	Section 7.3.1 - PISC and Site Closure Plan Reviews and Amendments
§146.93(b)	The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.	§5.206(k)(2) Post-injection storage facility monitoring. Following cessation of injection, the operator must continue to conduct monitoring as specified in the approved plan until the director determines that the position of the CO2 plume and pressure front are such that the geologic storage facility will not endanger USDWs.	Section 7.1 - Objectives
§146.93(b)(1)	Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to	§5.206(k)(2) Post-injection storage facility monitoring. Following cessation of injection, the operator must continue to conduct monitoring as specified in the approved plan until the director determines that the position of the CO2 plume and pressure front are such that the geologic storage facility will not endanger USDWs.	Section 7.1 - Objectives

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director.		
§146.93(b)(2)	If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.	§5.206(k)(2) Post-injection storage facility monitoring. Following cessation of injection, the operator must continue to conduct monitoring as specified in the approved plan until the director determines that the position of the CO2 plume and pressure front are such that the geologic storage facility will not endanger USDWs.	Section 7.1 - Objectives

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.93(b)(3)	Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.	§5.206(k)(3) Prior to closure. Prior to authorization for storage facility closure, the operator must demonstrate to the director, based on monitoring, other site-specific data, and modeling that is reasonably consistent with site performance that no additional monitoring is needed to assure that the geologic storage facility will not endanger USDWs. The operator must demonstrate, based on the current understanding of the site, including monitoring data and/or modeling, all of the following: (A) the estimated magnitude and extent of the facility footprint (the CO2 plume and the area of elevated pressure); (B) that there is no leakage of either CO2 or displaced formation fluids that will endanger USDWs; (C) that the injected or displaced fluids are not expected to migrate in the future in a manner that encounters a potential leakage pathway into USDWs; (D) that the injection wells at the site completed into or through the injection zone or confining zone will be plugged and abandoned in accordance with these requirements; and (E) any remaining facility monitoring wells will be properly plugged or are being managed by a person and in a manner approved by the director.	Section 7.4 – Demonstration of Non-Endangerment of USDW; Figure 7-3 Extent of Maximum CO2 Plume and Pressure Front Stabilized 55 Years from Start of Injection; Section 7.3.2 – Monitoring Above the UCCZ and USDW; Section 7.5.3 – Site Restoration;

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.93(b)(4)	If the demonstration in paragraph (b)(3) of this section cannot be made (i.e., additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the Director does not approve the demonstration, the owner or operator must submit to the Director a plan to continue post-injection site care until a demonstration can be made and approved by the Director.		Not Applicable
§146.93(d)	Notice of intent for site closure. The owner or operator must notify the Director in writing at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. The Director may allow for a shorter notice period.	§5.206(k)(4)Notice of intent for storage facility closure. The operator must notify the director in writing at least 120 days before storage facility closure. At the time of such notice, if the operator has made any changes to the original plan, the operator also must provide the revised plan. The director may approve a shorter notice period.	Section 7.5 Site Closure Plan
§146.93(e)	After the Director has authorized site closure, the owner or operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW.	§5.206(k)(5) Authorization for storage facility closure. No operator may initiate storage facility closure until the director has approved closure of the storage facility in writing. After the director has authorized storage facility closure, the operator must plug all wells in accordance with the approved plan required by §5.203(k) of this title and submit a plugging record (Form W-3) as required by §3.14 of this title (relating to Plugging).	Section 7.5 Site Closure Plan

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.93(f)	The owner or operator must submit a site closure report to the Director within 90 days of site closure, which must thereafter be retained at a location designated by the Director for 10 years. The report must include:	§5.206(k)(6) Storage facility closure report. Once the director has authorized storage facility closure, the operator must submit a storage facility closure report within 90 days that must thereafter be retained by the Commission in Austin. The report must include the following information:	Section 7.1 – Objectives; Section 7.5 – Site Closure Plan
§146.93(f)(1)	Documentation of appropriate injection and monitoring well plugging as specified in § 146.92 and paragraph (e) of this section. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the Director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The owner or operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office;	§5.206(k)(6)(A) documentation of appropriate injection and monitoring well plugging. The operator must provide a copy of a survey plat that has been submitted to the Regional Administrator of Region 6 of the EPA. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks including the Latitude/Longitude or X/Y coordinates of the surface location in the NAD 27, NAD 83, or WGS 84 coordinate system, a labeled scale bar, and northerly direction arrow;	Section 7.5.4 – Documentation of Site Closure
§146.93(f)(2)	Documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and	§5.206(k)(6)(B) documentation of appropriate notification and information to such state and local authorities as have authority over drilling activities to enable such state and local authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zones; and	Section 7.5.4 – Documentation of Site Closure
§146.93(f)(3)	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	§5.206(k)(6)(C) records reflecting the nature, composition, volume and mass of the CO2 stream. If mass is determined using volume, the operator must provide calculations.	Section 7.5.4 – Documentation of Site Closure

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.93(g)	Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:	§5.206(l)Permit conditions for deed notation. The operator of a geologic storage facility must record a notation on the deed to the facility property; on any other document that is normally examined during title search; or on any other document that is acceptable to the county clerk for filing in the official public records of the county that will in perpetuity provide any potential purchaser of the property the following information:	Section 7.5.4 – Documentation of Site Closure
§146.93(g)(1)	The fact that land has been used to sequester carbon dioxide;	§5.206(l)(2) that land has been used to geologically store CO2 ;	Section 7.5.4 – Documentation of Site Closure
§146.93(g)(2)	The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and	§5.206(l)(3) that the survey plat has been filed with the Commission; §5.206(l)(4) the address of the office of the United States Environmental Protection Agency, Region 6, to which the operator sent a copy of the survey plat; and	Section 7.5.4 – Documentation of Site Closure
§146.93(g)(3)	The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	§5.206(l)(5) the volume and mass of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred. If mass is determined using volume, the operator must provide calculations.	Section 7.5.4 – Documentation of Site Closure
§146.93(h)	The owner or operator must retain for 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the Director at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the Director for that purpose.	§5.206(m)(6) The operator must retain for 10 years following storage facility closure records collected to prepare the permit application, data on the nature and composition of all injected fluids, and records collected during the post-injection storage facility care period. The operator must submit the records to the director at the conclusion of the retention	Section 7.5.4 – Documentation of Site Closure

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		period, and the records must thereafter be retained at the Austin headquarters of the Commission.	

Section 8 - Emergency Response			
§146.82(a)(19)	Proposed emergency and remedial response plan required by § 146.94(a);	§5.203(l) Emergency and remedial response plan. The applicant must submit an emergency and remedial response plan that:	Section 8 – Emergency and Remedial Response Plan
§146.84(f)	The emergency and remedial response plan (as required by § 146.94) and the demonstration of financial responsibility (as described by § 146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.	§5.203(l) (1) Emergency and remedial response plan. The applicant must submit an emergency and remedial response plan that: (1) accounts for the entire AOR, regardless of whether or not corrective action in the AOR is phased;	"Section 8 - Emergency and Remedial Response Plan Figure 8-2"
§146.88(e)(2)	Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and	§5.206(d)(2)(F) (i) The operator must comply with the following requirements for alarms and automatic shut-off systems. (i) The operator must install and use alarms and automatic shut-off systems designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate or other parameters diverge from permitted ranges and/or gradients. On offshore wells, the automatic shut-off systems must be installed down-hole.	8.6 Response Plans for Risk Scenarios

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.88(e)(3)	Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.	§5.206(d)(2)(F) (i) The operator must comply with the following requirements for alarms and automatic shut-off systems.(i) The operator must install and use alarms and automatic shut-off systems designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate or other parameters diverge from permitted ranges and/or gradients. On offshore wells, the automatic shut-off systems must be installed down-hole.	Not Applicable
§146.88(f)	If a shutdown (i.e., down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under paragraph (e) of this section otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must:	§5.206(d)(2)(F) (ii) If an automatic shutdown is triggered or a loss of mechanical integrity is discovered, the operator must immediately investigate and identify as expeditiously as possible the cause. If, upon investigation, the well appears to be lacking mechanical integrity, or if monitoring otherwise indicates that the well may be lacking mechanical integrity, the operator must:	Section 8.6 - Response Plans for Risk Scenarios
§146.88(f)(1)	Immediately cease injection;	(I) immediately cease injection;	Section 8.6 - Response Plans for Risk Scenarios
§146.88(f)(2)	Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone;	(II) take all steps reasonably necessary to determine whether there may have been a release of the injected CO2 stream into any unauthorized zone;	Section 8.6.3 - Injection Well Monitoring Equipment Failure
§146.88(f)(3)	Notify the Director within 24 hours;	§5.206(d)(2)(F)(ii)(III) notify the director as soon as practicable, but within 24 hours;	Section 8.6 - Response Plans for Risk Scenarios

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.88(f)(4)	Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	§5.206(d)(2)(F)(ii)(IV) restore and demonstrate mechanical integrity to the satisfaction of the director prior to resuming injection; and	Section 8.6 - Response Plans for Risk Scenarios
§146.88(f)(5)	Notify the Director when injection can be expected to resume.	§5.206(d)(2)(F)(ii)(V) notify the director when injection can be expected to resume.	Section 8.6 - Response Plans for Risk Scenarios
§146.94	Emergency and remedial response		
§146.94(a)	As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	§5.203(l)Emergency and remedial response plan. The applicant must submit an emergency and remedial response plan that: (2) describes actions to be taken to address escape from the permitted injection interval or movement of the injection fluids or formation fluids that may cause an endangerment to USDWs during construction, operation, closure, and post-closure periods; §5.206(a)(1) Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit.	Section 8.6 - Response Plans for Risk Scenarios
§146.94(b)	If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:	§5.206(g)(3)(A) If an operator obtains evidence that the injected CO2 stream and associated pressure front may cause an endangerment to USDWs, the operator must:	Section 8.6 - Response Plans for Risk Scenarios
§146.94(b)(1)	Immediately cease injection;	§5.206(g)(4)(A)(i) immediately cease injection;	Section 8.6 - Response Plans for Risk Scenarios

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.94(b)(2)	Take all steps reasonably necessary to identify and characterize any release;	§5.206(h)(3)(A)(ii) take all steps reasonably necessary to identify and characterize any release;	Section 8.6 - Response Plans for Risk Scenarios
§146.94(b)(3)	Notify the Director within 24 hours; and	§5.206(h)(3)(A)(iii) notify the director as soon as practicable but within at least 24 hours; and	Section 8.6 - Response Plans for Risk Scenarios
§146.94(b)(4)	Implement the emergency and remedial response plan approved by the Director.	§5.206(h)(3)(A)(iv) implement the approved emergency and remedial response plan.	Section 8.6 - Response Plans for Risk Scenarios
§146.94(c)	The Director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.	§5.206(h)(4)Resumption of injection. The director may allow the operator to resume injection prior to remediation if the operator demonstrates that the injection operation will not endanger USDWs.	Section 8.6 - Response Plans for Risk Scenarios
§146.94(d)	The owner or operator shall periodically review the emergency and remedial response plan developed under paragraph (a) of this section. In no case shall the owner or operator review the emergency and remedial response plan less often than once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the Director that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:	§5.207(a)(2)(E) Annual updates. The operator must maintain and update required plans in accordance with the provisions of this subchapter. (i) Operators must submit an annual statement, signed by an appropriate company official, confirming that the operator has: (I) reviewed the monitoring and operational data that are relevant to a decision on whether to reevaluate the AOR and the monitoring and operational data that are relevant to a decision on whether to update an approved plan required by §5.203 or §5.206 of this title; and (II) determined whether any updates were warranted by material change in the monitoring and operational data or in the evaluation of the monitoring and operational data by the operator. (ii) Operators must submit either the updated	Section 8.10 - Plan Review

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		plan or a summary of the modifications for each plan for which an update the operator determined to be warranted pursuant to subclause (I) of this clause. The director may require submission of copies of any updated plans and/or additional information regarding whether or not updates of any particular plans are warranted.	
§146.94(d)(1)	Within one year of an area of review reevaluation;		
§146.94(d)(2)	Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or	§5.207(a)(3) The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or whenever the director determines that such a revision is necessary to comply with the requirements of this subchapter.	Section 8.10 - Plan Review
§146.94(d)(3)	When required by the Director.	§5.207(a)(3) The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or whenever the director determines that such a revision is necessary to comply with the requirements of this subchapter.	Section 8.10 - Plan Review

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
Section 9 - Financial Assurance			
§146.82(a)(14)	A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § 146.85;	§5.203(n) Fees, financial responsibility, and financial assurance. The applicant must pay the fees, demonstrate that it has met the financial responsibility requirements, and provide the Commission with financial assurance as required under §5.205 of this title (relating to Fees, Financial Responsibility, and Financial Assurance).	9.2 Financial Assurance Demonstration
§146.85(a)(6)(ii)	When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.		9.2 Financial Assurance Demonstration
§146.84(f)	The emergency and remedial response plan (as required by § 146.94) and the demonstration of financial responsibility (as described by § 146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.	§5.203(l) (1) Emergency and remedial response plan. The applicant must submit an emergency and remedial response plan that: (1) accounts for the entire AOR, regardless of whether or not corrective action in the AOR is phased;	9.7 Emergency and Remedial Response
§146.85	Financial responsibility		9.2 Financial Assurance Demonstration

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.85(a)	The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:	§5.205(b)(1)A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	9.3 Estimated Coverage Amounts
§146.85(a)(1)	The financial responsibility instrument(s) used must be from the following list of qualifying instruments:	§5.205 (c)(2)(A)The applicant must include in an application for a geologic storage facility permit:	9.0 Introduction

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.85(a)(1)(ii)	Surety Bonds.	§5.205(c)(2)(A)(ii) a copy of the form of the bond or letter of credit that will be filed with the Commission;§5.205(c)(2)(B) A geologic storage facility shall not receive CO2 until a bond or letter of credit in an amount approved by the director under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the director.§5.205(c)(2)(D)(i) The issuer of any geologic storage facility bond filed in satisfaction of the requirements of this subsection must be a corporate surety authorized to do business in Texas. The form of bond filed under this subsection must provide that the bond be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the director.	Claimed as PBI

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.85(a)(1)(iii)	Letter of Credit.	§5.205(c)(2)(A)(ii) a copy of the form of the bond or letter of credit that will be filed with the Commission; §5.205(c)(2)(B) A geologic storage facility shall not receive CO2 until a bond or letter of credit in an amount approved by the director under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the director. §5.205(c)(2)(D)(ii) Any letter of credit filed in satisfaction of the requirements of this subsection must be issued by and drawn on a bank authorized under state or federal law to operate in Texas. The letter of credit must be an irrevocable, standby letter of credit subject to the requirements of Texas Business and Commerce Code, §§5.101 - 5.118. The letter of credit must provide that it will be renewed and continued in effect until the conditions of the letter of credit have been met or its release is authorized by the director.	Claimed as PBI
§146.85(a)(1)(i)	Trust Funds.		Claimed as PBI
§146.85(a)(1)(vii)	Any other instrument(s) satisfactory to the Director.		9.2 Financial Assurance Demonstration

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.85(a)(2)	The qualifying instrument(s) must be sufficient to cover the cost of:	§5.205(c)(2)(C)The determination of the amount of financial assurance for a geologic storage facility is subject to the following requirements:§5.205(b)(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	9.4 Corrective Action
§146.85(a)(2)(i)	Corrective action (that meets the requirements of § 146.84);	§5.205(b)(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	9.4 Corrective Action

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.85(a)(2)(ii)	Injection well plugging (that meets the requirements of § 146.92);	§5.205(b)(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	9.4 Corrective Action, 9.5 Well Plugging, 9.6 Post-Injection Site Care and Site Closure Plan, 9.7 Emergency and Remedial Response
§146.85(a)(2)(iii)	Post injection site care and site closure (that meets the requirements of § 146.93); and	§5.205(b)(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	9.6 Post-Injection Site Care and Site Closure Plan

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.85(a)(2)(iv)	Emergency and remedial response (that meets the requirements of § 146.94).	§5.205(b)(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	9.7 Emergency and Remedial Response
§146.85(a)(3)	The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.	§5.205(c)(2)(C) The determination of the amount of financial assurance for a geologic storage facility is subject to the following requirements: (i) The director must approve the dollar amount of the financial assurance. The amount of financial assurance required to be filed under this subsection must be equal to or greater than the maximum amount necessary to perform corrective action, emergency response, and remedial action, post-injection monitoring and site care, and closure of the geologic storage facility, including plugging of wells, at any time during the permit term in accordance with all applicable state laws, Commission rules and orders, and the permit. The cost estimate must be performed for each phase separately and must be based on the costs to the Commission of hiring a third party	9.5 Well Plugging

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator;	
§146.85(a)(4)	The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.		9.3 Estimated Coverage Amounts
§146.85(a)(4)(i)	Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	§5.205(c)(2)(D)(iii) The qualifying financial responsibility instruments must comprise protective conditions of coverage. Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions; specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument; and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	9.3 Estimated Coverage Amounts

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.85(a)(4)(i)(A)	Cancellation - for purposes of this part, an owner or operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the Director. The cancellation must not be final for 120 days after receipt of cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable (or possible), any funds from the instrument being cancelled must be released within 60 days of notification by the Director.	§5.205(c)(2)(D)(iii)(I) Cancellation. An owner or operator must provide that its financial instrument may not cancel, terminate, or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the director. The cancellation must not be final until at least 120 days after the Commission receives the cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable or possible, any funds from the instrument being cancelled must be released within 60 days of notification by the director.	9.3 Estimated Coverage Amounts
§146.85(a)(4)(i)(B)	Renewal - for purposes of this part, owners or operators must renew all financial instruments, if an instrument expires, for the entire term of the geologic sequestration project. The instrument may be automatically renewed as long as the owner or operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.	§5.205(c)(2)(D)(iii)(II) Renewal. If a financial instrument expires, the owner or operator must renew the financial instrument for the entire term of the geologic storage project. The instrument may be automatically renewed as long as the operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.	9.3 Estimated Coverage Amounts

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.85(a)(4)(i)(C)	Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: The Director deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the Director or a U.S. district court or other court of competent jurisdiction; or the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid.	§5.205(c)(2)(D)(iii)(III) Financial instrument to remain in effect. Cancellation, termination, or failure to renew shall not occur and the financial instrument shall remain in full force and effect if on or before the date of expiration: (-a-) the director deems the facility abandoned; (-b-) the permit is terminated or revoked or a new permit is denied; (-c-) closure is ordered by the director or a United States district court or other court of competent jurisdiction; (-d-) the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or (-e-) the amount due is paid.	9.3 Estimated Coverage Amounts
§146.85(a)(5)	The qualifying financial responsibility instrument(s) must be approved by the Director.	§5.205(c)(2)(B) A geologic storage facility shall not receive CO2 until a bond or letter of credit in an amount approved by the director under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the director.	9.3 Estimated Coverage Amounts
§146.85(a)(5)(i)	The Director shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project prior to issue a Class VI permit (§ 146.82).	§5.205(c)(2)(B) A geologic storage facility shall not receive CO2 until a bond or letter of credit in an amount approved by the director under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the director.	9.3 Estimated Coverage Amounts

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.85(a)(5)(ii)	The owner or operator must provide any updated information related to their financial responsibility instrument(s) on an annual basis and if there are any changes, the Director must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The owner or operator must maintain financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration.	§5.205(c)(2)(F)The owner or operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic storage project, the owner or operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The owner or operator must provide to the director, within 60 days of notification by the director, an adjustment of the cost estimate if the director determines during the annual evaluation of the qualifying	9.4 Corrective Action

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.	
§146.85(a)(5)(iii)	The Director may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.		9.3 Estimated Coverage Amounts
§146.85(a)(6)	The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project.		9.2 Financial Assurance Demonstration
§146.85(a)(6)(i)	In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.		Not Applicable
§146.85(b)(1)	The owner or operator must maintain financial responsibility and resources until:		Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.85(b)(1)(i)	The Director receives and approves the completed post-injection site care and site closure plan; and	§5.205(b)(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	9.6 Post-Injection Site Care and Site Closure Plan
§146.85(b)(1)(ii)	The Director approves site closure.	§5.205(b)(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	9.6.2 Site Closure Plan

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.85(c)	The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response.	§5.205(c)(2)(F)The owner or operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic storage project, the owner or operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The owner or operator must provide to the director, within 60 days of notification by the director, an adjustment of the cost estimate if the director determines during the annual evaluation of the qualifying	9.6.2 Site Closure Plan

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.	
§146.85(c)(1)	The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.	§5.205(c)(2)(C)(ii) qualified professional engineer licensed by the State of Texas, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, must prepare or supervise the preparation of a written estimate of the highest likely amount necessary to close the geologic storage facility. The owner or operator must submit to the director the written estimate under seal of a qualified licensed professional engineer, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act; and	9.6.2 Site Closure Plan
§146.85(c)(2)	During the active life of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with paragraph (a) of this section and provide this adjustment to the Director. The owner or operator must also provide to the Director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan (§ 146.84), the	§5.205(c)(2)(F)The owner or operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any decrease or increase to the initial cost estimate. During the	9.3 Estimated Coverage Amounts

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and remedial response plan (§ 146.94).	active life of the geologic storage project, the owner or operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The owner or operator must provide to the director, within 60 days of notification by the director, an adjustment of the cost estimate if the director determines during the annual evaluation of the qualifying financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.	

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
§146.85(c)(3)	The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, the owner or operator must revise the cost estimate no later than 60 days after the Director has approved the request to modify the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and response plan (§ 146.94), if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Director. Any decrease to the value of the financial assurance instrument must first be approved by the Director. The revised cost estimate must be adjusted for inflation as specified at paragraph (c)(2) of this section.	§5.205(c)(2)(F)The owner or operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic storage project, the owner or operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The owner or operator must provide to the director, within 60 days of notification by the director, an adjustment of the cost estimate if the director determines during the annual evaluation of the qualifying	9.3 Estimated Coverage Amounts

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.	
§146.85(c)(4)	Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, 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 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 the owner or operator has received written approval from the Director.	§5.205(c)(2)(G) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, 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 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 the operator has received written approval from the director.	9.3 Estimated Coverage Amounts
§146.85(d)	The owner or operator must notify the Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure.	§5.205(d)(1)The owner or operator must notify the Commission of adverse financial conditions that may affect the owner's or operator's ability to carry out injection well plugging and post-injection storage facility care and closure. An owner or operator must file any notice of bankruptcy in accordance with §3.1(f) of this title (relating to Organization Report; Retention of Records; Notice Requirements). The owner or operator	Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		must give such notice by certified mail.	
§146.85(d)(1)	In the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.	§5.205(d)(2) The owner or operator filing a bond must ensure that the bond provides a mechanism for the bond or surety company to give prompt notice to the Commission and the owner or operator of any action filed alleging insolvency or bankruptcy of the surety company or the bank or alleging any violation that would result in suspension or revocation of the surety or bank's charter or license to do business.	Not Applicable
§146.85(d)(2)	A guarantor of a corporate guarantee must make such a notification to the Director if he/she is named as debtor, as required under the terms of the corporate guarantee.		Appendix J-2
§146.85(e)	The owner or operator must provide an adjustment of the cost estimate to the Director within 60 days of notification by the Director, if the Director determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by § 146.84), injection well plugging (as required by § 146.92), post-injection site care and site closure (as required by § 146.93), and	§5.205(c)(2)(F)The owner or operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any decrease or	9.3 Estimated Coverage Amount

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	emergency and remedial response (as required by § 146.94).	increase to the initial cost estimate. During the active life of the geologic storage project, the owner or operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The owner or operator must provide to the director, within 60 days of notification by the director, an adjustment of the cost estimate if the director determines during the annual evaluation of the qualifying financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.	
§146.85(f)	The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.		Not Applicable

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Underground Injection Control – Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 1 – INTRODUCTION

Rose Carbon Capture and Storage Project

Claimed as PBI

ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2024

SECTION 1 – INTRODUCTION

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Appendix A – Project Maps

Claimed as PBI

1.0 Introduction

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) proposes the Rose Carbon Capture and Storage (CCS) Project (Project) located in Claimed as PBI, Texas, Claimed as PBI The Project location is in the Houston Embayment of the Gulf Coast Basin, with well-documented formations for injection and containment of carbon dioxide (CO_2). The primary source of the CO_2 is Claimed as PBI Other sources of relatively pure CO_2 may be added over time to achieve the performance objectives for the Project.

ExxonMobil prepared this Underground Injection Control (UIC) Class VI Permit Application (Application) in accordance with the requirements of the UIC Program for Carbon Dioxide Geologic Sequestration Wells promulgated in Title 40 Code of Federal Regulations (40 CFR) Chapter 1, Subchapter D, Part 146, Subpart H. The Project is designed to collect, transport, and sequester between Claimed as PBI using three injection wells. ExxonMobil plans to sequester approximately Claimed as PBI . ExxonMobil secured legal rights to sequester CO_2 within a portion of the Area of Review (AoR) for the life of the Project by an agreement with Claimed as PBI .

The following subsections and associated appendix provide the required information listed in 40 CFR 146.82(a) in a cursory format. Please refer to the individual sections for the complete discussion of information and required points of evaluation. For ease of review and efficiency, the U.S. Environmental Protection Agency (EPA) Geologic Sequestration Data Tool (GSDT) content tracking check boxes were used in this section to demonstrate compliance with the particular requirements on a topic-by-topic basis.

1.1 Injection Well Location and Area of Review

Table 1-1 provides the location of the three injection wells as required by 144.31(2). A map showing the injection wells for which the permits are sought, the applicable AoR, and the features present within the AoR is provided in Figure A-1 in Appendix A [146.82(a)(2)]. ExxonMobil identified no indications of the presence of tribal lands; archaeological and cultural sites; military installations; mines and quarries; critical habitats; state and federal clean-up sites; and springs. Figure A-1 shows water bodies, wetland features, structures for human occupancy, surface trace of faults, injection well locations, monitoring well locations, and identified artificial penetrations.

Claimed as PBI

1.2 Contact Information

Pursuant to 40 CFR 144.31(e)(4), the name and mailing address for the operator as summarized below.

ExxonMobil Low Carbon Solutions Onshore Storage LLC
22777 Springwoods Village Parkway
Spring, TX 77389

Claimed as PBI

Pursuant to 40 CFR 146.82(a)(20), contact information related to the Project is outlined below. Table 1-2 summarizes key contact information for local, state, and federal agencies. This Project is not located on federal, state, or Indian lands.

Table 1-2: Local, State, and Federal Contact Information

Agency	Telephone Number
Claimed as PBI	Claimed as PBI
Claimed as PBI	Claimed as PBI
Claimed as PBI	Claimed as PBI
Claimed as PBI	Claimed as PBI
Texas Division of Emergency Management	(512) 424-2208
Texas Department of Public Safety	(512) 424-2000
State of Texas Spill-Reporting Hotline	(800) 832-8224
Texas Parks and Wildlife Department	(512) 389-4800
EPA Region 6	(800) 887-6063 or (214) 665-2760
Class VI Contact – Brandon Maples	(214) 665-7252
Texas Department of Natural Resources	(512) 389-4800

Agency	Telephone Number
Claimed as PBI	Claimed as PBI
National Response Center	(800) 424-8802
State of Texas Spill-Reporting Hotline	(800) 832-8224
EPA National Response Center (24 hours)	(800) 424-8802

ExxonMobil Low Carbon Solutions Onshore Storage LLC is a public entity. Pursuant to 40 CFR 144.31(e)(3), the Project is operating under Standard Industrial Classification Code 4953 – Refuse Systems (nonhazardous waste disposal sites).

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)]***

1.3 Site Characterization

Section 2 – Site Characterization provides a detailed narrative, tables, figures, and other relevant material to fulfill the site characterization requirements listed at 40 CFR 146.82(a)(2), (3), (5), and (6). References are cited in the completed Section 2 of the Application for completeness purposes. The purpose of this subsection is to provide a cursory review of the information provided in Section 2 with particular attention to the site characteristics that demonstrate site suitability for CO2 sequestration and protection of underground sources of drinking water (USDWs).

1.3.1 Objectives

The primary objectives of the site characterization were to gather available information and data and assemble the required maps and cross sections of the AoR that show formation depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s) and on lithology and facies changes. Attention was given to faults and fractures that may transect the confining zones in the AoR and the potential for impacts on CO2 containment. The scale of the Project warranted a detailed evaluation of the available geomechanical information on fractures, stress, ductility, rock strength, and in-situ fluid pressures within the confining zones. The potential for USDW endangerment was evaluated by developing the relationship between the injection and confining zones and the relative positions of the USDWs. A brief discussion of seismic history and baseline geochemical characteristics are provided using available information to assess the potential for either to interfere with containment and control of the CO2 plume.

1.3.2 Approach

The site characterization was developed using published public and private information. The type of information obtained includes seismic surveys and legacy well logs including faneous potential, gamma ray, resistivity, bulk density, and sonic. In November 2023, ExxonMobil completed a stratigraphic well Claimed as PBI to provide site-specific information and address potential uncertainty and data gaps. Core testing and data evaluation are underway and will be used to update the site characteristics. It is expected that the core and logging results from the stratigraphic well will strengthen the demonstration of compliance. In the meantime, sufficient information was available to demonstrate how the Project area meets the EPA's requirements for site suitability in the UIC Class VI Rule.

An integrated geologic model was developed for the Project site to represent the variation and continuity of structural, depositional, and petrophysical features. The model provides a three-dimensional representation of the injection and confining zones for subsequent evaluation of CO2 plume and pressure-front migration. The model covers Claimed as PBI and extends beyond the predicted plume or AoR boundaries. The geologic model incorporates regional core, log, and seismic data to characterize structural configuration; net sand, facies and property distribution; and porosity-permeability relationships among other data.

1.3.3 Summary of Site Suitability

The Project area is suitable for CO2 injection and containment into the proposed injection intervals of the Claimed as PBI exhibit high porosity and permeability that are ideal for CO2 storage and are "of sufficient areal extent, thickness porosity and permeability to receive the total anticipated volume of the carbon dioxide stream" [40 CFR 146.83(a)(1)]. Claimed as PBI confining zones are present that provide containment of CO2 in the injection zone. The upper composite confining zone (UCCZ) is located Claimed as PBI Both sealing layers extend across the AoR and are sufficient to "contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressure and volumes without initiating or propagating fractures in the confining zone" [40 CFR 146.83(a)(2)]. The top and bottom elevations of the injection intervals and confining zones are in Section 2 and show lateral continuity and substantial thickness within the AoR.

The Project is envisioned to inject CO2 in well-defined and characterized geologic features of the Gulf Coast Basin deemed ideal for CO2 sequestrations purposes:

- The proposed injection zone extends from Claimed as PBI ;
- Claimed as PBI which are thick and continuous with a net sand thickness of approximately Claimed as PBI , are separated by interbedded shales, and each exhibits an estimated average porosity of Claimed as PBI at the three proposed injection well locations; and
- Claimed as PBI are combined into a single injection interval offering a total net sand thickness of approximately Claimed as PBI

with average estimated Claimed as PBI [redacted] at the three proposed injection well locations.

Figure B-12 provided below is one of two local geologic cross-section maps for the Project area that is presented Section 2 – Site Characterization to characterize the local geology. As shown, the UCCZ above the injection zone is Claimed as PBI [redacted] (described in Section 2). Total interval thickness ranges from approximately Claimed as PBI near the injection wells. The top of the UCCZ is estimated to be contacted at approximately Claimed as PBI at the stratigraphic and injection well locations. This depth is approximately Claimed as PBI [redacted] in the vicinity of the injection wells, providing significant vertical separation between the first water-bearing zone above the UCCZ and lowermost USDW. The USDWs are associated with Claimed as PBI [redacted], which are utilized for potable water in the region and generally flow toward the Gulf of Mexico.

Claimed as PBI

In addition, Claimed as PBI [redacted]

Claimed as PBI [redacted]

[redacted]

The chemical and physical characteristics of the CO2 stream were found to be compatible with the geochemical conditions in the injection intervals and confining zones. A series of geochemical reaction scenarios were evaluated to assess what changes could potentially result from CO2 sequestration. The modeled mineralogy and brine geochemistry captured the major geochemical constraints that could cause changes in porosity and/or mobilize naturally occurring metals. The results of the assessment show that the expected variations in the mineralogy of the confining and injection zones could generate some mineral precipitation and dissolution, but the range of such reactions would not have an impact on pore-space or confinement.

1.4 AoR and Corrective Action Plan

1.4.1 AoR

A comprehensive modeling and evaluation effort was undertaken to assess the CO2 plume and brine pressure-front boundaries as a function of injection over time. Through the modeling effort, the artificial penetrations within AoR were reviewed to identify the potential for CO2 or brine cross flow to occur between the injection zone and groundwater above the UCCZ.

The primary objectives of the AoR and corrective action assessment included predicting the extent of the CO2 plume and pressure front using computational modeling and identify all artificial penetrations that require corrective action, provide a plan to perform the required corrective action, and support the development of effective monitoring strategies and emergency and remedial responses within or near the AoR that could be required. This understanding gained through development of the AoR and Corrective Action Plan provides a guide for periodic AoR reevaluations to inform site management and monitoring over the lifecycle of the Project. Figure 3-8 reproduced from Section 3 – Area of Review and Corrective Action Plan provides an illustration of the extent of the geologic model boundary, the simulation model boundary for evaluation of migration, and certain geologic features of interest.

Claimed as PBI

Claimed as PBI

ExxonMobil utilized parameter values for the prediction of the AoR that were based on available information from values published for similar rock types and relationships in the scientific literature. These data were used to derive initial estimates of hydrogeologic properties (e.g., porosity and permeability), fluid properties (e.g., fluid compression and viscosity), and chemical properties. Selected input parameter values include maximum bottomhole pressures ranging from Claimed as PBI

ExxonMobil is proposing a four-stage injection sequencing program to optimize CO2 injection rates and storage across the life of the Project. The injection phase is planned Claimed as PBI, after which time the rate of plume size growth is expected to diminish rapidly. The maximum areal extent of the CO2 plume was projected to be Claimed as PBI and follows a structural up-dip to the northwest. Figure 3-14 (reproduced from Section 3 – Area of Review and Corrective Action Plan) provides the modeled relationships between start of operation and plume size in terms of rate of growth and plume area. The extent of the CO2 plume is expected

to stabilize by Claimed as PBI after the start of injection, at which time the rate of CO2 plume growth was predicted to be less than Claimed as PBI.

1.4.2 Correction Action Plan

A comprehensive search of public and private databases, combined with an aeromagnetic survey and field reconnaissance was used to develop the list of artificial penetrations that could potentially be present within the AoR. A total of Claimed artificial penetrations were identified within the AoR, of which Claimed as PBI penetrated the UCCZ. ExxonMobil developed a Corrective Action Plan for each artificial penetration that was identified to have the potential to act as a vertical conduit because either: (1) it was not plugged; (2) it was improperly plugged and abandoned; or (3) it was not plugged in a manner that mitigates the potential for movement of CO2 or other fluids that could potentially endanger USDWs.

For Claimed as PBI requiring corrective action, the corrective action strategy is to re-enter each well for further assessment and install cement barriers inside the casing to mitigate migration potential through the casing as necessary to comply with requirements for protection of USDWs. The cement material to be used to form these additional plugs is designed to be compatible with

CO2 and will be used where appropriate. Logging will be conducted to establish external mechanical integrity and identify the potential for corrective action if there is not sufficient evidence that cementing has been completed to the surface. A reproduction of Appendix C-1 is provided below (from Section 3 – Area of Review and Corrective Action Plan) to illustrate the high standard of care undertaken by ExxonMobil in planning the plugging and abandonment for a legacy well within the AoR.

Claimed as PBI [redacted]

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:

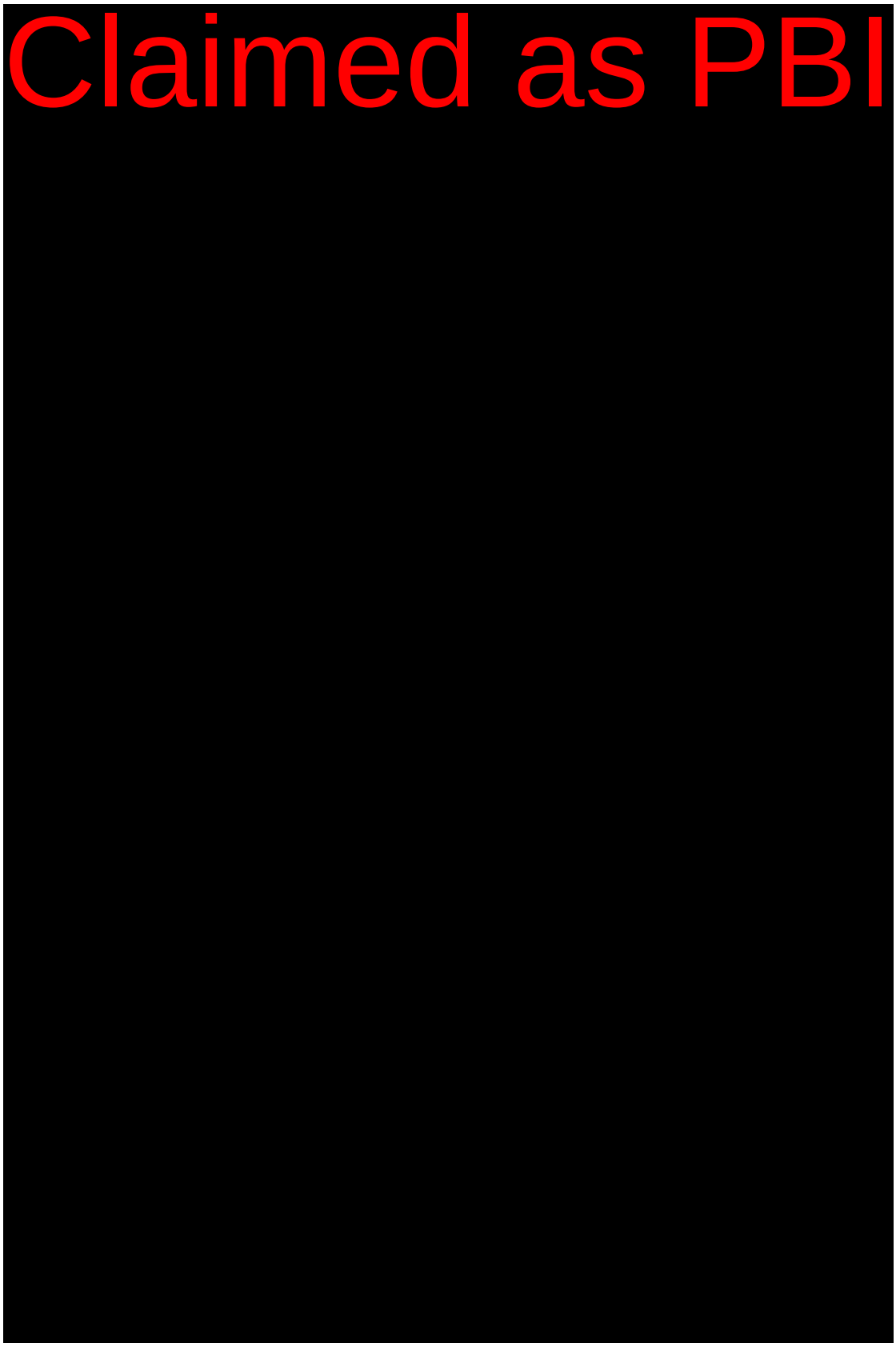
☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]***

☒ AoR and Corrective Action Plan ***[40 CFR 146.82(a)(13) and 146.84(b)]***

☒ Computational modeling details ***[40 CFR 146.84l]***

1.5 Financial Responsibility

Under Title 40 U.S. Code of Federal Regulations (40 CFR) 146.85, owners or operators of geologic sequestration (GS) injection wells are required to demonstrate financial responsibility for GS activities. Consistent with these regulatory requirements, ExxonMobil has prepared the necessary documentation to demonstrate financial responsibility for the injection wells that comprise the Project. Each of the required Project activities has been considered for the financial assessment and the estimated financial assurance coverage value is Claimed as PBI [redacted]. Each of the financial coverage / threshold requirement per §146.85(a)(6)(v) were met by ExxonMobil. In addition, the required documentation of the company's ability to meet the requisite financial coverage and threshold criteria was provided and the financial instruments will be updated and verified no less than annually. ExxonMobil will confirm that the coverage limits provided by the respective financial responsibility instruments are sufficient to cover the corresponding costs prior to initiating each major Project phase.


Claimed as PBI

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]***

1.6 Injection Well Construction

Section 4 – Well Construction Plan and Operating Conditions provides a description of the injection well construction design, casing design details, and testing plan for the three new CO2 injection wells for the Project. The injection well construction specifications provide a basis for material specifications and construction practices to provide a high degree of internal and external mechanical integrity for the duration of the Project. Claimed as PBI [redacted] CO2 compatible cement was selected to withstand the fluid conditions associated with CO2 injection. Section 4 – Well Completion Plan and Operating Conditions provides a description of the casing, cementing materials, tubing, and packer selected for the Project. Each has been designed to construct the injection wells with a seal at the UCCZ and compatible with the proposed CO2 stream [40 CFR 146.86(b)]. Together, the internal and external mechanical integrity of the injection wells is expected to have a high degree of performance and reduce the potential for USDW endangerment. Data will be collected during the construction process to assess the pre-operational conditions and align the well construction and operating strategy with site-specific results, as needed.

Of the engineering design features considered, one of the most critical aspects is the staged recompletion of each injection well to target injection into specific injection intervals to achieve the target CO2 storage amount. ExxonMobil plans to inject a maximum volume of [redacted] MMta into each of the injection wells. The tubing design, including size, weight, and grade, is based on the properties of the injectate, rate of injection, and injection pressures determined by the detailed reservoir modeling. The casing, cement, tubing, packer, continuous monitoring devices, and wellhead equipment were selected and designed to withstand the corrosive environment to which the materials and equipment will be exposed. Each was selected to have sufficient strength and material properties to withstand the pressure, temperature, and corrosive forces to which they will be subjected in the subsurface.

ExxonMobil has extensive experience designing, building, and operating wells throughout the world. The three injection wells (Rose CCS Project Injection Wells No. 01, No. 02, and No. 03) are designed for the injection and storage of CO2 safely in the Claimed as PBI [redacted] injection intervals at the Project site, and to contain the CO2 within the injection intervals to protect USDWs.

Claimed as PBI [redacted]

Upon installation of the completion assembly, injection will start at the injection interval shown on the injection sequencing plan in Section 3 – Area of Review and Corrective Action Plan. Once the target injection volume of CO2 is attained, that injection interval will be plugged back to isolate that interval from subsequent injections intervals. The next injection interval will then be accessed through additional perforations to establish communication with the reservoir. CO2 will continue into that new injection interval until the target CO2 storage amount has been achieved for that interval.

1.7 Well Construction Plan

Section 4 – Well Construction Plan and Operating Conditions provides details on the pre-operational testing plan in accordance with 40 CFR 146.82(a)(8) and 146.87. The scope of the pre-operational testing plan includes geophysical and core data collection, fluid sampling at target intervals, injection zone characterization, and pressure testing to assess the injection intervals in the stratigraphic well Claimed as PBI The Testing and Monitoring Plan (Section 5 – Testing and Monitoring Plan) provides the data collection activities for the pre-operational phase and the operational phase of the Project. A summary of that discussion is provided below for ease of review, with reference to the complete discussion in Section 5 for the pre-operational testing plan.

The objective of the plan is to gather site-specific data to further evaluate the site characterization and update the AoR and associated model. Information gathered from the pre-operational logging and testing will provide additional data and information that will be used to refine operational and construction strategies, which will be implemented to reduce the potential of migration of fluids from the injection zone to USDWs.

ExxonMobil is implementing this plan for the stratigraphic well Claimed as PBI that is being used to gather site-specific data for the Project. Information gathered from the well will be used to update the Application and further refine Section 4. The following illustration, Appendix D reproduced from Section 4 – Well Completion Plan and Operating Conditions, illustrates the completion plan for Rose CCS Project Injection Well No. 1.

Claimed as PBI

Pre-Operational Logging and Testing GSDT Submissions

GSDT Module: Pre-Operational 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]***

1.8 Operating Conditions

Section 4 – Well Construction Plan and Operating Conditions provides the plan for continuous injection and annulus monitoring systems for each injection well to help control injection pressure and trigger automatic shut-off devices and safety valves for CO2 injection, consistent with safe operating procedures. The proposed continuous monitoring and recording devices will be used to demonstrate internal mechanical integrity. The injection wells will be equipped with shutoffs and safety devices that are linked to operating limits specified in the permit for each injection well.

The maximum injection rates for the injection intervals of each well ranges from Claimed as PBI [redacted]. Both the maximum and average injection rates are predicted to result in reservoir pressure rises that are below 90% of the fracture pressure for the lifetime of the Project. Both injection rates and pressures are within the operating window of the injection wells. The Project will be operated within these parameters to reduce the potential migration of fluids from the injection zones to USDWs.

The CO2 stream is Claimed as PBI provided under contract from industrial sources. As required in the Testing and Monitoring Plan, the composition of the CO2 will be monitored during the operational life of the Project to confirm that the chemical composition and physical characteristics of the injectate are consistent with the well design standards and operating conditions of the Class VI permits.

In general, unanticipated interactions among the CO2 injectate and the reservoir fluids are not expected that would act to reduce the permeability, porosity, or injectivity of CO2 into the injection intervals over the life of Project. Specific mineralogy and fluid testing is being performed on core and fluid samples from the stratigraphic well that will be used to confirm these conditions prior to issuance of the Class VI permits and changes, if appropriate, will be made to further refine the engineering design and operating strategy. As outlined in Section 4, the current engineering design basis includes corrosion-resistant well completion materials selected to provide a high degree of mechanical integrity under future conditions for the formation fluids and CO2 plume.

Section 5 – Testing and Monitoring Plan provides a description of the analyses of the CO2 stream for the Projects, including tests for potential impurities that may be present and whether such impurities might alter the corrosivity of the injectate down-hole. The information provided in Section 5 was based on the expected chemical and physical characteristics of the CO2 stream and will be used to optimize operating parameters and comply with the UIC Class VI Rules.

1.9 Testing and Monitoring

Consistent with the requirements of 40 CFR 146.90, ExxonMobil developed a comprehensive Testing and Monitoring Plan for the Project using a risk-based approach. The objectives of this plan are to use site characterization data and the plume and pressure-front modeling to identify migration pathways and areas for potential concern, identify how potential leakage pathways and uncertainties in the confining zone and injection zone could affect the AoR boundaries; and select specific testing and monitoring strategies and technologies that are tailored to the site-specific risk factors associated with plume and pressure-front migration.

The following hypothetical scenarios were considered appropriate for identifying the scope of the testing and monitoring strategy:

Claimed as PBI

The maximum anticipated risk level is medium and associated with the site characterization and AoR evaluation, before implementation of mitigation measures including injection well placement, injection interval selection, operational limitations, and corrective action for artificial penetrations. These measures will be implemented before operation begins, resulting in a decrease in maximum risk to a low level.

The data collection strategy includes injectate monitoring, corrosion monitoring of the well tubular, internal and external mechanical integrity tests, pressure fall-off testing, seismic profiling, well logging, continuous monitoring of injection rate and pressure, groundwater quality monitoring, direct and indirect CO2 plume, and pressure-front tracking. Of the testing and monitoring programs developed for the Application, one of the most important is related to CO2 plume and pressure-front tracking. Claimed as PBI

Claimed as PBI [redacted] ExxonMobil will also be exploring emergent technologies to support plume monitoring.

After sufficient CO2 plume and pressure-front tracking data have been collected [redacted] Claimed as PBI [redacted]

Claimed as PBI [redacted]

The data generated from implementation of this plan provides the basis to verify the confinement of the injectate in the permitted injection formations during the active injection phase of the Project.

ExxonMobil intends for the review process for the Plan and subsequent iterations to continue throughout the life of the Project. An adaptive approach will be employed with respect to monitoring frequency of select parameters, whereby monitoring may be decreased based on positive test results. Monitoring results will be presented in semi-annual reports, wherein data will be evaluated, and any monitoring frequency modification would be justified. A defined schedule is proposed to address situations where there is a change in the AoR or other circumstances change, while adding little burden if the AoR reevaluation confirms that the Plan is appropriate as written. In this way, testing and monitoring results that indicate corrective action is required trigger the mitigation measures identified in the AoR reevaluation and the Emergency and Remedial Response Plan if needed, will be triggered at the appropriate time.

The Testing and Monitoring Plan will be reviewed and potentially revised at a minimum of every five years to:

- Identify Project-specific factors that warrant revision to the Plan;
- Incorporate information and changes necessary to monitor an increase in risk to or endangerment of USDWs; and/or
- Incorporate confirmed deviations from permitted conditions that require Plan modifications.

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

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]***

1.10 Injection Well Plugging

Section 6 - Injection Well Plugging Plan (Plugging Plan) was prepared to describe the actions that ExxonMobil will take to mitigate potential threats to USDWs during the post-injection period. ExxonMobil has selected materials for plugging the injection wells that are compatible with corrosive properties of the injection fluid and help to maintain mechanical integrity of the plug and well casing.

The planned plugging procedures are aligned with best practices for restoring the UCCZ integrity at each injection well location. These procedures include flushing the injection wells with buffer fluid, removal of well components and obstructions (if any), conducting mechanical integrity tests, as needed, confirming the adequacy of CO_2 compatible materials for use in setting cement plugs, and setting the plugs at the specific intervals. The detailed procedures for injection well plugging and abandonment are described in Section 6.

Claimed as PBI [redacted] Once the storage capacity has been reached, the last injection interval and the remainder of the injection well will be plugged for final abandonment and the well location restored.

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)]***

1.11 Post-Injection Site Care and Site Closure

Section 7 - Post-Injection Site Care (PISC) and Site Closure Plan describes the activities that will occur once injection operations have ceased and the Project moves into maintaining a non-endangerment condition for USDWs. The Site Closure Plan will be implemented once ExxonMobil demonstrates to the UIC Program Director that no additional monitoring is required to demonstrate protection of USDW and that the testing and monitoring system can be dismantled. The objective of the plan is to demonstrate the pressure differential between the pre-injection and predicted CO2 plume and associated pressure front; outline the post-injection monitoring program; identify the steps for bringing the site to closure; and outline the recordkeeping practices.

ExxonMobil's strategy for PISC monitoring is based on the same systems and processes as described in Section 5 – Testing and Monitoring Plan of this Application. The major monitoring elements include continued measurements of the CO2 plume and pressure-front location, monitoring above the UCCZ groundwater as well as USDWs. The data collected from this activity will be used to confirm compliance with the water quality objectives for the Project and generate information needed to support the final non-endangerment demonstration and subsequent site closure.

ExxonMobil will not cease post-injection monitoring until the non-endangerment demonstration pursuant has been approved by the UIC Program Director. The default PISC monitoring timeframe is 50 years after cessation of injection. ExxonMobil will monitor groundwater quality and track the position of the CO2 plume and pressure front for 50 years after cessation of injection unless a lesser period of time is approved by the UIC Program Director. At the time of this Application, an alternate timeframe has not been proposed for PISC monitoring. The end of the Project comes when the closure activities have been documented and approved by the UIC Program Director.

The CO2 plume is expected to Claimed as PBI [redacted]. The number of artificial penetrations for the Project is relatively low, which reduces the complexity of the PISC monitoring activities. ExxonMobil will utilize the data gathered throughout the life of the Project to update and maintain the PISC and Site Closure Plan with concurrent approval from the UIC Program Director. The intent of these updates and maintenance of the plan is to reduce the potential for migration of fluids from the injection zone to USDWs or the surface.

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)]***

1.12 Emergency and Remedial Response

Section 8 – Emergency and Remedial Response Plan (ERRP) describes the actions that the Project will undertake to immediately address a rare event where the movement of the injection fluid or formation fluid endangers an USDW during the construction, operation, or PISC periods of the Project. The purpose of this section is to provide the elements of the risk management process undertaken for the Project so that the UIC Program Manager can ultimately approve the remedial and response actions in advance. Once approved, ExxonMobil will be prepared to implement the actions necessary to facilitate and expedite response efforts for the rare occurrence of a leak from the injection zone.

The objectives of the ERRP are to identify and describe hypothetical risks scenarios and their associated adverse events toward USDWs, human health, or the environment; provide response actions for risk events with material outcomes, and consider the actions need to mitigate a release, including detection, response actions, and notification requirements. ExxonMobil has already created a number of engineering design and planning safeguards to reduce the potential of such a rare event from occurring in the first place. These steps are based on ExxonMobil's global experience and expertise with risk management for rare events in site selection, well drilling and completion, and reservoir operations. Additionally, ExxonMobil understands that as the Project proceeds, additional data and information will be gathered for the Project that will be implemented within this plan with concurrent approval by the UIC Program Director, which will further reduce risks to USDWs, human health, and the environment.

As discussed above for the Testing and Monitoring Plan, several hypothetical risk-based release scenarios were identified for risk assessment purposes. The nature of the risk scenarios included Claimed as PBI [redacted]

Claimed as PBI [redacted]. For each of these hypothetical scenarios, a mitigation plan was developed that aligns the severity of the event with a set of mitigation measures to avoid, detect, or respond with corrective action.

A number of risk reducing factors are or will be in place that will act to reduce the severity of potential releases of CO2. Section 2 – Site Characterization describes how the geologic setting is consistent with safe CO2 sequestration because of the favorable injection zone and confining zone characteristics that exist at the site. Section 3 – Area of Review and Corrective Action Plan describes how the CO2 plume and pressure front are predicted to be confined to the injection zone and how pressure will be managed below critical pressures to reduce the potential for leakage to USDWs. The few artificial penetrations through the confining zones will be recompleted to safeguard USDWs within the AoR. Section 4 – Well Construction Plan and Operating Conditions describes how the well design process and operating controls for mechanical integrity and pressure control to maintain a high level of risk reduction for the Project. Section 6 – Injection Well Plugging Plan demonstrates how ExxonMobil will utilize construction materials and practices that will reduce the potential for migration of fluids from the injection zone. Lastly, Section 5 - Testing and Monitoring Plan and Section 7 – Post-Injection Site Care and Site Closure Plan, provide the data acquisition plan for tracking the CO2 plume and brine pressure front to assess compliance with control and containment requirements.

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)]***

1.13 Injection Depth Waiver and Aquifer Exemption Expansion

ExxonMobil is not requesting an injection depth waiver [40 CFR 146.82(d) and 146.95(a)] or aquifer exemption expansion request [40 CFR 146.4(d) and 144.7(d)]. If required in future updates of this Application, ExxonMobil with notify the UIC Program Director for requested waivers or exemptions.

Injection Depth Waiver and Aquifer Exemption Expansion GSDT Submissions

GSDT Module: Injection Depth Waivers and Aquifer Exemption Expansions

Tab(s): All applicable tabs

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)]***

1.14 Environmental Justice

Section 10 – Environmental Justice. This Environmental Justice (EJ) Screening Report for the Project is an initial desktop assessment of potential EJ-related concerns for the Project location. The objective of the assessment is to identify community characteristics useful in guiding community and stakeholder engagement throughout the life of the Project. The report includes the use of an initial "EJ Study Area" to assess the presence of communities that may be associated with potential EJ concerns. The EJ Study Area comprises the area within a 2-mile radius around the Project footprint. The EJ Study Area includes 14 Census Block Groups (CGCs), which are all located in Claimed as PBI.

The EPA EJ guidance (EPA, 2016; EPA, 2022) does not prescribe a method for assessing potential EJ impacts. However, it does recommend that an appropriate methodology be adopted and applied. ExxonMobil has a corporate socioeconomic standards-driven process that assesses environmental, socioeconomic, and health considerations throughout a Project. As ExxonMobil's understanding of the local environment evolves during the Project lifecycle, the EJ assessment may be updated if warranted.

For this report, the EPA's EJScreen Tool Version 2.2 (EPA, 2023a) was used to assess demographic and environmental characteristics in areas crossed by or within the EJ Study Area. Use of the EJScreen Tool is intended to be a starting point in the identification of communities with potential EJ concerns. As discussed further in Section 10.4 of Section 10 – Environmental Justice, EJ Indexes at or above the 80th percentile nationally were used as a starting point for identifying geographic areas that potentially warrant further consideration, analysis, or engagement with respect to potential EJ concerns.

The following summarizes the socioeconomic characteristics of the Project area:

- Six of the 14 census block groups in the EJ Study Area have minority populations exceeding 50 percent (%).
- Low-income population percentages greater than that of Claimed as PBI occur in two Census Block Groups (CBGs): CT 113.04 BG 3 and CT 9802 BG 1. Both CBGs also have minority populations exceeding 50%.

- EJScreen EJ Indexes[1] are generally highest in the eastern and central portions of the EJ Study Area. Seven CBGs in the EJ Study Area have one or more EJ Indexes at or above the 80th percentile nationally. The environmental indicators with EJ Indexes at or above the 80th percentile nationally include: Air Toxics Cancer Risk (five CBGs), Toxic Releases to Air (five CBGs), Air Toxics Respiratory Hazard Index (four CBGs), Risk Management Plan Facility Proximity (four CBGs), particulate matter 2.5 (PM2.5; three CBGs), Ozone (two CBGs), Wastewater Discharge (two CBGs), Diesel Particulate Matter (one CBG), Superfund Proximity (one CBG), and Hazardous Waste Proximity (one CBG).
- Six of the seven CBGs in the EJ Study Area with EJ Indexes at or above the 80th percentile nationally (CT 13.03 BG 2, CT 113.04 BG 3, CT 114.02 BG 1, CT 114.02 BG 2, CT 9802 BG 1, and CT 9803 BG 1) also have a minority population above 50% and/or a low-income population greater than that of Claimed as PBI.
- The majority of the CBGs in the western portion of the EJ Study Area have EJ Indexes below the 80th percentile nationally.
- Both CT 9802 BG 1 and CT 9803 BG 1 contain correctional facilities, driving differences in demographic and socioeconomic conditions as compared to other CBGs in the EJ Study Area.

A Stakeholder Engagement Plan will be developed to manage the socioeconomic dynamics that may impact—or be impacted by—the Project. Considerations related to potential communities warranting further assessment from an EJ perspective, local economic development, workforce development, and grievances will continue to be measured, assessed, and used to inform stakeholder engagement and impact mitigation strategies throughout the Project's lifecycle. Consistent with ExxonMobil's socioeconomic management principles, a stakeholder grievance process is also under development that will allow stakeholders to have access to ExxonMobil throughout the Project lifecycle.

ExxonMobil anticipates that activities supporting Project development will be supportive of the environmental and socioeconomic needs of the communities in which the Project will operate.

[1] For each CBG, each environmental indicator has its own EJ Index, which combines the demographic index (which averages low-income and people of color populations) with the respective environmental indicator percentile value for the CBG. For example, the EJ index for traffic for a given CBG is calculated as (traffic indicator percentile for the CBG) x (average of low-income population percentage and the people of color population percentage for CBG).

1.15 Permits and Construction Approvals for Rose CCS Project

In accordance with 40 CFR 143.31(e)(6) and 40 CFR 144.4 and at the time of this Application, Table 1-3 summarized the federal, state, and local permits that have been acquired for the Project.

1.16 Other Additional Project Information

At the time of this Application and pursuant of 40 CFR 146.82(a)(21), no other information is being provided in support of the Project. If additional information is requested by the UIC Program Director, ExxonMobil will review the request and provide an adequate response to questions via the Project Information Tracking Module in the GSDT.

Prior to development of the Project, the following federal laws will be assessed for their applicability and potential impact. At this time, no impacts are expected.

- The Wild and Scenic Rivers Act, 16 U.S.C. 1273 et seq. – ExxonMobil will identify any national wild and scenic river that may be impacted by the activities associated with the Project.
- The National Historic Preservation Act of 1966, 16 U.S.C. 470 et seq. – In accordance with the National Historic Preservation Act, potential properties eligible for the National Register of Historic Places will be assessed within the area that may be impacted by the activities of the Project. For any historic properties identified, additional historic and/or cultural resource surveys will be conducted. The results of the surveys will be provided to the UIC Program Director.
- The Endangered Species Act, 16 U.S.C. 1531 et seq. – ExxonMobil will identify any endangered or threatened species that may be affected by the activities associated with the Project. If a previous endangered or threatened species survey has been conducted, provide the results of the survey.

Claimed as PBI

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Underground Injection Control – Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 2 – SITE CHARACTERIZATION

Rose Carbon Capture and Storage Project

Claimed as PBI

ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2024

SECTION 2 – SITE CHARACTERIZATION

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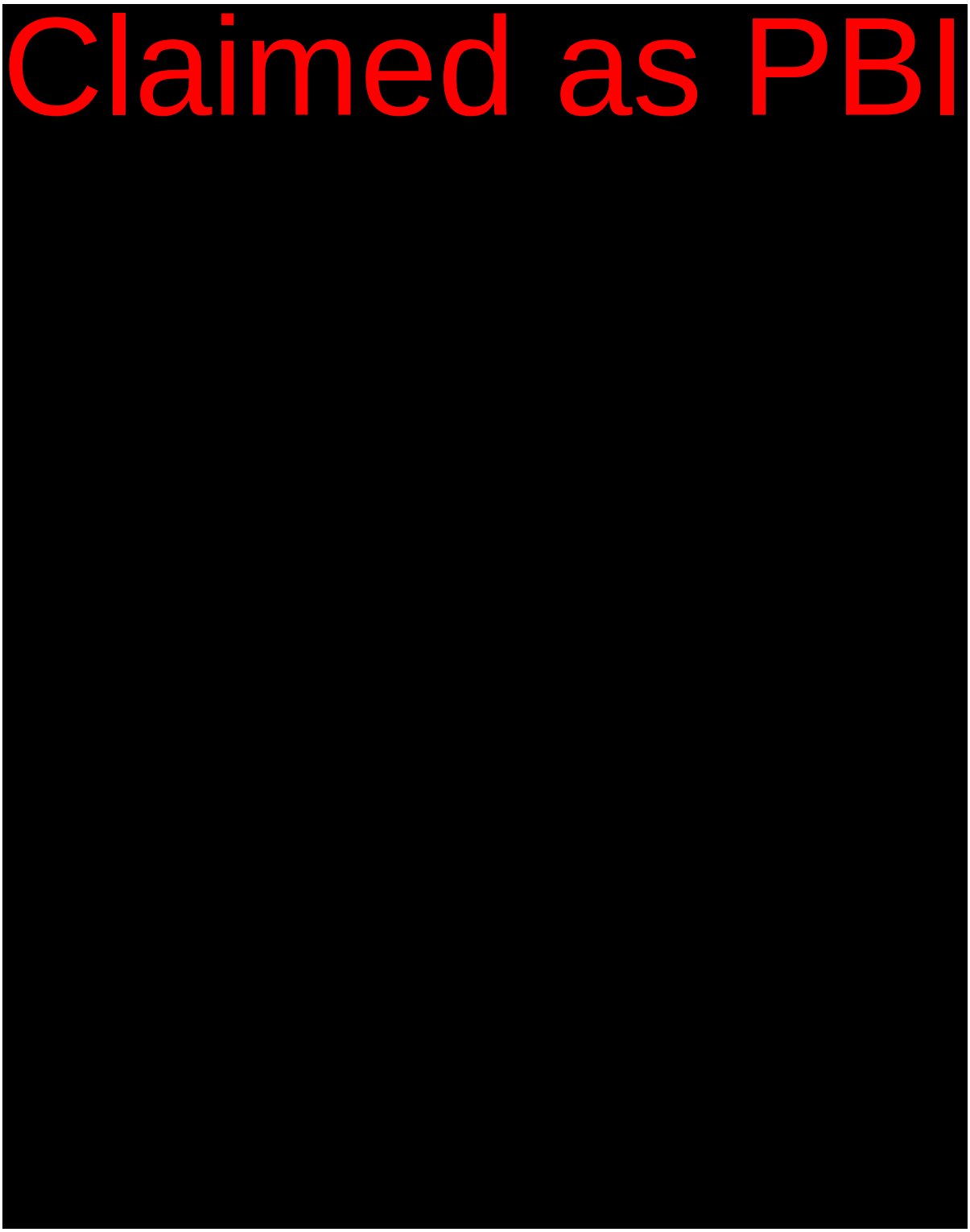

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List of Figures (Compiled in Appendix B – Site Characterization Files)

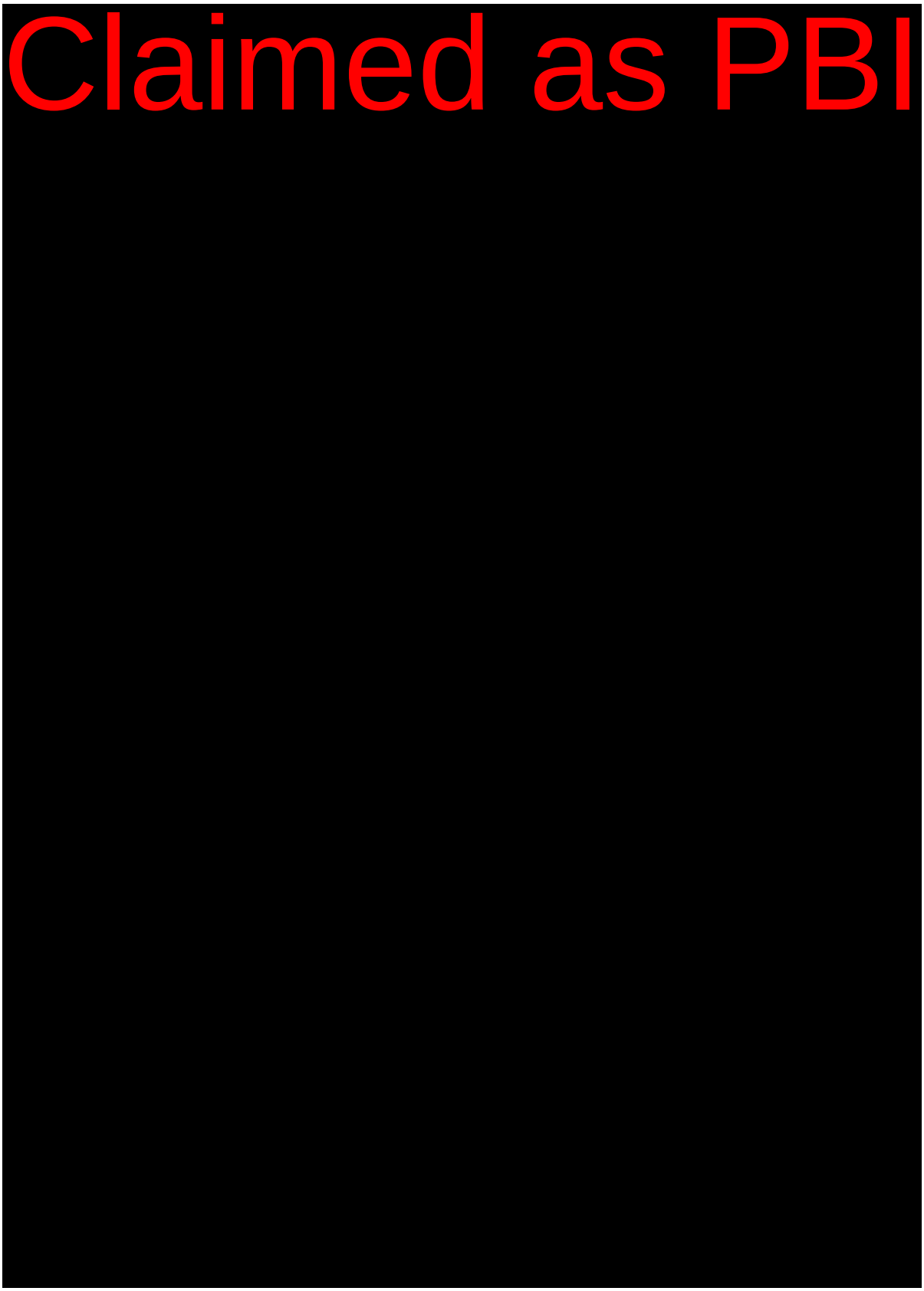
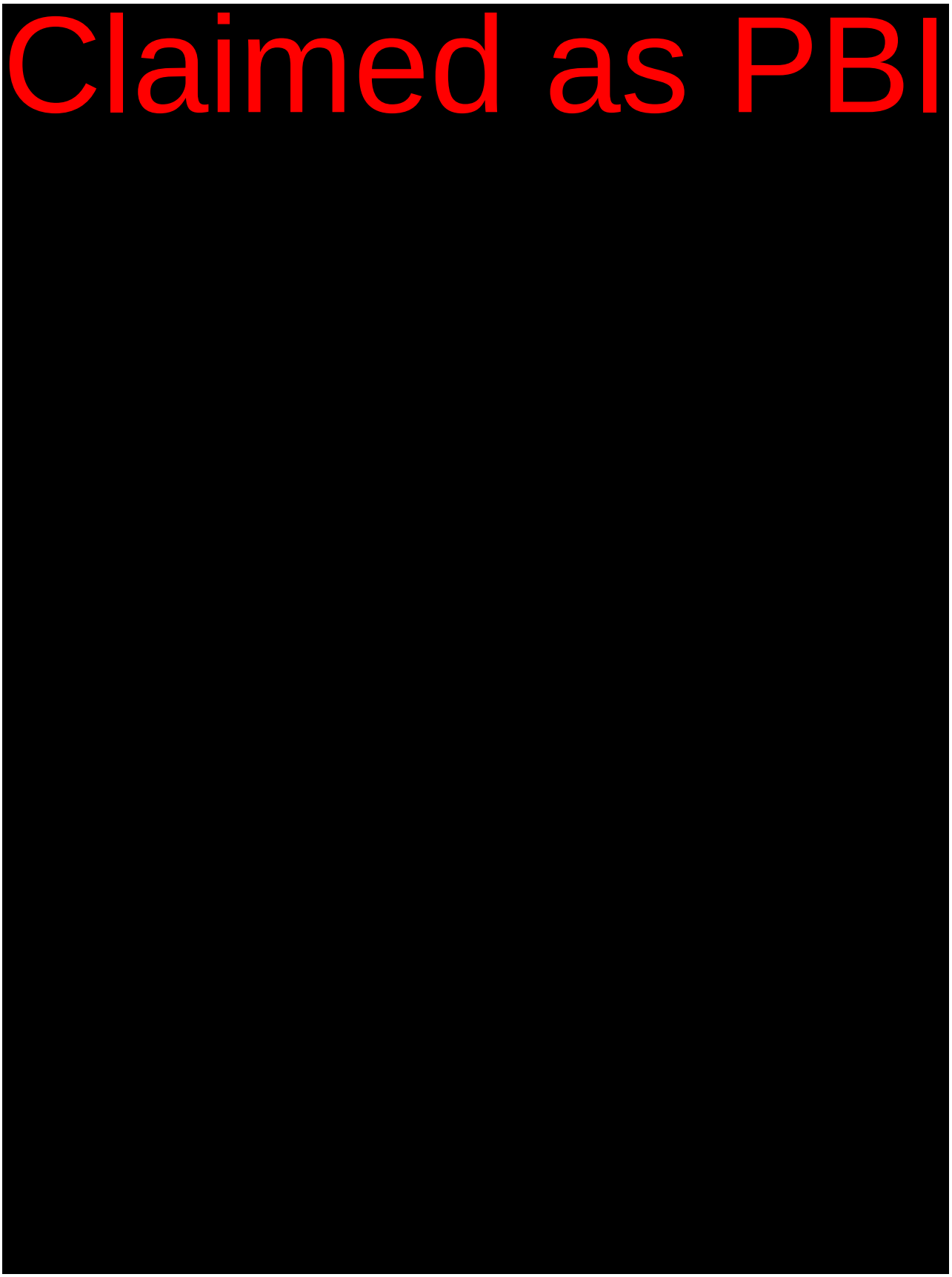


Figure B-49: World Stress Map - Maximum Horizontal Stress Orientations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2.0 Site Characterization

The site characterization for the Rose Carbon Capture and Storage (CCS) Project (Project) was prepared to meet the requirements of Title 40, U.S. Code of Federal Regulations [40 Code of Federal Regulation (40 CFR)146.82(a)(3)] and Texas Administrative Code, Part 1 Title 16 Chapter 5. ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is undertaking the Project in Claimed as PBI, Texas Claimed as PBI [redacted] The purpose of the site characterization section is to identify the potential risks and demonstrate, to the satisfaction of the Underground Injection Control Program Director, that the Project site is suitable for the sequestration project. The key aspects of this demonstration are that the geologic formations provide adequate storage capacity to store the intended volume of injected CO2 and a competent confining zone is present that will contain the injected CO2 throughout the life of the Project.

ExxonMobil has completed a thorough review of site characterization data and analyses from multiple data types including public, proprietary, and licensed data sets. A high degree of confidence has been gained during this process regarding the effectiveness of the storage and confining properties of the sequestration site and the anticipated alignment with data that will become available in the future. ExxonMobil anticipates that additional site characterization and pre-operational data should not entail major revisions to the site characterization or the plans that are dependent on this characterization. ExxonMobil anticipates that only slight adjustments would be needed to incorporate the latest available information for the site.

2.1 Objectives

The following objectives were developed to demonstrate compliance with the requirements of 40 CFR 146.82:

- Provide maps and cross sections of the area of review (AoR) [40 CFR 146.82(a)(3)(i) and 146.82(a)(2)];
- Identify the location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the AoR, along with an assessment that they will not interfere with containment [40 CFR 146.82(a)(3)(ii)];
- Summarize available data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s) and on lithology and facies changes [40 CFR 146.82(a)(3)(iii)];
- Discuss the available geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s) [40 CFR 146.82(a)(3)(iv)];
- Summarize the available information on the seismic history of the area, including the presence and depths of seismic sources, and an assessment of the potential for seismicity to interfere with containment [40 CFR 146.82(a)(3)(v)];
- Provide geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area [40 CFR 146.82(a)(3)(vi)];
- Present maps and stratigraphic cross sections indicating the general vertical and lateral limits of the underground sources of drinking water (USDWs) and water wells completion

details within the AoR, their positions relative to the injection zone, and the direction of water movement (where known) [40 CFR 146.82(a)(5)]; and

- Summarize the available baseline geochemical data on subsurface formations, including the USDWs in the AoR [40 CFR 146.82(a)(6)].

2.2 Regional Geology

The Project is located in Claimed as PBI, Texas within the Houston Embayment of the Gulf of Mexico Basin, as presented on Figure B-1 (Roberts-Ashby et al., 2014). On shore and near-shore, the Gulf of Mexico Basin is often referred to as the Gulf Coast region. The stratigraphic column of the Houston Embayment is presented on Figure B-2 (Baker Jr., 1995). The Gulf of Mexico Basin was formed by crustal extension and seafloor spreading during the breakup of Pangea that took place in the Mesozoic Era. A regional unconformity at the base of the sedimentary section is marked by the base of an evaporite layer (Galloway, 2008). These substantial evaporitic deposits (up to 4 km thick) became a defining characteristic for later structural evolution of the Basin. Salt deposition ceased at the end of the Late Jurassic Era, as continued rifting produced oceanic crust.

The outline and morphology of the present-day Gulf of Mexico Basin was sculpted by subsidence and rimming carbonate platform formation by the Early Cretaceous Era (Galloway, 2008). The Cenozoic Era depositional episodes along the northwestern Gulf of Mexico Basin are fluvial-deltaic and shore-zone dominated, which reflect major phases of adjacent North American structural events (Galloway, 2008).

There were five major North American tectonic phases that influenced deposition in the Gulf of Mexico Basin: (1) Laramide uplift, (2) the mid-Cenozoic thermal phase, (3) Basin and Range tectonism, (4) southern Appalachian and Cumberland Plateau uplift and erosion, and (5) Rocky Mountain plateau tectonic uplift. Specifically, the southern Appalachian and Cumberland Plateau uplift during the Cenozoic Miocene Epoch shifted the center of deposition from the northwest basin margin to the east, including present-day eastern Texas (Galloway, 2008).

Thick sedimentary sequence deposition within the Gulf of Mexico Basin was initiated in the Cenozoic Era that included a series of “off-stepping” sediment wedges (Galloway, 2008). These sedimentary wedge sequences thicken basin-ward and were largely deformed by early Cenozoic-age growth faults that extend through Eocene and Oligocene-aged formations. The combination of subsidence and rapid sediment loading upon a thick salt substrate resulted in significant gravity tectonics. Some of these gravity tectonic structures include growth faults, allochthonous salt bodies, salt welds, listric normal faults, salt diapirs with their related synclines and minibasins, and basin-floor compressional fold-belts (Galloway, 2008). Hyper-subsidence caused periodic structural down-warp and oceanic transgression, resulting in shale deposition atop sand sequences. The Oligocene Epoch off-stepping deposition initiated underlying salt movement upward and basin-ward, creating major salt canopies (Galloway, 2008). Salt withdrawal facilitated by sedimentation resulted in the movement of salt basin-ward creating withdrawal synclines and Gulf Shelf Minibasins, such as that underlying the Project area as presented in Figure B-3 (Galloway, 2008). The resulting salt canopies are located offshore.

As shown in Figure B-3, the Project site is contained within one of the northernmost and few land-based Shelf Minibasins, north of the Oligocene – Miocene Detachment. Figure B-4 is a regional cross section of the northern Gulf Coast region, constructed approximately 100 miles east of the Project and is labeled on Figure B-3 as Fig. 6 (Galloway, 2008). The upper cross

section in Figure B-4 presents the geologic age and structural features of sedimentary units in the area, while the lower cross section presents the interpreted depositional environments along the same cross section. Onshore Miocene and Oligocene-age sediments exhibit relatively gentle dip in the vicinity of the Project, although formation dip steepens basin-ward and in areas with faulting within the Lower Miocene, Oligocene, and underlying strata, as well as in areas exhibiting underlying salt features. The associated depositional environment for the Oligocene and younger sediments are associated with fluvial deltas, shore zones, and sandy shelves (Galloway, 2008).

To summarize, the stratigraphy of the northern Gulf of Mexico Basin exhibits characteristics associated with divergent continental margins. A major unconformity is evident at the base of the sedimentary column, marked by initial onlapping of strata along the subsiding basin margin. Subsequent to subsidence, basin margin aggradation occurred through off-lapping deposition, creating shelf edge and slope systems that exhibit faulting related to depositional loading and underlying salt movement (Galloway, 2008). This continued off-lapping deposition created the coastal plain and continental shelf, which have maintained a high degree of continuity throughout geologic time, up to the present day (Galloway, 2008). The depositional sequences throughout the Cenozoic Era are bounded by maximum flooding surfaces, marine and subaerial erosional unconformities, sediment starvation episodes, and faunal gaps (Galloway, 2008).

2.3 Major Stratigraphic Units: Confining and Injection Zones

Claimed as PBI [redacted] All formations underlying the UCCZ and overlying the lower confining zone (LCZ) are included in the injection zone, with the exception of the Anahuac Shale.

The injection intervals of the Fleming Formation underlie the UCCZ. Claimed as PBI [redacted] The Anahuac Shale occurs below the Claimed as PBI [redacted] and serves as a laterally continuous, interim sealing unit and a significant vertical flow barrier above the Claimed as PBI [redacted] The stratigraphic framework will be confirmed by biostratigraphic analysis of the stratigraphic test well.

The LCZ below the Upper Frio injection interval is composed of thick, extensive shale (Loucks et al., 1978). The stratigraphic column Claimed as PBI [redacted] presented in Figure B-2 and shows the stratigraphic relationship of the Fleming Formation, Anahuac Shale, and Frio Formation.

Figure B-5 displays the Cenozoic depositional episodes from the Upper Oligocene through the Pliocene in the Gulf Coast Region (Trevino and Rhatigan, 2017), with additional detail provided for Upper Oligocene through the Lower and Middle Miocene depositional sequences that comprise the injection zone and UCCZ. The episodes shown on Figure B-5 show the regressive sequences that coincided with higher rates of terrigenous sediment supply and that are

bounded by transgression at the top of each sequence. For example, the upper portion of the Amph 'B' Shale is marked by a transgressive sequence between the Middle and Lower Miocene. Oligocene sediments of the Frio in the Gulf Coast region are comprised of fluvial to near-shore sands, while Miocene sediments are fluvial to fluvial-dominated deltaic sands. In general, the Oligocene-Miocene along the Gulf Coast is characterized "as a thick wedge of regressive deltaic sands, silts, and clays" interspersed with transgressive marine-shale tongues (Bearb, 2014).

To summarize the depositional sequences, the Frio begins with transgressive, clay-rich shelf-slope shales that underlie massive deltaic sands deposited by the fluvially dominated Houston and Central Mississippi deltas. Reworking of these deltaic deposits created thick, sand-rich prograding shore-zone systems lateral to and atop muddy shelf deposits. That is, the Early Oligocene Frio is composed of muddy shelf-slope shales interfingered up-section with massive deltaic sands (Upper Frio) that were reworked as sand-rich prograding shore-zone systems. The Anahuac Shale overlies the Frio and represents a period of transgression, followed by deposition of thick Miocene successions of fluvial to fluvially dominated deltaic sands.

Figure B-6 displays an overview of the interpreted Gulf Coast region depositional environments during the Lower Miocene and Oligocene (modified from Galloway et al., 2000). As shown in this figure, during the Oligocene, much of the Houston Embayment area near the Project location exhibited a shore-zone depositional environment. Sedimentation at the Project area transitioned up-section to a mixed load dominated fluvial environment during the Lower Miocene. Overall, the depositional system from the Oligocene through the Middle Miocene resulted in alternating shales and sand beds representing a depositional history of transgressive-regressive sequences.

2.3.1 Lower Confining Zone

Claimed as PBI [redacted] Few wells have log data to verify the gross thickness of this interval near the site. ExxonMobil relied on seismic data to assess the occurrence and lateral continuity of LCZ as discussed in the description of shale deposition associated with the Frio Formation.

While not included in the LCZ, the Vicksburg Formation is a ubiquitous Upper Texas Gulf Coast interval underlying the shales of the Frio Formation and is comprised primarily of shales resulting from muddy prodeltaic shelf deposition (Loucks et al., 1978). Sand deposition increases up-section, though sand occurrence within the Vicksburg in the Upper Texas Gulf Coast was more isolated compared to the sands found in the Lower Texas Gulf Coast. The Vicksburg can also be considered a regional confining unit along the Gulf Coast. (Chowdhury and Turco, 2006).

2.3.2 Upper Frio Formation

The Frio Formation consists of alternating shales and sands, stemming from progradational shore-zone systems of the Gulf coastal plain. Specifically, in the Houston area and during the Early Oligocene, deposition of large volumes of sand from the fluvially dominated Houston and Central Mississippi deltas occurred, with subsequent wave reworking resulting in thick, sand-rich prograding shore-zone systems fronted by muddy shelf sequences Galloway et al.,

2000). Also, periodic salt withdrawal during the Mid-Oligocene triggered a brief phase of tilting, collapse, and submarine erosion that interrupted margin progradation.

Long-term retreat of the Houston and Central Mississippi Delta systems occurred during the late Oligocene Era, although high sediment load allowed for aggradation of coastal plain, delta and shore-zone systems at this time associated with the Upper Frio. Galloway et al. (2000) indicates that between deltaic systems, the Frio contains wave-dominated shore-zone systems "nourished by longshore reworking of sediment from the deltaic headlands." Claimed as PBI [redacted] Regionally, the reservoir quality of the Frio in the Houston Embayment area exhibits porosities ranging from 16 to 36 percent (%) and permeabilities of approximately 50 to 3,000 millidarcies (mD) (Swanson et al., 2013).

2.3.3 Anahuac Formation

The Anahuac Formation is located within the injection zone, overlying the Frio Formation, and underlying the Fleming Formation. It is a thick, continuous shale interval. The Anahuac Formation (Anahuac Shale) was deposited during a transgressive event following Frio deposition (Galloway, 2008). Prograding Miocene intervals, including the Fleming Formation, cap the Anahuac transgression (Swanson et al., 2013).

2.3.4 Fleming Formation

Early Miocene sediments of the Fleming Formation at the Project site are comprised of thick successions of fluvial to fluvially dominated deltaic sands that include more proximal facies than that of the underlying Oligocene-aged Frio intervals. The Red River became the dominant fluvial source, resulting in deposition of the fluvially dominated Calcasieu Delta System (Galloway et al., 2000). During the Miocene, hyper-subsidence and collapse were observed and resulted in subsidence events and periodic deposition of mudstones and transgressive shales that are interbedded throughout the Lower Miocene. Note that the Lower Miocene is referred to as the Fleming Formation and Oakville Sandstone throughout the Texas Gulf Coast, depending on the location (Chowdhury and Turco, 2006). In the Upper Gulf Coast region, the Fleming is the primary name of the Lower Miocene section.

The Lower Miocene was characterized by high sediment supply rates and general deltaic progradation in the Project area. Some transgressive sequences interrupted the Lower Miocene deposition, but the Lower Miocene is mainly bracketed by the underlying Anahuac Shale and overlying UCCZ that include the Amph 'B' Shale as the major transgressive sequence.

South of the Project site, the estimated porosities of the Miocene reservoirs range from 5 to 38%, with an average of 28% (Carr et al., 2017). Permeabilities range from 16 to 1,600 mD with an average of 338 mD (Carr et al., 2017). Lower Miocene sands at the Project site are expected to show similar reservoir characteristics based on the observed log signatures.

2.3.5 Upper Composite Confining Zone

The UCCZ is a thick muddy sequence that includes the Middle Miocene Amph 'B' Shale, a regionally continuous, transgressive marine unit (Galloway, 2008), that is recognized by the U.S. Geological Survey (USGS) National Assessment of Carbon Dioxide Storage Resources to be a good sealing unit and; therefore, a competent confining zone as required for CO2 sequestration project sites (Roberts-Ashby et al., 2014). Additionally, Carr et al. (2017) further define the Amph 'B' as:

"A mudrock unit informally called the Amph B and encompassing the Amphistegina B biochrono stratigraphic zone is the thickest and most extensive regional confining zone in the Miocene section of the upper Texas coast. The Amph B records a major transgressive event in the northwest Gulf of Mexico Basin that marks the end of the early Miocene" (Carr et al., 2017).

2.3.6 Regional Shale Beds

The Anahuac and the UCCZ, including the Amph 'B' Shale, are among those that are considered regional shale marker beds. The Amph 'B' Shale can be regionally correlated in logs and is thick enough to be identifiable in seismic datasets. Gulf Coast hydrocarbon production trends also indicate that the Amph 'B' Shale provides a regional fluid-migration barrier (Lu et al., 2017). The Anahuac Shale is a "world class seal" consisting of a regional shale bed in the Houston Embayment that provides a competent confining zone for hydrocarbons (Swanson et al., 2013). Based on the ability of the Anahuac Formation to trap hydrocarbons, the Anahuac Formation is considered as a confining zone restricting the vertical movement of CO2 and will effectively isolate the Upper Frio Formation from the Fleming Formation.

2.4 Regional Structural Setting

The Project site is located in the Houston Embayment as shown on Figure B-1. Sedimentary units in the region generally dip toward the center of the Gulf of Mexico, roughly perpendicular to the coastline, as shown on Figure B-7, which presents the structural elevation of the Frio Formation top (Swanson et al., 2013). The Miocene units generally follow this structural trend, also dipping toward the center of the Gulf of Mexico. Figure B-8 presents a regional dip-oriented cross section showing the formations deepening to the southeast (Baker et al., 1995). As shown in Figure B-8, the top of the Anahuac and underlying formations deepen quickly to the southeast of the Project site, reflecting the depositional system and the numerous faults in the region.

Faulting in the area includes syndepositional normal faults, with the downthrown blocks typically occurring toward the Gulf of Mexico. These are largely classified as growth faults that are common in the Gulf Coast region and were formed by simultaneous subsidence during sediment loading (Loucks et al., 1978). For example, the Vicksburg and Frio Formations are transected by these types of faults related to rapid sediment loading and subsidence, occurring within broad fault zones (i.e., the Frio Fault Zone and the Vicksburg Fault Zone, Figure B-9). The Vicksburg Fault Zone occurs southeast of the Project site, as shown on Figure B-9 (Loucks et al., 1978). Similarly, major faults occur within deeper portions of the Frio Formation in the Frio Fault Zone. (Loucks et al., 1978). Major faults in the region occur most frequently in Oligocene units, although some faults may extend to the Miocene and up to ground surface. Many oil and gas fields in the Houston Embayment contain Oligocene production, indicating that the faulting in the region often facilitates both structural and stratigraphic trapping (Swanson et al., 2013).

As discussed in more detail below, faults in the Project area are less common than reported for the region and are characterized as post-depositional normal faults with the majority having minor amounts of offset in the injection and upper confining zone.

2.5 Site Geology

2.5.1 Overview

Regional geologic observations informed the initial local geologic characterization process. ExxonMobil took full advantage of available site characterization data to fulfill the requirements listed in 40 CFR 146.82. Data sources used for site characterization within and surrounding the

AoR include various regional and local publications, seismic data (two-dimensional [2D] and three-dimensional [3D]), existing well logs, along with limited pressure and core data. In addition, a stratigraphic well Claimed as PBI was drilled and testing is underway to provide site-specific well logs, core analyses, and injection test data. ExxonMobil anticipates that additional site characterization data should not entail major revisions to the site geological characterization. ExxonMobil anticipates that only minor adjustments would be needed to incorporate the latest available information about the site.

2.5.2 Summary of Detailed Analyses for Site-Specific Geological Characterization

The following list presents the topics for detailed analysis in the site-specific geological characterization:

- The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zones in the AoR and a determination that they would not interfere with containment [40 CFR 146.82(a)(3)(ii)];
- Review of the available data on the depth, areal extent, and thickness of the injection and confining zones, and facies changes as well as an overview of data collection plans for the stratigraphic well;
- Assess data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s) including geology/facies changes [40 CFR 146.82(a)(3)(iii)];
- Evaluation of the available geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s) [40 CFR 146.82(a)(3)(iv)];
- Provide maps and stratigraphic cross sections indicating the USDWs, water wells and springs within the AoR, their positions relative to the injection zone, and the direction of water movement, where known [40 CFR 146.82(a)(5)]; and characterize the geochemistry of the subsurface formations.

2.5.3 Site-Specific Data Acquisition

For the purpose of this permit application, the local site characterization is based on data and analyses from public and private sources of information. Confirmation of the site characterization and of the local geological properties is underway in the completion and analysis of data from the stratigraphic well drilled to total depth in Claimed as PBI. Data being obtained from the stratigraphic well are outlined in Table 2-1, Table 2-2, and Table 2-3. Table 2-1 presents the wireline logging program, Table 2-2 presents the coring depths and Table 2-3 presents the core analysis program. The data collected from the stratigraphic well will confirm and be used to refine the local geologic characterization.

2.5.4 Site Location and Identification of Injection Intervals and Confining Zones

A site overview map is provided as Figure B-10. This figure presents the regulatorily required data as presented in [40 CFR 146.82(a)] and includes the location of the proposed injection wells, state or U.S. Environmental Protection Agency-approved subsurface cleanup sites, surface bodies of water, springs, mines (subsurface and surface), and quarries. The figure also shows, within the AoR, the location and name or number of the injection, producing, abandoned, plugged, dry, deep exploration, or water wells that were identified in a rigorous

search of available information. In addition, other surface features including structures intended for human occupancy, state, Tribal and Territorial Boundaries, and roads are presented.

Figures B-11a and 11b present the base map specific to geophysical survey sources and the well data that were utilized for the site characterization and the development of the geologic model for the Project. The cross section lines are presented for orientation purposes.

As presented in the regional geology subsection, the UCCZ overlying the injection zone consists of a thick muddy interval that includes the Amph 'B' Shale. After reviewing the available data on the Amph 'B' Shale marker, ExxonMobil concluded that a site-specific data collection program was warranted to characterize the physical properties of the Amph 'B' Shale. A comprehensive biostratigraphy program is underway for the stratigraphic well to confirm that the thick and continuous shale mapped across the AoR corresponds to this interval.

The UCCZ layer is shown in the well cross sections in Figures B-12 and B-13 where the fine-grained muddy interval is evident. The three sand intervals within the Fleming Formation, below the UCCZ, were selected as injection intervals.

In addition to the UCCZ, the Anahuac Shale offers isolation between the Claimed as PBI [redacted]. Due to the low permeability and the pervasive thickness of this shale, vertical cross flow between the Claimed as PBI [redacted] is not projected to occur. The LCZ consists of underlying Frio shales that would reduce the potential for any downward migration of formation fluids or carbon dioxide out of the injection zone.

2.5.5 Top and Bottom Elevations of Injection and Confining Zones

The formation tops at the Claimed as PBI and the estimated tops for proposed Project Injection Wells No. 01, No. 02, and No. 03 are provided in Table 2-4. These formation tops were estimated using site information including offset wells and seismic data. The formation elevations listed in Table 2-4 will be updated as necessary based on the results of the stratigraphic well and injection well data acquisition program.

The local structural dip in the area is oriented toward the Gulf of Mexico to the south-southeast. Claimed as PBI [redacted]

As shown on the cross sections, the confining zones and injection intervals are laterally continuous throughout the Project area Claimed as PBI [redacted]

Claimed as PBI Cross sections (Figures B-12 and B-13) also verify the lateral thickness and continuity of the UCCZ and Anahuac Shale across the AoR.

Log data for the stratigraphic well were used for stratigraphic purposes in addition to the type well selected for this site, Claimed as PBI located near Injection Well No. 01. The log data from Claimed as PBI provided a basis to evaluate formation top elevations, formation thickness, and lithologies from the UCCZ to below the base of the injection zone. Table 2-5 Note that while the Claimed as PBI extends through the base of the injection zone, it did not extend far into the LCZ. Therefore, the Claimed as PBI was used as the type log for the LCZ. The identified formation tops from the Claimed as PBI type wells are provided in Table 2-5. Table 2-5 and Figure B-14 presents the Claimed as PBI type log showing spontaneous potential Claimed as PBI log data from the top of the UCCZ to the LCZ. Claimed as PBI

Sands are the primary lithology for the injection intervals in both the Fleming and the Upper Frio. These sands contain interbedded shales of varying thicknesses. Claimed as PBI

In summary, the available core, well log, literature, and seismic data were used to identify and characterize the injection zone and confining zone depths and properties. The available core data for the Project area were evaluated and lithologic descriptions are provided from the historic well log analysis as well as regional and local publications. Formation thicknesses are determined based on well logs combined with 2D and 3D seismic data interpretation. The net sand maps are sourced from historical well data. In addition to the currently available data, more information will be analyzed for each interval from the stratigraphic well.

2.5.6 Geologic Characteristics of the Injection Zone

The depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection zone are based on lithology and facies changes and were developed for each of the Claimed as PBI to demonstrate how the geological features of each interval align with the target storage volumes [40 CFR 146.82(a)(3)(iii)].

Claimed as PBI

While sediment deposition in the Upper Frio and Fleming Formations were both fluvially dominated, the Claimed as PBI interval is interpreted to have been shore-zone influenced while the Claimed as PBI injection intervals appear to have been sourced in a deltaic channel environment. Claimed as PBI

Claimed as PBI These injection intervals are continuous across the AoR.

2.5.6.1 Claimed as PBI

Claimed as PBI The Fleming Formation Sands have been observed to be fine to medium-grained sands (Galloway et al., 1986).

Claimed as PBI

The presented information, as well as additional lithologic descriptions and characterization, such as mineralogy and petrology will be updated following the results of the stratigraphic well.

2.5.6.2 Claimed as PBI Injection Interval

Claimed as PBI

Claimed as PBI

Claimed as PBI

dditional mineralogy and petrology data will be acquired from the stratigraphic well to confirm this assessment.

2.5.7 Geologic Characteristics of the Confining Zones

The UCCZ occurs immediately above the Claimed as PBI. The geological characteristics of the UCCZ are consistent with the requirements of 40 CFR 146.82(a)(3)(iii) for confining the CO2 plume and acting to protect USDWs from endangerment. Although not relied upon as the primary confining zone, the Anahuac Shale within the injection zone offers additional CO2 plume confinement features for the Upper Frio injection interval. Beneath the Upper Frio injection interval is the LCZ, characterized as a thick marine shale. The following discussion presents the available evidence of the confining properties of the UCCZ, Anahuac Shale, and LCZ.

2.5.7.1 Upper Composite Confining Zone

Claimed as PBI

Claimed as PBI [redacted]

[redacted]

Literature sources cite the potential for these shales to be either Type A or B Seals and will serve as flow barriers, as they are described to have a high degree of impermeability relative to hydrocarbon movement (Sneider, 1995). A Type A Seal estimates that a 35-degree API oil column will be trapped by a shale thickness from greater than or equal to 1,000 ft to less than 5,000 ft. A Type B Seal estimates that a 35-degree API oil column will be trapped by a shale of greater than or equal to 500 ft to less than 1,000 ft (Sneider, 1995).

2.5.7.2 Anahuac Shale

Claimed as PBI [redacted]

2.5.7.3 Lower Confining Zone

Claimed as PBI [redacted]

2.5.8 Local Geologic Structure

The local geologic structure was interpreted using a combination of analyses of 2D and 3D seismic data as well as historical log data. The location of two representative 2D lines extracted from the 3D survey and the wells that were utilized for the well ties is presented on Figures B-11a and 11b. Claimed as PBI [redacted] The results of the local geologic analysis are consistent with the regional geology in terms of formation structure orientation. The seismic data were utilized to create both structure contour maps of the relevant surfaces and to interpret faults within and surrounding the AoR.

2.5.8.1 Upper Composite Confining Zone

The UCCZ consists of a fine-grained, muddy interval that includes the Amph 'B' Shale marker. Claimed [redacted]

Claimed as PBI

2.5.8.3 Anahuac Shale

Claimed as PBI

2.5.8.5 Lower Confining Zone

Claimed as PBI

2.5.9 Seismic Data

Legacy 2D and 3D seismic data were obtained and licensed by ExxonMobil. Claimed as PBI

2.5.9.1 Velocity Control and Synthetic Seismogram

Claimed as PBI

Claimed as PBI

2.5.9.2 Interpreted Structural Features – Faults

Claimed as PBI

2.5.9.3 Interpreted Structural Features – Fractures

As previously discussed, Claimed as PBI . This data collection program for the stratigraphic well includes extensive coring, logging, and testing to obtain geologic, geomechanical, hydrologic, and other data pertinent to confirming injection zone and confining zone suitability. Claimed as PBI

Claimed as PBI. Evidence of fracture development is being assessed by examining imaging logs and core data from the stratigraphic well. Core data are being analyzed to identify cemented or uncemented fractures that may be present. Fracture type, lateral and vertical extent, and fracture apertures identified in the core, if any, will be described and documented. Further, core samples that do not show evidence of fracturing will be identified.

The imaging log run in the stratigraphic well is being analyzed to assess if any occurrences of partially or fully conductive fractures (open fractures) are present in the system. Due to the lithology of the confining zone, it is expected that the log and core samples will confirm that there are no fractures in the UCCZ that have any potential to impact the effectiveness of the confining zone.

2.5.9.4 Uncertainties and Limitations in the Available Data

During the evaluation of the available 2D and 3D seismic data, some uncertainties and limitations naturally arose regarding the potential for faults and fractures to be present within the AoR that could, potentially, contribute to the vertical transmissivity of CO2 or displaced formation fluids to the lowermost USDW. As discussed below, ExxonMobil possesses a high degree of confidence in the suitability of the analysis performed and anticipates that additional site characterization should not entail major revisions to the site characterization.

Claimed as PBI

2.6 Geomechanics and Petrophysics

The information discussed in this section is from existing sources, such as publications and offset well data. Well data Claimed as PBI are used to estimate the local stress conditions, elastic moduli, and fracture gradients of the injection and confining zones.

2.6.1 Local Stress Conditions

The World Stress Map is a "global compilation of information on the crustal present-day stress field maintained since 2009 at the Helmholtz Centre Potsdam GFZ German Research Centre for Geosciences." Claimed as PBI

Vertical stress was characterized primarily using bulk density logs from offset wells. Claimed as PBI

The minimum horizontal stress, which will be utilized to estimate the fracture gradient, was estimated using two processes: 1) calculate a Poisson's Ratio using available dipole sonic log data; and 2) use Eaton's equation to estimate minimum horizontal stress Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

2.6.2 Elastic Moduli

Dynamic elastic modulus E_{dyn} was calculated using shear wave velocity and the Poisson's Ratio ν as follows.

Claimed as PBI

2.6.3 Injection Zone Fracture Gradient Calculation

As discussed in Section 2.6.1, Eaton's equation was used to estimate the minimum horizontal stress in both sand and shale and guided the estimate of the injection zone fracture gradient. Claimed as PBI

2.6.4 Confining Zone Fracture Gradient Calculation

Similarly, Claimed as PBI . These values will be updated once field test results from the stratigraphic well become available.

2.6.5 Maximum Injection Pressure Calculation

40 CFR 146.88(a) requires that the maximum bottomhole injection pressure must not exceed 90% of the fracture pressure of the injection zone to reduce the potential for existing fractures to propagate during normal operations. Claimed as PBI

2.6.6 Capillary Pressure Data

Capillary threshold pressure (P_{cth}) is the critical pressure at which a nonwetting fluid, in a continuous flowing phase, may displace a wetting-phase fluid from the pore space. For core mercury injection capillary pressure (MICP) measurements, this is the pressure at which the percentage of nonwetting mercury volume increases rapidly depending on the rock's pore throat distribution. It implies the capillary force available to hold the buoyancy force of a fluid and is directly proportional to seal quality. MICP P_{cth} for available analog core material was performed using the Thomeer-hyperbola method which enables objective determination of capillary threshold pressure (Thomeer, 1960). P_{cth} is typically a small number for permeable sand but is important to include in the rock property description and simulation model.

In this study, rocks of different reservoir quality are binned into five sets based on permeability range, Claimed as PBI

2.7 Evaluation of Surface Air and Soil Gas Monitoring Data

Claimed as PBI

2.8 Reservoir Characterization and 3D Geologic Modeling

Characterization of the Claimed as PBI was carried out within the confining and injection zones to develop an understanding of the sealing effects of the confining zone and characterize the reservoir heterogeneity within the injection zone. Based on the analysis and understanding of the Project area, a 3D geologic model was developed to estimate the storage potential for the CO2 and evaluate its confinement, both laterally and vertically.

2.8.1 Geologic Model of the AoR

Using available data, an integrated geologic model was developed for the site to represent the structural setting and depositional environment, as well as distribute petrophysical properties within the model boundaries. This model provides a 3D grid to enable predictive CO2 plume and pressure modeling over time. Available site data used to inform the 3D geologic model includes seismic surveys and legacy well logs, such as SP (original log for volume of shale, used in most of the VShale calculations), gamma ray logs (another lithologic log that can also be used to calculate VShale, used sparingly in this geologic model), resistivity, bulk density (density porosity), and sonic logs (sonic porosity). The geologic model incorporates regional core data,

log, and seismic data to characterize structural configuration, net sand, facies and property distribution, and porosity-permeability relationships.

Log properties were upscaled to model resolution and populated in a 3D grid over an area that exceeds the spatial limit of the AoR. The geological model is built with a lateral resolution of 500 by 500 ft oriented in northwest-southeast direction and a vertical resolution of approximately 5 ft and upscaled to 20 ft in geologic model. The total cell count is approximately 19 million cells. The geologic model covers approximately 115,322 acres and extends well beyond the predicted plume or AoR boundaries to negate any potential for model edge effects.

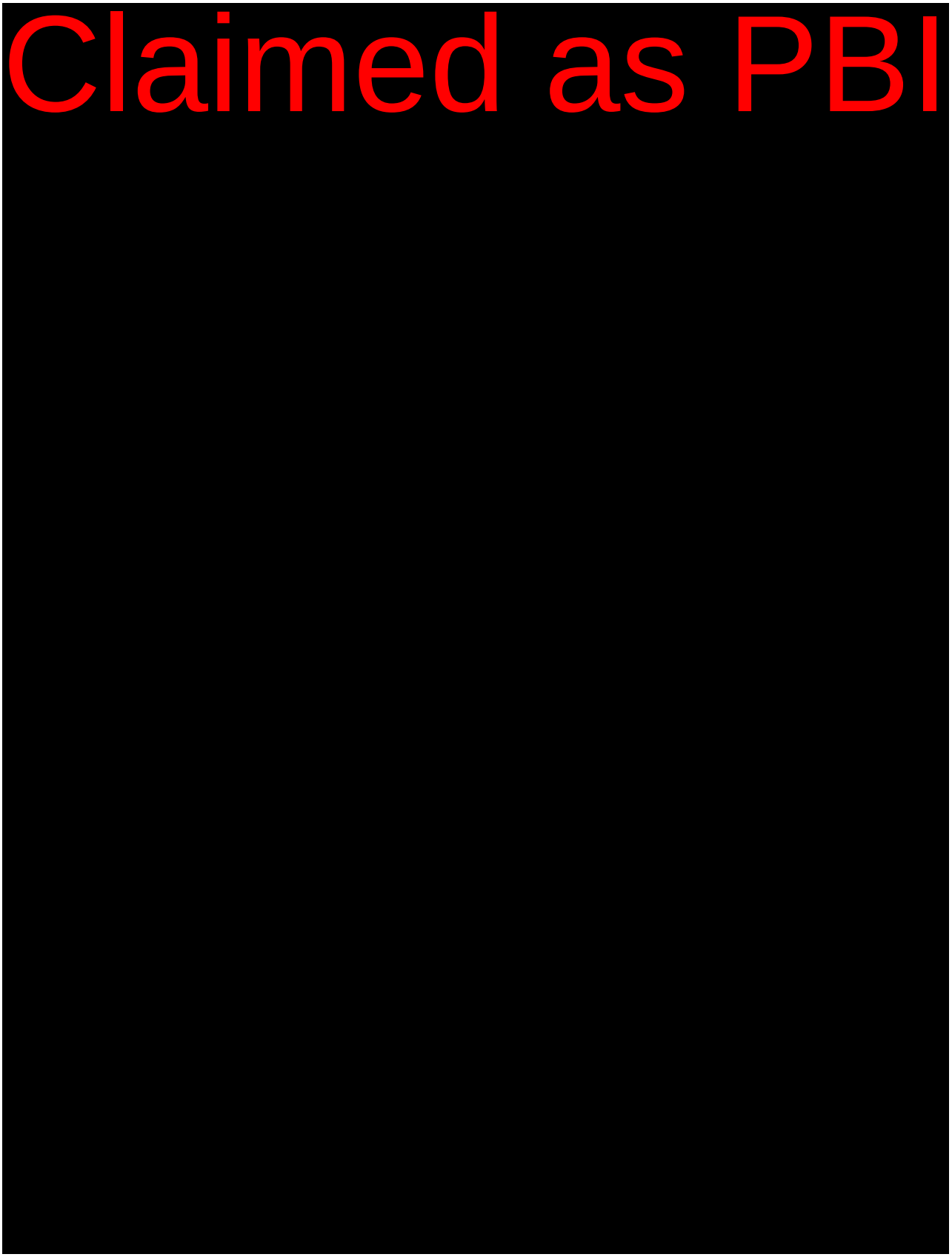
The conceptual site model will be updated as more information becomes available from the stratigraphic well. In addition, the model will be updated periodically during and following injection activities.

2.8.2 Structural Model

Claimed as PBI

2.8.3 Net and Non-Net Model

Claimed as PBI


Claimed as PBI

Claimed as PBI

2.8.4 Net Facies Model

Claimed as PBI

2.8.5 Net-to-Gross Model

Claimed as PBI

Claimed as PBI

2.8.6 Porosity Model

Claimed as PBI

2.8.7 Permeability Model

Permeability was modeled based on the results of the total porosity estimate. The porosity-permeability relationship is derived from a compilation of routine core analysis data from the United States Gulf Coast Region Claimed as PBI

Claimed as PBI

2.8.8 Injection Zone Storage Potential

Based on the 3D geologic model built for the site integrating the available seismic and well data, geologic concepts, and regional rock properties, the estimated storage potential for the developable area around the proposed injection well locations is Claimed as PBI

2.8.9 Model Uncertainties

Based on the available data used in the geologic model, these uncertainties are not expected to have a significant impact on the model results and delineation of the AoR. The available geologic data are sufficient to characterize the depositional system for the purposes of characterizing the key geologic features of the Project area. In the future, the geologic characterization data collected from Claimed as PBI will be used to refine the model and reduce these uncertainties.

2.9 Assessment of Injection Interval and Confining Zone Geochemical Reactions

The injection interval fluid geochemistry and minerology were evaluated to assess the compatibility of the CO2 stream with subsurface conditions. The following discussion describes the potential for chemical reactions to occur that could potentially mobilize trace metals that are naturally occurring in the injection intervals and potentially endanger USDWs.

2.9.1 Summary of Available Geochemical Data

The geochemical data for fluids in the injection intervals were obtained from the USGS National Produced Waters Geochemical Database (Blondes et al., 2018). This database contains information on the likely range of geochemical parameter concentrations and the nature of connate formation brines present in the proposed injection intervals. Claimed as PBI

[redacted]

Claimed as PBI

2.9.2 Data Acquisition for Potential Geochemical Reactions

The potential for brine-mineral-CO2 interactions were modeled to assess the potential alteration of both the reservoir and the sealing lithologies during and following CO2 injection. Claimed as PBI

[redacted]

2.9.2.1 Methodology

Claimed as PBI

Claimed as PBI

2.9.2.2 Brine Geochemistry

Claimed as PBI

2.9.2.3 Injection Interval Mineralogy

Claimed as PBI

2.9.2.4 Confining Zone Mineralogy

Claimed as PBI

2.9.3 Modeling Approach for Potential Geochemical Reactions

Claimed as PBI

2.9.4 Modeling Results for Potential Geochemical Reactions

Claimed as PBI

2.9.5 Summary of Predicted Geochemical Reactions and Potential for USDW Endangerment

A series of geochemical scenarios were modeled to provide predictions of how compatible the injection intervals, the UCCZ, and the Anahuac Shale could be to the injection of CO2. The range of model inputs were selected to represent a broad range of TDS expected to be present within the AoR. Over three separate scenarios, the model results consistently showed no significant alteration of the pore-space volume and no significant mobilization of naturally occurring metals that could potentially endanger any USDWs.

2.10 Hydrogeology

The Project site is located in Claimed as PBI, overlying the Gulf Coast Aquifer. The Gulf Coast Aquifer is a major aquifer designated by the Texas Water Development Board (TWDB) extending from the eastern border with Louisiana to the United States border with Mexico. The maximum total sand thickness of the Gulf Coast Aquifer ranges from approximately 700 ft in the south to approximately 1,300 ft in the north. According to George et al. (2011), freshwater saturated thicknesses average approximately 1,000 ft. The Gulf Coast Aquifer is used for municipal, industrial, and irrigation purposes.

2.10.1 Identification of USDW

2.10.2 Total Dissolved Solids and Groundwater Flow Direction

Multiple studies of the Gulf Coast Aquifer hydrogeology have been performed and a considerable number of studies have been conducted regarding the formation brine salinity trends (i.e., TDS) with depth. Baker (1978) published multiple cross sections characterizing groundwater salinity with depth in the Gulf Coast Aquifer and identified an estimated depth of the occurrence of groundwater with TDS concentrations below 3,000 mg/L. Young et al. (2016) has produced an extensive evaluation of water quality in the Gulf Coast Aquifer and mapped groundwater quality with depth for several TDS intervals. These include what the authors describe as “fresh,” “slightly saline,” “moderately saline,” “very saline,” and “brine,” at upper TDS values of 1,000, 3,000, 10,000, 35,000 mg/L, and above, respectively.

Claimed as PBI presents a general hydrogeologic cross section in the northern portion of the Gulf Coast Aquifer, which generally represents the configuration of these units near the Project area. Figure B-71 also presents the maximum depth of freshwater (defined as less than 1,000 mg/L TDS) based on groundwater sampling in five-by-five mile grid blocks by Young et al. (2016).

Claimed as PBI [redacted] Below this depth, a review of TWDB potable water quality data indicates that the TDS levels increase above 1,000 mg/L TDS with little increase in depth.

Claimed as PBI presents the estimated depths to the base of fresh water (less than 1,000 mg/L TDS) and estimated depths to the base of 3,000 mg/L TDS groundwater in the Gulf Coast Aquifer. These data are based on water quality calculations by Young et al. (2016). Near the site, these depths range between 250 to 500 ft (fresh water) and 1,000 to 1,500 ft (less than 3,000 mg/L TDS; Claimed as PBI). Claimed as PBI [redacted]

[redacted] Below this depth, the TDS values were found in the literature and water well records to be greater than 10,000 mg/L. Claimed as PBI [redacted]

2.10.3 Evaluation of the Lowermost USDW

This section presents a site-specific evaluation of water quality with depth, the identification of the lowermost USDW, and distance from the lowermost USDW to the top of the injection zone within the AoR. Three lines of evidence were used to assess water quality with depth in the vicinity of the site. Each line of evidence is presented below. Claimed as PBI [redacted] The other two lines of evidence corroborate this value and increase the confidence that this depth is protective within the AoR.

2.10.3.1 Literature Review

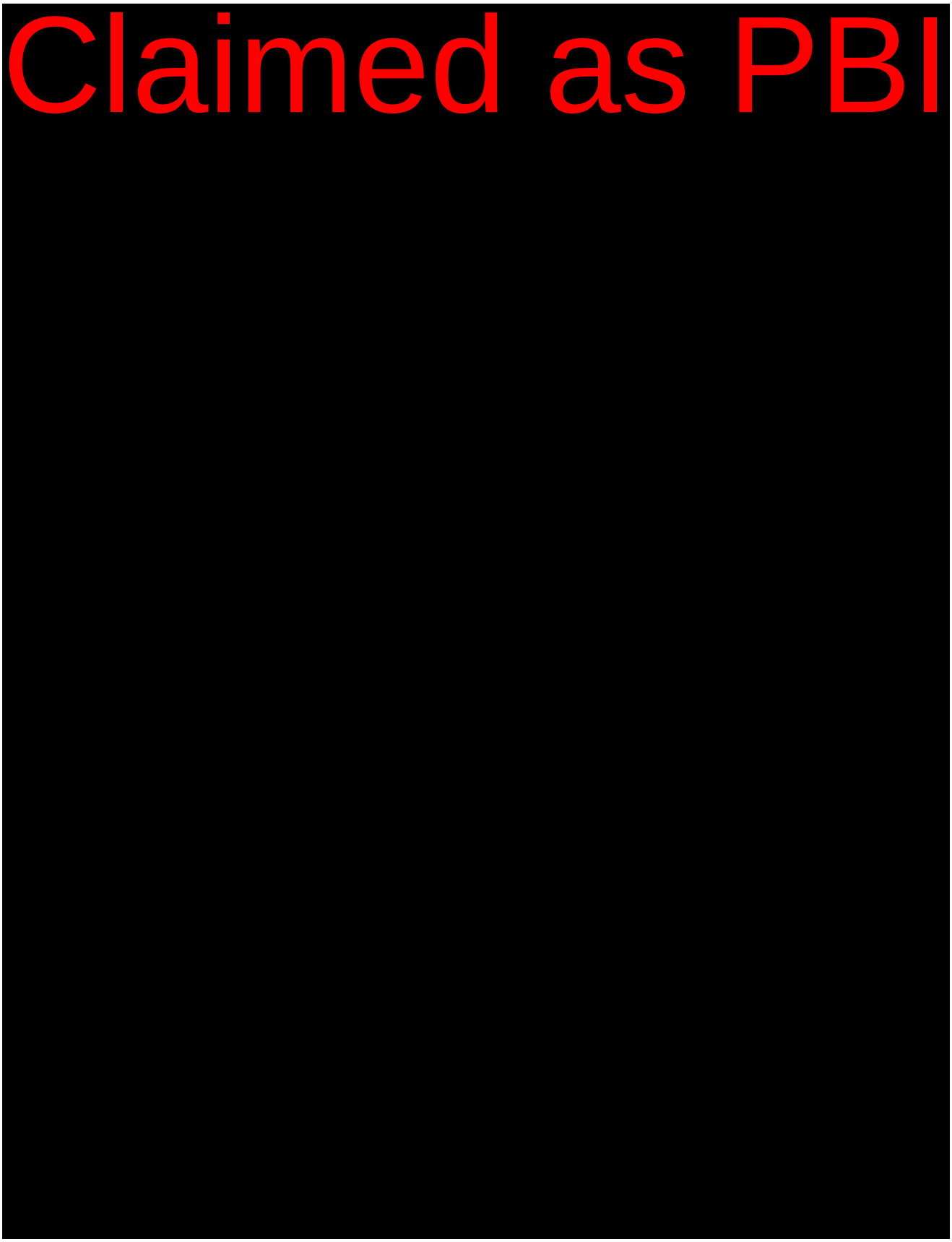
Claimed as PBI presents estimated depths to the base of groundwater with TDS concentrations less than 10,000 mg/L (or base of the lowermost USDW defined by 40 CFR 146.3) and also for brines that contain less than 35,000 mg/L TDS, based on water quality calculations by Young et al. (2016). Claimed as PBI [redacted] At depths that exhibit TDS concentrations greater than 35,000 mg/L TDS, salinity levels are generally observed to continue to rise or remain steady with depth, and generally do not exhibit salinity levels less than 35,000 to 50,000 mg/L (Young et al., 2016).

Claimed as PBI

2.10.3.2 Water Quality Calculations

Water quality calculations were conducted to characterize water quality at depth in the Gulf Coast Aquifer and delineate USDW depths near the AoR. The data were sourced from published literature and studies of the Gulf Coast Aquifer and imaged well logs from the Railroad Commission of Texas, as well as the TWDB Brackish Resources Aquifer Characterization System. Water quality calculations presented in this section are based on available geophysical data (i.e., wireline log data) from oil and gas wells near the AoR.

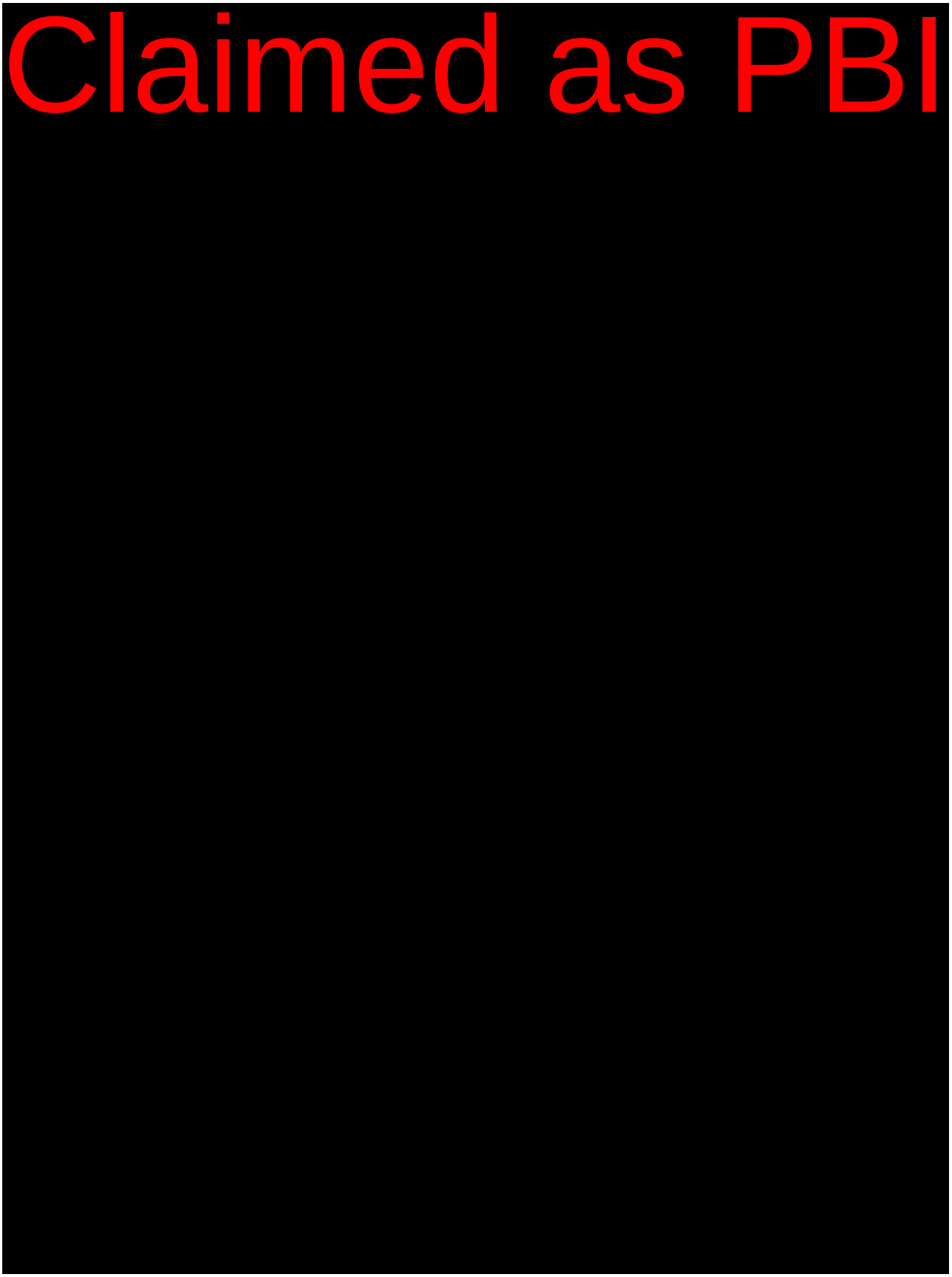
Claimed as PBI


Claimed as PBI

2.10.3.3 Base of Lowermost USDW at the Stratigraphic Well

2.11 Seismic Risk and Fault-Slip Potential for AoR

The Project area is reported by USGS to be of very low seismic hazard (low peak acceleration [4–6%g] seismic hazard, i.e., a 2% chance in 50 years of peak ground acceleration at 4–6%g, acceleration of gravity). Claimed as PBI In addition, there have been no recorded earthquakes in the vicinity of the Project area since 1973, based on a search of the USGS national earthquake database. The injection pressures will be limited to values that reduce the potential for the initiation or propagation of fractures. No induced seismicity is expected to occur under the proposed permit conditions. The following evaluations were conducted to provide a site-specific technical evaluation of the seismic risk within the AoR.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Based on the seismic history of the Project area and the conforming pore pressure calculations, the potential for induced seismicity from CO2 injection at the Project area is not a significant risk. Appendix I includes additional information of the methodology used to estimate the fault-slip potential within the AoR.

2.12 Site Suitability

The purpose of this subsection is to present a summary of the geologic site characterization information, as required for the Underground Injection Control Program Director to evaluate site suitability. The Project area is suitable for CO2 injection into the proposed injection intervals of the Fleming and Frio Formations. The sands within these formations exhibit high porosity and permeability that are ideal for CO2 storage and are "of sufficient areal extent, thickness porosity and permeability to receive the total anticipated volume of the carbon dioxide stream" [40 CFR 146.83(a)(1)]. Both the UCCZ and Anahuac Shale are thick, continuous sealing intervals across the AoR and are sufficient to "contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressure and volumes without initiating or propagating fractures in the confining zone" [40 CFR 146.83(a)(2)]. The following site features substantiate these conclusions.

2.12.1 Local Geology and Injection Interval Suitability

The Project area is located in the Houston Embayment of the Gulf Coast Basin. Claimed as PBI The Fleming sedimentary intervals were deposited in a fluvially dominated delta system. Hyper-subsidence and collapse with periodic deposition of slope mudstones form transgressive shales are observed at the site. Claimed as PBI The Fleming Sands are thick and continuous across the AoR.

Claimed as PBI Sediments within the Frio injection interval include thick sand intervals deposited in association with a fluvially dominated delta system. Wave reworking of these deposits resulted in thick, sand-rich prograding shore-zone systems fronted by narrow, muddy shelfs. Claimed as PBI The Upper Frio Sands are thick and continuous across the AoR.

Claimed as PBI

Claimed as PBI [redacted] The analysis performed on these faults showed there to be effective sealing at the faults.

2.12.2 Summary of Storage Capacity

[redacted]

2.12.3 Summary of Confining Zone(s) Suitability

The UCCZ is a thick muddy interval in the Miocene that encompasses the Amphistegina 'B' marker shale. Claimed as PBI [redacted]

The Anahuac Shale overlies the Upper Frio Formation and offers confinement above the [redacted] Claimed as PBI . The Anahuac is a thick and continuous shale bed in the region, including the AoR. Claimed as PBI [redacted]

The LCZ is a very thick Frio Shale package that is several thousand ft thick and the base is often below the total depth of most of the exploration wells in the area.

2.12.4 Summary of CO2 Stream Compatibility and Suitability

A series of geochemical reaction scenarios were evaluated to generate insights into how the subsurface confining and injection formations could respond to CO2 sequestration. [redacted] Claimed as PBI [redacted]

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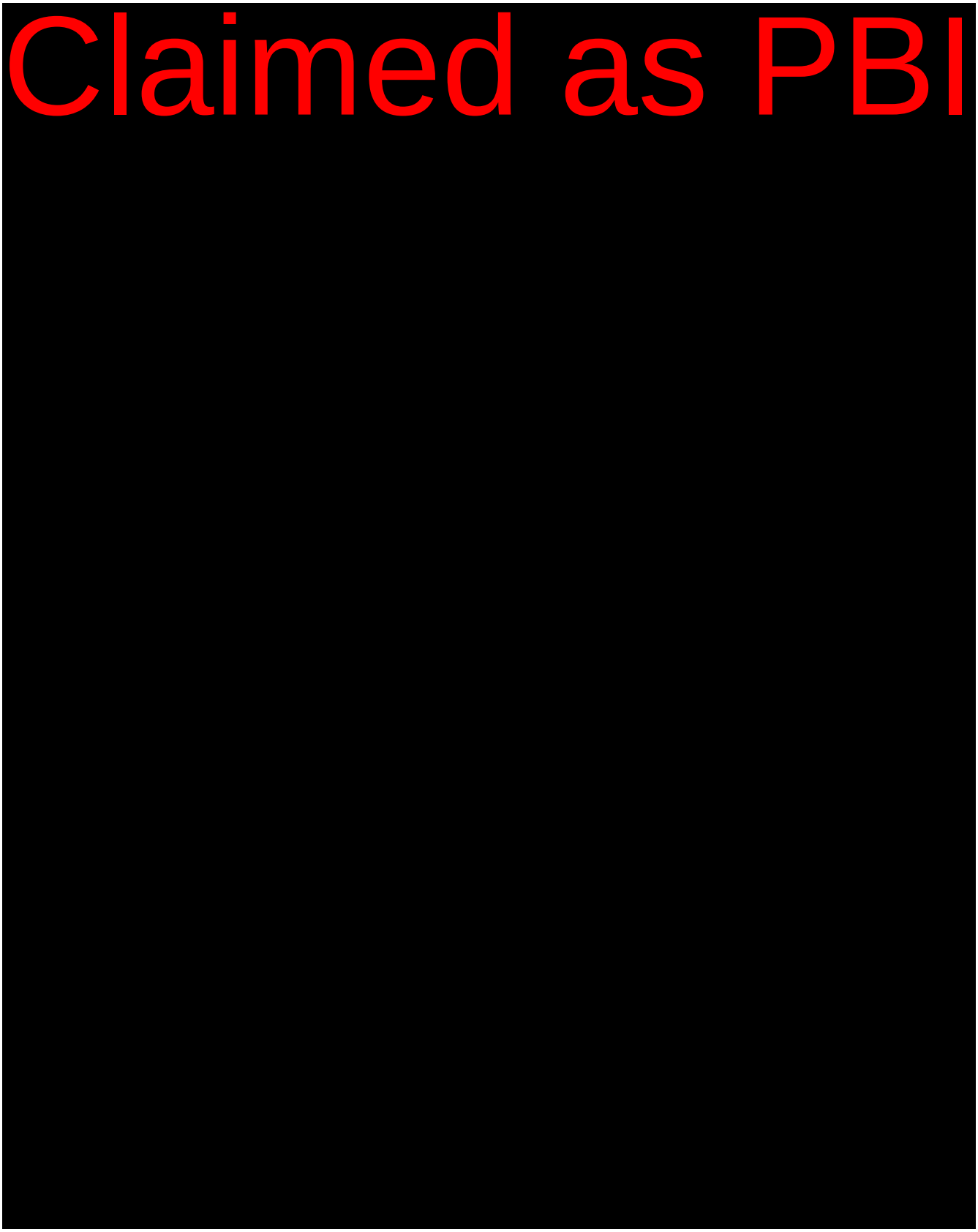
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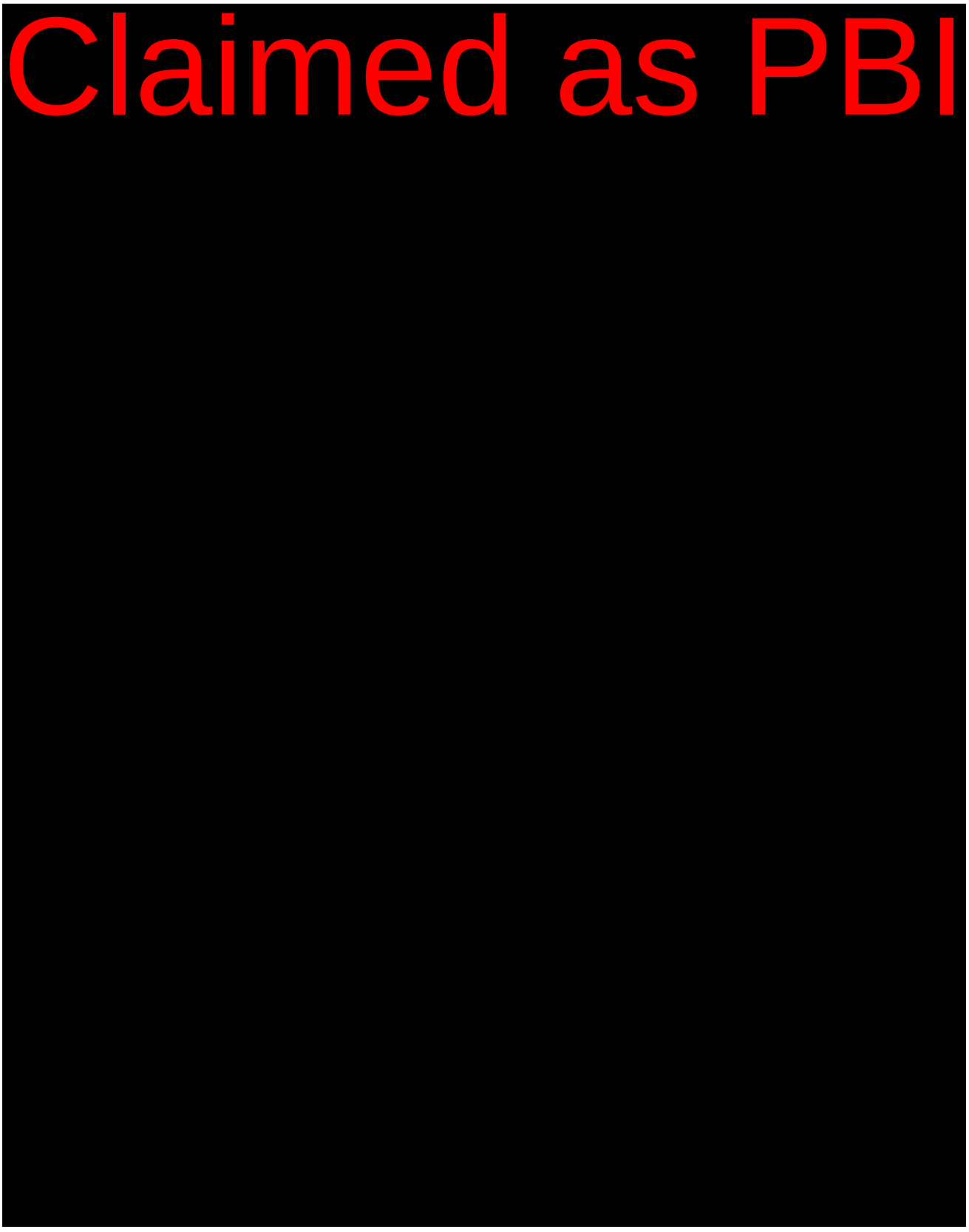
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Underground Injection Control – Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

Rose Carbon Capture and Storage Project

Claimed as PBI

ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2024

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

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3.0 Area of Review and Corrective Action Plan

The Area of Review (AoR) and Corrective Action for the Rose Carbon Capture and Storage (CCS) Project (Project) was prepared to meet the requirements of Title 40, U.S. Code of Federal Regulations (40 CFR) 146.84(b) and Texas Administrative Code, Part 1 Title 16 Chapter 5. ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is undertaking the Project in Claimed as PBI to sequester between Claimed as PBI million metric tonnes per annum (MMta) of carbon dioxide (CO_2) for Claimed as PBI of CO_2 will be sequestered over the life of the Project.

The purpose of the AoR and Corrective Action section is to describe how ExxonMobil has delineated the AoR using appropriate models and assumptions, addressed the apparent deficient artificial penetrations within the AoR, and describe how the AoR modeling will be periodically updated throughout the life of the Project.

ExxonMobil is pursuing individual Class VI permits for three injection wells consistent with 40 CFR 144.33. Given the close proximity of the injection wells for the Project, ExxonMobil plans to obtain approval from the underground injection control (UIC) Program Director to delineate the AoR and prepare the Corrective Action Plan to represent the collective effects of the three injection wells within the Project AoR. Although the effects were evaluated in the collective, the required maps showing the delineated AoR and the Corrective Action Plan for artificial penetrations are submitted separately for each well so that they may be incorporated into each injection well's Class VI permit.

3.1 Objectives

A comprehensive modeling and evaluation effort was undertaken to accomplish the following objectives, consistent with the requirements of 40 CFR 146.84(b):

- Predict the extent of the CO_2 plume and pressure front, which form the basis for the AoR using computational modeling and identify all wells that require corrective action [40 CFR 146.84(c)];
- Provide a plan to perform the required corrective action on artificial penetrations in the AoR [40 CFR 146.84(d)] that could threaten underground sources of drinking water (USDW);
- Support the development of effective monitoring strategies for the Testing and Monitoring Plan by identifying the locations where groundwater quality or pressure monitoring should be performed;
- Help direct emergency response planning by identifying potential vulnerable areas within or near the AoR that could require consideration when implementing an emergency response;
- Ensure that the Emergency and Remedial Response Plan and financial responsibility demonstration account for the most recently approved AoR [40 CFR 146.84(f)];
- Provide a guide for periodic AoR reevaluations to informed site management and monitoring over the lifecycle of the injection Project [40 CFR 146.84(e)]; and
- Retain modeling inputs and data used to support AoR reevaluations for 10 years [40 CFR 146.84(g)].

3.2 Facility Information

The following facility information is provided to specify the names and locations of the three injection wells.

Geologic Sequestration Project name: ExxonMobil Low Carbon Solutions Onshore Storage LLC – Rose Carbon Capture and Storage Project

Injection Well Information:

Well Name and Number	**Rose CCS Project Injection Well No. 01**
County	Claimed as PBI
Location (RR D, S, A)	Claimed as PBI
Latitude / Longitude (NAD83)	Claimed as PBI

Well Name and Number	**Rose CCS Project Injection Well No. 02**
County	Claimed as PBI
Location (RR D, S, A)	Claimed as PBI
Latitude / Longitude (NAD83)	Claimed as PBI

Well Name and Number	**Rose CCS Project Injection Well No. 03**
County	Claimed as PBI
Location (RR D, S, A)	Claimed as PBI
Latitude / Longitude (NAD83)	Claimed as PBI

3.3 Derivation of Input Parameter Values for Geologic Properties

ExxonMobil recognizes that parameter values for the prediction of the AoR are to be based on site-specific data to the extent possible. A stratigraphic well was completed and is being evaluated to obtain the necessary site geologic characterization data. In the meantime, the parameter values were estimated from standard values published for similar rock types and relationships in the scientific literature. As outlined below, ExxonMobil derived initial estimates of formation intrinsic permeability, porosity, relative permeability, compressibility, fluid viscosity, and fluid density from the available information. Once the geologic testing of the core and formation testing are complete, the results will be used to refine and update the AoR model and submitted to the UIC Program Director.

The site-specific characteristics that make the Project site ideal for carbon sequestration are described in Section 2.12 of Section 2 – Site Characterization. In summary, the Project area is suitable for CO2 injection into the proposed injection intervals of the Claimed as PBI The sands within these formations exhibit high porosity and permeability that are ideal for CO2 storage and are “of sufficient areal extent, thickness porosity and permeability to receive the total anticipated volume of the carbon dioxide stream” [40 CFR 146.83(a)(1)]. Both

the upper composite confining zone (UCCZ) and Anahuac Shale are thick, continuous sealing intervals across the AoR and are sufficient to "contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressure and volumes without initiating or propagating fractures in the confining zone" [40 CFR 146.83(a)(2)].

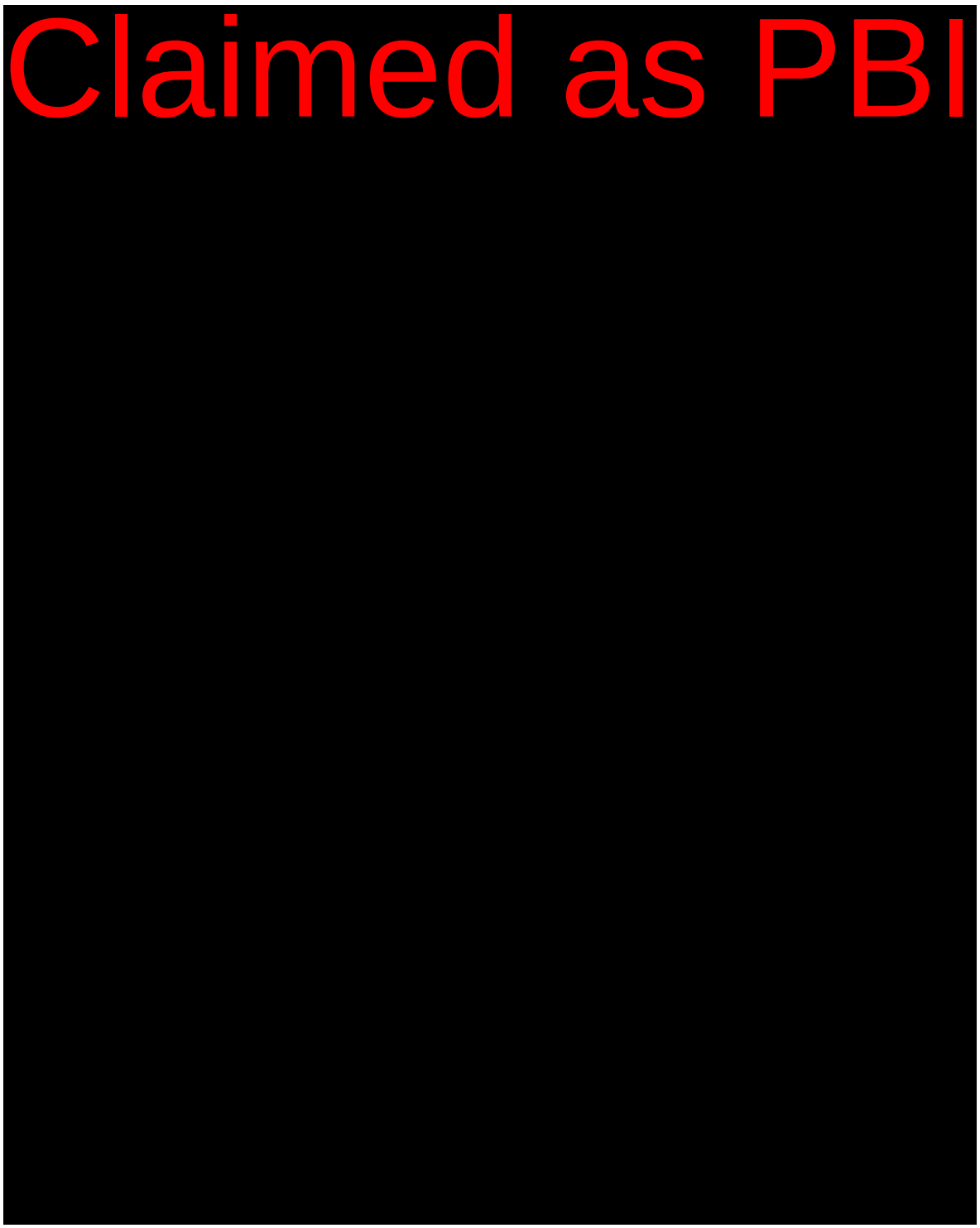
3.3.1 Porosity and Permeability

As an initial approach, porosity information was obtained from six well logs within the geologic model of the area of interest, which includes the AoR and a significant area surrounding the AoR. This information was utilized to generate a three-dimensional geologic model for the Project area. Most of the porosity data were provided based on compressional sonic data. Some bulk density data were also used to inform the estimates of porosity for the formations.

A porosity-permeability relationship was derived from a compilation of routine core analysis data available to ExxonMobil for the Gulf Coast Region of the United States. Claimed as PBI [redacted] The scope of the porosity-permeability relationship includes data reported for the injection zone, Claimed as PBI [redacted]

3.3.2 Rock Compressibility

A literature review was conducted to assess the rock compressibility of the Claimed as PBI [redacted] References to each are incorporated throughout this Application Claimed as PBI [redacted]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3.3.3 Relative Permeability

Relative-permeability curves were generated based on research of analogous depositional environments. Traditional core testing has difficulty accurately measuring the endpoints of the curves, resulting in high irreducible water saturations and low CO2 endpoints (Benson et al., 2013). In drainage CO2-brine relative-permeability experiments, as water saturation decreases, capillary forces become larger [i.e., capillary pressure (P_c)] and increase rapidly in the approach to the irreducible water saturation. During the experiment, the increase in capillary forces limits further reduction in water saturation (i.e., the viscous force is too small relative to the capillary force). This causes the experimental relative-permeability measurements to end at water saturations higher than the actual irreducible water saturation. For this reason, it is recommended to fit a Corey-Brooks expression to the experimental data and to extrapolate the curve to a representative value of irreducible water saturation.

Claimed as PBI

3.3.4 Capillary Pressure

Initial estimates of capillary pressure were estimated using capillary pressure functions by the

Claimed as PBI

3.3.5 Fluid Pressure

Claimed as PBI

3.3.6 Temperature

Claimed as PBI

Claimed as PBI [redacted]

3.3.7 Formation Compressibility

Total formation compressibility includes rock compressibility (Section 3.3.2) and fluid compressibility (Section 3.4.3). Both are accounted for during simulation of CO2 injection.

3.3.8 Water Saturation

Claimed as PBI [redacted]

3.3.9 Carbon Dioxide Saturation

Claimed as PBI [redacted]

3.4 Derivation of Input Parameter Values for Fluid Properties

3.4.1 Fluid Composition

Claimed as PBI [redacted]

3.4.2 Fluid Density and Viscosity

Brine and CO2 properties (including density, viscosity, and compressibility) are functions of pressure, temperature, and salinity. Industry standard method can be employed to determine the pure phase properties and their interaction.

For this study, a specific CO2 sequestration compositional modeling method was used that was developed by Schlumberger for the Eclipse™ numerical reservoir simulator (version 2020.4). This specific model, called CO2STORE, can accurately evaluate fluid density and viscosity based on following method in Eclipse™:

- The gas density is obtained by an accurately tuned cubic equation of state;
- The brine density is first approximated by the pure water density and then corrected for salt and CO2 effects by Ezrokhi's method (Zakirov et al., 1996); and
- The CO2 gas viscosity is calculated using methods provided by Vesovic et al. (1990) and Fenghour et al. (1998).

CO2 can dissolve in brine and vice versa, and the saturated CO2 and brine will have slightly altered density and viscosity. A sample table for pure phase and saturated phase CO2 and brine viscosity and density are illustrated below in Table 3-2.

Claimed as PBI

Figures 3-4 and 3-5 illustrate density variation for CO2 and brine vs. depth. Claimed as PBI

3.4.3 Fluid Compressibility

3.5 Derivation of Input Parameter Values for Chemical Properties

3.5.1 Aqueous Solubility

CO2 can dissolve in water and dissolved CO2 is considered permanently sequestrated in the saline aquifer. Therefore, dissolution is an important sequestration mechanism.

Claimed as PBI

3.5.2 Solubility in Carbon Dioxide

Claimed as PBI

3.6 Model Design and Input Parameters

The model design is based on the use of state-of-the-art computer simulation tools with a proven record of modeling multiphase flow. Claimed as PBI

3.6.1 Model Background

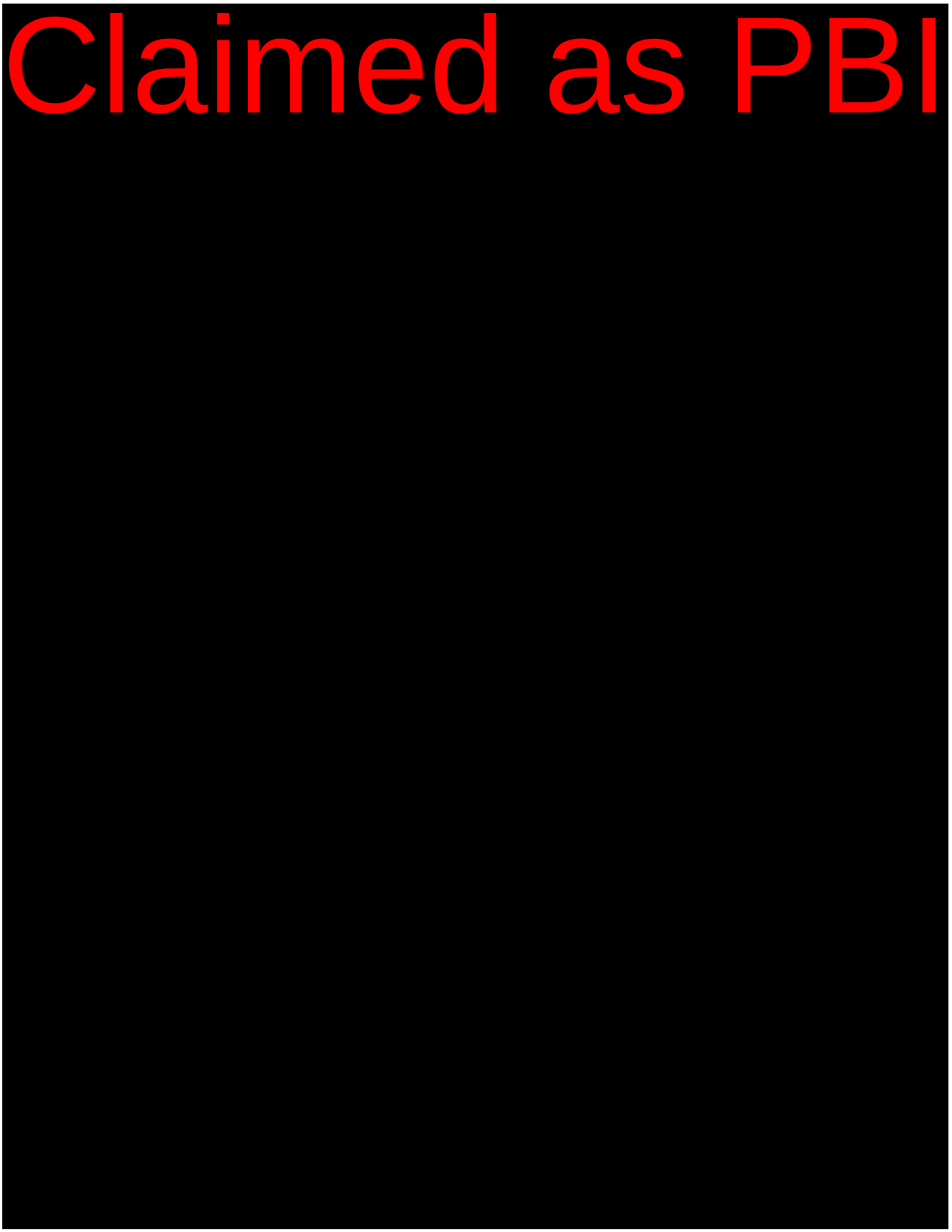
Schlumberger's Petrel™ Software was chosen to create a detailed geologic model for the Project. This state-of-the-art software is used worldwide and combines information from logs and seismic data to build a sophisticated representation of the underground reservoir. The Petrel™-developed geologic model incorporates the geologic layers of the site described in the Section 2 – Site Characterization, including three targeted injection zones within the Claimed as PBI

Claimed as PBI [redacted]

The geologic model developed in Petrel™ was used as an input into the Schlumberger Eclipse™ numerical reservoir simulator. Eclipse™ is a widely recognized tool used for modeling both compositional and unconventional reservoirs. The simulator uses advanced computational methods and equation-of-state algorithms to evaluate compositional, chemical, and geochemical processes to produce a reliable simulation for CCS. The software has modules and options specifically intended to allow the study of CCS injection activities, can handle large data sets and multiple grids, and offers various tools for data management, visualization, and uncertainty analysis.

3.6.2 System Orientation and Simulation Controls for Model

Claimed as PBI [redacted]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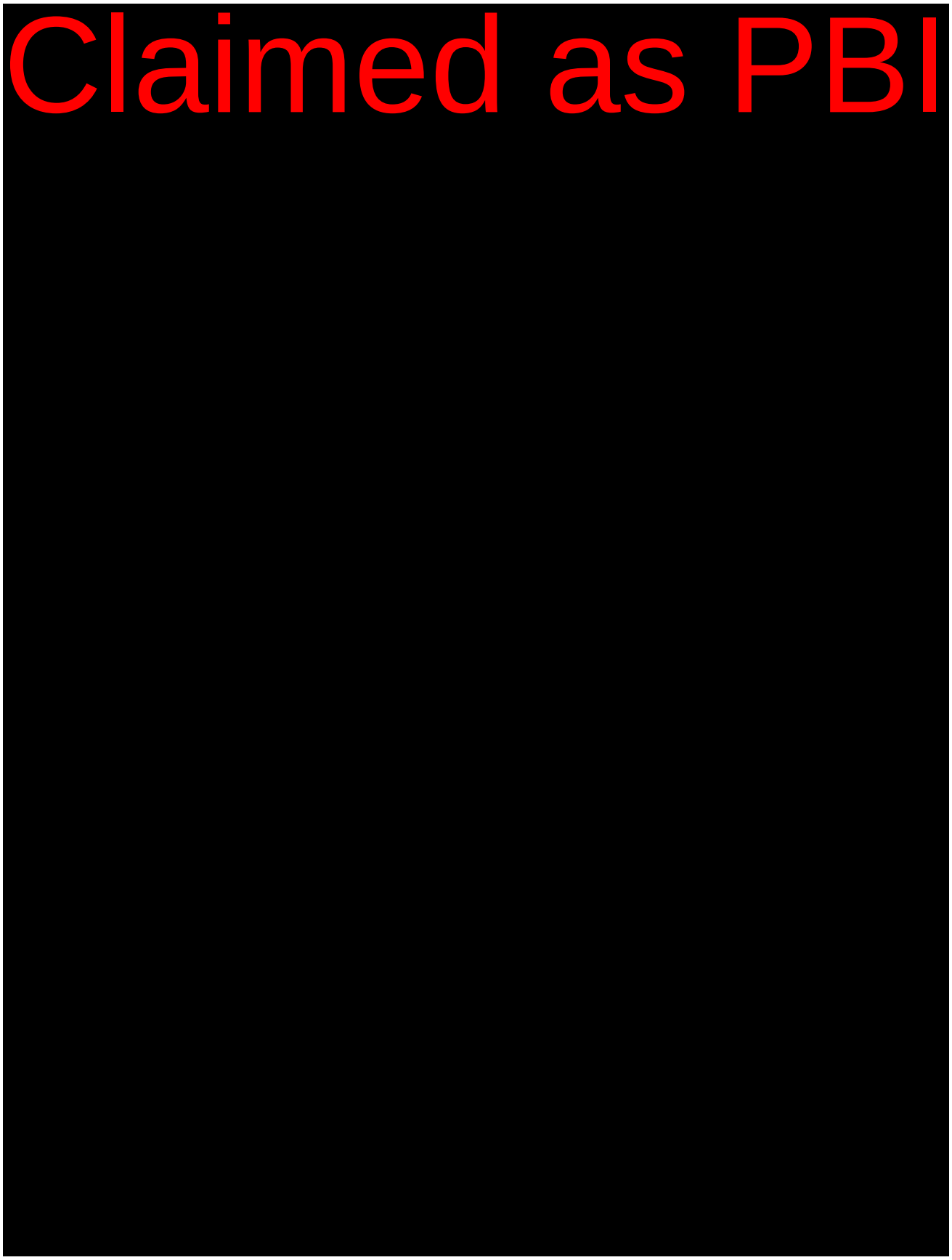
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Claimed as PBI

3.6.4 Fracture Pressure and Fracture Gradient

Claimed as PBI

Claimed as PBI

Claimed as PBI

3.6.5 Boundary Conditions

ExxonMobil selected the boundary condition for the model domain that describes the fluid flow rates and/or pressures at the edges of the model domain and at the location of injection wells. Claimed as PBI [redacted]

[redacted]

3.7 AoR Delineation Based on Model Results

3.7.1 Extent of CO2 Plume

The areal grid block size in the model was selected to optimize model runtimes, limit grid distortion effects, and allow for sufficiently accurate contouring of plume extent over a distance of multiple miles. The operational and geologic input parameters were used in the Eclipse™ model to generate projections of plume and pressure migration versus time. Claimed as PBI [redacted]

[redacted]

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Claimed as PBI

[redacted]

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3.7.2 Delineation of the Critical-Pressure Front

In accordance with 40 CFR 146.84, the AoR was delineated by the critical-pressure front created by the injection of CO2 into the injection intervals. Critical pressure is the increase in reservoir pressure that has a potential to create crossflow of brine from the injection zone into the lowermost USDW, assuming the presence of a hypothetical bridging conduit such as an unplugged borehole. The first step to predict the pressure front of interest is to calculate the critical pressure for each completion stage. Once critical pressure is estimated, a numerical simulation is used to predict the size and shape of the critical-pressure front defined by this pressure contour.

3.7.2.1 Critical-Pressure Calculations

The methodology for determining critical pressure was sourced from Claimed as PBI

For the purposes of the critical-pressure calculations, the base of the USDW within the AoR was Claimed as PBI

Claimed as PBI

The critical pressure was calculated for each completion phase of each injection well, with the top of the effective injection interval perforations ranging from depths

Claimed as PBI

Claimed as PBI

3.7.2.2 AoR Delineation

The maximum areal extents of both the CO2 plume and the critical-pressure front were used to delineate the AoR at any time interval or depth. The larger extent of either CO2 saturation or critical-pressure rise was used to define the AoR boundary. Claimed as PBI

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Claimed as PBI

[redacted]

Claimed as PBI

[redacted]

3.8 Model Calibration and Validation

Representative input has been assigned to the model based on analysis of applicable logs, seismic data, offset well, and literature data that were available. Modeling inputs that currently rely on these data and on correlations will be confirmed and revisions made as necessary to improve the predictive capabilities of the model. The stratigraphic well data and testing results will be the basis for the first set of model updates. Subsequently, additional model refinement may be needed based on data collected at the time of injection well installation. Once the injection of CO2 commences, the testing and monitoring data obtained will provide a means to calibrate the model and revise model predictions based on observed system behavior.

3.9 Corrective Action Plan and Schedule

Consistent with 40 CFR 146.84, the primary objective of this Corrective Action Plan is to identify the potential risk for loss of CO2 or brine containment through artificial penetrations of the UCCZ and to specify corrective actions that would be taken to restore the integrity of the UCCZ, if needed. ExxonMobil undertook a thorough investigation of artificial penetrations within and immediately adjacent to the AoR. Public and private databases were searched, historical aerial photographs were reviewed, Claimed as PBI [redacted]

This section provides a rigorous corrective action process for each well that begins with additional well assessment activity and ends with establishing incremental barriers to remedy the potential for CO2 or brine crossflow between the injection zones and USDW. Claimed as PBI [redacted], the process and status of gaining access to the wells is described to demonstrate confidence that access to the legacy wells will be achieved and will not be an issue for implementation of the corrective action measures.

3.9.1 Data Acquisition and Evaluation of Artificial Penetration Information

In accordance with 40 CFR 146.82(a)(4) and 40 CFR 146.84(c)(2), a search was conducted to identify and assess the occurrence of artificial penetrations within and immediately beyond the AoR. Artificial penetrations included oil and gas wells; Class I, II, III, IV, and V UIC wells; water wells; mines; quarries; and potential subsurface cleanup sites. The following data sources were reviewed to identify potential artificial penetrations within the AoR:

- The Railroad Commission of Texas (RRC) GIS Database;
- The Texas Water Development Board;
- Texas Commission on Environmental Quality UIC Central File Room database;
- Brackish Resources Aquifer Characterization System;
- Database for underground mines and quarries [U.S. Geological Survey (USGS) Mine Related Features and USGS Mineral Resources];
- State- or EPA-approved subsurface cleanup sites; and

Claimed as PBI

No subsurface cleanup sites, mines, or quarries were identified within the AoR. Based on the well locations identified in the above databases, additional review was conducted utilizing historical records to assess their veracity of each implied well presence, geospatial location, and historical completion, along with plugging, casing, and cementing procedures for each artificial penetration. Duplicative well identifications were merged if appropriate based on the records. The following are additional analyses that were conducted for artificial penetrations:

- Historical aerial photograph reviews for the identified artificial penetration locations;
- A physical record request was made to the RRC, and the available documents were reviewed;

Claimed as PBI

Using a combination of the data above, a tabulation of identified artificial penetrations within the AoR has been created and is summarized in Table 3-15. The identified artificial penetrations can be found on Figure 3-16. Available records for the identified legacy wells can be found in Appendix C.

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3.9.1.1 Review of Historical Aerial Photographs

ExxonMobil conducted a review of readily available historical aerial photographs for selected legacy wells to confirm well location and completion dates. Claimed as PBI

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Claimed as PBI

Claimed as PBI

3.9.1.2 Physical Records Review

For wells within the AoR, ExxonMobil obtained copies of physical records for Claimed as PBI

Claimed as PBI

Due to the age of well development in the area, additional data collection was conducted in selected portions of the AoR, wherein additional insight into well locations or details was required to improve accuracy. Claimed as PBI

Claimed as PBI

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Claimed as PBI

3.9.1.4 Review of Abandoned Well Plugging Records

ExxonMobil conducted an evaluation of the information available for the artificial penetrations listed in Table 3-15. The list of topics reviewed included:

- Well depth and completion;
- Well drilling date;
- Well abandonment date;
- Open hole or cased hole identification;
- Location of reported plugs;
- Casing and cementing records;
- Records of mechanical integrity tests (MITs) or logs performed; and
- Well deviations.

3.9.1.5 Summary of Artificial Penetrations Tabulation

ExxonMobil conducted a thorough assessment of the potential for artificial penetrations to be present within the AoR. Wells and boreholes completed above the UCCZ were determined to pose no hypothetical risk to function as a vertical conduit from the injection zone. For those artificial penetrations that were completed below the UCCZ, multiple sources of information were reviewed, and the relevant information was analyzed in detail [40 CFR 146.84(c)(2)]. Table 3-15 presents a summary of the artificial penetrations of interest for developing the Corrective Action Plan. The following summarizes the findings to date for each well:

3.9.2 Corrective Action Plan for Artificial Penetrations

ExxonMobil developed a Corrective Action Plan for each artificial penetration that was identified to have the potential to act as a vertical conduit because it was not plugged, it was plugged and abandoned improperly, or not plugged in a manner that mitigates the movement of CO2 or other fluids that could potentially endanger USDWs as required by 40 CFR 146.84(c) and (d). Claimed as PBI

For the Claimed as wells identified to have plugging deficiencies, the basis for the corrective action strategy is to re-enter each well that has insufficient proof that it has been sealed to reduce the potential for vertical flow through the UCCZ and to install cement barriers inside the casing to mitigate migration potential through the casing. The CO2-compatible cement material will be used to form these additional plugs and will be used where appropriate in accordance with 40 CFR 146.84(d).

As previously discussed in this section, Claimed as PBI

Claimed as PBI [redacted]

3.9.2.1 Tabulation of Artificial Penetrations for Corrective Action

Figure 3-24 shows the location of the wells identified for corrective action in relation Claimed as PBI [redacted] as identified for corrective actions prior to injection based on the expected arrival times of the CO2 plume and pressure front. Claimed as PBI [redacted] Based on the projections generated with reservoir simulation, Claimed as PBI [redacted]

As described in the Testing and Monitoring Plan of this UIC Class VI Permit Application, direct and indirect monitoring technologies will be used to track the CO2 plume and pressure front. A planned reevaluation of the AoR will occur after five years of injection and throughout the lifecycle of the Project. If at any time the rate of the CO2 plume or pressure front expansion is predicted to impact Claimed as PBI [redacted], the Corrective Action Plan will be amended to include the necessary corrective action to reduce the potential for USDW endangerment in accordance with 40 CFR 146.84(b)(2)(i)–(iv).

3.9.2.2 Analysis of Wells Identified for Corrective Action

Table 3-17 summarizes the available information concerning the borehole or well completion features and the P&A activities, as appropriate. ExxonMobil reviewed this information and determined the specific defects that require mitigation under 40 CFR 146.84(c) and (d).

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3.9.3 Corrective Action Sequence Plan

The following corrective action sequences will be undertaken in accordance with 40 CFR 146.84(c)(3) for the five artificial penetrations listed in Table 3-17. The planned actions are based on the plug deficiencies potentially present in each well based on the available records (Table 3-17). Each artificial penetration in the CO2 plume will be re-entered, and if sufficient barriers are not present, each well will have the appropriate barriers installed during the corrective action P&A field operations. The barriers will be established at the UCCZ, the surface casing shoe, the base of the lowermost USDW, and wellhead surface. The barrier at the UCCZ will be constructed of CO2-compatible material consistent with 40 CFR 146.84(d).

A general approach for well re-entry and corrective actions is summarized in the sections below. A detailed summary of the corrective action sequence for each well is presented in Table 3-18 and as specific well schematics for each well to be re-entered in Appendix C.

Claimed as PBI

A cement that is compatible with CO2 will be used as the UCCZ cement plug. ExxonMobil will evaluate potential cement options prior to implementing the cementing operations with concurrence of the UIC Program Director. The intent is to select a cement system that is designed to provide a long-term cement sheath or plug that can withstand the temperature, pressure, and chemical interactions.

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Claimed as PBI

3.9.4 Site-Specific Review of Corrective Actions

Table 3-18 provides the corrective action sequences for each of the Claimed as PBI

provide the well schematics of each legacy well that will be re-entered for evaluation and re-plugging that have been developed based on the historical information and based on completion of the associated proposed corrective actions.

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Claimed as PBI

3.9.5 Stratigraphic Well P&A Plans

The following section outlines the plan for the P&A of the stratigraphic well referred to as [redacted]. The stratigraphic well was completed in the immediate vicinity of the injection wells for the purpose of gathering site-specific physical and chemical information on the confining and injection zones as well as to conduct conductivity testing. Once the data gathering activities have been completed, the stratigraphic well will be plugged and abandoned to maintain the sealing properties of the UCCZ.

3.9.5.1 Pre-Plugging Activities (Notifications, Permits, and Inspections)

ExxonMobil will comply with reporting and notification provisions for stratigraphic wells drilled in Texas in accordance with RRC. The following notifications and permits will be submitted:

- Provide notice of Intention to Plug and Abandon Form W-3A to the RRC at least five days before plugging operations are scheduled to begin; and
- Complete Plugging Record Form W-3 to be filed with the RRC District Office 3 within 30 days after plugging.

ExxonMobil will also submit these records to the UIC Program Director for completeness purposes.

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3.9.6 Plan for Site Access

In accordance with 40 CFR 146.84(b)(2)(iv) and 40 CFR 146.84(d), ExxonMobil is in the process of negotiating land access for each of the artificial penetrations identified for corrective action. Research to identify the well owners via regulatory databases has been completed. The process of securing necessary access rights will be complete in advance of the final submittals to the UIC Permit Director for the Class VI UIC permit application. The limited number of legacy wells requiring corrective action prior to commencing operations is a significant factor in mitigating the risk for the Project.

ExxonMobil has an extensive history of successfully negotiating access agreements with landowners in southeast Texas. Discussions are underway with the owner and operators of record to enter into an access agreement to perform corrective action. As shown in Table 3-19, it is expected that access will be provided for Claimed as PBI . If appropriate and necessary, ExxonMobil will seek plugging orders from the RRC in accordance with Subchapter C of Chapter 89 of the Texas Natural Resource Code to obtain access for corrective actions.

If the AoR reevaluation conducted at the minimum schedule of once every five years identifies the potential for corrective action requirements at additional wells, ExxonMobil will promptly begin review of the additional wells in accordance with the process described this Corrective Action Plan. If site access issues are identified for wells identified for corrective action, ExxonMobil will notify the UIC Program Director.

Claimed as PBI

3.10 AoR Reevaluation Plan and Schedule

3.10.1 Frequency of AoR Reevaluation

ExxonMobil adopts the minimum frequency of five years for the AoR and Corrective Action Plan reevaluation. Information gathered from implementation of the Section 5 – Testing and Monitoring Plan will be used to evaluate whether a more frequent review period is warranted based on the observed conditions of CO2 plume and pressure front migration.

If an alteration of the AoR reevaluation frequency of a minimum of every five years is recommended, the change in frequency will be aligned with the data evaluation and findings relative to the degree of protectiveness of USDW. ExxonMobil acknowledges that any amendments to the AoR and Corrective Action Plan must be approved by the UIC Program Director, must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate. ExxonMobil also acknowledges the requirement in 40 CFR 146.84(b)(2)(i) of “The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review.”

3.10.2 Content of the AoR Reevaluation

The requirements for AoR reevaluation are specified in 40 CFR 146.84(e) and include the following considerations:

- Reevaluate the AoR in the same manner specified in 40 CFR 146.84(c)(1);
- Identify all wells in the reevaluated AoR that require corrective action in the same manner specified in 40 CFR 146.84(c);
- Perform corrective action on wells requiring corrective action in the reevaluated AoR in the same manner specified in 40 CFR 146.84(d); and
- Submit an amended AoR and Corrective Action Plan or demonstrate to the UIC Program Director through monitoring data and modeling results that no amendment to the AoR and Corrective Action Plan is needed. Any amendments to the AoR and Corrective Action Plan must be approved by the UIC Program Director, must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate.

3.10.3 Conditions Warranting AoR Reevaluation

The monitoring and operational conditions that would warrant a reevaluation of the AoR prior to the next scheduled reevaluation [i.e., the minimum fixed frequency established in 40 CFR 146.84 (b)(2)(i)] are outlined below. These triggering events are based on a review of the hydrogeological site characteristics, the AoR and plume model results, and the pre-operational and operational plans for the Project. For each triggering event, Table 3-20 provides a summary of how the monitoring and operational data will be used to inform an AoR reevaluation and how corrective action will be conducted to reduce the potential for threats to USDW, if any arise.

As discussed above, certain corrective actions will be performed prior to injection and certain corrective actions will be performed on a phased basis. This includes a description of the phased basis for corrective action, how corrective action will be adjusted if there are changes in the AoR, and how site access will be guaranteed for future corrective action.

Table 3-20 provides a list of the potential triggers for an AoR reevaluation consistent with the requirements of 40 CFR 146.84(b)(2)(ii).

Table 3-20: Triggers for AoR Reevaluation

No.	Events that may Trigger an Unscheduled AoR Reevaluation, with concurrence of the UIC Program Director	How Will Monitoring and Testing Data Inform the AoR Reevaluation?	How Corrective Action will be Conducted to Reduce the Potential for Threats to USDW
1	Compliance with minimum fixed frequency of at least once every five years [40 CFR 146.84(b)(2)(i)].	The AoR may need to be reevaluated more frequently than the minimum fixed frequency based on significant changes in operations or results from site monitoring that differ from model predictions. In these cases, the schedule for AoR reevaluation may be updated appropriately.	ExxonMobil will notify the UIC Permit Manager that a more frequent AoR reevaluation is warranted based on significantly changed conditions. This notification will form the basis of a permit modification and updates to the relevant portions of the permit application.
2	Significant changes in operations that mandate AoR reevaluation under 40 CFR 146.84(c) as outlined below.	AoR reevaluation will be informed by both planned changes to operations and by testing and obtaining monitoring data that signal potential unexpected CO2 plume migration impacting the extent of the AoR. Examples include installation of an additional injection well or identification of new offset well installation by third parties. Certain short-term operational changes, such as temporary well shut-ins, are not expected to warrant AoR reevaluation.	ExxonMobil will notify the UIC Program Director of the plan for significant changes in operations by pre-permitting engagement and the necessary modifications to the permit. The UIC Program Director may require an AoR reevaluation prior to approving such operational changes or changes may be allowed to occur prior to reevaluation of the AoR. The AoR reevaluation be submitted to the UIC Program Director within an agreed-upon timeframe of instituting such changes, as described in the AoR and Corrective Action Plan.
2A	Plan to significantly change injectate composition mixture.	Re-run the reservoir plume model with a new composition mixture. If plume extents increase, reevaluate the AoR.	Within one month of composition change, notify the UIC Program Director of significant change and potential need to reevaluate AoR.
2B	New offset operations are established that could affect the injection intervals.	Re-run the reservoir plume model with new data. If plume increases in shape or extents, reevaluate the AoR.	Within one month of commencement of new operations, notify the UIC Program Director of significant change and potential need to reevaluate AoR.
2C	Measured supercritical gas saturation that greatly deviates from the modeled gas saturation.	Re-run the reservoir plume model with new data. If plume increases in shape or extents, reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on model results.

No.	Events that may Trigger an Unscheduled AoR Reevaluation, with concurrence of the UIC Program Director	How Will Monitoring and Testing Data Inform the AoR Reevaluation?	How Corrective Action will be Conducted to Reduce the Potential for Threats to USDW
2D	Anomalous change in surface pressure of more than ±1,000 psi in injection well for sustained period that deviates from modeled pressure response.	Incorporate new pressure information and re-run the reservoir plume model with new data. If plume increases in shape or extents, reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on model results.
2E	Change in bottomhole temperature by more than 25%.	Incorporate new temperature information and re-run the reservoir plume model with new data. If plume increases in shape or extents, reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on model results.
2F	Casing or tubing leak detected by casing integrity logging.	Investigate possible tubing leak and trigger contingency monitoring to reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on contingency monitoring results.
2G	Positive pressure loss in tubing annulus.	Investigate possible pressure loss and trigger contingency monitoring to reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on contingency monitoring results.
3	Results from site monitoring that differ from model predictions [40 CFR 146.84(b)(2)(ii)] as outlined below.	An evaluation of monitoring data [required under 40 CFR 146.90] indicates that CO2 and/or pressure front migration is significantly different than that predicted by the current AoR delineation model and, therefore, warrants an AoR reevaluation. The following examples provide specific criteria for differences in monitoring data and model predictions that may trigger an AoR reevaluation [40 CFR 146.84(b)(2)(ii)].	Notification of significant difference to UIC Program Director within one month of confirmed findings.
3A	Seismic event greater than M3.0 within 1-mile radius of injection well.	Evaluate pressure data relative to operating limits and pressures in monitoring wells. Evaluate the need to enhance monitoring program to confirm extent of CO2 plume.	Provide notice to UIC Program Director within one month of findings of assessment of operational compliance and adequacy of monitoring program to delineate CO2 plume and pressure front.

No.	Events that may Trigger an Unscheduled AoR Reevaluation, with concurrence of the UIC Program Director	How Will Monitoring and Testing Data Inform the AoR Reevaluation?	How Corrective Action will be Conducted to Reduce the Potential for Threats to USDW
3B	Annual plume migration survey identifies the plume migration direction that is significantly different then the modeled direction of migration.	Re-run the reservoir plume model incorporating injection well pressure and temperature data for calibration and other available information on plume migration and reevaluate the AoR.	Within one month of detection, ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on calibrated model results.
3C	The horizontal CO2 plume migration rate is significantly different than predicted.	Re-run the reservoir plume model incorporating injectors data for calibration and new information on plume migration and reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on calibrated model results.
3D	Sustained acoustic anomaly, which is unrelated to oil and gas activity in the area, detected by DAS or noise log.	Investigate DAS data anomaly and decide if the change triggers contingency monitoring to reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on DAS data analysis and or results from contingency monitoring.
3E	Statistically significant increases of indicator parameter concentrations above baseline for USDW samples of TDS, major cations and anions, CO2 concentration, isotopic values, or pH.	Resample fluid sample that contained the elevated concentrations and compare resample results with numerical criteria for trends and/or exceedances of target concentrations.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on resampling results and data evaluation.
3F	The presence of separate-phase CO2 in the sampled fluids above the confining zone, but below the lowermost USDW resulting from CO2/fluid migration out of the injection zone.	Investigate possible migration pathways and trigger contingency monitoring to reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on contingency monitoring results.
DAS = distributed acoustic sensing			

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Underground Injection Control – Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 4 – WELL CONSTRUCTION PLAN AND OPERATING CONDITIONS

Rose Carbon Capture and Storage Project

Claimed as PBI

ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2024

SECTION 4 – Well Construction Plan and Operating Conditions

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4.0 Well Construction Plan and Operating Conditions

The Well Construction Plan and Operating Conditions section for the Rose Carbon Capture and Storage (CCS) Project (Project) was prepared to meet the requirements of Title 40, U.S. Code of Federal Regulations (40 CFR) 146.82 and 146.86 and Texas Administrative Code, Part 1 Title 16 Chapter 5. ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is undertaking the Project in Claimed as PBI to sequester a total of approximately Claimed as PBI. The purpose of this section is to describe how ExxonMobil has designed and will test three CO2 injection wells for the Project and ExxonMobil's operating strategy for sequestering approximately Claimed as PBI

The three injection wells (Rose CCS Project Injection Wells No. 01, No. 02, and No. 03) are designed for the sole purpose of injection and storage of CO2 safely in the Upper Frio and Fleming Sand injection intervals at the Project site, and to contain the CO2 within the injection intervals to protect underground sources of drinking water (USDWs). The formation properties of the injection intervals make the Project site an excellent candidate for injection of CO2, Claimed as PBI Interbedded and overlying shale layers confine the injection intervals from USDW.

The well materials are compatible with all fluids with which they may come into contact and the design considered the depth of all porous formations, as identified during site characterization. The wells' design and materials are also appropriate to the proposed operating parameters. The planned formation testing at the injection well locations will be sufficient to fill potential gaps in available site characterization data and address key uncertainties in the Area of Review (AoR) delineation modeling.

The injection well construction specifications and testing plan is tailored to account for the data acquired from the logging, testing plan, and preliminary results for a stratigraphic well Claimed as PBI

This section provides a narrative document with associated schematics and data summary tables that describe how ExxonMobil will construct the injection wells to meet the goals of 40 CFR 146.86. The engineering design is based on the collection of as much site-specific data as possible, particularly from the stratigraphic well, before submitting the initial Class VI Permit Application. This level of effort was undertaken to facilitate the permit modification process, between conducting the pre-construction activities required at 40 CFR 146.82(a) and the pre-operation phase activities required at 40 CFR 146.82(c). Through a series of pre-permitting engagements with Region 6 of the U.S Environmental Protection Agency and the Railroad Commission of Texas, an early proactive planning process helped to align the current and potential future conditions at the Project site. This planning process also helped to identify potential issues related to Project strategy and information as early and expeditiously as possible.

4.1 Objectives

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

- The injection well construction design, material specifications, and construction will be compatible with the composition of the CO2 stream over the duration of the Project to reduce the potential for endangerment of USDWs [40 CFR 146.82(a)(11),(12); 146.86].
- The injection wells will undergo logging and testing prior to operation to assess injection well and formation performance and update the operating strategy as necessary before injection of CO2 [40 CFR 146.82(a)(8); 146.87].
- The injection well operating strategy provides continuous injection and annulus monitoring systems for each injection well to control injection pressure and trigger automatic shut-off devices and safety valves for CO2 injection, consistent with safe operating procedures [40 CFR 146.82(a)(7),(9),(10); 146.88(e)].

4.2 Engineering Design

The engineering design parameters for the three injection wells are based on the planned injection rates, injection volumes, fluid properties, and chemical properties of the injectate fluid. In addition, the engineering design includes recompletion of each injection well to target specific injection intervals to achieve the target CO2 storage amount.

ExxonMobil plans to inject a maximum volume of Claimed as PBI [redacted] The tubing design, including size, weight, grade, and metallurgy is based on the properties of the injectate, rate of injection, and injection pressures determined by the detailed reservoir modeling.

The casing, cement, tubing, packer, continuous monitoring devices, and wellhead equipment were selected and designed to withstand the corrosive environment to which the materials and equipment will be exposed. Each was selected to have sufficient strength and material properties to withstand the pressure, temperature, and corrosive forces to which they will be subjected in the subsurface.

The following discussion presents the engineering design basis for the proposed well materials including casing, tubing, and cement. Well design schematics and locations are included in Appendix D.1-1 to D.1-9, which illustrate the well materials, design layout, and the locations of the packer and perforation intervals as well as the well location at the Project site.

4.2.1 Overview of Injection Well Perforation Strategy

Claimed as PBI [redacted]

Upon installation of the completion assembly, Claimed as PBI [redacted]

Claimed as PBI The perforation depths provided in Tables 4-1 to 4-3 are based on the current geologic model and will be updated after integration of the stratigraphic well results.

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4.2.2 Production Casing Design and Completion

The production casing will use a Claimed as PBI [redacted] In accordance with the metallurgical analysis provided in Appendix E, this design uses [redacted] Claimed as PBI [redacted] Table 4-4 presents the standard CO2 conditions used in the modeling and flow calculations.

[redacted] Claimed as PBI

This design also allows for continuous monitoring of each casing and tubing annulus for wellbore and mechanical integrity parameters. Appendices D.1-1 to D.1-9 provide the proposed wellbore designs and initial completion configurations for Injection Wells No. 01, No. 02, and No. 03, respectively, along with the certified well-location plats.

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

[redacted] Claimed as PBI

In addition to the injection wells, CO2-compatible cement will be used for all future in-zone monitoring wells as discussed in Section 5.9.

A detailed metallurgical analysis was performed that considered the chemical composition of the injectate and downhole conditions as shown in Appendix E. The injectate stream is projected to be made up Claimed as PBI [redacted] to reduce the potential for corrosion and downhole failures, should any fluids enter the wellbore over the short-term from the reservoir.

To reduce the potential for CO2 migration out of the injection interval, CO2-compatible cement will be run from Claimed as PBI [redacted], to provide a suitable barrier across the UCCZ. By using CO2-compatible material, the cement is protected from carbonic acid, maintaining integrity throughout the life of the Project.

Throughout the life of each well, the Project will have Claimed as PBI [redacted]

Claimed as PBI

The engineering and design parameters for the production casing are summarized in Tables 4-5 and 4-6.

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Tables 4-7 to 4-9 provide the production casing cement volume calculations for each injection well.

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Claimed as PBI The proposed placement of centralizers through the production casing is shown in Table 4-10.

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The Claimed as P injection tubing size and material were selected for use in the Project wells based on injection volumes, rates, and injectate composition. Consistent with the design approach used for the casing strings, the injectate and the potential for a corrosive environment are important considerations when selecting the metallurgy of the tubing. The planned design offers protection from the potential corrosive environment of the injectate stream and potential for influx of reservoir brine. A complete summary of the metallurgical analysis is included in Appendix E.

The production tubing will be Claimed as PBI or its equivalent in all sections where the CO2 will contact the tubulars.

A tubing design sensitivity analysis was conducted that considered calculated pipe-friction losses, exit velocities, compression requirements, and economic evaluations. Bottomhole pressures (BHP) were calculated from detailed reservoir-engineering model runs as shown in Figures 4-1 through 4-3. The data identify when the maximum BHP occurs during the life of the Project; the resulting maximum bottomhole flowing pressure allows for proper design of the casing, tubing, and wellhead configurations.

Claimed as PBI

For the reservoir model, a conservative value of 100% CO2 was used for the injectate stream. The anticipated chemical composition of the most-concentrated constituents delivered via the CO2 pipeline is presented in Table 4-11. Trace amounts of other constituents may be present at de minimis concentrations.

Claimed as PBI

The input injection parameters from the model are shown in Table 4-12. The calculated injection parameters are shown in Tables 4-13 through Table 4-15 for Injection Wells No. 01 to No. 03, respectively.

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Taking into consideration the possibility of a Claimed as PBI

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The unconsolidated nature of the sediments in the upper subsurface soil requires the installation of a conductor pipe to establish and maintain borehole integrity. A cellar will be installed, a Claimed as PBI

Claimed as PBI

The surface hole will be drilled Claimed as PBI casing will be run and cemented with the casing centered in the open hole with centralizers. The generalized surface casing centralizer placement for the injection wells is provided in Table 4-18.

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A summary of surface casing design parameters is presented in Tables 4-19 through 4-21. The engineering calculations for the three injection wells are based on the wellbore conditions and maximum setting depth for the surface casing at Injection Well No. 02. Minor adjustments may be needed for actual surface casing installation at each of the injection wells based on site-specific conditions.

Claimed as PBI

Claimed as PBI [redacted]. Prior to setting the packer, the tubing annulus will be filled with a non-corrosive fluid. Figure 4-4 provides a schematic illustration of a suitable packer design and completion for the Project.

4.2.7 Safety and Continuous Monitoring Device Design and Completion

The following safety and continuous monitoring devices were designed for installation in the injection wells.

4.2.7.1 Safety Injection Valve

Claimed as PBI In the event that injection is interrupted, the injection valve will limit the potential for fluid backflow into the injection tubing string and will keep the reservoir pressurized until equilibrium is achieved. When the safety injection valve is closed, it will maintain the injected CO2 below the valve in a supercritical state.

Claimed as PBI Figure 4-5 provides a schematic and specifications for the safety injection valve. This type of valve or a suitable equivalent will be used depending on availability.

4.2.7.2 Downhole Pressure and Temperature Gauge Design and Completion

Claimed as PBI Figure 4-6 provides specifications of the downhole pressure and temperature gauge. This type of gauge or a suitable equivalent will be used depending on availability.

4.2.7.3 Fiber Optic Design and Completion

Claimed as PBI

4.2.8 Wellhead Equipment Design and Completion

The wellhead is designed to manage working pressures and provide a high degree of mechanical integrity for the injection well. Claimed as PBI

The wellheads will be configured as illustrated in Figure 4-7. Suitable equivalents for the specific manufacturers or equipment models indicated in the figure may be substituted as appropriate based on vendors used and equipment availability.

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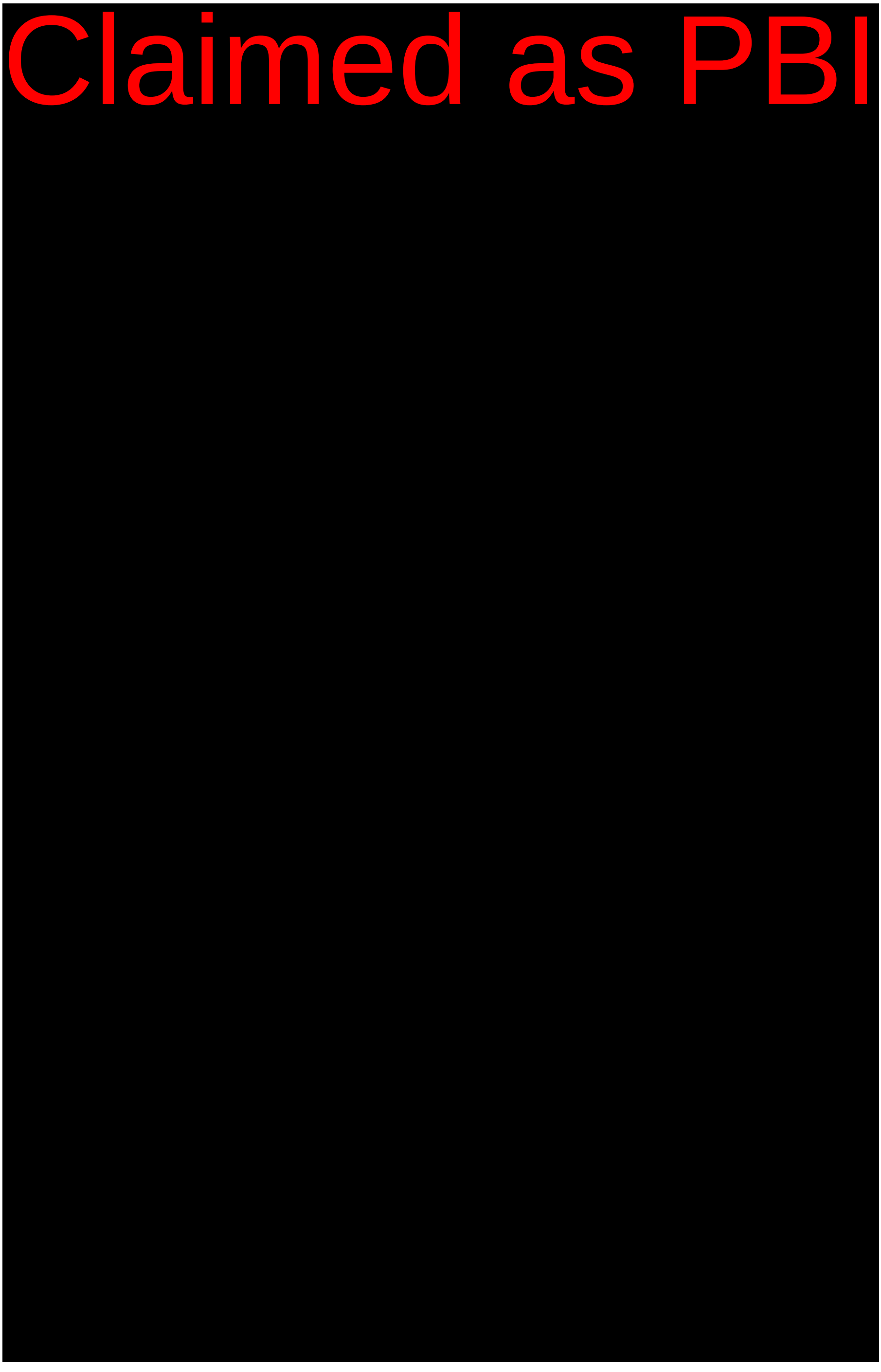
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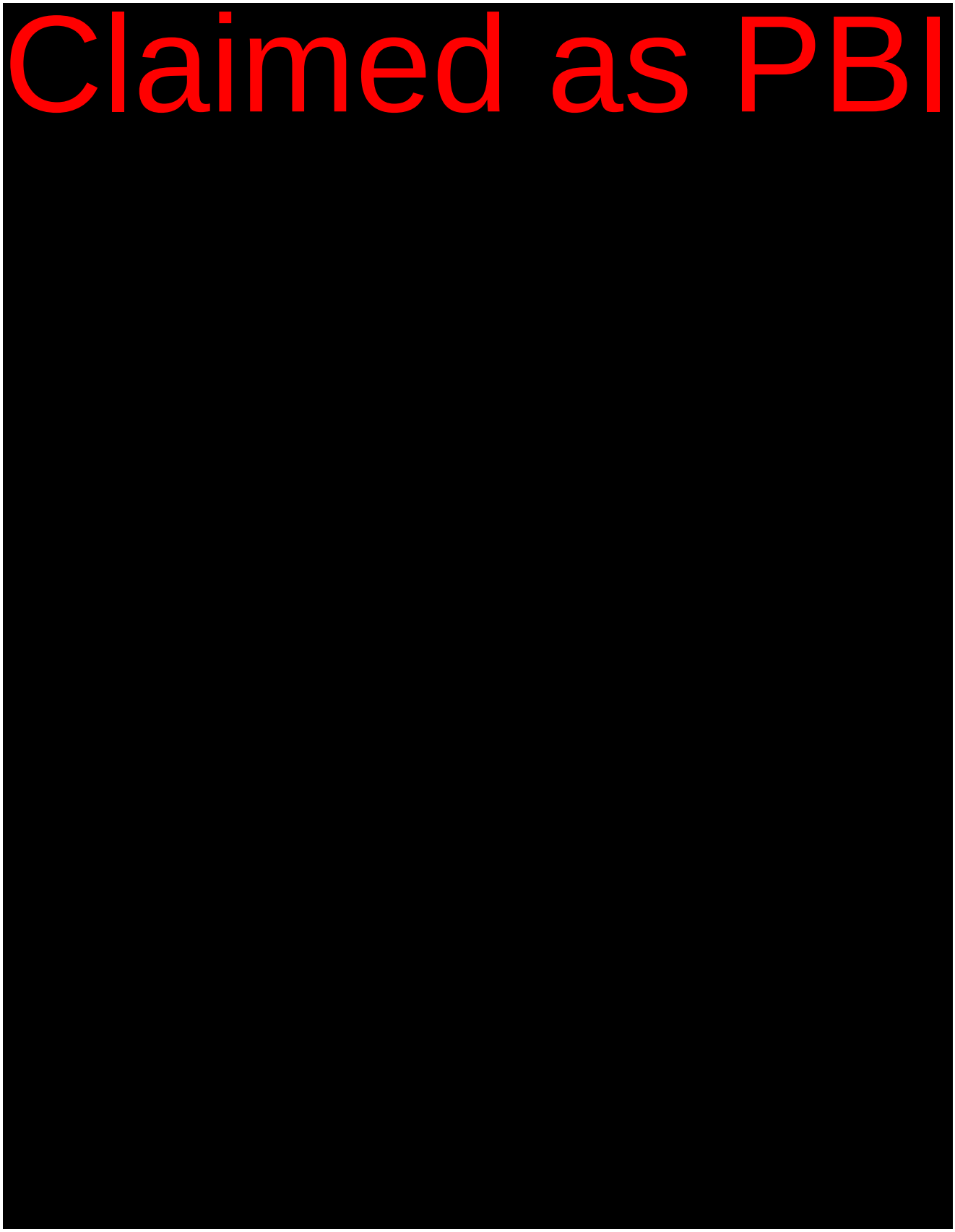
4.3 Well Drilling and Completion Design

4.3.1 Drilling and Completion Design for Injection Well No. 01

The proposed drilling and completion design for Injection Well No. 01 is described below. Claimed as PBI provides the well design and completion details and the certified well plot map. The final completion depths may be modified based on actual formation depths and/or conditions encountered during drilling.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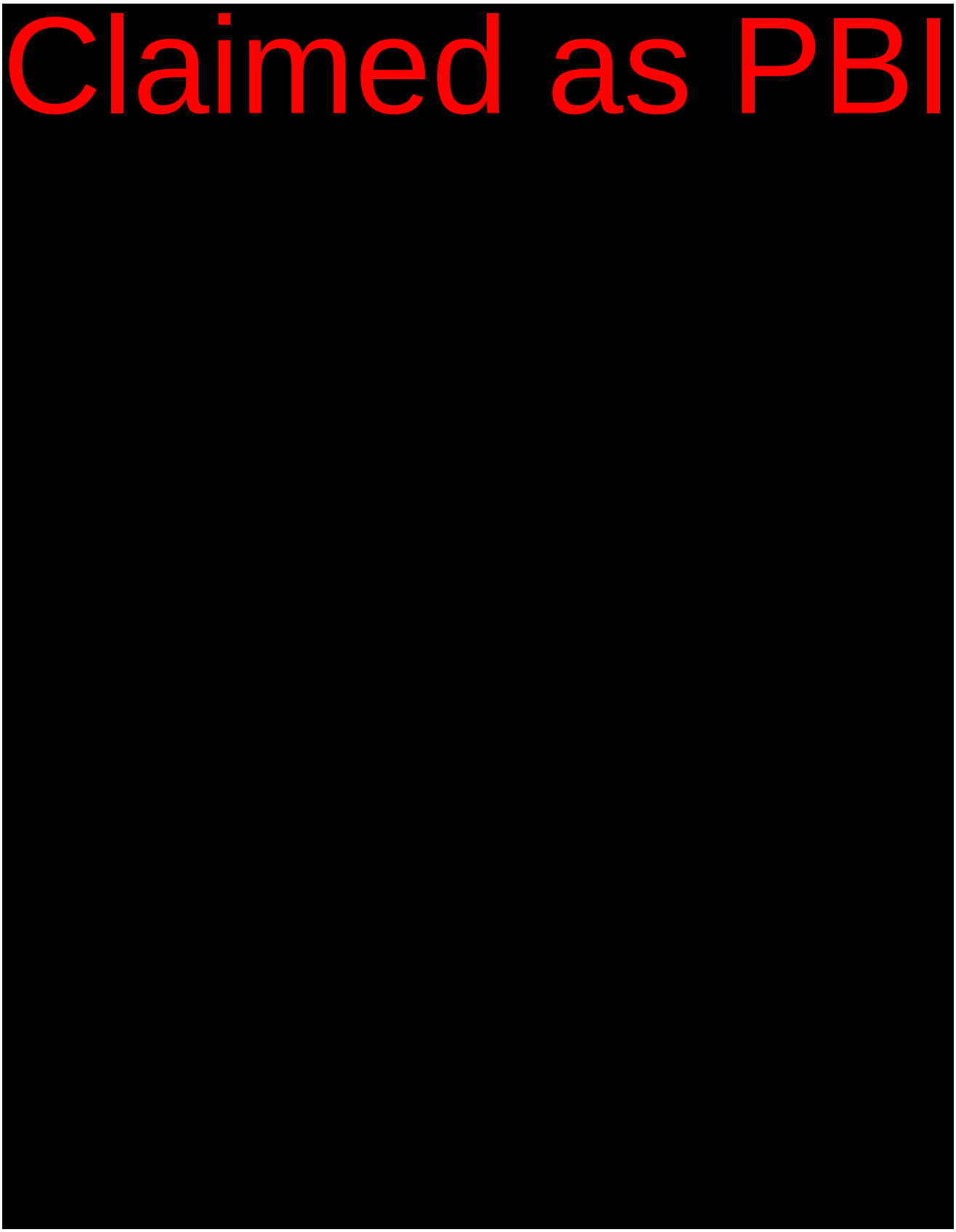
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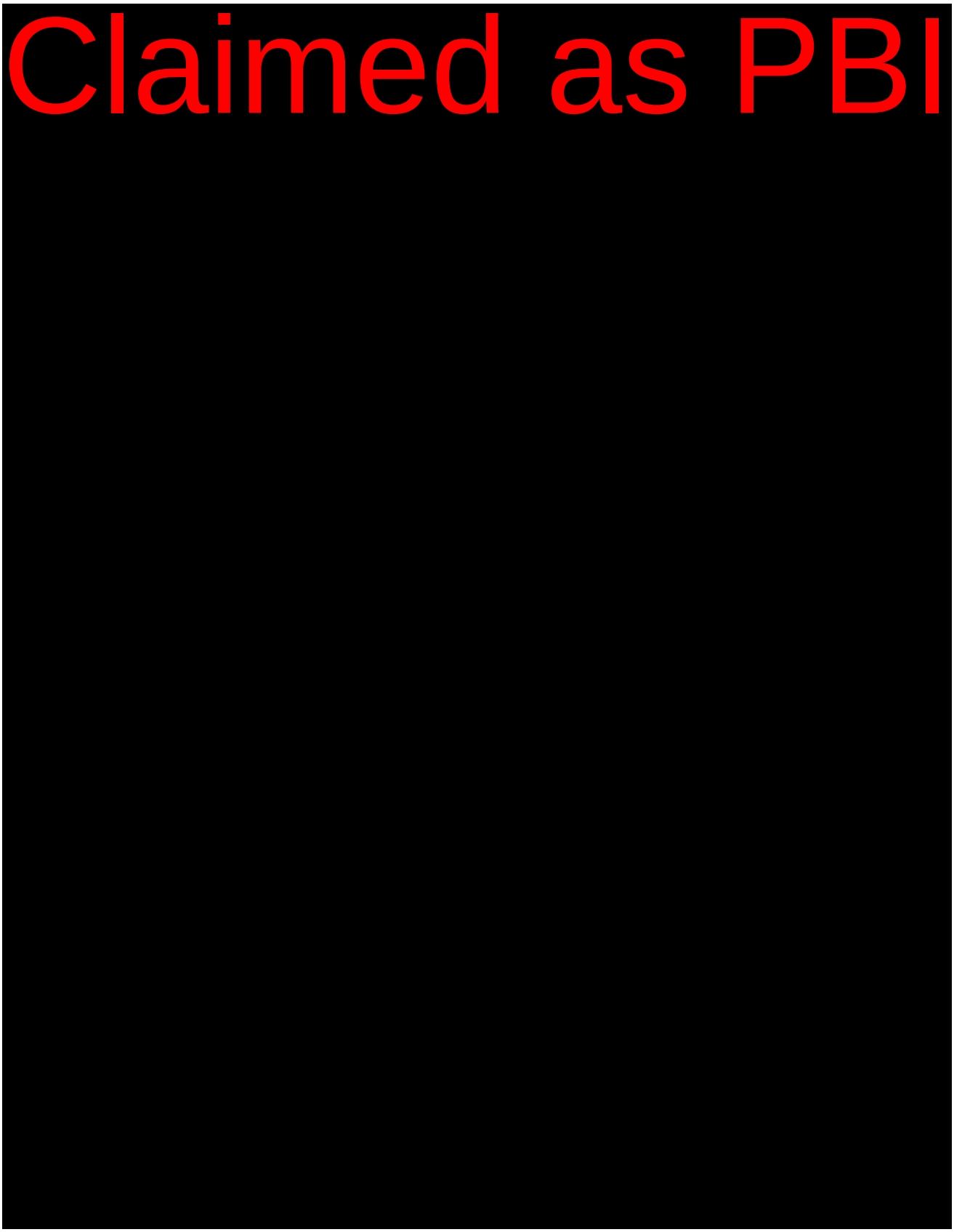
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Claimed as PBI

4.3.4 Injection Well Completion Stage and Injection Interval

Claimed as PBI

Each discrete injection interval was selected to maximize the use of the pore space and collectively maximize the usage of the acreage position for CO2 sequestration. A summary of the planned injection stages and duration by injection zone are listed in Tables 4-22 through 4-24. These injection zones are based on the current geologic model and will be updated after integration of the stratigraphic well results.

Claimed as PBI

4.4 Pre-Operational Testing Plan

The scope of the pre-operational testing plan included geophysical and core data collection in the stratigraphic well, fluid sampling at target intervals, and pressure testing to assess the injection intervals. Certain verification and logging data may be collected at the injection wells as needed for the site characterization, plume model, and AoR determination. The Testing and Monitoring Plan (Section 5 – Testing and Monitoring Plan) provides the data collection activities for the pre-operational phase and the operational phase of the Project. A summary of that discussion is provided below for ease of review, with reference to the complete discussion in Section 5 for the pre-operational testing plan.

4.4.1 Tests During Well Drilling and Construction

A variety of geophysical well logs were collected during the construction of the stratigraphic well to verify and evaluate further the depth, thickness, porosity, permeability, lithology, and formation fluid salinity in the relevant geologic formations. Data collected from the stratigraphic well will also be used to appropriately construct the injection wells and provide data to verify the design for mechanical integrity purposes.

The drilling procedure in Appendix D.2 discusses the detailed coring procedures for the stratigraphic well (Claimed as PBI). The coring depths, formations, and footages for full core samples are provided in Table 4-25. The cores taken from the stratigraphic well are near the injection wells and represent the properties of the injection and confining zones near the injection wells. Data acquisition from the stratigraphic well includes sufficient and representative information on the injection and confining zones porosities, permeabilities, petrologies, and mineralogies.

4.4.2 Injection and Confining Zone Core Sampling

During the drilling and completion of the injection wells, a subset of the stratigraphic well's logging and coring data collection plan will be used to verify certain key parameters for injection well performance and AoR modeling. At this time, the following geophysical logs are planned for each injection well. The open-hole logging plan is detailed in Table 4-26. The cased-hole logging plan is detailed in Table 4-27.

Claimed as PBI

4.4.3 Injection Zone Characterization

The injection zone is being characterized in detail using the data acquired in the stratigraphic well (Claimed as PBI) and outlined in Appendix D.2. The location of the stratigraphic well relative to the injection wells is provided on Figure 5-3. ExxonMobil collected characterization data for each injection interval of the injection wells including formation fluid temperature, pH, and specific conductivity; formation pressure, and static fluid level. This data is currently being analyzed and will be provided in a subsequent update to this Application.

4.4.4 Fracture Pressure, Fluid Characteristics, and Downhole Conditions

ExxonMobil will characterize the formation fluids in the injection zone using samples collected from the stratigraphic well. ExxonMobil will use these data to evaluate the compatibility of the injectate with the formation fluids in the injection zone. These groundwater samples that were collected during the pre-operation phase of the Project will form the baseline data for comparison with water quality data representing the operating and post-operating phases of the Project. In general, the baseline data established include pressure, temperature, fluid, and physical characteristics present in the injection intervals and above the UCCZ from a single sample event at the stratigraphic well and a routine sampling frequency for the USDW monitoring wells.

The sampling and analysis plan for the water sample collected above the UCCZ at the stratigraphic well is specified in Table 4-28. The USDW monitoring wells will be drilled and monitored to provide a representative baseline of geochemical concentrations and pressure conditions in the AoR and surrounding area as described in Section 5 – Testing and Monitoring Plan. The analyses of geochemical and water quality parameters for the groundwater samples from the USDW monitoring wells are specified in Section 5. Similarly, groundwater characterization between the lowest most USDW and the top of the UCCZ will be tested and sampled inside the limits of the AoR to establish a representative baseline of geochemical and pressure conditions of the monitoring zone in the local Project area.

Claimed as PBI

Claimed as PBI

The groundwater samples were analyzed in the field for certain physical parameters including temperature, pH, alkalinity, dissolved oxygen, and electrical conductivity. Laboratory-based analyses included total dissolved solids, concentrations of cations, anions, CO2, and CH4. Samples for cations and anions will be collected in appropriate acid-washed bottles to eliminate possible contamination.

A primary monitoring technique to be implemented at the site for plume tracking involves the use of Claimed as PBI will be acquired prior to CO2 injection to establish how the technology responds to conditions in the AoR and the initial state of the subsurface fluid distribution.

4.4.5 Injection and Confining Zone Formation Testing

ExxonMobil collected pre-operational formation tests and data logging from the stratigraphic well to provide needed data on the geologic and hydrogeologic properties of subsurface formations. A step-rate test and a pressure fall-off test were performed at the stratigraphic well using a maximum injection rate above operating injection rate. The recorded steps were above and below the fracture calculated fracture pressure. Tables 4-29 and 4-30 provide the step-rate injection test and pressure fall-off test parameters.

Claimed as PBI

Claimed as PBI

Pressure transient well testing (e.g., a pressure fall-off test) was completed in the stratigraphic well and will be conducted in each of the injection wells as a part of completion activities. These tests are intended to confirm reservoir and operational parameters used in the permitting process and provide needed data on the geologic and hydrogeologic properties of subsurface formations. The following injection well fall-off pressure test procedures are proposed:

- A non-hazardous test fluid will be used during the injection test.
- Injection Well Fall-Off Pressure Test:
    - The purpose of this test is to evaluate the injectivity index, skin, and permeability-thickness of the injection intervals.
    - For each injection zone, an injectivity test will be performed.
    - Shut-in well and record pressure fall-off with downhole gauges over sufficient time for proper analysis.

4.4.6 Quality Assurance Surveillance Plan

ExxonMobil will prepare and submit a Quality Assurance Surveillance Plan (QASP) as a supplement to the testing and monitoring requirements of this section as well as Section 5 – Testing and Monitoring Plan and Section 7 – Post-Inject Site Care and Site Closure Plan. The goal of the QASP is to provide reliable data to verify that the Project is operating as permitted without endangerment to USDWs. The QASP will provide a verifiable set of standards and controls that include the technologies, methodologies, frequencies, sample quality assurance, and procedures to demonstrate the collection data activities will provide accurate and reliable information about the Project operations. The QASP will be unique to the Project, informed by site-specific details, monitoring technologies selected, and will be updated as the Project evolves in concert with the Testing and Monitoring Plan. The QASP will be submitted after confirmation from the Underground Injection Control (UIC) Program Director that the proposed testing and monitoring elements of the Application are consistent with the requirements.

4.5 Injection Well Operating Strategy

4.5.1 Injection Rate and Pressure

Table 4-31 provides the proposed operations for the injection wells including injection rate and pressure by well. The maximum injection rates for the injection intervals of each well ranges from Claimed as PBI MMta. The average injection rate range is from Claimed as PBI MMta. Both the maximum and average injection rates are predicted to result in reservoir pressure rises that are

below 90% of the critical fracture pressure, shown in Table 4-31. Both the injection rates and pressures are within the operating window of the injection wells.

The proposed continuous monitoring and recording devices will demonstrate internal mechanical integrity [40 CFR 146.88(e)] and that the well is equipped with shutoffs and safety devices that are linked to final operating limits specified in the permit for each injection well. The anticipated bottomhole injection pressures and interval-specific pressure constraints are shown in Tables 4-32 through 4-34. The injection depths are based on the current geologic model and will be updated after integration of the stratigraphic well results. The injection rate schedule presented in this Application is based on defined rate limitations without the modeled projections predicting sufficiently high reservoir pressures that result in maximum BHP constraining predicted well operations.

4.5.2 CO2 Volume

ExxonMobil plans to inject approximately Claimed MMt of CO2 over the life of the Project. It is projected that the CO2 will be injected and will remain in a supercritical state through the life of the Project. The Fleming and Upper Frio sands have relatively high porosity and high permeability. These reservoir properties and the lateral extent of the injection zone are projected to allow the system to store significant volumes of CO2 with limited reservoir pressure rise and is projected to result in relatively rapid pressure fall-off upon shut-in. The CO2 volume was determined to meet the requirements of managing the threat of endangerment to USDW.

4.5.3 Annulus Pressure

The annulus pressure will be adjusted to be at least Claimed as PBI , with a maximum allowable pressure Claimed as PBI as reported in Section 5 – Testing and Monitoring Plan.

4.5.4 Well Stimulation Procedures

ExxonMobil is not proposing a stimulation program for the proposed injection wells. In accordance with 40 CFR 146.91(d)(2), if a stimulation program is proposed, ExxonMobil will provide an advance notice of the proposed stimulation procedures to the UIC Program Director in writing at least 30 days prior to implementation.

4.5.5 CO2 Stream Characteristics

The CO2 stream chemical composition is described in Table 4-11 Claimed as PBI Claimed as PBI

In general, unanticipated interactions among the CO2 injectate and the reservoir fluids are not expected that would act to reduce the permeability, porosity, or injectivity of CO2 into the injection intervals over the life of Project. Specific mineralogy and fluid testing is being performed on core and fluid samples taken from the stratigraphic well that will be used to confirm these conditions prior to issuance of the Class VI permits and changes, if appropriate, will be made to further refine the engineering design and operating strategy. This will include an assessment of the potential for mineral dissolution or precipitation within the Fleming and Upper Frio injection intervals that could potentially endanger USDWs. As outlined in this section, the current engineering design basis includes corrosion resistant well completion materials selected to provide a high degree of mechanical integrity under future conditions for the formation fluids and CO2 plume. See Section 6.2.5 for a summary of the proposed CO2 compatible cement.

Section 5 – Testing and Monitoring Plan provides a description of the analyses of the CO2 stream for the Project, including tests for potential impurities that may be present and whether such impurities might alter the corrosivity of the injectate downhole. The information provided in Section 5 was based on the expected chemical and physical characteristics of the CO2 stream and will be used to refine the well operating parameters while maintaining compliance with the Class VI permits.

A sample of the CO2 stream will be collected and analyzed for the suite of parameters listed in Table 5-3 prior to commencing injection and throughout injection operations at the proposed frequency. The details of the sampling process and frequency are described in Section 5 for approval by the UIC Program Director.

4.6 Operational Reporting Plan

During the operational phase of the Project, ExxonMobil will report, within 24 hours, a confirmed endangerment to USDWs to the UIC Program Director pursuant to the requirement in 40 CFR 146.88(f)(3); 146.91(c); and 146.94(b)(3)], including:

- Evidence that the CO2 plume or pressure front may endanger a USDW or USDWs;
- The non-compliance situation as it relates to a permit condition;
- Apparent malfunction of the injection system;
- Triggering of a shut-off system or a loss of mechanical integrity; or
- A release of CO2 to the atmosphere or biosphere.

4.7 Injection Well Construction and Operation Summary

The geologic setting for this Project is ideally situated for carbon sequestration because of the geologic properties of the injection and confining zones and the compatibility of the reservoir fluids with CO2. The Project brings together the proven engineering practices of ExxonMobil in the design of the wells with a state-of-the-art monitoring system and a robust reservoir management strategy. The proposed well designs are engineered to address the potential risks associated with the installation and operation of Class VI injection wells with a primary objective of protecting USDW from the threat of endangerment. The engineering design of the casing setting points, materials, and cement meet and exceed the requirements for Class VI injection well and for the conditions that have been projected for the Project. ExxonMobil will comply with the requirements and regulations required by the UIC Program Director for the well design and

completion standards and the continuous monitoring and safety equipment to be installed. In addition, the operating strategy is designed to manage the pressure effects of CO2 injection in the injection zones, to use the available pore space to the fullest extent, and to mitigate potential issues through a robust operational and testing and monitoring strategy.

Underground Injection Control – Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 5 – TESTING AND MONITORING PLAN

Rose Carbon Capture and Storage Project

Claimed as PBI

ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2024

SECTION 5 – TESTING AND MONITORING PLAN

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Appendix F – Testing and Monitoring

5.0 Testing and Monitoring Plan

Consistent with the requirements of 40 Code of Federal Regulations (CFR) 146.90, ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) developed a comprehensive Testing and Monitoring Plan strategy for the Rose Carbon Capture and Storage (CCS) Project (Project) using a risk-based approach. The data collection strategy includes injectate monitoring, corrosion monitoring of the well tubular, mechanical, and cement components; pressure fall-off testing; seismic profiling; well logging; continuous monitoring of injection rate and pressure; groundwater quality monitoring; carbon dioxide (CO2) plume and pressure front tracking. The data generated from implementation of the Plan provides the basis to verify the confinement of the injectate in the permitted injection formations during the active injection phase of the Project. The post-injection phase of monitoring is provided in Section 7 – Post-Injection Site Care (PISC) and Site Closure Plan consistent with the structure of the Underground Injection Control (UIC) Class VI Permit Application for the Project. In conjunction with careful site selection and Area of Review (AoR) delineation, this Plan will be a critical component of the successful operation, PISC, and eventual closure of the Project.

A key feature of the Testing and Monitoring Plan is the alignment between the injection operation plan and the geological site features that determine CO2 plume and pressure front migration. This Plan puts forth a data collection plan to confirm whether the injection is working according to the permit requirements. The testing and monitoring strategy also includes a phased/triggered approach for the incremental implementation of testing and monitoring technology, consistent with U.S. Environmental Protection Agency's (EPA's) presentation of phased/triggered monitoring in the *Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance*. Overall, the risk of underground source of drinking water (USDW) endangerment is mitigated by balancing the increases in CO2 plume and pressure front size with the collection and analysis of data to track migration and assess the potential for leaks through the upper composite confining zone (UCCZ).

ExxonMobil intends for the review process for the Plan and subsequent iterations to continue throughout the life of the Project. An adaptive approach will be employed with respect to monitoring frequency of select parameters, whereby monitoring may be decreased based on positive test results. Monitoring results will be presented in semiannual reports, wherein data will be evaluated, and any monitoring frequency modification would be justified. Baseline data will be collected and comparisons to the baseline data will be made during the operational period of the Project. The adaptive approach will be applied if the data collected during the injection period shows results within the expected range. An ongoing dialogue between ExxonMobil and the UIC Program Director is envisioned, marked by tying the Plan reviews to the AoR reevaluation frequency. Consistent with the discussion of AoR reevaluation in Section 3 – Area of Review and Corrective Action Plan, a defined schedule is proposed to address situations where there is a change in the AoR or if other circumstances change, while affording an efficient review process if the AoR reevaluation confirms that the Plan is appropriate as written. In this way, testing and monitoring results that indicate corrective action is required trigger the mitigation measures identified in the AoR reevaluation (Section 3), and the Emergency and Remedial Response Plan (Section 8), if needed, will be triggered at the appropriate time.

5.1 Objectives

The following objectives were developed for the Testing and Monitoring Plan in alignment with 40 CFR 146.90:

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

5.2 Overall Strategy and Approach for Testing and Monitoring Plan

The Class VI Rule requires various testing and monitoring activities to identify potential risks to, and the potential for endangerment of, USDWs during the injection phase of the Project. ExxonMobil consulted with the EPA, Region VI UIC Program Director, and the Railroad Commission of Texas in pre-application discussions to identify the testing and monitoring activities that were best suited for the Project. The site features that affect the degree of risk and potential for endangerment of a USDW include:

Claimed as PBI

Of these features, the key risk factor that is most critical for the design of this Plan is the potential for Claimed as PBI .
ExxonMobil completed a variety of technical tasks discussed in Section 3 – Area of Review and Corrective Action Plan to identify and evaluate the potential for Claimed as PBI

Other potential risks associated with the Project were deemed to be of a lower probability and consequence.

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

Claimed as PBI

Figure 5-1 presents a summary of the risk assessment process for the lifecycle of the Project.

Claimed as PBI

As shown in Figure 5-1, the anticipated risk level is Claimed as PBI

The injection

well locations and injection intervals were selected to provide separation from geologic features (e.g., faults) that could potentially contribute to CO2 or brine crossflow between the injection zone and USDW. The maximum injection pressure will be maintained below the potential hydraulic fracturing or activation pressure of a natural fault to mitigate the potential for CO2/brine leaks through seal(s) due to mechanical fracturing or migration of CO2/brine along faults. State-of-the-art construction and mechanical integrity testing will be employed to reduce the potential for the loss of external mechanical integrity, which could potentially release CO2. The composition of the injectate stream will be managed and monitored such that unexpected reactions with the potential to impact containment are mitigated. Monitoring and predictive reservoir modeling are being used to limit the potential for CO2 plume and pressure front migration to encounter artificial penetrations that have the potential for CO2 or brine crossflow from the injection intervals to the lowermost USDW.

The accompanying Class VI Rule testing and monitoring requirements address the potential risk scenarios identified by ExxonMobil as warranting monitoring and testing. Scenarios that were found to have elevated risk will be the subject of corrective action prior to operations. Three artificial penetrations Claimed as PBI [redacted].

An array of data collection technologies was screened to identify the most reasonable and appropriate methods for the Testing and Monitoring Plan. The screening criteria include: (1) selection of appropriate direct and indirect mature monitoring technologies; (2) cost benefit analysis of each technology to mitigate potential; and (3) a mix between continuous and periodic implementation schedule. ExxonMobil recognizes mature technologies based on their Technology Readiness Levels (TRL), as defined by the International Energy Agency in their report *Energy Technology Perspectives, 2020; Special Report on Carbon Capture Utilisation and Storage*. This scheme is applicable to any technology, including those described in Table 5-1 for implementation on the Project. As described on Figure 5-2, mature technologies are those with Claimed as PBI [redacted] and higher.

Table 5-1 provides a summary of mature technologies selected for tracking the CO2 plume and pressure front. Consistent with the stated interests of the EPA, the Testing and Monitoring Plan is intended to be a flexible approach using appropriate technologies and techniques that are refined and adapted based on site-specific information over time. ExxonMobil will continue to assess the feasibility of emerging technologies and conduct performance evaluations to continue to improve the performance of the testing and monitoring system.

ExxonMobil will communicate with the UIC Program Director on plans and the potential for updates to the Testing and Monitoring Plan. Through the combination of proven and emerging technology pilot testing, a cost-effective testing and monitoring strategy will be maintained for the Project that measures the CO2 plume and pressure front migration paths and serves to provide reliable data for reevaluating the AoR model.

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Claimed as PBI

Claimed as PBI

5.3 Use of Phased and/or Triggered Approach

The testing and monitoring strategy for CO2 plume and brine pressure front tracking makes use of the phased and/or triggered approach to scale the testing and monitoring network with the extent of the AoR and the site features that warrant monitoring. The goal of the approach is to provide the data necessary to demonstrate that USDWs are protected from the potential leakage of CO2 or brine. The scaling aspect of the strategy is aligned with the staged-injection approach outline in Section 3 – Area of Review and Corrective Action Plan that Claimed as PBI [redacted] The initial monitoring network is based Claimed as PBI [redacted] deemed appropriate to track the CO2 plume and brine pressure front during that time period. From that point, the AoR reevaluation process will be used to assess the adequacy of the testing and monitoring program to detect potential leakage should it occur and make recommendations for changes if necessary to demonstrate protection of USDWs.

Claimed as PBI [redacted]

Claimed as PBI

Claimed as PBI

5.4 Mechanical Integrity Test Methods

5.4.1 Internal Mechanical Integrity Testing – Annulus Pressure Test

In accordance with 40 CFR 146.89(b), ExxonMobil will assess the internal mechanical integrity of each injection well by performing annulus pressure tests after the well has been completed, prior to injection, and annually thereafter. Annular pressure testing verifies the Part I or internal integrity of the annulus between casing and tubing above the packer. During well construction, prior to the installation of the injection tubing and packer, the casing will also be pressure tested to the maximum anticipated annulus-surface pressure to verify its integrity.

The annular pressure tests are designed to demonstrate mechanical integrity of the casing, tubing, and packer. These tests will be conducted by pressuring the annulus to a minimum of [redacted] pounds per square inch (psi) surface pressure.

The injection tubing annulus pressure will be continuously monitored at the wellhead during all other times. The tubing annulus pressure will be recorded and reported to the regulatory permitting authority in semiannual reports to demonstrate compliance with casing integrity requirements.

5.4.2 External Mechanical Integrity Testing

Following the requirements of 40 CFR 146.89(c), ExxonMobil will perform an annual Part 2 external mechanical integrity test (MIT). Claimed as PBI [redacted]

Claimed as PBI [redacted]

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

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

An oxygen activation tool will be used for the purpose of detecting and quantifying the flow of water in or around the well using the following procedures.

- Procedures for Acquiring Oxygen Activation (OA) Log
  - Rig-up wireline company and run logging tool into the injection zone.
  - Conduct a short baseline gamma ray Log and casing collar locator near the top of the injection zone prior to taking the stationary readings with the OA tool. Verify calibration of the OA tool.
  - All stationary readings will be taken with the well injecting fluid near maximum allowable rate, or as the average of recent flow rates allow, with minimal rate and pressure fluctuations.
  - Bottomhole cement checks will, at a minimum, include stationary readings to be taken near the base of the overlying confining zone and the base of the lowermost USDW.
  - Flow behind casing checks will be conducted near the top of confining zone and immediately above the injection zone.
  - If a false positive regarding flow is suspected, move uphole or downhole to rerun the log. Per EPA *Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Testing and Monitoring Guidance* dated March 2013, another option is to vary injection rate to (25, 50, and/or 75 percent [%] of maximum rate) to determine false positive.
  - If significant flow is indicated by the OA Log at a station, move uphole or downhole as necessary and take additional stationary readings to determine the area of fluid migration.
  - Pull OA tool out of hole and rig-down wireline equipment.

An OA test is considered passing when no upward-flow is detected outside of the injection zone. To minimize the potential of false positives, checks near the same depth will be performed on any anomalous log response as outlined in the procedure above. Threshold velocities for false positives will be determined based on the vendor's logging equipment.

5.4.3 Reporting Results of MIT

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

5.5 Continuous Recording of Operational Parameters During Injection

ExxonMobil will install and use continuous measurement devices to monitor injection pressure, rate, and mass injected; the pressure on the annulus between the tubing and the long-string casing; and the temperature of the CO2 stream, as required under [40 CFR 146.88(e)(1), 146.89(b), and 146.90(b)]. Data will also be collected to document the addition or removal of any fluid from the annulus system. Data interfaces will be created for equipment that is not linked directly to a data management system or suitable equivalent, and it will be integrated into a unique surveillance platform. In the monitoring program, the sensors, transducers, and controllers will be connected in a central platform to monitor the operating conditions, set alarms for alerting operations of malfunction, and establish safety protocols in case of abnormal conditions. Alarms will additionally be set for pressures outside described tolerances (generally 90% of fracture gradient and prescribed wellhead pressures), and changes in annular pressure and fluid.

Instrument calibration standards, precision, and tolerances will be determined based on manufacturer recommendations. The automated control system data will be visually monitored for anomalies on a regular basis. Average values will be compared to baseline and predicted values to determine if there are any significant deviations relevant to integrity or containment.

The operating parameters, monitoring values, laboratory results, reports, and surveillance documents for the Project will be stored in a database to support AoR reviews, quality assurance / quality control review programs, and routine reporting. Table 5-2 provides a summary of the typical sampling devices, locations, and data storage frequencies for the continuous monitoring program. As may become necessary, paper records may be substituted for digital records at the discretion of the operator. Suitable equivalent devices may be used as technology availability and maintenance dictate.

Table 5-2: Sampling Devices, Locations, and Data Frequencies for Continuous Monitoring

Parameter	Device(s)	Location	Estimated Min. Sampling Frequency	Estimated Min. Recording Frequency
Surface Injection Pressure	Wellhead Pressure Logger	Surface, injection well piping	5 seconds	5 minutes
Downhole pressure gauge	Pressure Gauges	Injection Unit	5 seconds	5 minutes
Injection rate	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Injectate density	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Total mass injected	Coriolis Meter	Central Pad piping	5 seconds	5 minutes
Annular pressure	Pressure Gauge	Well Head	5 seconds	5 minutes
Annulus fluid volume	Pressure Gauge	Annulus System Tank	5 seconds	5 minutes
CO2 stream temperature	Coriolis Meter/Wellhead Pressure Logger	Well Head, injection well flowing	5 seconds	5 minutes
Note: The word “continuous” is used to express the frequency of measures collected during monitoring equipment operation is defined as the instrument’s normal data collection frequency as defined by the manufacturing. The frequency will vary by instrument and application. Measurements that are collected “continuously” will be averaged across a reasonable and appropriate time interval for reporting the detection monitoring results during the operational phase of the Project.				

5.5.1 Continuous Monitoring of Injection Rate and Volume

ExxonMobil will collect continuous measurements necessary to calculate and report the injection mass flow rate and volume in compliance with 40 CFR 146.90(b). A data management system or suitable equivalent will be used to facilitate continuous collection of intake pressure at the central pad transfer point, pressure within the distribution system to each injection well, and the wellhead of the injection wells.

A Coriolis flow meter will be used to measure the flow rate at the central pad and compute flow rates for each injection well. The Coriolis flow meter directly measures the mass flow rate of the injected fluid. Analytical methods will be conducted at a periodic interval to determine the mass percentage concentration of CO2 and CO. The mass percentage concentration of CO2 and carbon monoxide (CO) are multiplied by the total mass flow reading from the Coriolis flow meter to estimate the total mass of captured CO2 and CO for a given period. The meter will be placed directly at the point of injection. The meter will be calibrated to manufacturer specifications.

Claimed as PBI [redacted]

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

5.5.2 Continuous Monitoring of Injection Temperature and Pressure at Injection Well]

ExxonMobil will perform continuous monitoring of the injection pressure, temperature, mass flow rate, and injection annulus pressure in compliance with 40 CFR 146.90(b). The injected CO2 stream pressure will be continuously monitored in the CO2 flowline near the wellhead interface. The annulus pressure will also be continuously recorded. The combined wellhead and downhole monitoring data will be used to continuously characterize the injection stream in detail.

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

5.5.3 Continuous Monitoring of Injection Temperature and Pressure in Reservoir

Reservoir temperatures and pressures will be measured using a Claimed as PBI [redacted] the Project will use additional support from the provider of the selected technologies to perform QC and verification of the data as well as calibration of the systems as needed. See Section 4 for well diagram(s). The Wellhead Pressure Logger will also continuously measure the temperature and can be used as a backup in case the DTS fails.

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

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

5.5.5 Positive Annular Pressure

Per 40 CFR 146.88(c), pressure will be maintained in the annulus at a value of at least [redacted] psi greater than the injection pressure. ExxonMobil will fill the annulus with a non-corrosive fluid approved by the UIC Program Director. A system will be set up to maintain pressure in the annulus using compressed non-corrosive fluid or gas and it will be tied into the alarms or a suitable equivalent system designed to signal pressure drops below set-points.

5.6 Corrosion Monitoring

The tubing and casing materials will be monitored during the operational period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to demonstrate that the well components continue to meet the minimum standards for material strength and performance. Monitoring will take place based on well-specific conditions that are encountered but will take place not less than once per year.

5.6.1 Monitoring Location and Frequency

Corrosion coupons will be placed in continuous contact with the CO2 stream in a selected location deemed representative of the three injection wells. The samples will be exposed to the process stream conditions immediately prior to injection using a recycle loop or sample retriever. Exposure is to be representative of conditions at the top of the tubing. Initially, coupons will be tested quarterly. After establishing service life trends, coupon testing frequency may be reduced but will be conducted at a minimum of once per year.

Casing inspection logs (CILs) (e.g., ultrasonic imaging tool, electromagnetic, cement bond log, and caliper) will be conducted on the long-string casing at a minimum frequency of once every five years at the time of permit renewal. Claimed as PBI [redacted]

5.6.2 Monitoring of Corrosion Coupon

Monitoring of well tubing and casing material corrosion will initially be conducted on a quarterly basis to evaluate the corrosion coupon monitoring system. After establishing service life trends, coupon testing frequency may be reduced but will be conducted at a minimum of once per year. A corrosion coupon station or rack will be provided as part of well-materials integrity monitoring. Any coupon in active use will be exposed to the stream composition to provide ongoing evaluation of material compatibility with the CO2 stream. The results will be reported to the regulatory permitting authority such as the EPA UIC Director semiannually.

The coupons will be assessed for corrosion using American Society for Testing and Materials (ASTM) and Association for Materials Protection and Performance (AMPP) standards for evaluating corrosion tests such as ASTM G1-03 (2017), Standard Practice for Preparing, Cleaning, and Evaluating Corrosion Test Specimens or a suitable equivalent. When the coupons are removed, they will be inspected visually for signs of corrosion or pitting. The weight and size of the coupons will be measured each time they are removed. The rate of corrosion will be calculated using a weight loss method where the rate equals the weight loss during the exposure period divided by the duration of the period.

The coupon initial baseline measurements will follow the recommendations of AMPP NACE SP0775-2023 (included in references). Coupons will be prepared from the material used to construct the injection well. A method of coupon preparation will be chosen that does not alter the properties of the metal. For example, grinding operations will be controlled to avoid high surface tensions/temperatures that could change the microstructure of the coupon. Coupons may be prepared by smooth grinding with 120 grit paper, by tumbling with loose grit, or blasting with abrasive blasting material. A consistent finish may be obtained by blasting with glass beads. The abrasives will be free of metallic particles. A permanent serial number shall be etched or stamped on each coupon. ExxonMobil will machine or polish the edges of the coupon to remove cold-worked metal if the cold-worked edges adversely affect the data. ExxonMobil will dry, measure length, measure width, measure thickness, and weigh the coupons to within ± 0.5 mg., record the mass, serial number, and exposed dimensions, calculate the surface area (including the edges) and record. The areas covered by the coupon holder and shielded areas of flush-mounted coupons will be excluded.

5.6.3 Cement Evaluation and Casing Inspection Logs

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

Repeat electromagnetic CILs will only be performed if other monitoring measurements create concern about the integrity of the casing of the well, and the technical determination is made that a repeat CIL is most suitable to address those concerns. Examples include a loss of annulus pressure or anomalous distributed noise and temperature measurements using the fiber optic cables installed in the well. Changes in the recorded electromagnetic response in such a repeat CIL will be analyzed to identify and localize casing corrosion, addressing 40 CFR 146.89(d).

5.7 Pressure Fall-Off Testing

Required pressure transient fall-off testing will be conducted Claimed as PBI [redacted] he objective of periodic testing is to monitor for any changes in the near-well bore environment that may impact permeability and reservoir pressures during active injection. A report containing the pressure fall-off data and interpretation of the reservoir pressure will be submitted to the EPA within 30 days of the conclusion of the test. Although test procedures or methods may be changed based on request of the permittee and approval by the UIC Program Director, the following procedure is expected to be typical for such periodic monitoring.

5.7.1 Testing Method

The procedures to conduct a pressure fall-off test are as follows:

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

5.7.2 Analytical Methods

Near-wellbore conditions, such as the prevailing flow regimes, well skin, reservoir properties and boundary conditions will be assessed through the use of standard pressure transient diagnostic plotting and well test simulators, as required. This assessment will be accomplished from analysis of observed pressure changes and pressure derivatives on standard diagnostic log-log and semi-log plots. Significant changes in the well or reservoir conditions will be identified by comparing pressure fall-off tests performed prior to initial injection with later tests. These well parameters resulting from fall-off testing will be compared against those used in AoR determination and site computational modeling. Notable changes in reservoir properties may dictate that an AoR reevaluation is necessary.

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

5.7.3 Quality Assurance/Quality Control

The surface field equipment will undergo inspection and testing prior to operation. The pressure gauges will be calibrated prior to installation per manufacturer instructions. Documentation certifying proper calibration will also be enclosed with the test results. Further validation of the test results will be justified by extended collection of pressure data from the plugged and abandoned injection stages. The continuation of pressure monitoring in deeper, inactive stages allows for recording of the naturally occurring pressure decay. Pressure communication between stages may also be evaluated with this approach.

5.8 Monitoring of CO2 Stream

Consistent with 40 CFR 146.90(a), ExxonMobil will install and use measurement devices to analyze the chemical composition of the injection stream to assess the potential for interactions between CO2 and other injectate components and compatibility with the well completions materials. Temperature and pressure will also be measured at the sample collection point.

5.8.1 Sampling Frequency

Quarterly sampling of the CO2 stream is proposed for the first two years of operation, after which the frequency may be reduced to twice per year if the results of the CO2 stream analyses are consistent. If a new source is introduced after transition to semiannual sampling, quarterly sampling would be re-initiated from the time the new source is included in the CO2 stream for a period of one year. If a consistent stream composition is observed for a period of one year, sampling would be reduced to twice per year.

5.8.2 Sampling Methods

The quarterly measurements will be obtained by collecting representative samples of CO2 at a sample port on the Project's central pad beyond the last stage of compression in the compression build or similar point. Sufficient mixing and residence time in the system will have occurred at this sampling point for the sample to be representative of the injected CO2 stream. The sampling station will be equipped with the ability to purge and collect a gas sample into a sealed container. The central pad is the connection point between the CO2 pipeline and the sequestration field's distribution system.

Sampling activities will be conducted at the direction of site representatives and in accordance with the certified or accredited analytical laboratory procedures and will meet the minimum

current standard EPA procedures. A sample will be collected by depressurizing the liquid stream and sampling the CO2 as a gas in either a Tedlar® bag, a Summa cannister, or laboratory-approved alternate. The grab sample will be sent to an independent contract laboratory for analysis.

Each sample will be accompanied by a facility or contract laboratory Chain-of-Custody (COC) form that provides a record of sample handling, starting with sample acquisition, documenting the sample transfer process up to laboratory analysis. Samples taken are to be logged in the field using the COC form. Sample transfer containers (e.g., coolers) will be sealed and delivered to the laboratory with a COC form. The COC form shall provide the following items recorded by the sampler:

1. Sample ID including code or name, in addition to date and time;
2. Name of sample collector; (include sampling company name if not site personnel);
3. Sample collection method;
4. Sample collection date;
5. Sample collection point; and
6. Sample presentation technique, as applicable.

Standard laboratory COC forms that document the times and dates of all personnel handling the sample, along with standard labels and container seals sufficient to distinguish between samples and prevent tampering, will be acceptable.

Sample COC will be followed at all times during the sampling and subsequent analysis. COC will be used to document the handling and control necessary to identify and trace a sample from collection to final analytical results.

5.8.3 Analytical Plan

Table 5-3 presents the test parameters, analytical methods, and sample frequency for each test parameter. The selected parameters and constituents for analysis are consistent with the composition of the CO2 stream described in Section 4 – Well Construction Plan and Operating Conditions.

Table 5-3: Summary of CO2 Sampling and Analysis Plan

Parameter/Constituents	Analytical Method(s)[1]	Frequency[2]
CO2 Purity	ISBT 2.0, GC/DID or Method 3A	Quarterly
Water	ISBT 3.0, GC/FTIR, Method 320, EPA Method 4	Quarterly
Oxygen	ISBT 4.0, GC/DID or Method 3A	Quarterly
Nitrogen	ISBT 4.0, GC/DID or by difference	Quarterly
Sulfur Dioxide	ISBT 14.0, GC	Quarterly
Hydrogen Sulfide	ISBT 14.0, GC	Quarterly
Oxides of Nitrogen	ISBT 7.0	Quarterly
Total Hydrocarbons	ISBT 10.0, GC	Quarterly

Parameter/Constituents	Analytical Method(s)[1]	Frequency[2]
Carbon Monoxide	ISBT 5.0, GC/DID	Quarterly
Methane	ISBT 10.1, GC	Quarterly

FTIR = Fourier transform infrared; GC/DID = gas chromatography-discharge ionization detector; ISBT = International Society of Beverage Technologists

[1] Or suitable alternate analytical method may be used.

[2] Proposed quarterly sampling for the first two years of operation with the option to reduce frequency to twice a year after two years if the CO2 stream analytical results are consistent. The addition of a new source would require return to quarterly sampling for one year.

5.9 CO2 Plume and Pressure Front Tracking

Claimed as PBI

[redacted]

5.9.1 Direct Pressure Front Tracking

Claimed as PBI

[redacted]

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Claimed as PBI

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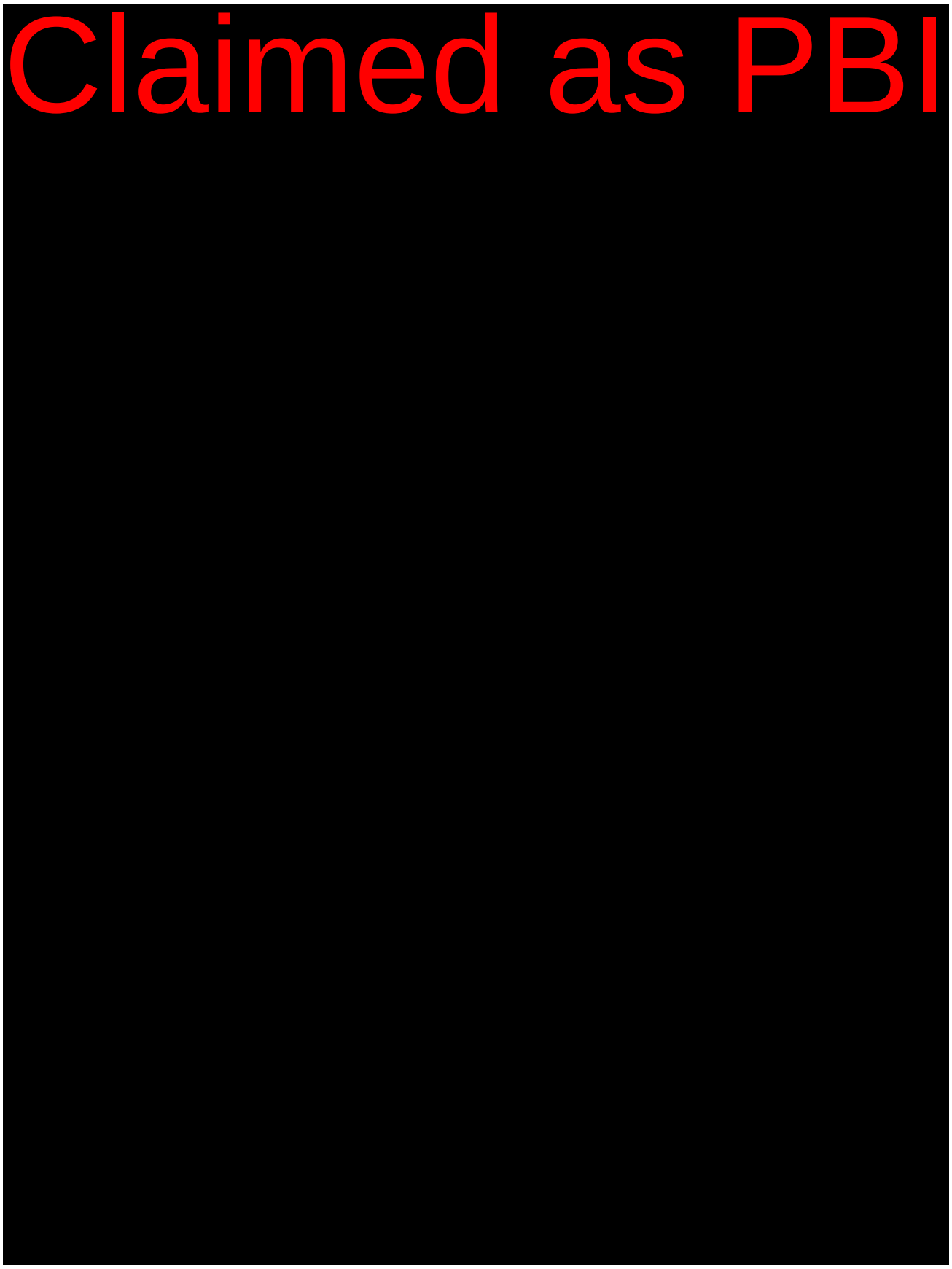
Any periods of shut-in for an injection well may be observed and treated as a fall-off test by recording the shut-in wellhead pressure, bottomhole pressure, and temperature readings. This information, together with the continuous measurements obtained during regular operating conditions, will aid in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

5.9.2 Plume and Pressure Front Tracking Using Indirect Geophysical Techniques

Claimed as PBI

[redacted]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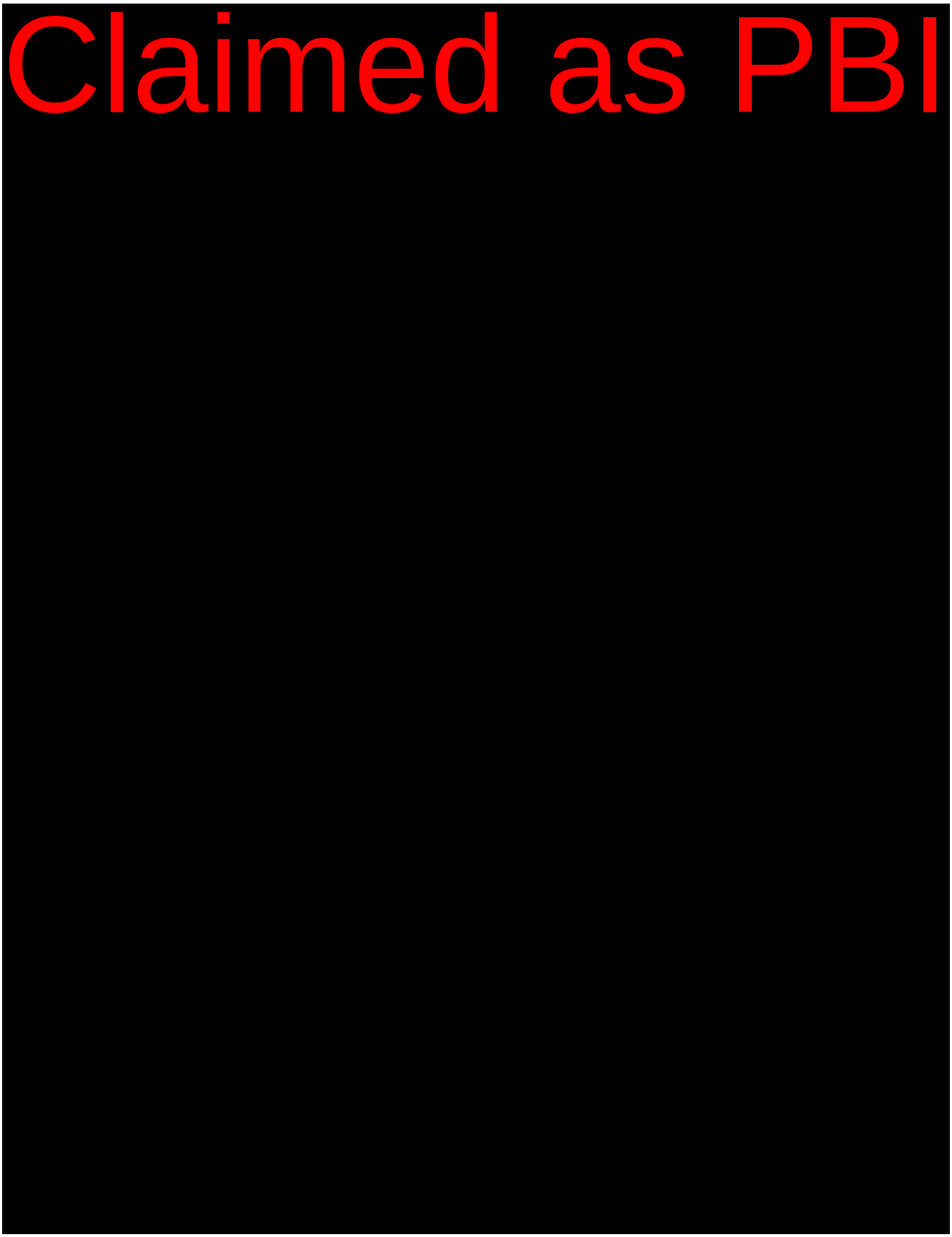
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5.10 CO2 Plume Tracking Using Groundwater Monitoring Data

5.10.1 Phased and Triggered Monitoring

The phased and/or triggered monitoring strategy was adopted for the installation of in-zone monitoring wells, potential additional USDW monitoring wells, soil gas monitoring wells, and air monitoring locations. The phased approach was deemed reasonable and appropriate based on the schedule of CO2 injection for three injection wells and the degree of protectiveness evident based on the geologic site characterization and demonstrated by the plume modeling. This type of approach allows the site-specific testing and monitoring strategies to be tailored to changes in predicted performance and in response to potential increased risks to USDWs identified or detected during the course of injection.

Claimed as PBI

Claimed as PBI

Claimed as PBI

5.10.2 Design of the Monitoring Well Network

The monitoring well network includes the monitoring wells that will be used to support compliance with the testing and monitoring requirements under the Class VI Rule. Combined with the monitoring of pressure build-up at each injection well, the design of the monitoring well network was selected to provide a high degree of confidence in detecting a leak through the confining zone that may endanger USDW. The relevant site data considered for the design of the monitoring well network included the phased injection depths, rate, and volume; the geology, and the presence of the legacy wells as required at 40 CFR 146.90(d)(1) and (2).

5.10.3 USDW Monitoring Well Construction

To comply with 40 CFR 146.90(d), a phased approach to USDW monitoring well installation is proposed. Initially, Claimed as PBI will be completed at the locations shown on Figure 5-4. These locations were selected to provide a baseline of geochemical data in the vicinity of the following areas of significant interest:

Claimed as PBI

The Chicot Aquifer is the most prolific USDW aquifer within the AoR, and its relatively shallow water-bearing zones are a target for completion of water wells, typically at depths ranging from approximately 150 to 400 feet (ft) below ground level (BGL) in the AoR. Claimed as PBI

The deepest USDW formation is the Evangeline Aquifer at a depth of approximately Claimed as PBI BGL at the Project site. Below this depth, the total dissolved solids (TDS) values were found to be greater than 10,000 mg/L. Claimed as PBI

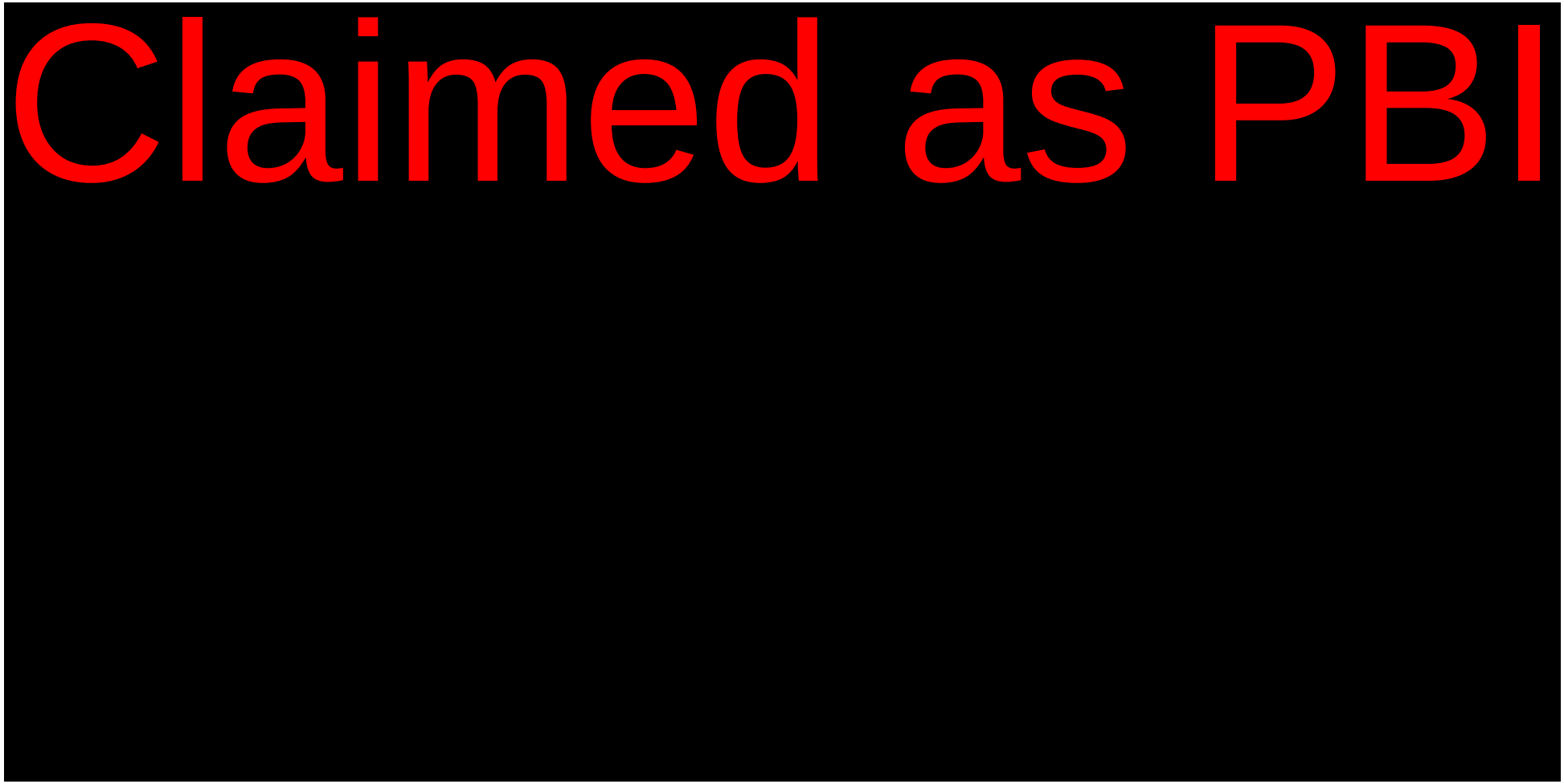
[redacted]

At this time, it was assumed that up to [redacted], if necessary, could be completed in a phased approach to expand USDW monitoring coverage commensurate with the expanse of the CO2 plume and pressure front. The target schedule for expansion is after an initial period from the start of operations. During this time, data will be collected to reduce the uncertainty in CO2 plume and pressure front migration. The locations of any potential additional USDW monitoring wells will be selected for areas where a risk of leakage either remains uncertain or plume and pressure tracking indicators that a leakage feature, such as a legacy well, warrant additional groundwater monitoring.

5.10.4 Summary of Water Well Data for the AoR

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

A total of [redacted] water wells were identified in and near the AoR as listed on Table 5-6 from the Texas Water Development Board well registration list and the Texas Commission on Environmental Quality environmental well database. Appendix F-1 illustrates the location of the water wells. Each of these wells is completed in the Chicot Aquifer with a maximum depth of [redacted]. For planning purposes, the extent of the CO2 plume and pressure front relative to the water wells will be reviewed after sufficient data have been collected to assess whether additional USDW groundwater monitoring is needed for situations of potential USDW endangerment.


Claimed as PBI

Groundwater samples will be collected using dedicated tubing and pumps capable of producing representative groundwater samples to the surface with the least pumping effort. The fluid sampling parameters and frequencies for the in-zone and USDW monitoring wells are shown in Table 5-4. Additional USDW monitoring wells will be added to assess the potential for USDW endangerment if necessary.

A wellbore schematic is provided for USDW Monitoring Wells No. 01 to No. 03 in Claimed as PBI [redacted]. The USDW monitoring wells will be completed to collect groundwater samples for the Chicot Aquifer at depths from approximately Claimed as PBI

Claimed as PBI

[redacted]

5.10.6 Collection and Analysis of Groundwater Samples

Fluid samples will be taken periodically from the USDW monitoring wells and the Claimed as PBI [redacted]. The USDW monitoring wells target the Chicot Aquifer, which is the most used aquifer in the AoR for potable and non-potable purposes. The initial sampling frequency for the USDW monitoring wells is Claimed as PBI This sampling frequency is for both the pre-injection phase and the first [redacted] years of injection. This Claimed as PBI sampling characterizes the potential seasonal fluctuation in this USDW. After the initial phase, the sampling becomes Claimed as PBI with the optimal season of data collection determined by analysis of the first years of Claimed as PBI samples. Claimed as PBI

[redacted]

Table 5-4 summarizes the parameters analyzed and the planned sampling frequency, which apply to the USDW and in-zone monitoring wells. Anomalous measurements will trigger re-sampling and additional data analysis, including a more detailed evaluation of data using statistical comparisons approved by EPA for detection monitoring programs. This analysis could also include geochemical modeling to compare the compositions of groundwater from before and during operations.

If warranted, other tests may be added to the evaluation if re-sampling and detailed analysis of the fluid samples does not satisfactorily rule out a leakage scenario.

Measurements are performed on gases collected from the fluid samples by depressurizing them to atmospheric conditions in a controlled laboratory environment.

5.10.6.1 Analytical Methods

ExxonMobil will test the fluid samples and maintain results for the parameters listed in Table 5-4. If results indicate the existence of impurities in the injection stream, the diagnostic power of these constituents will be assessed to determine if they should be included in the analysis of the water samples. Testing results will be stored in an electronic database.

Fluid chemistry data will be monitored for deviations from baseline, predicted, and average values. If a significant variance occurs, the numerical model will be reevaluated. Potential geochemical signs that fluid may be leaking from the injection interval may be detected upon observation of the following trends:

- Change in TDS;
- Change in signature of major cations and anions;
- Increase in CO2 concentration;
- Decrease in pH;
- Increase in concentration of injectate impurities; and
- Increase in concentration of leached constituents.

5.10.6.2 Laboratory to be Used/COC Procedures

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

5.10.6.3 Quality Assurance and Surveillance Measures

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

5.10.6.4 Plan for Guaranteeing Access to All Monitoring Locations

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

5.10.7 Injection Interval Monitoring

In-zone fluid samples were collected from the stratigraphic test well and are being analyzed for water quality and geochemical parameters. The results of these tests will be provided subsequently. No in-zone fluid sampling is proposed for the CO2 plume or pressure front tracking.

5.10.8 Seismic Monitoring (Induced Seismicity)

Claimed as PBI

[redacted]

5.11 Reporting Requirements

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

- Provide the necessary data to verify predictions of CO2 plume and pressure front movement; and
- Provide the basis for evaluating the model inputs, making necessary changes, and reevaluating the AoR.

In compliance with 40 CFR 146.91, ExxonMobil will provide reports to the UIC Program Director in routine semiannual reports that document the performance of the system and CO2 plume and pressure front tracking data. Relevant records pertaining to the Class VI Testing and Monitoring program will be submitted to the EPA. In addition, ExxonMobil will follow the prescribed notification requirements for deviation from permit conditions, operational malfunction that may allow CO2 or brine to migrate into or between USDWs, or for other evidence of USDW endangerment.

The semiannual reports will include the data collected during each reporting period and a list of notifications triggered during a semiannual period, if any. The following information is proposed for the routine performance reporting:

- Monthly average, maximum, and minimum values of injection pressure, flow rate and volume, and annular pressure;
- Monthly volume and/or mass of the CO2 stream injected over the reporting period, and the volume injected cumulatively over the life of the Project;
- Monthly annulus fluid volume added;
- Results of CO2 plume and pressure front tracking as described herein;
- Any significant changes to the physical, chemical, and other relevant characteristics of the CO2 stream from the proposed operating data that could impact plume migration or protection of USDWs;
- A description of any event which triggered a shut-off device required to 146.88 (e) and the response taken; and
- A description of any event that exceeded operating parameters for annulus pressure or injection pressure specified in the permit.

The semiannual reports will be submitted 30 days after the completion of the quality control, quality review of the data for each reporting period. Table 5-8 describes the non-routine reporting triggers, contents, and schedule.

Table 5-9: Summary of Triggering Events for Notification and Reporting Schedule

Triggering Event	Reporting Schedule
Planned well workover, stimulation activities, or other planned test of an injection well.	Notification to the UIC Director, in writing, 30 days in advance of planned activity.
Completion of well workover.	30 days after completion of well workover.
Any test of the injection well conducted, if required by the UIC Director.	30 days after completion of any testing required by UIC Director.
Evidence of potential non-compliance with a permit condition, or malfunction of the injection system that may cause fluid migration into or between USDWs.	Verbal Notification – Reported within 24 hours of verification of non-compliance or malfunction.
Primary evidence that the injected CO2 stream or associated pressure front may cause an endangerment to a USDW.	Verbal Notification – Reported within 24 hours of verification of endangerment
A failure to maintain mechanical integrity.	Verbal Notification – Reported within 24 hours of verification of MIT failure
A statistically significant change to the physical, chemical, and other relevant characteristics of the CO2 stream from the composition described in the proposed operating plan.	Written Notification – Reported within 72 hours of verification of composition change.
An operational condition that exceeds operating parameters for annulus pressure or injection pressure as specified in the permit.	Verbal Notification – Reported within 24 hours of verification of non-compliance with permit conditions. Written Notification – Reported within 72 hours of verification of non-compliance with permit conditions.
A shut-off device anywhere in the injection well system that is triggered.	Verbal Notification – Reported within 24 hours of event. Written Notification – Reported within 72 hours of event.

ExxonMobil will submit all reports, submittals, and notifications to both the EPA and the Railroad Commission of Texas and retain records in accordance with 40 CFR 146.91(f) for a 10-year period after site closure. Additionally, injected-fluid data, including nature and composition, will also be retained for the 10-year period following site closure. Monitoring data will be retained for a minimum of 10 years post-collection, while well-plugging reports, PISC data, and the site closure report will be retained for 10 years after site closure.

5.12 Testing Plan Review and Updates

In accordance with 40 CFR 146.90(j), the Testing and Monitoring Plan will be reviewed and revised at a minimum of every five years to:

- Identify Project-specific factors that may warrant revision to the Plan;
- Incorporate information and changes necessary to monitor an increase in risk to or endangerment of USDWs; and/or
- Deviations from permitted conditions that require Plan modifications.

ExxonMobil will incorporate the collected monitoring data that characterizes the Project-specific factors and the changes needed, if any, to monitor increased potential risk to USDW and overall Plan compliance with the UIC Director's requirements. Plan amendments will be submitted within one year of an AoR reevaluation, following significant facility changes (such as the development of offset monitoring wells or newly permitted injection wells within the AoR), or as the UIC Director requires. Table 5-10 summarizes the various measurements discussed in the Testing and Monitoring Plan and the frequency of measurements for data collection and reporting purposes.

Table 5-10: Testing and Monitoring Plan Measurements and Frequency

Equipment / Measurement	Regulation	Objective	
Coriolis flow meter	146.90b	Measure mass flow rate	Claimed as PBI
Corrosion coupon	146.90c	Measure corrosion levels on the types of metal used in the Project	Claimed as PBI
Injection stream sampling	146.90a	Provide more detailed analysis via periodic lab analysis of injection stream	Claimed as PBI
Central pad temperature gauge	146.90a	Measure temperature of the total injection stream at the pad before partitioning to injections	Claimed as PBI
Injection wellhead tubing P gauge	146.90a	Measure downstream of choke	Claimed as PBI
Injection wellhead annulus P gauge	146.90b	Verify annulus pressure maintained	Claimed as PBI
Injection annulus pressure test	146.89b	Verify absence of leak in annulus	Claimed as PBI
Injection Well downhole pressure and temperature gauge for active/open injection interval	146.90b	Measure downhole pressure and temperature (injection mass to volume conversion, verifying that it is not exceeding maximum pressure)	Claimed as PBI
	146.90f	Measure fall-off of pressure after abandoning injection stage and initiating injection in next stage above	Claimed as PBI
	146.90g(1)	Direct measurement of pressure, sensitive to pressure from other injections, especially when injection intervals are staggered between wells	Claimed as PBI
Injection well behind-casing fiber	146.90g(2)	DAS-VSP: main imaging fiber	Claimed as PBI
	146.87a(3)(ii)	DTS for cement long portion of long-string casing where fiber is cemented in place	Claimed as PBI

Equipment / Measurement	Regulation	Objective	Claimed as PBI
	146.90e	Supplementary fiber for external MIT; does not cross the UCCZ, which is important for external MIT, but is closer to formation and may therefore have heightened sensitivity to potential flow through channels through or along cement	Claimed as PBI
Injection well CIL	146.90e	Through-tubing log to detect loss of metal mass in casing due to corrosion	Claimed as PBI
Claimed as PBI	Claimed as PBI	Claimed as PBI	Claimed as PBI
Claimed as PBI	Claimed as PBI	Claimed as PBI	Claimed as PBI
Claimed as PBI	Claimed as PBI	Claimed as PBI	Claimed as PBI
Claimed as PBI	Claimed as PBI	Claimed as PBI	Claimed as PBI
Claimed as PBI			

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Underground Injection Control – Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 6 – INJECTION WELL PLUGGING PLAN

Rose Carbon Capture and Storage Project

Claimed as PBI

ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2024

SECTION 6 – INJECTION WELL PLUGGING PLAN

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Appendix H – Plugging Schematics and Procedures

Claimed as PBI

6.0 Injection Well Plugging Plan

The Injection Well Plugging Plan section for the Rose Carbon Capture and Storage (CCS) Project (Project) Class VI Underground Injection Control (UIC) Permit Application was prepared to meet the requirements of Title 40, U.S. Code of Federal Regulations (40 CFR) 146.92 and Texas Administrative Code, Part 1 Title 16 Chapter 5 for plugging and abandonment (P&A) of the Rose CCS Project Injection Wells No. 01, No. 02, and No. 03. ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is undertaking the Project in Claimed as PBI , to sequester approximately Claimed as PBI . The purpose of the Plugging Plan is to demonstrate the actions that ExxonMobil will take to mitigate the threat to underground sources of drinking water (USDW) during the post-injection period.

ExxonMobil has selected materials for plugging the injection wells that will resist the corrosive properties of the injection fluid to maintain mechanical integrity of the plug and well casing. The planned plugging procedures are aligned with best practices for restoring the upper composite confining zone (UCCZ) integrity at each injection well location. Claimed as PBI .

Separately, the procedures and details for the stratigraphic well (Claimed as PBI) P&A are included in this plan for completeness purposes.

6.1 Objectives

The Plugging Plan represents one of the final steps in the lifecycle of each of the three injection wells for the Project. ExxonMobil will properly plug and abandon the injection wells, maintain the integrity of the UCCZ throughout the remainder of the post-closure care period, and monitor the performance of the plugged wells to contain CO2 and brine in the injection zone, reducing the potential risk of USDW endangerment.

The Plugging Plan and procedures were designed to meet the following objectives:

- Measure the bottomhole reservoir pressure prior to conducting plugging activities [40 CFR 146.92(b)(1)];
- Assess the external mechanical integrity of the long-string casing by using appropriate testing methods to demonstrate isolation consistent with 40 CFR 146.92(b)(2);
- Select the type, grade, and quantity of material to be used in plugging to withstand contact with CO2 and acidified liquids in the injection intervals [40 CFR 146.92(b)(5)]; and
- Detail the methods, locations, and types of plugs used within the well [40 CFR 146.92(b)(4) and 40 CFR 146.92(b)(6)].

6.2 Preparation of Well Prior to Plugging

Prior to plugging, the well will be flushed with a buffer fluid, the bottomhole pressure will be measured, well components will be removed as needed, and an external mechanical integrity test (MIT) will be performed. The proposed plugging methods and materials used are corrosion compatible to the injection interval conditions.

As needed, ExxonMobil will repair deficiencies identified during the life of the well to mitigate potential leaks to USDWs [40 CFR 146.88(f)]. Historical MIT data and prior remedial measures will be considered prior to plugging operations. If required, those remedial activities will be included in an amendment to this plan.

6.2.1 Flushing Well with Buffer Fluid

Pressure control will be accomplished through the use of kill-weight brine that is weighted and compatible with the injectate and formation fluids. The kill-weight brine fluids will be circulated through the injection well to remove fluids or fine debris that could have a significant impact on the integrity of cementing operations. The fluids will be chemically compatible with the formation fluids and solids in the downhole environment. The following components that have been in contact with injection or annular fluids will be flushed:

- Any components in the annular space between the injection tubing and the production casing;
- The long-string casing;
- The perforated injection zone; and
- The injection packer, if needed.

Claimed as PBI [redacted]. After the well has ceased operation, flushing fluid will be circulated through tubing to flush the well of free solids, as necessary.

6.2.2 Removal of Well Components and Obstructions

The removal of well equipment prior to plugging will be completed to open the well for access. In general, uncemented and non-permanent components of the well will be removed. This includes downhole monitoring devices and potentially shut-off devices. Tubing will be removed with the use of a rig. The tubing will be pulled out of the packer.

The surface and long-string casings will be cemented to the surface and will remain in place.

6.2.3 Planned Tests or Measures to Determine Bottomhole Pressure

Claimed as PBI [redacted] The bottomhole reservoir pressure will be used to estimate the density of kill-weight brine (buffer fluid compatible with CO2 fluid) needed to establish static equilibrium prior to plug placement.

6.2.4 Planned External MITs

MIT will be used to identify the potential for significant fluid movement toward the USDW in the casing, tubing, or packer [40 CFR 146.89(a)]. ExxonMobil will conduct at least one of the tests listed in Table 6-1 as part of the monitoring program, to verify external mechanical integrity as required in 40 CFR 146.92(a).

Table 6-1: External MIT Methods

Test Description	Method of Testing
Temperature Log	Claimed as PBI [redacted]
Noise Log	Claimed as PBI [redacted]
Oxygen Activation Log	Wireline log
Radioactive Tracer Log	Wireline log

The results of the MIT will be documented and provided to the UIC Program Director.

6.2.5 CO2-Compatible Materials

In accordance with 40 CFR 146.92(b)(3) and (5), a cement that is compatible with CO2 will be used as the UCCZ cement plug. The procedures for corrective action on artificial penetrations of the UCCZ were described in Section 3 – Area of Review and Corrective Action Plan. ExxonMobil will evaluate potential cement options prior to implementing the cementing operations with concurrence of the UIC Program Director. The intent is to select a cement system that is designed to provide a long-term cement sheath or plug that can withstand the temperature, pressure, and chemical interactions.

Cement at intervals above the UCCZ will be based on blended Portland cement. A list of common cement additives is provided in Table 6-2 for the blended Portland cement to improve setting time, reduce porosity, and improve overall strength if needed. ExxonMobil will report the wet density and will retain duplicate samples of the cement used for each plug in the plugging reports.

Table 6-2: Common Cement Additives

Additive Type/Category	Additives
Fluid-loss additive	Claimed as PBI [redacted]

Additive Type/Category	Additives
	Claimed as PBI
Dispersant	
Retarder	
Accelerator	
Antifoam agent	

Claimed as PBI

6.2.6 Planned Site Restoration Activities

After the injection wells have been plugged and abandoned, the wellhead equipment and surface facilities will be removed from the well site. The surface will be restored to a condition agreed upon by the landowner and by the UIC Program Director, as appropriate.

6.3 Injection Well Zonal Isolation and Final P&A

As discussed above, a plug will be set for injection zone isolation and the final P&A will occur at the end of the Project. The following details outline the procedures for both types of plugs to be installed. The volume and depth of the plugs will depend on the final geology and downhole conditions of the well as assessed during construction.

6.3.1 Zonal Isolation and Intermediate Plug-Back Plan

Claimed as PBI

Claimed as PBI [redacted]

6.3.1.1 Pre-Zonal Isolation Activities

ExxonMobil will comply with reporting and notification provisions for the UIC Program Director, which require a 60-day advanced written notice before planned recompletion efforts are undertaken [40 CFR 146.92(c)]. A similar notice of recompletion will be communicated to the Railroad Commission of Texas (RRC). The bottomhole reservoir pressure will be measured using the Claimed as PBI [redacted] [40 CFR 146.92(a)]. Schematics of the initial completion plans for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03 are presented in Appendix D.1 - Well Construction Design and Completion.

6.3.1.2 Zonal Isolation Activities

A barrier will be set above the injection zone to be isolated. This is generally completed via a bridge plug or a permanent packer with plug in nipple profile completed with approximately 10 ft of CO2 compatible cement. The plug integrity will be assessed by conducting a pressure test or tagging. The perforations will not be squeezed.

6.3.2 Final P&A

After injection operations cease and after post-operational monitoring in a well is completed, the injection well will be prepared for final P&A. The general final P&A procedures are described below.

6.3.2.1 Pre-Plugging Activities (Notifications, Permits, and Inspections)

ExxonMobil will comply with reporting and notification provisions and provide written notification to the UIC Program Director 60 days before planned plugging efforts. If changes have been made to the original approved Injection Well Plugging Plan, ExxonMobil will provide the amended Injection Well Plugging Plan [40 CFR 146.92(c)]. A Notice of Intention to Plug and Abandon Form W-3A will be submitted to the RRC at least 5 days before plugging operations are planned to commence. In accordance with 40 CFR 146.92(d), a plugging report will be submitted to the UIC Program Director and RRC within 60 days after plugging. Plugging Record Form W-3 will be filed with RRC District Office 3 within 30 days after plugging.

The following plugging activities are planned for each injection well:

- The bottomhole reservoir pressure will be measured using the Claimed as PBI [redacted] [40 CFR 146.92(a)];
- The external mechanical integrity will be demonstrated through approved testing methods discussed above [40 CFR 146.92(a)]; and
- The injection well will be flushed with a buffer fluid prior to pulling the injection tubing and packer [40 CFR 146.92(a)], as described in Table 6-3.

Claimed as PBI

6.3.2.2 Plugging Procedure, Injection Well No. 01

The following sequence of plugging procedures are planned:

Claimed as PBI

Claimed as PBI

6.3.2.3 Plug Details, Injection Well No. 01

Table 6-4 provides the plugging details for Injection Well No. 01; Appendix H shows the final plugged schematic.

6.3.2.4 Plugging Procedure, Injection Well No. 02

The following sequence of plugging procedures are planned:

6.3.2.5 Plug Details, Injection Well No. 02

Table 6-5 provides the plugging details for Injection Well No. 02; Appendix H shows the final plugged schematic.

6.3.2.6 Plugging Procedure, Injection Well No. 03

The following sequence of plugging procedures are planned:

6.3.2.7 Plug Details, Injection Well No. 03

Table 6-6 provides the plugging details for Injection Well No. 03; Appendix H shows the final plugged schematic.

6.4 Notifications and Record Keeping

The procedures described above are subject to modification during execution, as necessary, for implementation of plugging operations that protect worker safety and the USDW. Significant modifications due to unforeseen circumstances will be reported to the UIC Program Director within 24 hours of occurrence during field operations and documented in the plugging report. Completed plugging forms, records, and lab information will be supplied to the regulatory agencies as required by the permit. The plugging report will be certified as accurate by ExxonMobil and the plugging contractor and will be submitted to the UIC Program Director within 60 days after plugging is completed [40 CFR 146.92(d)]. Well plugging reports, post-injection site care data (including data and information used to develop the demonstration of the alternative post-injection site care timeframe), and the site closure report collected pursuant to the requirements in 40 CFR 146.93 (f) and (h), will be retained by ExxonMobil. Site closure and reporting is discussed in Section 7 – Post-Injection Site Care and Site Closure Plan.

The plugging report will provide the following information:

- Results of tests to determine BHP and mechanical integrity;
- Type and number of plugs used;
- Cement type, grade, weight, and quantity of material for plugs;
- Method of cement plug emplacement; and
- Top and bottom of each cement plug.

6.5 Monitoring Well P&A

Monitoring wells must be plugged in accordance with 40 CFR 146.93(e) to not allow movement of injection or formation fluids that could endanger USDWs. Specific monitoring wells will remain in place after injection wells have been plugged and abandoned for use in monitoring activities associated with the Post Injection Site Care and Site Closure Plan. ExxonMobil will assess the monitoring well plugging procedures prior to P&A in relation to this plan. Documentation of appropriate P&A of the monitoring wells will be submitted to the UIC Program Director in accordance with 40 CFR 146.93(f)(1).

6.6 Amendments to the P&A Plan

The Plugging Plan will be amended to account for changes in conditions that trigger modification to the Area of Review. ExxonMobil will inquire with the UIC Program Director to confirm whether such changes in condition warrant amendments to the Plugging Plan. Revisions to the Injection Well Plugging Plan can be made at any time and submitted when notifying the UIC Program Director of the intent to plug the well at least 60 days prior to conducting the plugging activity [40 CFR 146.92(c)].

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Underground Injection Control – Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

Rose Carbon Capture and Storage Project

Claimed as PBI

ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2024

SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

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Claimed as PBI

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7.0 Post-Injection Site Care and Site Closure Plan

The Post-Injection Site Care (PISC) and Site Closure Plan for the Rose Carbon Capture and Storage (CCS) Project (Project) Injection Wells No. 01, No. 02, and No. 03 was prepared to meet the requirements of Title 40, U.S. Code of Federal Regulations (40 CFR) 146.93. and Texas Administrative Code, Part 1 Title 16 Chapter 5. ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is undertaking the Project in Claimed as PBI , to sequester approximately Claimed as PBI . Through injection into the three CO2 injection wells for the Project, ExxonMobil will sequester approximately Claimed as PBI

The PISC Plan describes the activities that will occur once injection operations have ceased, and the Project moves into maintaining a non-endangerment condition for underground sources of drinking water (USDW). The Site Closure Plan will be implemented once ExxonMobil demonstrates to the Underground Injection Control (UIC) Program Manager that no additional monitoring is required to demonstrate protection of USDW and that the testing and monitoring system can be dismantled. ExxonMobil's strategy for PISC monitoring is based on the same systems and processes as described in Section 5 – Testing and Monitoring Plan of this Class VI UIC Permit Application (Application). The major monitoring elements include continued measurements of the CO2 plume and pressure front location, monitoring above upper composite confining zone (UCCZ) groundwater as well as USDW. The data collected from this activity will be used to confirm compliance with the water quality objectives for the Project and generate information needed to support the final non-endangerment demonstration and subsequent site closure. The end of the Project comes when the closure activities have been documented and approved by the UIC Program Director.

7.1 Objectives

The PISC and Site Closure Plan have been developed to meet the following objectives as outlined in 40 CFR 146.93:

- Describe the pressure differential between pre-injection and predicted post-injection pressures in the injection zones as well as the predicted positions of the CO2 plume and associated pressure front at site closure;
- Describe the post-injection monitoring locations, methods, and proposed frequencies to demonstrate non-endangerment to USDW over the timeframe of the PISC;
- Identify the pre-closure, plugging, and site-restoration steps to achieve approval for site closure; and
- Outline the documentation and recordkeeping practices that will provide the information for decision-making purposes.

ExxonMobil will not cease post-injection monitoring until the non-endangerment demonstration pursuant to 40 CFR 146.93(b)(3) has been approved by the UIC Program Director. Pursuant to 40 CFR 146.93(b)(1), the default PISC monitoring timeframe is 50 years after cessation of injection. ExxonMobil will monitor groundwater quality and track the position of the CO2 plume and pressure front for 50 years after cessation of injection unless a lesser period of time is approved by the UIC Program Director. Once the non-endangerment demonstration has been

approved, ExxonMobil will plug the monitoring wells, restore each well pad to the landowner's agreed-upon condition, and submit a Site Closure Report to the UIC Program Director.

7.2 Calculation of Pre- and Post-Injection Pressure Differentials

As described in 40 CFR 146.93(a)(2)(i), the Class VI non-endangerment demonstration will establish that pressure has declined to a level that no longer poses potential endangerment of USDW. For the purposes of this section, ExxonMobil evaluated the pressure differentials by comparing the pre-operating pressure with the post-injection pressure differentials predicted by the plume model. The predicted pressure differential between pre-injection and the modeled post-injection pressures are favorable, showing a steep and continuous decline in pressure toward pre-operational baseline conditions. The primary mechanisms responsible for the anticipated pressure decay rates are the injection sequencing plan, the geological conditions of the injection zones (e.g., net sand thickness, permeability, porosity) and confining zones, and the projected CO2 storage volume for the Project site.

A staged injection sequence is planned for the injection wells to optimize the storage of CO2 in the Claimed as PBI [redacted] Section 3 – Area of Review and Corrective Action Plan and Section 4 – Well Construction Plan and Operating Conditions of the Application provide detailed discussions of the injection sequencing strategy. Figure 7-1 summarizes the injection sequence schedule for the proposed [redacted] -year injection period. The actual injection period will depend on the issuance of the permits for each injection well.

Claimed as PBI

Table 7-1 provides the model-predicted maximum pressure differential and the change in injection pressures in each injection interval over time pursuant to 40 CFR 146.93(a)(2)(i). Figure 7-2 presents a graphical representation of the pressure differential data provided in Table 7-1.

Claimed as PBI

Claimed as PBI

7.3 Predicted Position of the CO2 Plume and Pressure Front at Site Closure

Pursuant to 40 CFR 146.93(a)(2)(ii), the area of review (AoR) was delineated using computational modeling that accounts for all phases of CO2 (e.g., supercritical, dissolved, etc.) under proposed operational conditions. The AoR consists of both the CO2 plume and the extent of the pressure front. The following discussion provides the predicted evolution of both the CO2 plume and pressure front throughout the course of the 50-year PISC timeframe.

Figure 7-3 shows the extent of the AoR and its subcomponents at [redacted] years from start of injection and [redacted] years from cessation of injection. Based on the model, the CO2 plume stabilization is predicted to occur [redacted] years after injection with pressure differentials below the critical pressure threshold, reducing the potential for USDW endangerment. The CO2 plume from the three injection wells is indicated by the Claimed as PBI , based on the maximum extent of any injection interval. Claimed as PBI [redacted]

Claimed as PBI

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Post-Injection Monitoring Plan

PISC monitoring is required by 40 CFR 146.93(b) to demonstrate that USDW is not endangered during the post-injection phase of the Project. Much like the operational phase, direct and indirect forms of monitoring will be used to track the evolution of the CO2 plume and pressure front after cessation of CO2 injection. The strategy for the Post-Injection Monitoring Plan is to rely on a core set of monitoring locations that were established during the operational phase of the Project. The following set of core monitoring locations were assumed to be installed and monitored pursuant to the Testing and Monitoring Plan and found sufficient pursuant to the AoR reevaluation process:

Claimed as PBI

Figure 5-4 in Section 5 – Testing and Monitoring Plan illustrates the locations of these USDW monitoring wells. In the event that additional monitoring locations are added during the course of the injection operations under the direction of the UIC Program Manager, this core set of monitoring wells will be updated to reflect the detection monitoring system found sufficient for CO2 plume and pressure front migration evaluation at the close of the injection phase of the Project.

In accordance with 40 CFR 146.93(b)(1), monitoring of the pressure front and CO2 plume will occur for at least 50 years or an alternate duration approved by the UIC Program Director. ExxonMobil is proposing a schedule to submit PISC monitoring results annually and within 30 days of the anniversary date of injection cessation [40 CFR 146.93(a)(2)(iv)].

The following discussion provides details on the elements of the PISC monitoring strategy outlined above.

7.3.1 PISC and Site Closure Plan Reviews and Amendments

As required by 40 CFR 146.93(a)(3), ExxonMobil will submit an amended PISC and Site Closure Plan or demonstrate that no amendment is needed upon cessation of injection. Amendments to the plan, or the demonstration that no revisions are necessary, will be based on monitoring data collected during injection and the most-recent AoR delineation. The plume model will continue to be updated throughout the Project using monitoring information and the AoR reevaluation process and reporting requirements.

During PISC monitoring, ExxonMobil will conduct periodic reviews to incorporate new monitoring data, changes to the site computational model that may warrant changes in PISC monitoring, and/or changes in the methodology proposed to demonstrate non-endangerment of USDW. This approach will also support the use of new technologies that may be available in the future that facilitate a higher level of performance than the existing system. Pursuant to 40 CFR 146.84(e) and as described in Section 4 – Well Construction Plan and Operating Conditions, ExxonMobil will reevaluate the AoR periodically by comparing model predictions with monitoring results. Following an AoR reevaluation process, if the AoR and Corrective Action Plan are

amended, ExxonMobil will review the PISC and Site Closure Plan to determine whether any updates are needed to ensure consistency across all plans. ExxonMobil may submit an amended PISC that describes how changes to the model affect predictions of pressure dissipation, plume migration rates, CO2 trapping, and additional processes that need to be accounted for in the non-endangerment demonstration.

In accordance with 40 CFR 146.93(a)(4), at any time during the life of the Project, ExxonMobil may modify and resubmit the PISC and Site Closure Plan for the UIC Program Director's approval within 30 days of such change.

7.3.2 Monitoring Above the UCCZ and USDW

During the injection phase, periodic monitoring of groundwater quality for significant geochemical changes above the UCCZ is required by 40 CFR 146.90(d) for the purpose of detecting potential leakage through the UCCZ. As described in Section 2 – Site Characterization, the UCCZ is a Claimed as PBI [redacted] In accordance with 40 CFR 146.93(b)(1), groundwater quality and geochemical characteristics will be monitored in the AZMI at In-Zone Monitoring Well No. 01 and in the USDW at USDW Monitoring Wells No. 01, No. 02, and No. 03 during the post-injection period.

ExxonMobil's strategy for monitoring groundwater above the UCCZ is a risk-based approach correlated to modeled CO2 plume and injection zone characteristics. By the time the PISC monitoring program is initiated, the risk mitigating effects of injection sequence plan, the operating strategy, and corrective actions taken on artificial penetrations will likely have demonstrated protection of USDW throughout the operational phase of the Project. The list of analyses to be performed at these monitoring wells is summarized in Table 7-2 based on the same approach used for the operational phase of the Project.

Table 7-3 provides a summary of indirect monitoring technologies to be used for above-zone CO2 plume and pressure front monitoring during the PISC phase of the Project. This monitoring strategy is consistent with the details and rationale provided in Section 5 – Testing and Monitoring Plan of this Application. The results of the monitoring activities will be submitted in the annual report for the year in which they occur and within 30 days of the anniversary date of injection cessation or through an alternate agreed schedule with the UIC Program Director.

Claimed as PBI [redacted]

The analytical methods and quality assurance/quality control measures for collecting and analysis of fluid samples discussed in Section 5 – Testing and Monitoring Plan and will apply to the data collection program of the PISC, as appropriate.

7.3.3 In-Zone CO2 Plume and Pressure Front Tracking

ExxonMobil proposes to use direct and indirect methods to track the extent of the CO2 plume and pressure front in the injection zone during the PISC period. Direct monitoring in the injection zone includes continuous pressure and temperature measurements in the final injection zone for Injection Wells No. 01, No. 02, No. 03, and in Claimed as PBI By the start of the PISC phase of the Project, the direct and indirect monitoring activities will have been used for approximately Claimed years and will be a proven set of monitoring technologies for detection monitoring of CO2 plume and brine crossflow potential.

Table 7-4 describes the proposed CO2 and pressure plume tracking methods for the PISC Plan. The water quality and geochemical parameters to be analyzed are presented in Table 7-5, consistent with Section 5 – Testing and Monitoring Plan where additional information on the monitoring methods described and how deviations would be identified.

Table 7-4: Direct and Indirect In-Zone Monitoring Program for PISC

Monitoring Element	Strategy
Time Period	Immediately following and for up to 50 years from cessation of injection operations.
Monitored Locations, Conditions, and Frequency	Claimed as PBI
Planned Changes in Monitoring Techniques	None. The model-predicted rapid decrease in CO2 plume movement and pressure significantly reduces the potential for USDW endangerment following injection and eliminated need for additional monitoring.
Triggers	Table 3-20 in Section 3 – Area of Review and Corrective Action Plan provides a list of triggers for the AoR reevaluation process. Those triggers are applicable to the monitoring program.
Claimed as PBI	

Claimed as PBI

7.3.4 Submitting PISC Monitoring Results

In accordance with 40 CFR 146.93(a)(2)(iv), ExxonMobil will submit PISC monitoring data to the UIC Program Director in annual reports within 30 days following the anniversary of the date that injection ceases. The annual reports will contain information and data generated during the reporting period, such as:

- A list of monitoring events performed during the reporting period and the associated dates;

- A brief description of sampling/testing/analytical locations, elevations/depths, equipment, and procedures, indicating whether (and why) departures from the procedures specified in the PISC and Site Closure Plan occurred;
- Changes to the monitoring program that took place during the reporting period (e.g., repair to monitoring wells, implementation of approved changes in the frequency of monitoring activities based on criteria established in the PISC and Site Closure Plan and approval of UIC Program Director);
- Synthesis and interpretation of the results that describe trends in parameter values or lack of trends, statistical tests performed, alignment between actual and plume model predictions, the appearance of anomalous or unexpected results, and progress toward attaining the U.S. Environmental Protection Agency (EPA) and Railroad Commission of Texas (RRC) criteria for non-endangerment;
- Map(s) and cross section(s) showing the AoR, monitoring locations, and the interpreted extent of the separate-phase CO2 plume and the pressure front; and
- Any recommended changes to the PISC and Site Closure Plan to continue protection of USDWs.

7.4 Demonstration of Non-Endangerment of USDW

Prior to the approval of the site closure authorization and in accordance with 40 CFR 146.93(b)(2) and 40 CFR 146.93(b)(3), ExxonMobil will provide documentation to assess the potential for USDW to be at risk of endangerment from the CO2 plume at the end of the PISC phase of the Project. The non-endangerment demonstration will be based on monitoring data and a demonstration that the structure of the confining zones, combined with the geochemical conditions of the subsurface, have effectively permanently sequestered the stored CO2. This information will be used to demonstrate that additional monitoring is not needed to protect USDW and the Project has met the compliance obligations to receiving authorization for site closure.

This demonstration will be in the form of a detailed report submitted to the UIC Program Director that synthesizes site- and Project-specific information and demonstrates a current understanding of system behavior at the time of the non-endangerment demonstration. The following subsections outline the type of information to be presented in the non-endangerment demonstration report.

ExxonMobil will engage the UIC Program Director as soon as the available data are aligned with the criteria for site closure, which may ultimately be less than the default PISC duration of 50 years pursuant to 40 CFR 146.93(b)(2) and 40 CFR 146.93(c).

7.4.1 Introduction and Overview for Non-Endangerment Demonstration

A summary of relevant background information will be provided in the introduction section, including the operational history of the injection Project, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

7.4.2 Summary of Existing Monitoring Data

The monitoring data collected throughout the Project's lifecycle will be summarized and used to describe how the UCCZ functioned as a barrier to mitigate endangerment of USDW and how the CO2 is effectively trapped in the injection zones. The non-endangerment demonstration will include a summary of previous monitoring data collected at the site, pursuant to the details in Section 4 – Well Construction Plan and Operating Conditions, and Section 5 – Testing and Monitoring Plan of this Application as well as the PISC and Site Closure Plan. 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 all monitoring events, changes to the monitoring program over time, and an explanation of the monitoring infrastructure that has existed at the site. The data will be compared with baseline data collected during site characterization, including the use of statistical analyses as warranted [40 CFR 146.82(a)(6) and 146.87(d)(3)] to assess trends in key parameters that support the proposal for site closure.

7.4.3 Summary of Computational Modeling History

A series of data sources detailed in Section 5 – Testing and Monitoring Plan of this Application will be used to update the computational model at least once every five years, more frequently if warranted. The following measured data will be utilized to update the computational model to demonstrate non-endangerment:

- In-zone temperature and pressure data;
- Injection rate and volume data;
- CO2 plume location based on indirect geophysical monitoring; and
- AZMI data regarding the performance of the UCCZ.

The procedure used to reevaluate the AoR will be based upon the data collected between reevaluations and the well conditions at the time of reevaluation. The post-injection data will include historical injection rates, pressures, pressure fall-off, and historical operational parameters of the three injection wells. ExxonMobil will rely on a process of history matching the plume model results with the actual monitoring data. The measured data will be used as a calibration point for the plume model and the input parameters adjusted to provide a reasonable match between the two data sets. Through this or a similar process, ExxonMobil will provide a validation of the model performance for the CO2 plume and pressure front.

7.4.4 Evaluation of Reservoir Pressure

The non-endangerment demonstration will include an evaluation of the residual pressure and the potential for future endangerment of USDW continued trends in pressure dissipation. Information will be provided to describe how the pressure and buoyancy effects on plume and pressure migration decayed over time and how the residual levels comply with the requirements for non-endangerment. This evaluation will consider the most-recent AoR delineation/modeling results and pressure monitoring data. The same model that supported the delineation of the AoR or similar approved model by UIC Program Manager will be used for this modeling as it will be verified (or calibrated) by actual monitoring and operational data via AoR reevaluations.

7.4.5 Evaluation of the CO2 Plume

The evaluation of the CO2 plume will evaluate the characteristics of the gas-phase CO2 plume, the aqueous-phase CO2 plume, and the dissolved-phase CO2 plume, as appropriate. The evaluation of the potential CO2 plumes will rely on monitoring data including geochemical and geophysical analyses and the most-recent AoR modeling results. Direct measurements of temperature and pressure of CO2 in the injection zone as well as the results of geophysical measurements will be used to confirm plume location and demonstrate plume migration rates. A comparison of monitoring data with the most-recent modeling results will also be used to corroborate model predictions of the phase-state of CO2 and the degree and processes of CO2 trapping over time.

7.4.6 Evaluation of Emergencies or Other Events

Seven artificial penetrations of the UCCZ were noted in Section 3 – Area of Review and Corrective Action Plan. Claimed as PBI [redacted] and corrosion resistant cement plugs will be placed at multiple intervals to restore the integrity of the UCCZ and protect USDW from crossflow potential. If any subsequent artificial penetrations are discovered to have a potential to threaten USDW, they will have been remediated using the same procedures such that no artificial penetrations of concern remain at the time of site closure.

The data and evaluation methods specified pursuant to the requirements of Section 5 – Testing and Monitoring Plan as well as the PISC Plan provide the basis for demonstrating that no future endangerment of USDW is likely to occur.

7.5 Site Closure Plan

ExxonMobil will conduct site closure activities to meet the requirements of 40 CFR 146.93(d) through (h) as described below. ExxonMobil will submit a final Site Closure Plan and notify the UIC Program Director at least 120 days prior of its intent to close the site. Once the UIC Program Director has approved closure of the site, ExxonMobil will plug all injection and monitoring wells and submit a site closure report to the EPA and RRC. The activities, as described below, represent the planned activities based on information provided to EPA. The actual Site Closure Plan may employ different methods and procedures. 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.

Additionally, ExxonMobil will record a notation on the deed to the site that the land has been used to sequester CO2. Site closure activities will also include removing all surface equipment and restoring the site to its prior land surface condition.

7.5.1 Pre-Closure

In accordance with 40 CFR 146.93(d), a notice of intent to close the site will be submitted to the UIC Director at least 120 days prior to the commencement of closure operations. If any changes are made to the original PISC and Site Closure Plan, a revised plan will also be submitted. Relevant notifications and applications, such as plugging requests, will be submitted and approved by the appropriate agency prior to commencing such activities.

The site closure notice submitted to the UIC Program Director will include the following:

- Facility information, name, and location;

- A list of contact personnel for allowing timely direct communication to resolve any pressing issues; and
- A projected closure date, no less than 120 days following the site closure notification submission, unless the UIC Program Director has approved a different period prior to notice submission.

7.5.2 Plugging Activities

Injection Wells No. 01, No. 02, and No. 03; Claimed as PBI [redacted]) will be plugged as discussed in Section 6 – Injection Well Plugging Plan. After injection in the injection wells ceases and after the appropriate post-injection monitoring period is complete, the monitoring wells will be plugged and abandoned to meet the requirements at 40 CFR 146.92 and in compliance with applicable state requirements. The plugging procedure and materials will be designed to mitigate fluid movement and protect USDW. Prior to plugging the wells, the necessary procedural revisions to address new information will be submitted to the UIC Program Director for review and approval. The final plugging plans will be submitted to the UIC Program Director no later than 60 days prior to plugging of the wells.

Following receipt of the approved plugging plans, wells below the lowermost USDW Claimed as PBI [redacted] feet [ft]) and above the UCCZ will be logged and pressure tested to ensure mechanical integrity. If a loss of mechanical integrity is discovered, it will be repaired prior to proceeding with plugging operations. The casing in these wells will be closed in place and it will not be retrieved at abandonment. A combination of bridge plugs and cement plugs will be set to plug the wells. All casing strings will be cut at least three ft below ground level. A steel plate, with the required permit information, will be welded to the top of the casing, to the extent required by State of Texas requirements.

7.5.3 Site Restoration

Once the injection and monitoring wells are plugged and abandoned, the surface equipment will be decommissioned and removed from the well site. The well site will be restored to a condition agreed upon with the landowner.

7.5.4 Documentation of Site Closure

Within 90 days of site closure, a final report will be submitted to the UIC Program Director per the requirements of 40 CFR 146.93(f) and will include the following:

- Documentation of appropriate injection and monitoring well plugging, including a copy of the survey plats [40 CFR 146.93(f)(1)];
- The survey plat will indicate the locations of the injection wells relative to permanently surveyed benchmarks and will include the location(s) of the monitoring well(s);
- Documentation of well-plugging report will be filed with the RRC [40 CFR 146.93(f)(2)];
- Post-injection monitoring records will be summarized; and
- Records of the nature, composition, and volume of the CO2 stream for the injection period will be summarized [40 CFR 146.93(f)(3)].

Pursuant to 40 CFR 146.93(g), a record of notation in the Project facilities and infrastructure will be filed on the property deed to provide notice to landowners of the following:

- The land use to sequester CO2;
- The name of the state agency with which the survey plat was filed (RRC) and the EPA Regional Office (Region VI) at which it was submitted; and
- The total volume of CO2 injected, the injection zones into which it was injected, and the period over which injection occurred.

As required by 40 CFR 146.93(h), ExxonMobil will retain all records collected during the PISC period for 10 years following site closure. At the end of the retention period, ExxonMobil will deliver all records to the UIC Program Director for retention at a location designated by the UIC Director for that purpose.

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Underground Injection Control – Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

Rose Carbon Capture and Storage Project

Claimed as PBI

ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2024

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

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8.0 Emergency and Remedial Response Plan

This Emergency and Remedial Response Plan (ERRP) was developed in compliance with the requirements of Title 40 Code of Federal Regulations (CFR) 146.94 to develop and maintain an ERRP that describes actions to be taken to address events that may cause endangerment to an underground sources of drinking water (USDWs) during the construction, operation, and post-injection site care periods of the Rose Carbon Capture and Storage (CCS) Project (Project). Under 40 CFR 146.90(g), the actions described in the ERRP are to be implemented immediately to address a rare event where the movement of the injection fluid or formation fluid endangers USDW. ExxonMobil prepared this ERRP to provide both the scope of actions to be taken and the schedule under which the actions would be implemented.

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) is undertaking the Project in Claimed as PBI , to sequester between Claimed as PBI . The ERRP was developed for injection of CO2 into Rose CCS Project Injection Wells No. 01, No. 02, and No. 03, which will sequester a total of approximately Claimed as PBI .

ExxonMobil has already created a number of engineering design and planning safeguards to reduce the potential for a rare emergency and remedial response event from occurring in the first place. These steps are based on ExxonMobil's global experience and expertise with risk management for rare events in site selection, well drilling and completion, and reservoir operations. The risk management approach is evident in the preparation of sections of this Underground Injection Control Class VI Permit Application (Application). Section 2 – Site Characterization describes how the geologic setting is favorable to safe CO2 sequestration because of the favorable injection zone and confining zone characteristics that exist at the site. Section 3 – Area of Review and Corrective Action describes how the CO2 plume and pressure front are predicted to be confined to the injection zone and how pressure will be managed to reduce the potential for leakage to USDWs. The few artificial penetrations through the confining zones will be re-abandoned to safeguard USDWs within the Area of Review (AoR). Section 4 – Well Construction Plan and Operating Conditions describes how the well design process and operating controls for mechanical integrity and pressure control to maintain a high level of risk reduction for the Project. Lastly, Section 5 – Testing and Monitoring Plan, provides the data acquisition plan for tracking the CO2 plume and brine pressure front to assess compliance with control and containment requirements.

The purpose of this section is to provide the elements of the risk management process undertaken for the Project so that the underground injection control (UIC) Program Director can ultimately approve the remedial and response actions in advance. Once approved, ExxonMobil will be prepared to implement the actions necessary to facilitate and expedite response efforts for the rare occurrence of a leak from the injection zone. The ERRP will apply over the life of the Project, including throughout the post-injection site care period [40 CFR 146.94(a)].

8.1 Objectives

The ERRP is a risk-based document that identifies a set of hypothetical potential risk scenarios that could create an endangerment to USDWs and the actions to be taken to mitigate such risk. The objectives of the ERRP are aligned with the requirements of 40 CFR 146.94, which include:

- Identify potential risk scenarios and adverse events that could impact USDW in the AoR. The assessment focuses on those events that were found to have a combined probability and consequence that makes them more likely to have an impact than other factors.
- Provide a description of the response actions necessary to reduce the potential consequences to USDWs. For each scenario considered to be of material concern, describe the anticipated severity of the event, the phase during which the event could occur (i.e., construction, injection and/or post-injection phases), the proposed avoidance measures, what methods will detect the loss of containment or control, the response actions, notification requirements, and personnel and equipment that would be employed to mitigate the risk; and
- Provide contact information for response personnel, a communications plan, and a description of staff training and exercise procedures.

8.2 Overview of Risk Management Process

ExxonMobil took the findings from the site characterization, AoR, and corrective action sections of the Application and identified hypothetical risk scenarios that could pose a threat to USDWs in the rare event of occurrence. ExxonMobil's risk assessment process was used to estimate the probability and consequence of each risk scenario based on the experience and judgment of the risk subject matter experts for the Project. The list was sorted from the most probable and consequential risk scenario to the least probable and consequential scenarios so that the critical scenarios could be identified and the response actions to be undertaken.

As shown in Figure 8-1 below, the maximum anticipated risk level for the Project, including the combination of the selected risk scenarios for the ERRP, is within the medium risk category. As mentioned above, a number of risk management steps were already taken to address the potential for CO2 or brine migration to occur.

Claimed as PBI

Claimed as PBI The potential for these features in the upper composite confining zone (UCCZ) to become a migration pathway for a release of CO2 were mitigated by planning for the following actions described in the Application:

- Artificial penetrations through the UCCZ will be re-abandoned to restore containment integrity at each artificial penetration location where the potential for elevated crossflow risk was identified;
- The maximum injection pressure will be maintained below the potential hydraulic fracturing or activation pressure of a natural fault to mitigate the potential for CO2/brine leaks through seal(s) due to mechanical fracturing or migration of CO2/brine along faults;
- State-of-the-art injection well and monitoring well construction methods and mechanical integrity testing (MIT) will be employed to reduce the potential for the loss of internal or external mechanical integrity, which could potentially release CO2 to USDWs or the atmosphere;
- The composition of the injectate stream will be managed and monitored such that unexpected reactions with the potential to impact containment are mitigated;
- CO2 plume and pressure front tracking will be undertaken using a combination of direct and indirect measurements and reported semiannual for review and consideration in AoR reevaluations, at a minimum frequency of every five years; and

- The predictive reservoir modeling will be calibrated and verified using monitoring data to identify the potential for the CO2 plume and pressure front to encounter artificial penetrations that have the potential for CO2 or brine crossflow from the injection intervals to the lowermost USDW and take preventive measures before such an event could occur.

8.3 Identification of Resources/Infrastructure in Area of Review

Claimed as PBI [redacted] The infrastructure development is primarily in the form of county roads and power transmission lines to service the few developed areas.

The water resources in the vicinity of the Project that may be affected by a rare CO2 or brine leakage event that endangers USDW include water wells completed in the Chicot and Evangeline Aquifers above a depth of approximately Claimed as PBI [redacted] which is the lowermost USDW within the AoR.

A total of three water wells were reported to be present within the AoR. A plugged/destroyed water well Claimed as PBI [redacted] was reportedly located Claimed as PBI of Injection Well No. 01. Other water wells reported as plugged/destroyed include Claimed as PBI [redacted], and an unused water well Claimed as PBI [redacted]. One active water well (State Claimed as PBI [redacted]) was reported near the AoR.

Two water conveyance features were identified as the Gallier Canal and Green Pond Gully.

A total of nine oil and gas wells were identified within the AoR, and all were reported as plugged and abandoned in the available records from the Railroad Commission of Texas. Beyond the AoR, the City of Beaumont, Texas, is located more than 5 miles northeast of the AoR boundary and the Town of China, Texas, is located approximately 1 mile northwest of the AoR boundary.

8.4 Identification of Risk Scenarios of Interest

Through the risk assessment process, the following list of scenarios were considered of material probability and consequence as to warrant development of response action plans. Other scenarios were considered but were found to have relatively low probability and consequence factors and do not warrant further consideration at this time. As shown below, a total of nine risk scenarios were considered of material probability and consequence for the ERRP.

Claimed as PBI [redacted]

Claimed as PBI

Claimed as PBI

[redacted]

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8.5 Use of Severity to Define Scope of Response Action

Response actions were developed for each of the nine hypothetical risk scenarios identified for the ERRP. As listed in Table 8-2, the severity of the risk scenario was fit to a three-tiered categorization of emergency conditions. In addition, the response actions envision a stage-gate process where the information regarding the degree of severity for the emergency condition is evaluated to align the appropriate level of response to bring about mitigation of the emergency event.

Table 8-2: Degrees of Risk for Emergency Events

Emergency Condition	Definition
Major emergency	Events pose immediate substantial risk to USDWs and indirectly from USDW endangerment to resources or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) must be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to USDW and indirectly from USDW endangerment to resource or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to USDW, resources, or infrastructure.

In accordance with 40 CFR 146.94(b), for the events below, if the injected CO2 stream and associated brine pressure front may cause an endangerment to a USDW, each set of response actions start with immediately ceasing injection and notifying the UIC Program Director within 24 hours of the confirmation of a release event and the intention to implement the appropriate response action in the ERRP.

8.6 Response Plans for Risk Scenarios

The following response action details are provided to have a pre-approved set of actions in place should measurements collected pursuant to the Section 5 – Testing and Monitoring Plan indicate a malfunction or deviation from permitted limits.

8.6.1 Integrity of Injection Well Casing or Cement Seal

Two hypothetical release mechanisms were identified for injection wells that could possibly result in a release of CO2 and/or brine to USDWs. CO2 could be detected at an injection well, implying that internal or external mechanical integrity of an injection well may have been compromised and released CO2 to USDWs. CO2 or brine could also be released to USDW at the injection well because of subsurface cement degradation or annular space defects in cement completion.

Hypothetical Release Mechanism: mechanical integrity failure at injection well resulting in release of CO2 and/or CO2 and/or brine to USDWs.
Severity:
• Minor: A malfunction in the monitoring equipment created a false positive indication of a release when in fact none occurred. Alternatively, detection monitoring equipment at the wellhead facility detects the release and the well was shut-in, representing a minor CO2 release.

• Serious: A failed MIT identified a release mechanism, but detection of brine or CO2 was not apparent in the detection monitoring system.
• Major: A detection of CO2 and/or brine to USDW within the AoR prior to confirming the source of the injection well release point.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Proper wellbore design, including the use of corrosion resistant cement and CO2 compatible metallurgy of the casing and tubing, will be used for construction of the injection well.
• Routine inspection of the well casing and cement integrity to identify potential corrosion or deficiencies.
Detection methods:
• Deficiency identified during continuous pressure and temperature monitoring, pressure falloff tests, and annulus pressure tests.
• Wellhead pressure exceeds the maximum pressure specified in the permit.
• Annulus pressure indicates a loss of external or internal integrity/containment.
• CO2 plume and pressure tracking above UCCZ indicates a change in conditions.
• Fluid samples from above the UCCZ and USDW indicate a statistically significant change in conditions.
• MIT identifies a potential issue in the integrity of the well.
• Well casing and cement bond logs conducted during shut-ins to assess loss decay or corrosion more than acceptable limits.
Response actions:
• Notify ExxonMobil Site Manager and site personnel.
○ The Site Manager will respond to the event for an initial assessment to determine severity of event.
• Minor Event:
Claimed as PBI

Claimed as PBI

- Serious or Major Event:

Claimed as PBI

Personnel: Emergency response personnel, geotechnical professionals, and environmental or water-treatment professionals.
Equipment: Drill rig, logging equipment for cement or casing materials, MIT equipment, environmental media sampling equipment, well plugging equipment.

8.6.2 Integrity of Injection Well Casing or Cement Seal for Legacy Wells

Consistent with the potential for CO2 or brine to migrate to USDW at an injection well, artificial penetrations of the UCCZ from legacy oil and gas activities may provide a similar risk scenario. Legacy wells were identified within the AoR that penetrate the UCCZ. The plugging of [redacted] legacy wells will be recompleted as a corrective action prior to operation. [redacted] remaining legacy wells are present, of which [redacted] are proposed for phased corrective action and [redacted] wells were found to have sufficient casing and cement plugs to protect USDW. The objective of this risk scenario is to provide the response actions in the event that legacy wells are suspected of CO2 and/or brine leakage to USDWs because of casing or cement integrity issues that are detected in the AoR.

Hypothetical Release Mechanism: CO2 and/or brine migrate to USDW at an artificial penetration as detected within the AoR.
Severity:
• Minor: direct and indirect CO2 plume and pressure front tracking indicate that the legacy well is in the path of migration with the potential to create elevated pressures and a potential for corrosive environment to be created at the well location.
• Serious: direct and indirect CO2 plume and pressure front tracking indicate that the legacy well has been impacted with minor increases of CO2 and/or brine pressures and corrosive fluids.
• Major: direct and indirect CO2 plume and pressure front tracking indicate that the legacy well has been impacted by significantly elevated pressures and a corrosive environment is present that could create a crossflow potential between the injection zone and USDW if a conduit were present.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Compliance with CO2 plume and brine tracking systems.
• Plume model updates to predict pressure front arrival times at legacy well locations and adjust timing of phased corrective action.
Detection methods:
• CO2 plume and pressure tracking indicates impact is likely.

• Fluid samples from above the UCCZ and USDW indicate a statistically significant change in conditions.
• Well re-entry to collect casing and cement bond logs to assess integrity and well completion materials.
Response actions:
For minor severity Claimed as PBI [redacted]
For major and serious events:
Claimed as PBI [redacted]
Personnel: Emergency response personnel, geotechnical professionals, and environmental or water-treatment professionals.
Equipment: Drill rig, logging equipment for cement or casing materials, MIT equipment, environmental media sampling equipment, well plugging equipment.

8.6.3 Injection Well Monitoring Equipment Failure

Loss of mechanical integrity of well pressure equipment may occur during operation of the injection wells. A pressure gauge malfunction or other similar equipment could create a shut-off valve malfunction and result in an uncontrolled pressure situation and CO2/brine crossflow to USDW by fault or fracture activation or well casing and/or cement failure in the vicinity of the production casing perforations.

Hypothetical Release Mechanism: Loss of mechanical integrity of well pressure equipment could create a shut-off valve malfunction and result in an uncontrolled pressure situation and CO2/brine crossflow to USDW by fault or fracture activation or by well casing and/or cement failure in the vicinity of the production casing perforations.
Severity:
• Minor: Failure of monitoring equipment to document compliance with permit operating conditions, but subsequent evaluation of available information demonstrates that well integrity has not been impacted.
• Serious/Major: Failure of monitoring equipment to document permit operating conditions and subsequent evaluation of the data documents non-compliance with permitted operating conditions and potential for well integrity impacts.
Timing of event: Injection phase and/or post-injection phase.
Avoidance measures:
• Routine equipment inspection and maintenance to identify potential integrity issues that may be a result of equipment failure.
• Routine inspections and calibration of monitoring equipment in accordance with manufacturers recommended procedures.
• Consistent fluid sampling throughout the detection monitoring well network to detect a release above the UCCZ.
• Redundant pressure and temperature measurements in the injection zones to confirm compliance with permitted operating conditions.
Detection methods:
• Anomalies in pressure and rate monitoring, pressure falloff tests, and annulus pressure tests.
Response actions:
• Notify ExxonMobil Site Manager and site personnel.

- The Site Manager will respond to the event for an initial assessment to determine severity of event.

- Notify the UIC Director within 24 hours per 40 CFR 146.91(c).

- Determine the cause and severity of failure to determine if the CO2 stream or formation fluids may have been released into any unauthorized zone.

- For a Minor emergency Claimed as PBI [redacted]

[redacted]
Claimed as PBI

- For a Major or Serious emergency Claimed as PBI [redacted]

[redacted]
Claimed as PBI

Claimed as PBI
Personnel: Emergency response personnel, geotechnical professionals, and environmental or water-treatment professionals.
Equipment: Drill rig, logging equipment, cement or casing materials, and air and water testing equipment.

8.6.4 Integrity of the UCCZ

Several potential risk scenarios were considered that involve a hypothetical release through naturally occurring faults and fractures or penetration of the UCCZ, creating a migration pathway toward USDW. For example, CO2 could hypothetically leak through natural faults or fractures in the UCCZ within or beyond the AoR and impact USDWs. CO2 or brine could hypothetically migrate horizontally to artificial penetrations within or beyond the AoR that are not sealed at the UCCZ and result in a release to USDWs. Response actions were developed to address such scenarios in the rare event that they occur.

The primary limiting factor for the magnitude of the release for these scenarios was based on the site characteristics described in Section 2 – Site Characterization. CO2 and brine leaks through shales due to mechanical fracturing were not considered a material concern for the Project because of the physical nature of the confining shale materials. Above the UCCZ is approximately Claimed as PBI feet of saturated shale and sand. Such a release would likely be detected by the detection monitoring program for groundwater prior to release to the surface. Therefore, ambient air monitoring in the AoR was contingent on the confirmed release of CO2 to USDW at sufficient concentrations to migrate to the surface at levels above health-based thresholds.

The following response actions were developed to mitigate the potential for releases through the UCCZ, which were assumed to occur during injection operations and/or post-injection site care.

Hypothetical Release Mechanism: release through naturally occurring faults and fractures or penetration of the UCCZ, creating a migration pathway toward USDWs.
Severity:
• Minor: direct and indirect CO2 plume and pressure front tracking indicate that a fault or fracture is in the path of migration with the potential to create elevated pressures sufficient to cause crossflow above the UCCZ.
• Serious: direct and indirect CO2 plume and pressure front tracking indicate that a fault or fracture has been impacted with minor increases of pressures.
• Major: direct and indirect CO2 plume and pressure front tracking indicate that a fault or fracture has been impacted by significantly elevated pressures that will likely create a crossflow potential between the injection zone and USDW.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Compliance with CO2 plume and brine tracking systems.
• Plume model updates to predict pressure front arrival times at fault and fracture locations and adjust timing of phased detection monitoring programs elements.
Detection methods:
• CO2 plume and pressure tracking indicates impact is likely.
• Fluid samples from above the UCCZ and USDW indicate a statistically significant change in conditions.
• Third-party direct or indirect data confirm impact to fault, fracture, or artificial penetration outside of AoR.
Response actions:
• In the event that the detection monitoring program outline in the Section 5 – Testing and Monitoring Plan or similar third-party monitoring program detects a confirmed release of CO2 or brine through the UCCZ to the first water-bearing zone above the UCCZ or USDW, notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
• Determine the severity of the event, based on the information available, within 24 hours of notification.
• For all emergencies (Major, Serious, or Minor):
[redacted]

Claimed as PBI

Claimed as PBI

Personnel: Emergency response personnel, geotechnical professionals, and environmental or water-treatment professionals.
Equipment: Drill rig, logging equipment, cement or casing materials, and air and water testing equipment.

8.6.5 Induced or Natural Seismic Event

Natural or induced seismic events of sufficient magnitude to create damage were found to be highly improbable for the site location and under permitted operating conditions that are below the critical fracture pressure. In the very rare chance that such seismic conditions occurred, the consequences could be of significance regarding the integrity of the artificial penetrations of the UCCZ and the natural faults and fractures. Therefore, the following response actions were developed to gather information regarding the potential for CO2 and brine confinement issues to arise under such events.

ExxonMobil will rely upon U.S. Geologic Survey seismic monitoring data for the site and surrounding area to provide information on a seismic event, should one occur. If a review of the data indicates that the event was more likely than not associated with the injection zone in or near the AoR, ExxonMobil will notify the UIC Program Director of the intent to install a site-specific network of seismic stations to provide additional information with the regional seismic data. The details of the site-specific seismic monitoring system will be provided to the UIC Program Director as a modification of Section 5 – Testing and Monitoring Plan. Table 8-3 provides the response actions depending on severity of the seismic event.

Claimed as PBI

[redacted]

[1] Specified magnitudes determined by local or U.S. Geological Survey (USGS) seismic monitoring stations or reported by the USGS National Earthquake Information Center (NEIC) using the national seismic network.

Claimed as PBI

8.7 Response Personnel and Equipment

Site personnel, Project personnel, and local authorities will be relied upon to implement this ERRP and will be dispatched in the case of an emergency. In the event of an emergency, appropriate city, county, and state emergency responders and agencies may be notified based on severity of the risk. Contact information for ExxonMobil Emergency Authorities and state and local emergency services are outlined in Table 8-4 and Table 8-5, respectively.

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

Table 8-4: Contact Information of ExxonMobil Emergency Authorities

Name	Title	Telephone Number
Claimed as PBI	LCS USGC Venture Executive	Claimed as PBI
Claimed as PBI	Emergency Response & Preparedness Manager	Claimed as PBI
Claimed as PBI	Public & Government Affairs Advisor	Claimed as PBI

Table 8-5: Emergency Services

Agency	Telephone Number
Claimed as PBI	Claimed as PBI
Texas Division of Emergency Management	(512) 424-2208
Texas Department of Public Safety	(512) 424-2000
State of Texas Spill-Reporting Hotline	1-800-832-8224
Texas Parks and Wildlife Department	(512) 389-4800
EPA Region 6	800-887-6063 or 214-665-2760
EPA Class VI Contact – Brandon Maples	214-665-7252
Texas Department of Natural Resources	(512) 389-4800
Claimed as PBI	
National Response Center	1-800-424-8802
State of Texas Spill-Reporting Hotline	1-800-832-8224
EPA National Response Center (24 hours)	(800) 424-8802

Necessary equipment for emergency and remedial response may vary depending on the event. Generally, no specialized equipment will be required for response actions (such as cessation of injection, well shut-in, and evacuation). If specialized equipment (such as a drilling rig or logging equipment) is required, ExxonMobil will be responsible for its procurement.

8.8 Communications Plan and Emergency Notification Procedures

As appropriate, ExxonMobil will communicate to the relevant public authorities about an event that may require emergency response so that the public understands the emergency event and if there are any environmental, health, or safety concerns. Based on the emergency event, ExxonMobil will determine the appropriate information, timing, and communication method for the event. This information may include potential impact of the event on drinking water or the severity of the event, actions taken or planned to address the event, and other information needed to protect the public during the event.

If required, ExxonMobil will also communicate with other entities who may need to be informed about or act in response to the event. These may include local water purveyors or operators, CO2 suppliers, pipeline operators, oil and gas operators, landowners, and other departments or authorities as guided by the UIC Program Director.

8.9 Flood Hazard Risk

Injection Wells No. 01, No. 02, and No. 03 and the surrounding area are designated as Federal Emergency Management Agency flood hazard zone X (unshaded). Flood hazard zone “X” (unshaded) corresponds to areas determined to be outside of the 500-year floodplain. This zone is an area of minimal flood hazard, which is higher than the elevation of the 0.2-percent-annual-chance flood. The well locations and Federal Emergency Management Agency flood zones are shown in Appendix E.

8.10 Plan Review

The UIC Program Director will evaluate this proposed ERRP to verify that ERRP meets the requirements of 40 CFR 146.94(a) and that the plan accounts for all site-specific conditions. The approved ERRP is enforceable, whether or not it is a condition of the permit, because the plan itself and UIC Program Director’s approval are required by the Class VI Rule [40 CFR 146.93(a)].

This ERRP shall be reviewed:

- At least once every five years following its approval by the permitting agency [40 CFR 146.94(d)].
- Within one year of any AoR reevaluation [40 CFR 146.94(d)(1)].
- Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director [40 CFR 146.94(d)(2)]; or
- When required by the Director [40 CFR 146.94(d)(3)].

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

amendments shall be made and submitted to the permitting agency within 30 days following an event that initiates the ERRP review procedure.

The amended plan must be approved by the UIC Program Director and would then be incorporated into the Class VI Permit. If significant changes to the plan are needed, the UIC Program Director may need to modify the permit. A permit modification under 40 CFR 144.39 would require notification of the public and an opportunity for comment. Minor changes to the plan, as defined under 40 CFR 144.41, do not require a permit modification or a public process under 40 CFR Part 124.

8.11 Staff Training and Exercise Procedures

Personnel will be trained in their duties and responsibilities related to these facilities. Emergency Response Drills will be conducted annually via simulated onsite or table top scenarios. All plant personnel, visitors, and contractors must complete a plant overview orientation before entering the facilities. ExxonMobil will coordinate with local mutual aid emergency responders over the potential hazards and response scenarios of the site.

Underground Injection Control – Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 9 – FINANCIAL ASSURANCE

Rose Carbon Capture and Storage Project

Claimed as PBI

ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2024

SECTION 9 – FINANCIAL ASSURANCE

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Appendix J – Financial Assurance

Claimed as PBI

9.0 Financial Assurance

Under Title 40 U.S. Code of Federal Regulations (40 CFR) 146.85, owners or operators of geologic sequestration (GS) injection wells are required to demonstrate financial responsibility for GS activities[1]. ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) plans to construct three Class VI injection wells as part of the Rose Carbon Capture and Storage (CCS) Project (Project) for the purpose of sequestering approximately Claimed as PBI Claimed as PBI. Consistent with these regulatory requirements, ExxonMobil has prepared this document to demonstrate financial responsibility for the injection wells that comprise the Rose CCS Project (Rose Site[2]).

The sections that follow summarize the Project's GS activities, as well as the qualifying financial instrument that ExxonMobil proposes to use, to demonstrate financial responsibility for the following Project phases: (1) Corrective Action; (2) Injection Well Plugging; (3) Post-Injection Site Care (PISC) and Site Closure; and (4) Emergency and Remedial Response (ERR).

9.1 Facility Information

Facility Name:	ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) – Rose
Facility Contact:	Claimed as PBI ExxonMobil Low Carbon Solutions Onshore Storage LLC
Project Site Name:	Rose Carbon Capture and Storage Project
Project Location: Rose CCS Project Injection Well No. 01 Rose CCS Project Injection Well No. 02	Claimed as PBI

[1] The use of the term "geologic sequestration activities" is unique to this section of the Application. It is used to provide additional clarity on which activities of the Project's lifecycle necessitate financial assurance from those that do not, consistent with U.S. Environmental Protection Agency guidance for financial assurance.

[2] Reference to the Project as the "Rose Site" is used in this section of the Application to distinguish between this Project and other future ExxonMobil project applications undergoing simultaneous financial assurance review.

Rose CCS Project Injection Well No. 03

Claimed as PBI

9.2 Financial Assurance Demonstration

Per 40 CFR 146.85(a)(1)(v), ExxonMobil requests approval from the underground injection control program (UIC) Program Director, or their designee, to use a corporate guarantee from Exxon Equity Holding Company (EEHC) for purposes of demonstrating financial responsibility for Corrective Action, Injection Well Plugging, PISC and Site Closure, as well as ERR. EEHC is an indirectly wholly owned subsidiary of Exxon Mobil Corporation (EMC), which provides financial support to or on behalf of its affiliates. EEHC maintains significant intercompany relationships with EMC and its affiliates as shown in Figure 9-1, and as of December 31, 2022, the company had interest-bearing deposits with EMC and its affiliates totaling $8,348,583,000. The deposit balances are current and can be called upon demand. See Appendix J-1 for a copy of the independently audited financial statements for EEHC.

Claimed as PBI

In support of the financial assurance demonstration, EEHC has provided a corporate guarantee to ExxonMobil, which is consistent in form to the corporate guarantee language included in Appendix B of the U.S. Environmental Protection Agency's (EPA's) July 2011 guidance document.[3] See Appendix J-2 for a copy of the executed corporate guarantee. As shown in

[3] U.S. Environmental Protection Agency. *Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Financial Responsibility Guidance* (July 2011). PA 816-R-11-005. B-22 Appendix B: Recommended Financial Responsibility Instrument Language (Forms/Templates). https://www.epa.gov/system/files/documents/2022-11/uicfinancialresponsibilityguidancefinal072011v_0.pdf

Table 9-1, EEHC satisfies both Part 1 and Part 2 of the corporate financial test criteria in 40 CFR 146.85(a)(6)(v).

Table 9-1: Financial Coverage and Threshold Criteria for EEHC, as Guarantor to ExxonMobil for the Rose Site

Financial Coverage / Threshold Requirement per §146.85(a)(6)(v)[4]	EEHC Financial Measure
Part 1	
1. Tangible net worth of at least $100 million?[5]	[redacted]
2. Net working capital at least six times the sum of the current corrective action, well plugging, PISC and site closure, and ERR costs?	[redacted]
3. Tangible net worth of at least six times the sum of the current corrective action, well plugging, PISC and site closure, and ERR costs?	[redacted]
4. Assets in the United States amounting to at least 90% of total assets or Assets in the United States amounting to at least six times the sum of the current corrective action, well plugging, PISC and site closure, and ERR cost estimate?	[redacted]
Part 2	
5. Total liabilities to net worth ratio less than 2.0?	[redacted]
6. Current assets to current liabilities ratio greater than 1.5?	[redacted]
7. Sum of net income plus depreciation, depletion, and amortization to total liabilities ratio greater than 0.1?	[redacted]
8. Current assets minus current liabilities to total assets ratio greater than *minus* 0.1?	[redacted]
9. Net profit (revenues minus expenses) greater than $0?	[redacted]

Appendix J-3 is a completed letter from [redacted] of EEHC, serving as the Chief Financial Officer of EEHC, that demonstrates the company's ability to meet the requisite financial coverage and threshold criteria, per 40 CFR 146.85(a)(6)(v). Appendix J-3 is consistent in form to the "Letter from Chief Financial Officer" included in Appendix B of the EPA's July 2011 guidance document.[6]

Consistent with the EPA's July 2011 guidance, ExxonMobil provides this demonstration of fiscal responsibility with the understanding that the financial instruments referenced herein will be updated and verified no less than annually. As each GS activity phase is initiated, ExxonMobil

[4] As stated in Note 3 of EEHC's independently audited financial statements, *Deposits receivable from Exxon Mobil Corporation and affiliates* are current and can be called upon demand. All other assets were considered "non-current" for the purposes of this analysis. In addition, all liabilities were considered "current" since the audited financial statements do not differentiate current from non-current liabilities.

[5] ExxonMobil recognizes that 40 CFR 146.85(a)(6)(v) requires that its guarantor meet a Tangible Net Worth of an amount approved by the UIC Program Director. For purposes of this financial assurance demonstration, EEHC affirms that it maintains a Tangible Net Worth of at least $100 million, per the recommended threshold included in EPA's July 2011 Class VI financial responsibility guidance (p. 15).

[6] *op.cit.* See B-19 Appendix B: Recommended Financial Responsibility Instrument Language (Forms/Templates).

will confirm that the coverage limits provided by the respective financial responsibility instruments are sufficient to cover the corresponding costs prior to initiating the Project phase.

9.3 Estimated Coverage Amounts

The total current cost estimate for the Project's GS activities necessitating financial assurance at the Rose Site is Claimed as PBI in 2024 dollars. This total cost estimate assumes the hiring of independent, third-party contractors to perform the required activities for each Project phase. The cost estimate is separated into the following phases[7]:

Claimed as PBI

Table 9-2 summarizes the total estimated cost of performing each GS activity, along with the timeline for which financial assurance coverage is expected to be needed. The values included in this demonstration of financial responsibility are based on cost estimates developed as part of the permit application process and assume the hiring of third-party contractors to perform the services or to procure the goods associated with the performance of each GS activity. These values are subject to change during the life of the Project to account for inflation of costs and changes to the Project that may affect the cost of covered activities. Per 40 CFR 146.85(c), during the active life of the Project, ExxonMobil will adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial assurance instrument. In addition, ExxonMobil will provide to the UIC Program Director written updates of adjustments to the cost estimate within 60 days of any amendments to the AoR and Corrective Action Plan [40 CFR 146.84], the injection well plugging plan [40 CFR 146.92], the PISC and Site Closure Plan [40 CFR 146.93], and the emergency and remedial response plan (ERRP) [40 CFR 146.94].

ExxonMobil will adjust the value of its financial assurance instruments in response to any changes in cost estimates and will resubmit its revised demonstration of financial responsibility to the UIC Program Director or their designee for review and approval. ExxonMobil will not adjust the established coverage values of any financial assurance instrument without prior approval from the UIC Program Director, or their designee.

[7] Assumes receipt of permit in 2026, start of injection in 2026, and 16 years of injection.

[8] Financial responsibility coverages for well plugging reflect the current estimated cost for plugging the three injection wells and four monitoring wells related to the Project.

Claimed as PBI

9.4 Corrective Action

The Corrective Action Plan is discussed in detail in Section 3 – Area of Review and Corrective Action Plan. Per the requirements of 40 CFR 146.84, the plan specifically outlines both a plugging plan for the artificial penetrations found within CO2 plume and brine pressure front and the recompletion schedule whereby the wellbore modifications will have been completed.

For the planned activities at the Project, workovers on the legacy wells found to have sufficient deficiency as to represent a potential loss of CO2 or brine containment will be re-entered and plugged prior to receiving approval to inject from the UIC Program Director. Claimed as PBI Claimed as PBI The estimated financial assurance coverage value for this GS activity includes costs associated with the two legacy wells as shown in Table 9-3.

Per 40 CFR 146.84(a)(5)(ii), this financial responsibility demonstration will be updated annually to account for any changes in expected financial coverage values and to confirm that the financial instrument(s) then in place remain adequate for use.

Claimed as PBI

9.5 Well Plugging

9.5.1 Injection Well Plugging

Plugging and abandonment (P&A) of the injection wells at the Project will meet the requirements of 40 CFR 146.92. The P&A plan for the injection wells was designed to reduce the potential for movement of CO2 or brine from the injection interval through the upper composite confining zone (UCCZ) and toward underground sources of drinking water (USDWs).

A detailed P&A plan is discussed in Section 6 – Injection Well Plugging Plan. In alignment with the requirements for the P&A plan, the estimated financial assurance coverage value includes costs for logs/wireline to be run in the wellbore before cementing occurs, if necessary. CO2-compatible cement will be used to set the cement plug for the first Claimed as PBI , followed by additional plugs at the base of the lowermost USDW and at the well surface. The expenses relating to personnel and equipment have been accounted for in Table 9-3.

9.5.2 Monitoring Well Plugging

P&A of the Claimed as PBI associated with the Project will also meet the requirements of 40 CFR 146.92. As detailed in Section 6 – Injection Well Plugging Plan, the P&A of the monitoring wells was designed to protect USDW from potential endangerment. The estimated financial assurance coverage value for this GS activity includes the costs for logs and wireline to be run in the in-zone monitoring well before cementing occurs to the extent necessary. The expenses relating to personnel and equipment have been accounted for in Table 9-4.

9.6 Post-Injection Site Care and Site Closure Plan

The PISC and Site Closure Plan has been designed to meet the requirements of 40 CFR 146.93. The estimated financial assurance coverage value for this GS activity includes the cost categories summarized in Table 9-5, while the plan itself is discussed in Section 7 – Post-Injection Site Care and Site Closure Plan.

9.6.1 Post-Injection Monitoring

As discussed in Section 5 – Testing and Monitoring Plan, vertical seismic profile (VSP) and pressure and temperature monitoring will be conducted during operation and after the end of injection to assess the integrity of the well and to track the migration of the CO2 plume and brine pressure front.

9.6.2 Site Closure Plan

Site closure will occur when the UIC Program Director has released the owner from PISC duties and the demonstration of non-endangerment for USDWs has been approved. The estimated financial assurance coverage value for this GS activity is summarized in Table 9-5 and reflects the expected amount to decommission and close the site.

9.7 Emergency and Remedial Response

The ERRP is discussed in Section 8 – Emergency and Remedial Response Plan and is designed to satisfy the requirements of 40 CFR 146.94, which necessitates an ERRP that describes actions ExxonMobil will take to address movement of injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and PISC periods.

The financial assurance coverage value for ERR is estimated to be Claimed as PBI in 2024 dollars and is summarized in Table 9-6. This estimate assumes coverage for the following event-based risk activities at the Project: mechanical integrity of injection well casing or cement seal, artificial penetrations of the UCCZ, mechanical integrity of operating equipment, and natural features affecting sealing properties of the UCCZ. Details regarding the approach used to develop the risk-based scenarios, the levels of severity considered, and the actions to be taken to avoid, monitor, respond, and notify the occurrence of risk events are summarized in detail in Section 8.

Claimed as PBI

Appendix J contains the following documents:

Claimed as PBI

CONFIDENTIAL BUSINESS INFORMATION

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Underground Injection Control – Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 10 - ENVIRONMENTAL JUSTICE

Rose Carbon Capture and Storage Project

Claimed as PBI

ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2024

SECTION 10 – ENVIRONMENTAL JUSTICE[1]

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[1] Note: Applicant is including this analysis due to its commitment to, and the importance of, community engagement in the Class VI well permitting process, as well as existing federal guidance. Applicant reserves the right in the future to revise this analysis if interpretation or implementation of federal law or regulation should change.

Appendix K – Environmental Justice

Claimed as PBI

10.0 Environment Justice

This Environmental Justice (EJ) Screening Report (the Report) for the proposed Rose Carbon Capture and Storage Project (Project) is an initial desktop assessment of potential EJ-related concerns for the area in which the Project will be located and will continue to be refined throughout the life of the Project. The Report identifies community characteristics useful in guiding engagement through Project planning, permitting, construction, operation, and decommissioning.

ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) anticipates that activities supporting Project development will be supportive of the environmental and socioeconomic needs of the communities in which the Project will operate. In addition, ExxonMobil will develop a Stakeholder Engagement Plan to facilitate meaningful community engagement with local leaders, residents, economic developers, environmental organizations, and others. Consistent with ExxonMobil's socioeconomic management principles,[2] a stakeholder grievance process is also under development that will allow stakeholders to have access to ExxonMobil throughout the Project lifecycle.

The Report includes the use of an initial "EJ Study Area" to assess the presence of communities that may be associated with potential EJ concerns. The EJ Study Area comprises the area within a 2-mile radius around the Project Footprint. The Project Footprint is the physical area that will be occupied by the Project operations facilities or disturbed by Project construction or operations activities.[3] A radius of 2 miles was selected for the EJ Study Area because the bulk of construction and operation activities for the Project are expected to be concentrated within this area. The EJ Study Area includes 14 Census Block Groups (CBGs)[4] and these are all located in Jefferson County (EPA, 2023a) (Figure 10-1). Although a small portion of Claimed as PBI [redacted] falls within a 2-mile radius of the Project Footprint, this CBG was not included based on the relatively small amount of the CBG within the 2-mile radius. As the Project is defined in further detail and community engagement continues, it is possible that additional CBGs may warrant assessment.

[2] https://corporate.exxonmobil.com/news/reporting-and-publications/sustainability-report/social/socioeconomic-management/community-engagement-and-grievance-management#Objectives

[3] For the purpose of this Report, the Project Footprint does not include the existing roadways that will be used to transport Project construction materials or workers.

[4] A CBG is the smallest geographic unit used by the U.S. Census Bureau to collect data for decennial census data. A CBG consists of Block Groups (BGs) within Census Tracts (CTs). Throughout this EJ Report, individual CBGs are referred to by an identifier in the form "CT XXX BG X."

Claimed as PBI

10.1 Executive Summary

This Report employs the use of U.S. Census and other data for early identification of potential Project-related impacts and opportunities associated with potential EJ concerns. The [redacted] CBGs within the EJ Study Area demonstrate a range of socioeconomic characteristics. Based on an analysis of the data provided in this Report, the following are noted:

10.2 Methodology

The U.S. Environmental Protection Agency (EPA) defines EJ as the:

> "[F]air treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. This goal will be achieved when everyone enjoys:

[5] For each CBG, each environmental indicator has its own EJ Index, which combines the demographic index (which averages low-income and people of color populations) with the respective environmental indicator percentile value for the CBG. For example, the EJ index for traffic for a given CBG is calculated as (traffic indicator percentile for the CBG) x (average of low-income population percentage and the people of color population percentage for CBG).

- The same degree of protection from environmental and health hazards; and
- Equal access to the decision-making process to have a healthy environment in which to live, learn, and work."

The EPA EJ guidance (EPA, 2016; EPA, 2022) does not prescribe a method for assessing potential EJ impacts. However, it does recommend that an appropriate methodology be adopted and applied. ExxonMobil has a corporate socioeconomic standards-driven process that assesses environmental, socioeconomic, and health considerations throughout a Project. As ExxonMobil's understanding of the local environment evolves during the Project lifecycle, the EJ assessment may be updated if warranted.

For this Report, the EPA's EJScreen Tool Version 2.2 (EPA, 2023a) was used to assess demographic and environmental characteristics in areas crossed by or within the EJ Study Area (Figure 10-1). Use of the EJScreen Tool is intended to be a starting point in the identification of communities with potential EJ concerns. As discussed further in Section 10.4, EJ Indexes at or above the 80th percentile nationally were used as a starting point for identifying geographic areas that potentially warrant further consideration, analysis, or engagement with respect to potential EJ concerns.

10.2.1 Minority Populations

In accordance with the EPA's EJ guidance (EPA, 2016; EPA, 2022), this EJ Report uses demographic and socioeconomic data to assess levels of minority[6] population percentages present in the EJ Study Area and the broader Claimed as PBI County. The U.S. Council on Environmental Quality (CEQ) states that "minority populations should be identified where either: (a) the minority population of the affected area exceeds 50% or (b) the minority population percentage of the affected area is *meaningfully greater* [emphasis added] than the minority population percentage in the general population or other appropriate unit of geographic analysis" (CEQ, 1997). The CEQ recommends using an "appropriate unit of geographic analysis" that does not "artificially dilute or inflate the affected minority population" (CEQ, 1997). While "meaningfully greater" is not explicitly defined in the CEQ's guidance, federal guidelines suggest that 10% greater than the reference population is considered a reasonable threshold for "meaningfully greater" (EJ IWG and NEPA Committee, 2019). To identify minority populations for the CBGs in the EJ Study Area, Claimed as PBI County was used as the reference population.

For this EJ Report, potential minority populations are identified as present in a CBG if it meets either of the following criteria:

- The percentage of minorities in the CBG is more than 50%; or
- The percentage of minorities in the CBG is at least 10% higher than that of Claimed as PBI County.

[6] "Minority" was initially defined by the Federal Interagency Working Group on Environmental Justice in an appendix to the 1997 CEQ EJ Guidance as "individuals who are members of the following population groups: American Indian or Alaskan Native; Asian or Pacific Islander; Black, not of Hispanic origin; or Hispanic" (CEQ, 1997).

10.2.2 Low-Income Populations

In accordance with the EPA's EJ guidance (EPA, 2016; and EPA, 2022), this EJ Report uses socioeconomic data to assess levels of low-income percentages of populations present in the EJ Study Area and the broader Claimed as PBI County. Guidelines for identifying low-income populations vary among federal and state agencies. Low-income populations can be identified using either (1) the U.S. Census Bureau poverty thresholds, (2) local data sources on poverty, or (3) the U.S. Department of Health and Human Services poverty guidelines. Additionally, low-income communities can be identified by using a "meaningfully greater" analysis, the percentage of *individuals* below the poverty level, the percentage of *households* below the poverty level, and/or the percentage of *families with children* below the poverty level (EJ IWG and NEPA Committee, 2019). The National Environmental Policy Act uses the "meaningfully greater" analysis to identify low-income populations.

For this Report, potential low-income populations are identified as present in a CBG if it meets the following criterion:

- The percentage of households below the poverty level in the CBG is greater than that of Claimed as PBI County.

10.2.3 Additional Socioeconomic Indicators

Additional socioeconomic indicators measured by the EJScreen Tool include unemployment rate, percentage of population that is limited English speaking, percentage of population with less than high school education, percentage of population under age 5, percentage of population over age 64, a Demographic Index,[7] and a Supplemental Demographic Index.[8] Values for each of these indicators are compared between Claimed as PBI County and each of the CBGs.

10.2.4 EPA EJScreen Tool EJ Indexes

There are 13 EJ Indexes in the EJScreen Tool corresponding to 13 environmental indicators, each combined with demographic indicators. An EJ Index can be used to characterize CBGs in

[7] The demographic index in EJScreen is a combination of percentage of low-income and percentage of minority, the two socioeconomic factors that were explicitly named in Executive Order 12898 on Environmental Justice. For each CBG, these two percentages are averaged together to derive the Demographic Index. The formula is as follows: demographic index = (% minority + % low-income) / 2.

[8] The supplemental demographic index in EJScreen is a combination of five socioeconomic factors averaged together for each CBG. The supplemental demographic index can provide an additional perspective on potential community vulnerability and may be more relevant for use in certain situations. The formula is as follows: supplemental demographic index = (% low-income + % unemployed + % less than high school education + % limited English speaking + low life expectancy) / 5. For BGs where low life expectancy data is missing, the formula will average the other four factors.

terms of the combination of their low-income and people of color[9] populations and a given environmental indicator for the CBG. To calculate a CBG's EJ Index for a given environmental indicator, EJScreen multiplies the CBG's associated environmental indicator percentile by the average percentages of low-income and people of color (i.e., the Demographic Index) in the CBG.

Technical documentation for EJScreen recommends the use of an initial filter to promote consistency and as a pragmatic first step when interpreting screening results. The EPA has identified the 80th percentile filter as that initial starting point (i.e., an area with any of the 13 EJ Indexes at or above the 80th percentile may warrant further review).

EJScreen reports present the EJ Index percentiles both nationally and statewide. The national percentiles are the focus of this Report based on EPA technical guidance documents (EPA, 2016; EPA, 2022). National and state percentiles can be found in Appendix K-1, which includes the full EJScreen Community Reports for [redacted] County and each of the CBGs as of October 2023. Tables 1 and 2 in Appendix K-2 present individual demographic and environmental indicators that have resulted in a particular percentile, as of October 2023.

10.3 EPA EJScreen EJ Indexes

Of the 14 CBGs in the EJ Study Area, seven have EJ Indexes at or above the 80th percentile nationally. EJ Indexes with one or more CBGs with rankings at or above the 80th percentile nationally include PM2.5, Ozone, Diesel PM, Air Toxics Cancer Risk, Air Toxics Respiratory HI, Toxic Releases to Air, Superfund Proximity, Risk Management Program Facility Proximity, Hazardous Waste Proximity and Wastewater Discharge. The most common EJ Indexes at or above the 80th percentile nationally in the EJ Study Area are Air Toxics Cancer Risk and Toxic Releases to Air, each present above the 80th percentile nationally in five CBGs.

Table 10-1 summarizes the EJ Index national percentile rankings for [redacted] County and each of the CBGs in the EJ Study Area. Values at or above the 80th percentile nationally are shown in bold and the cells are shaded dark gray.

[9] In EJScreen, "low-income" is defined by the EPA as the percentage of a block group's population in households where the household income is less than or equal to twice the federal "poverty level." "People of color" are defined by the EPA as the percentage of individuals in a block group who list their racial status as a race other than white alone and/or list their ethnicity as Hispanic or Latino (i.e., all people other than non-Hispanic white-alone individuals, where the word "alone" in this case indicates that the person is of a single race, not multiracial) (EPA, 2022; EPA, 2023b).

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10.4 Demographic Indicators

This Report considers a subset of EJScreen demographic indicators for the CBGs in the EJ Study Area. The full EJScreen reports for each of the CBGs are provided in Appendix K-1. The state and national percentile rankings tables are provided in Appendix K-2. Table 10-2 summarizes the percentage values for demographic indicators for each CBG and for Jefferson County. Table 10-2 uses the combined "meaningfully greater" and 50% threshold methodologies to identify the CBGs that may warrant further evaluation on the basis of minority population percentages. For all other demographic indicators, Table 10-2 uses a direct comparison of the value for the CBG and that of Claimed as PBI County. CBG values exceeding these comparison thresholds are shown in bold and the cell is shaded dark gray. Six of the 14 CBGs have populations of people of color greater than 50%. Both Claimed as PBI and Claimed as PBI also have low-income populations higher than the Claimed as PBI County reference population. The Demographic Index (an average of the percentage of low-income and percentage of people of color) is greater than that of Claimed as PBI County percentage and above 50% in three of the 14 CBGs.

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10.5 Critical Service Gaps

EJScreen includes indicators for critical service gaps such as broadband internet subscription gaps, lack of health insurance,[10] housing burden, transportation access, and presence of food deserts.[11] Descriptions of the indicators for these EJScreen layers are as follows:

- Broadband gaps refer to the percentage of households with a broadband internet subscription as reported in the Census Bureau's American Community Survey (ACS) five-year summary estimates (Figure 10-2).
- Lack of health insurance is the percentage of all persons without health insurance coverage as reported in the Census Bureau's ACS data (Figure 10-3).
- Housing burden is a percentile related to housing cost, which is the percentage of households that are both earning less than 80% of Housing and Urban Development's Area Median Family Income and are spending more than 30% of their income on housing costs (Climate and Economic Justice Screening Tool [CEQ, 2023]) (Figure 10-4).
- Transportation access is an average of four transportation-related indicator percentiles: transportation cost burden, national walkability index, percentage of households with no vehicle available, and mean commute time to work (Climate and Economic Justice Screening Tool) (Figure 10-5).
- Food desert tracts are those that are both low-income and "low-access," the latter of which is identified as tracts that are separated from affordable and nutritious foods by a distance of 1 mile for urban areas and 10 miles for rural areas, as reported by the U.S. Department of Agriculture (Figure 10-6).

Broadband internet subscription gaps at or above the 80th percentile occur within the portion of the EJ Study Area between Interstate 10 (I-10) and West Port Arthur Road. Lack of health insurance surpasses the 80th percentile for the entire portion of the Project Footprint from the eastern end of the Project Footprint near Central Gardens up until just east of I-10. Housing burden does not exceed the 80th percentile in the EJ Study Area. Transportation access burdens occur above the 80th percentile in only two of the CBGs: Claimed as PBI and Claimed as PBI BG 1. These two CBGs contain Claimed as PBI, so these rankings are as expected. Food desert designation does not appear within the EJ Study Area.

Figures 10-2 through 10-6 show the graphical data from the EJScreen Tool for each of the above critical services gaps.

[10] Percentage of all persons without Health Insurance Coverage as reported in the Census Bureau's ACS data.

[11] Food desert tracts are low-income and low-access CTs with limited access to affordable and nutritious foods, measured at 1 mile distance for urban areas and 10 miles distance for rural areas, as reported by the U.S. Department of Agriculture.

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10.6 Stakeholder Engagement

A Stakeholder Engagement Plan will be developed to manage the socioeconomic dynamics that may impact—or be impacted by—the Project. Considerations related to potential communities warranting further assessment from an EJ perspective, local economic development, workforce development, and grievances will continue to be measured, assessed, and used to inform stakeholder engagement and impact mitigation strategies throughout the Project's lifecycle.

Since announcing its carbon capture and storage (CCS) agreement with Linde, the ExxonMobil public and government affairs (P&GA) team has been working to engage and inform the local community, community leaders and elected officials on topics related to CCS and the overall Project. ExxonMobil has actively engaged in community initiatives, such as participating in a roundtable hosted by the Claimed as PBI and collaborating with the Claimed as PBI as a leader sponsor for their family science, technology, engineering, and math (STEM) night. During both events, ExxonMobil provided opportunity for guests to learn more about CCS and insights into ExxonMobil's upcoming activities occurring in the area. ExxonMobil has conducted specific outreach through community door knocking, informative flyers in public locations, one-on-one meetings with community stakeholders and developing communication channels for community members to learn more about ExxonMobil activities, ask questions and voice potential concerns.

In addition to participating in community events, ExxonMobil's P&GA team has prioritized informing local community stakeholders and elected officials about ExxonMobil's activities occurring in the area. This has included providing community stakeholders and local officials with timely information related to the Project, current and upcoming activities, and ongoing and planned community engagements.

A summary of specific actions completed to date are summarized below:

- In Claimed as PBI, ExxonMobil conducted a community roundtable hosted by the Claimed as PBI to provide an overview of ExxonMobil's Low Carbon Solutions business and the Claimed as PBI.
- On Claimed as PBI, ExxonMobil spoke with local Claimed as PBI leaders in the community to outline the upcoming activities and allow for flyers to be posted on their community poster board.
- On Claimed as PBI, ExxonMobil Public and P&GA team walked neighborhoods in close proximity to the Claimed as PBI ExxonMobil went door-to-door to provide community members with information regarding the upcoming activities and answering any questions that they may have. Each house visited received a door hanger that contained a link to a webpage with additional details related to ExxonMobil activities.
- On Claimed as PBI, ExxonMobil Low Carbon Solutions and P&GA visited with ExxonMobil Claimed as PBI to provide an overview of the Low Carbon Solutions business and information on the drilling of the stratigraphic well in support of the Rose Project.
- On Claimed as PBI, ExxonMobil participated in the Claimed as PBI. The event welcomed over an estimated 1,000 community members to learn more about STEM activities that included an interactive CCS display.

ExxonMobil plans to continue to engage and grow involvement with the local community as the Stakeholder Engagement Plan is developed and implemented for the Project.

Appendix A Project Maps

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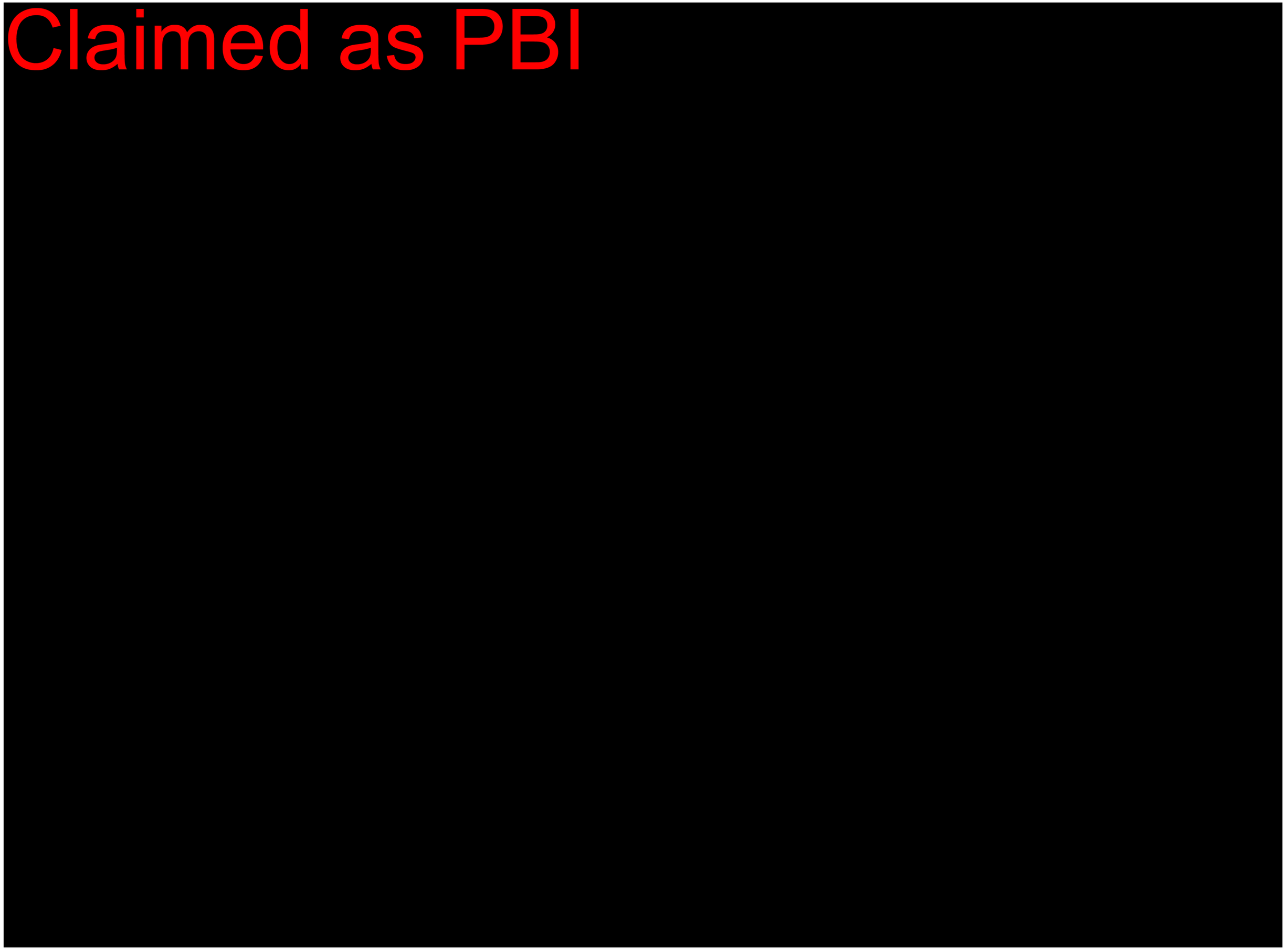

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- geol. indicators
- breakouts

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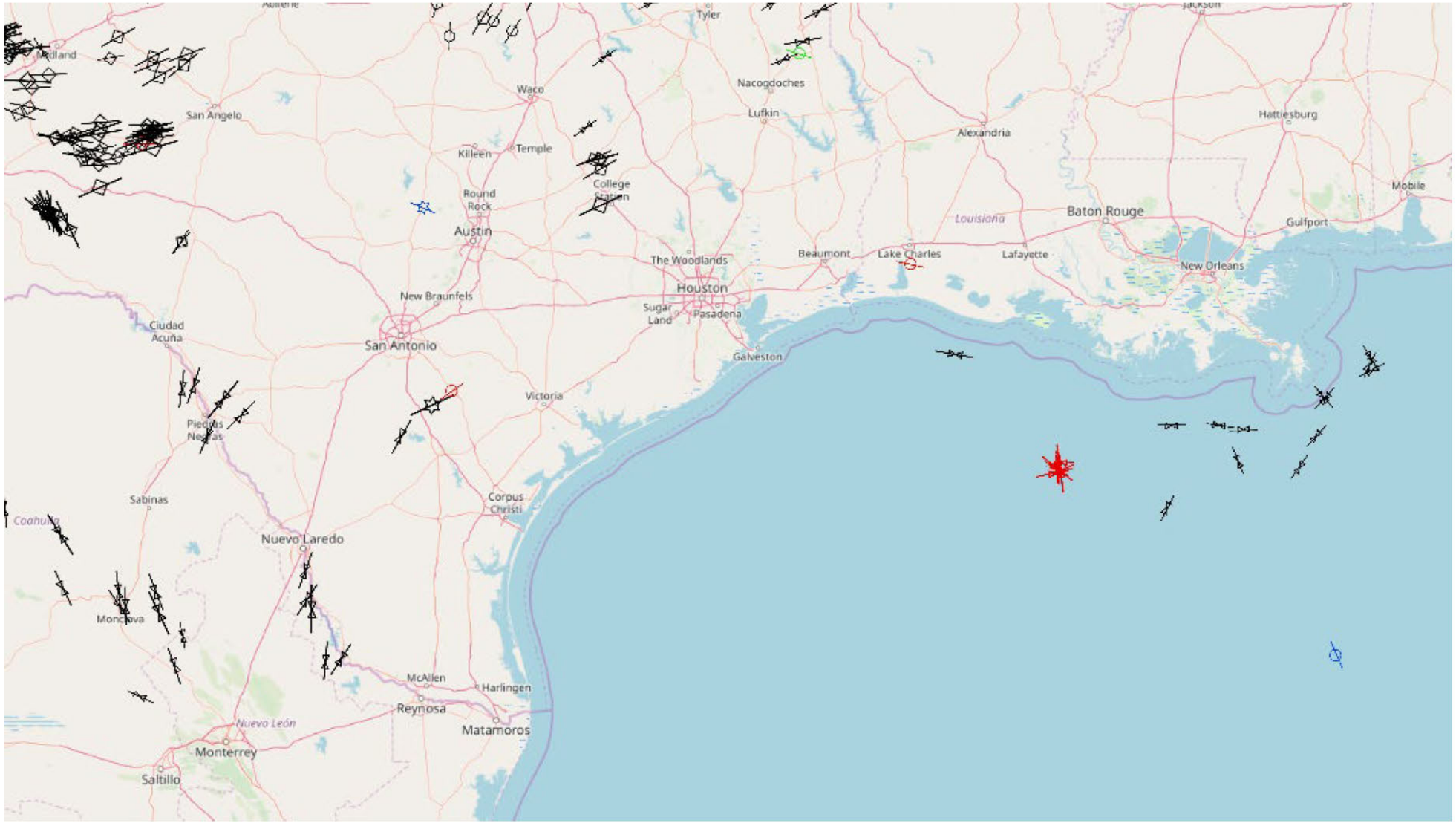

Figure B-49
World Stress Map – Maximum Horizontal Stress Orientations
Rose Carbon Capture and Storage Project
ExxonMobil Low Carbon Solutions
Onshore Storage LLC
Jefferson County, Texas

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Source: https://www.world-stress-map.org/

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Appendix D Well Construction Schematics and Procedures

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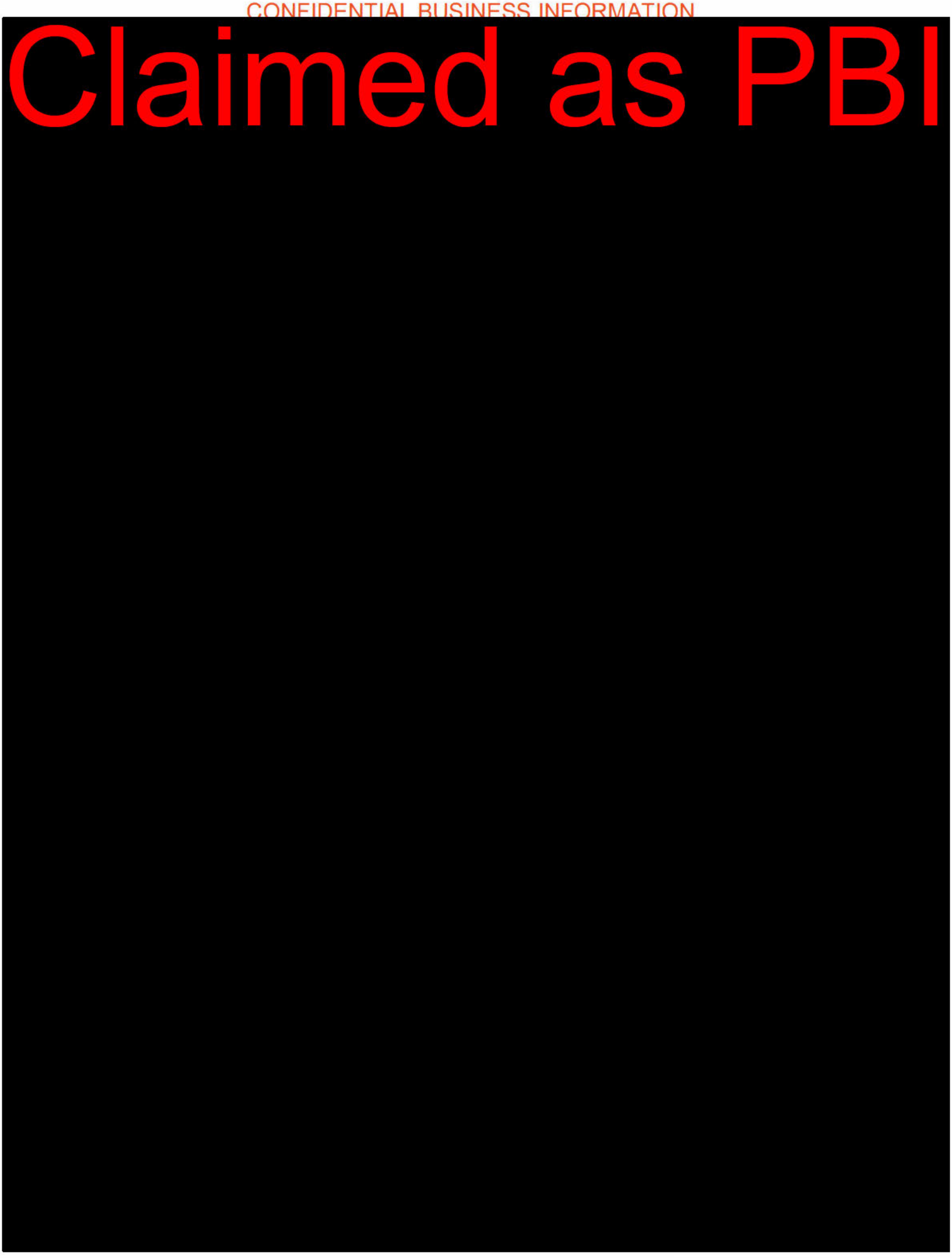

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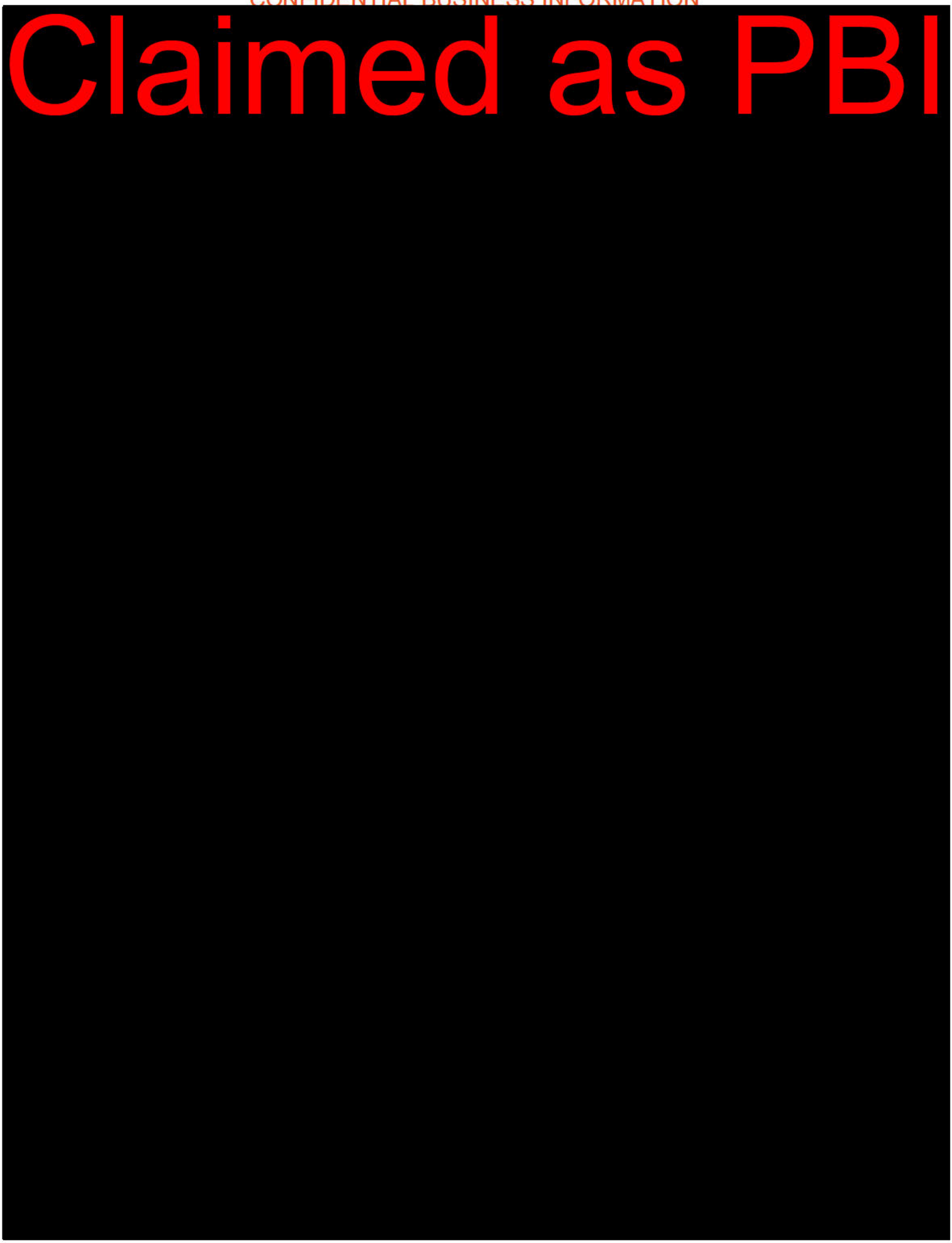

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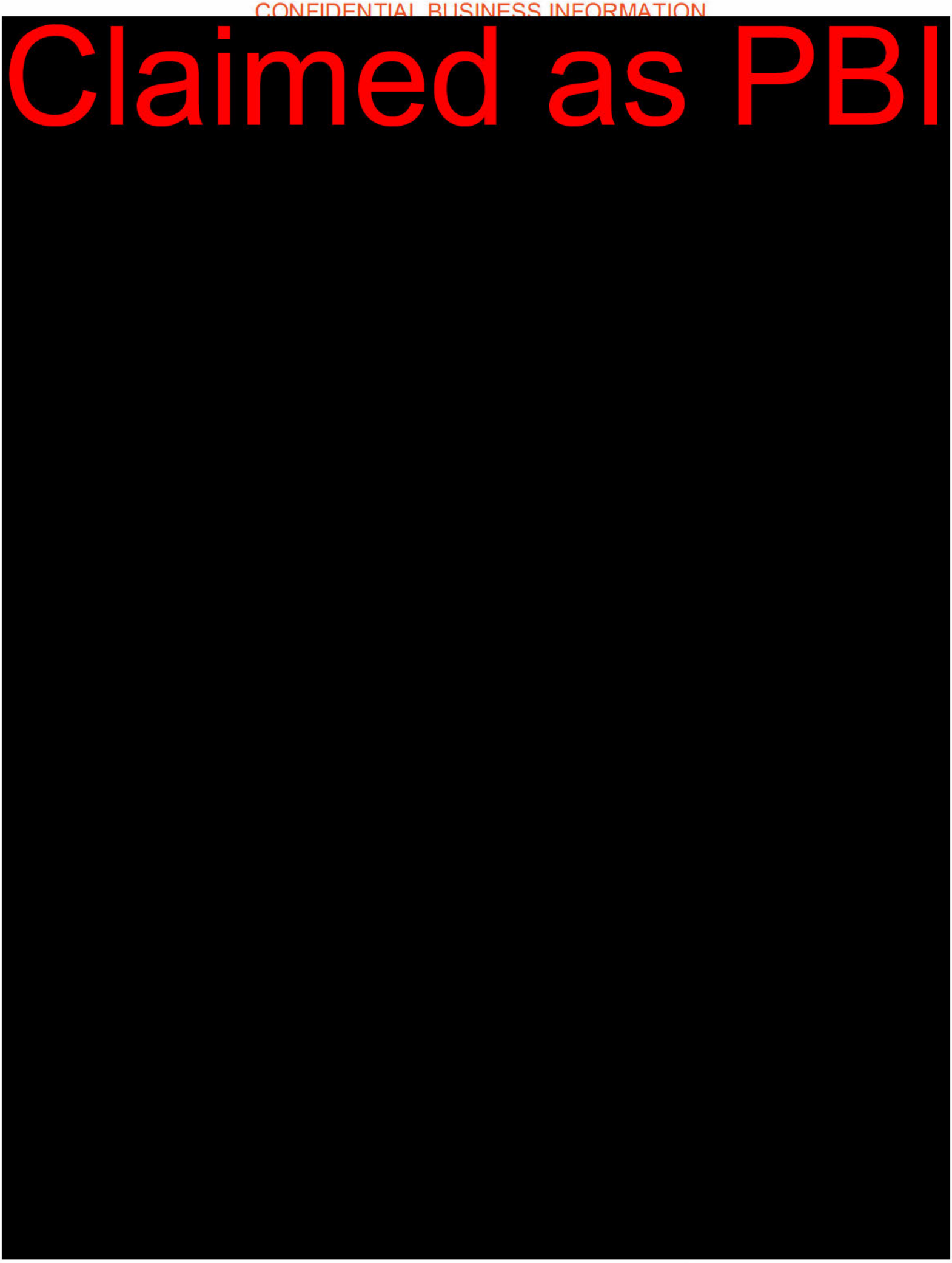

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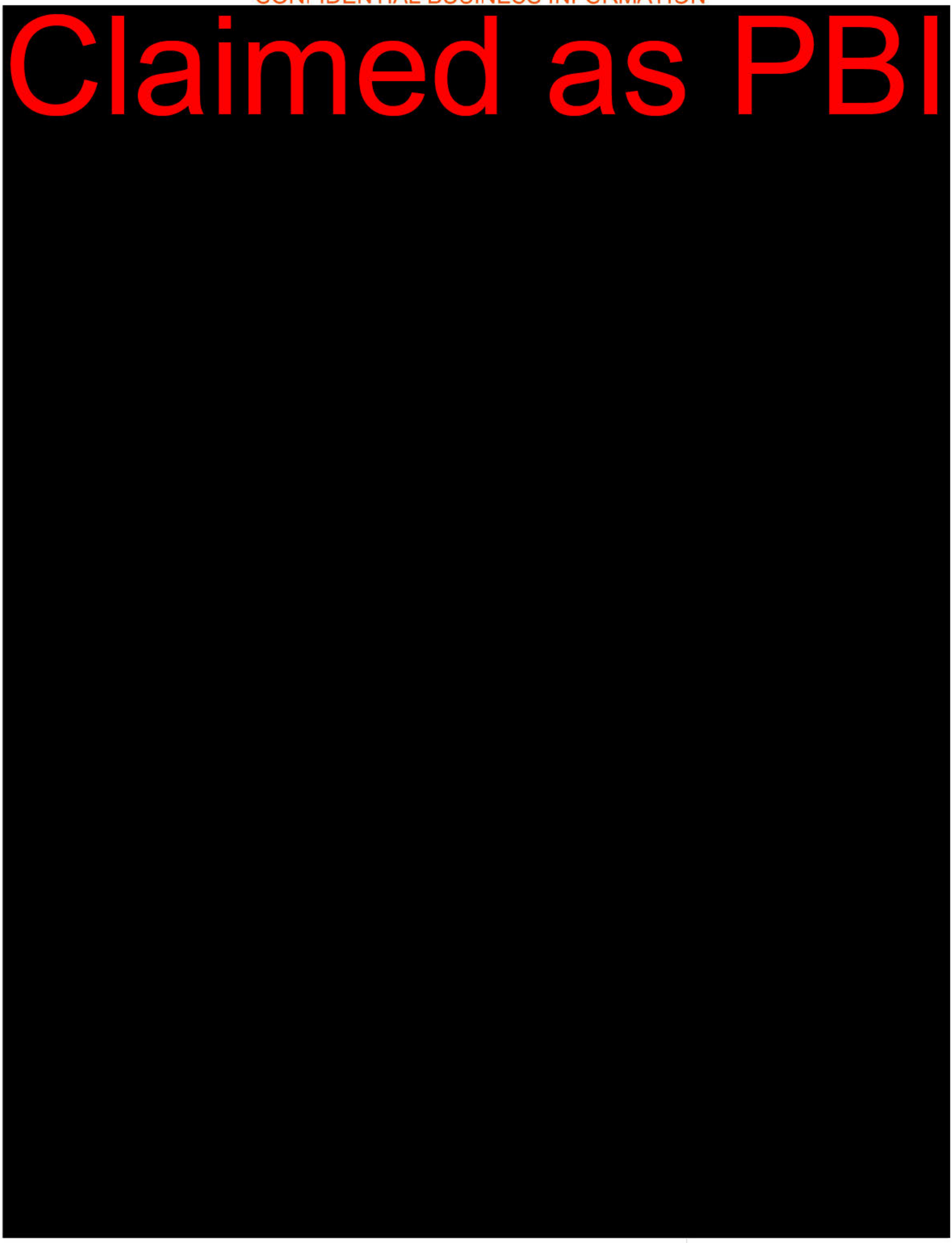

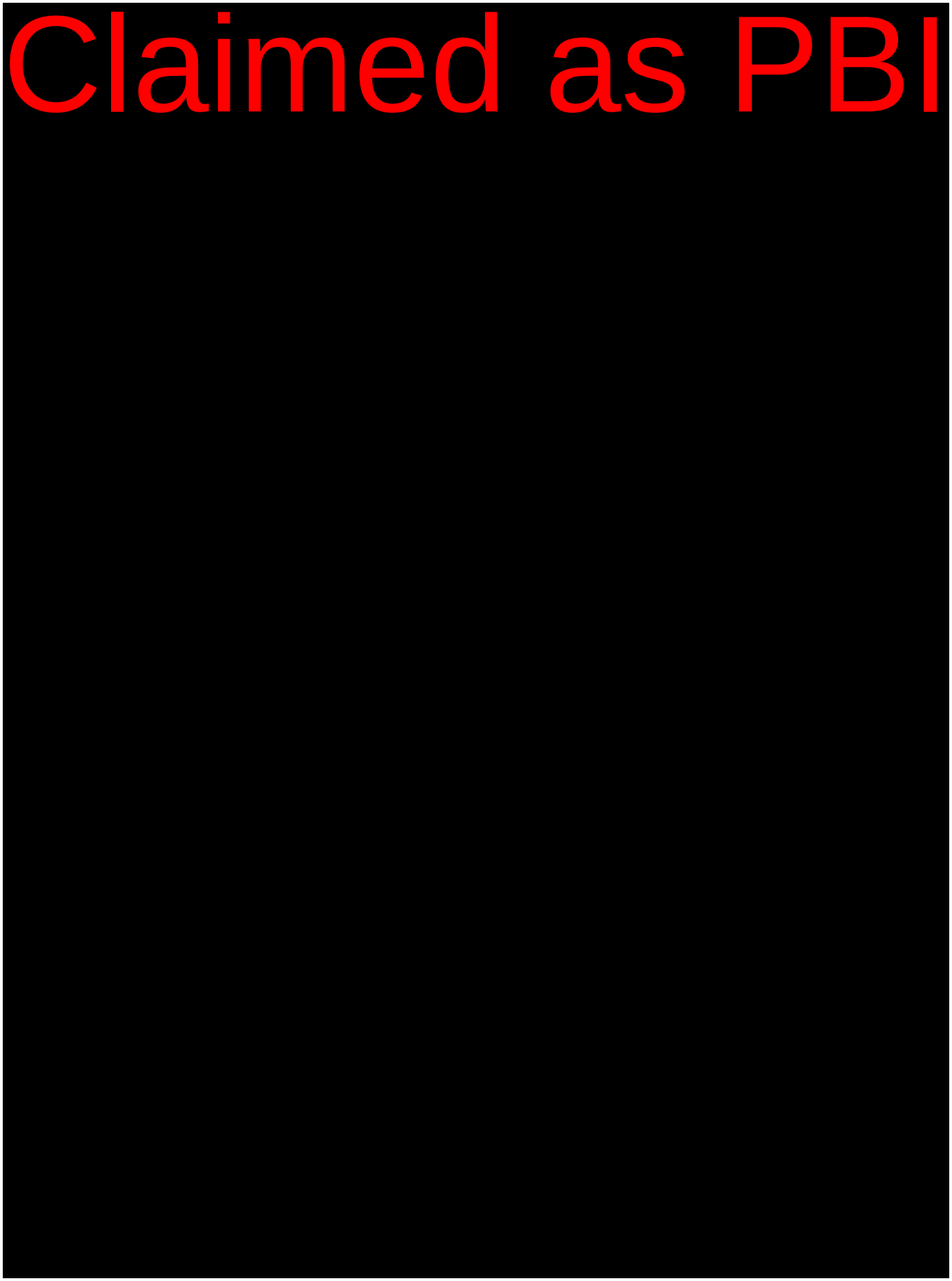
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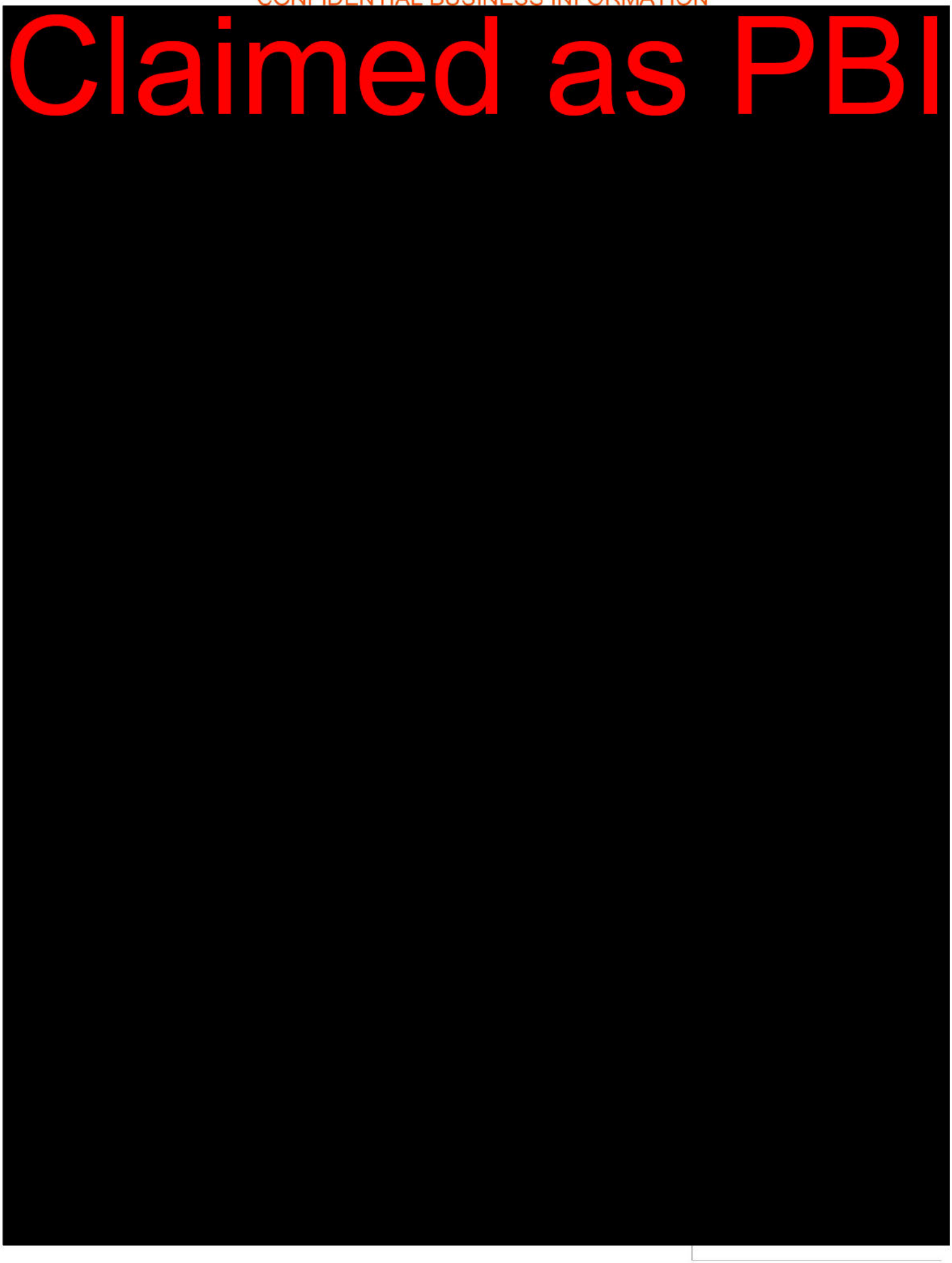

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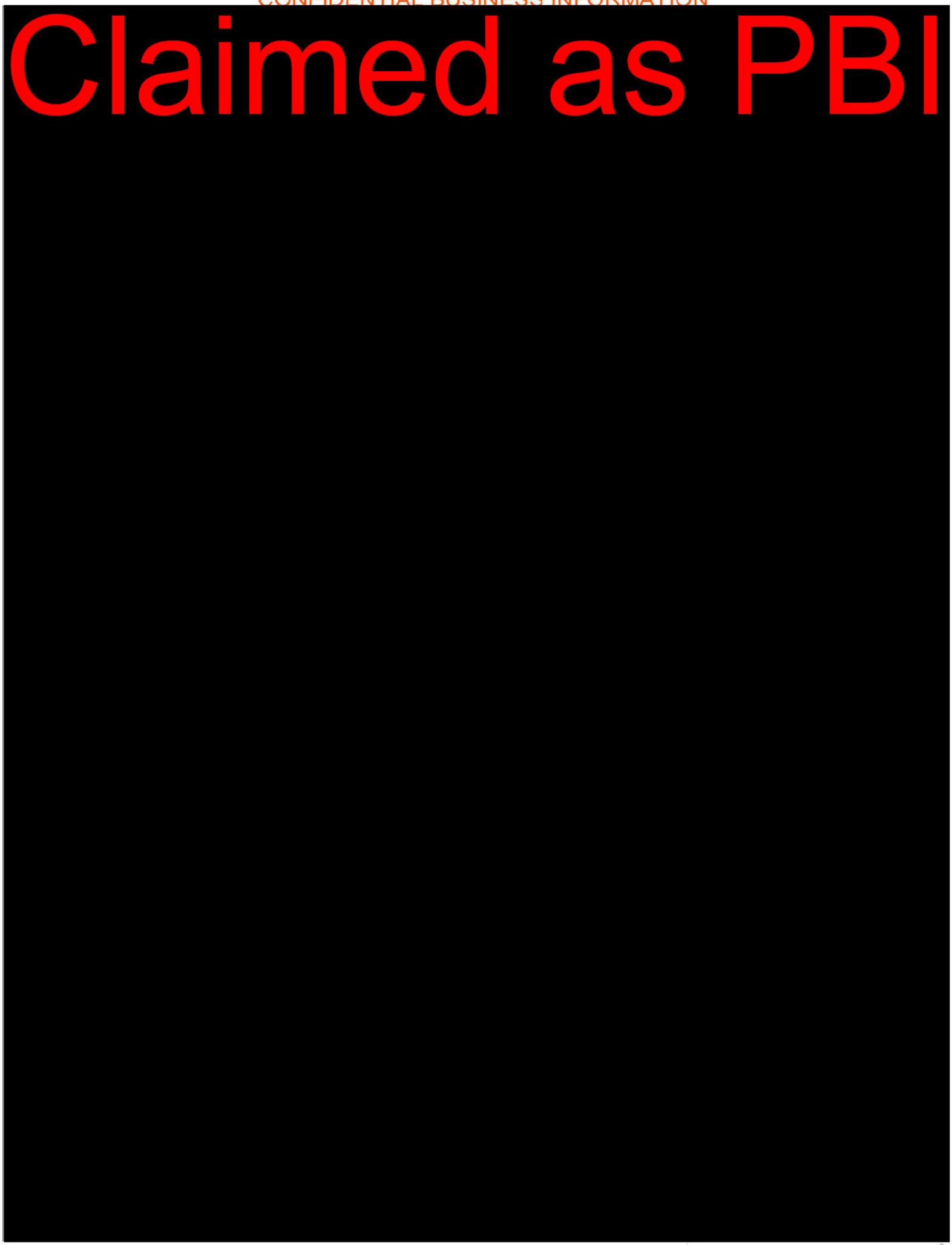

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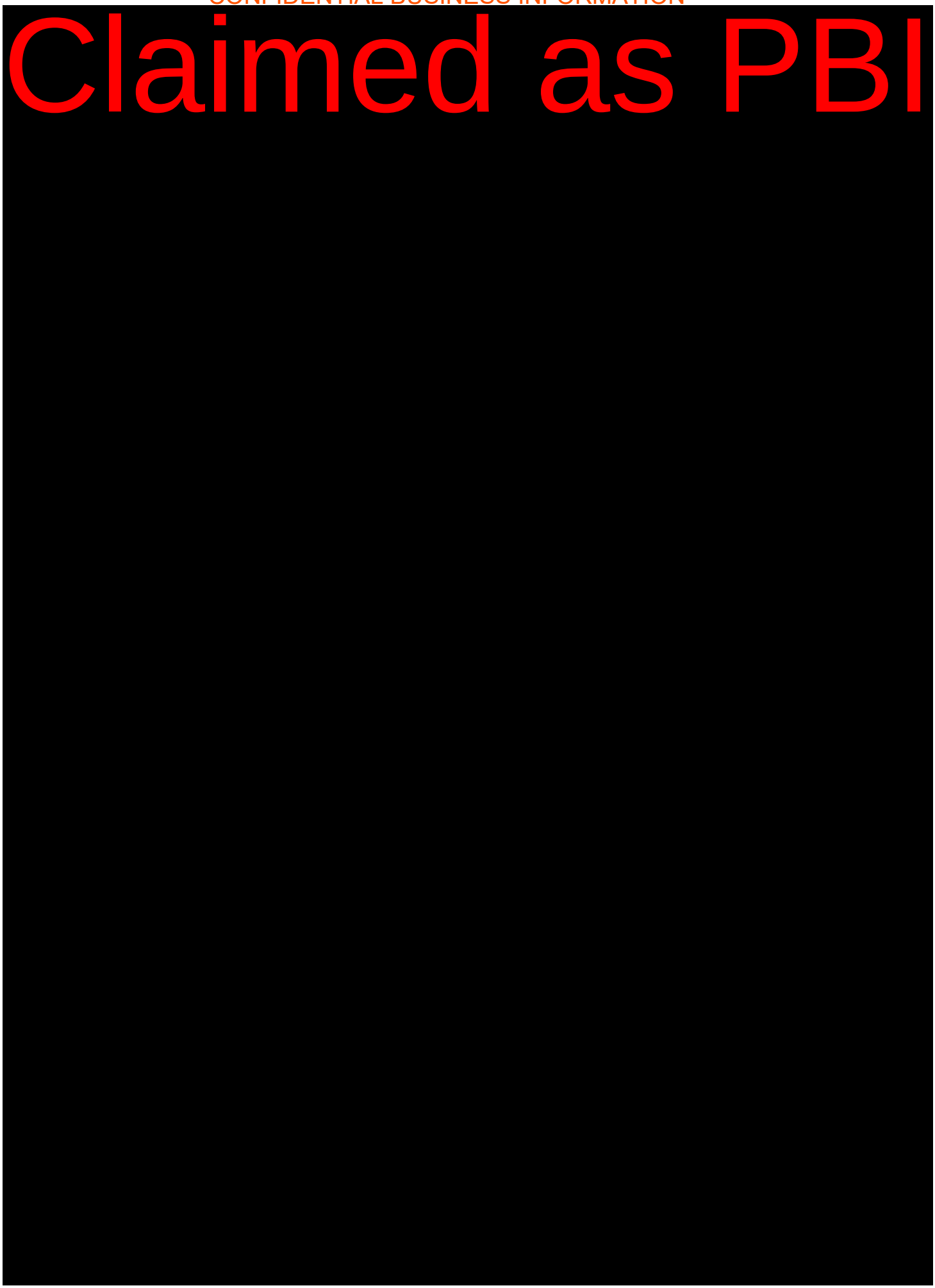

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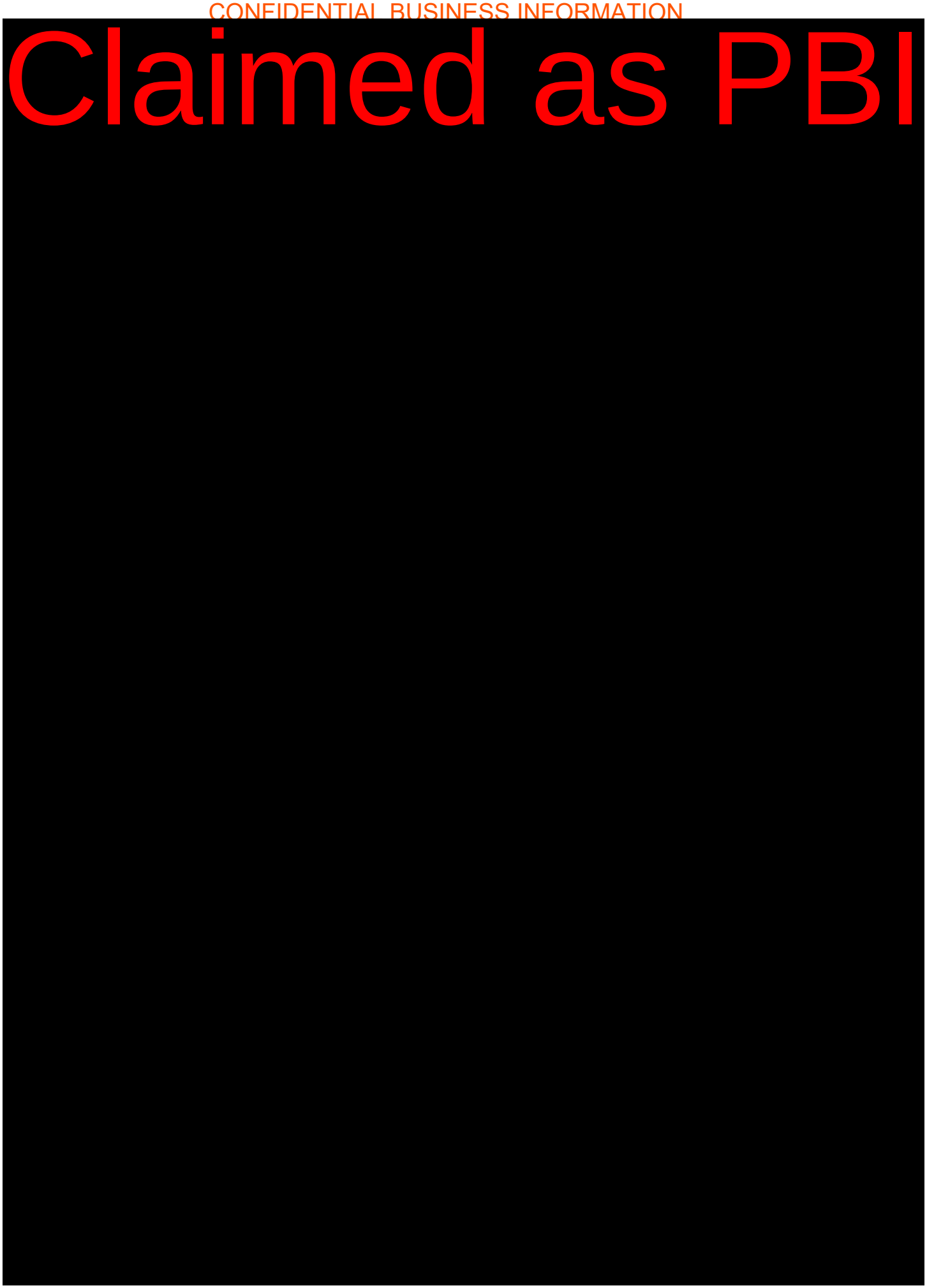

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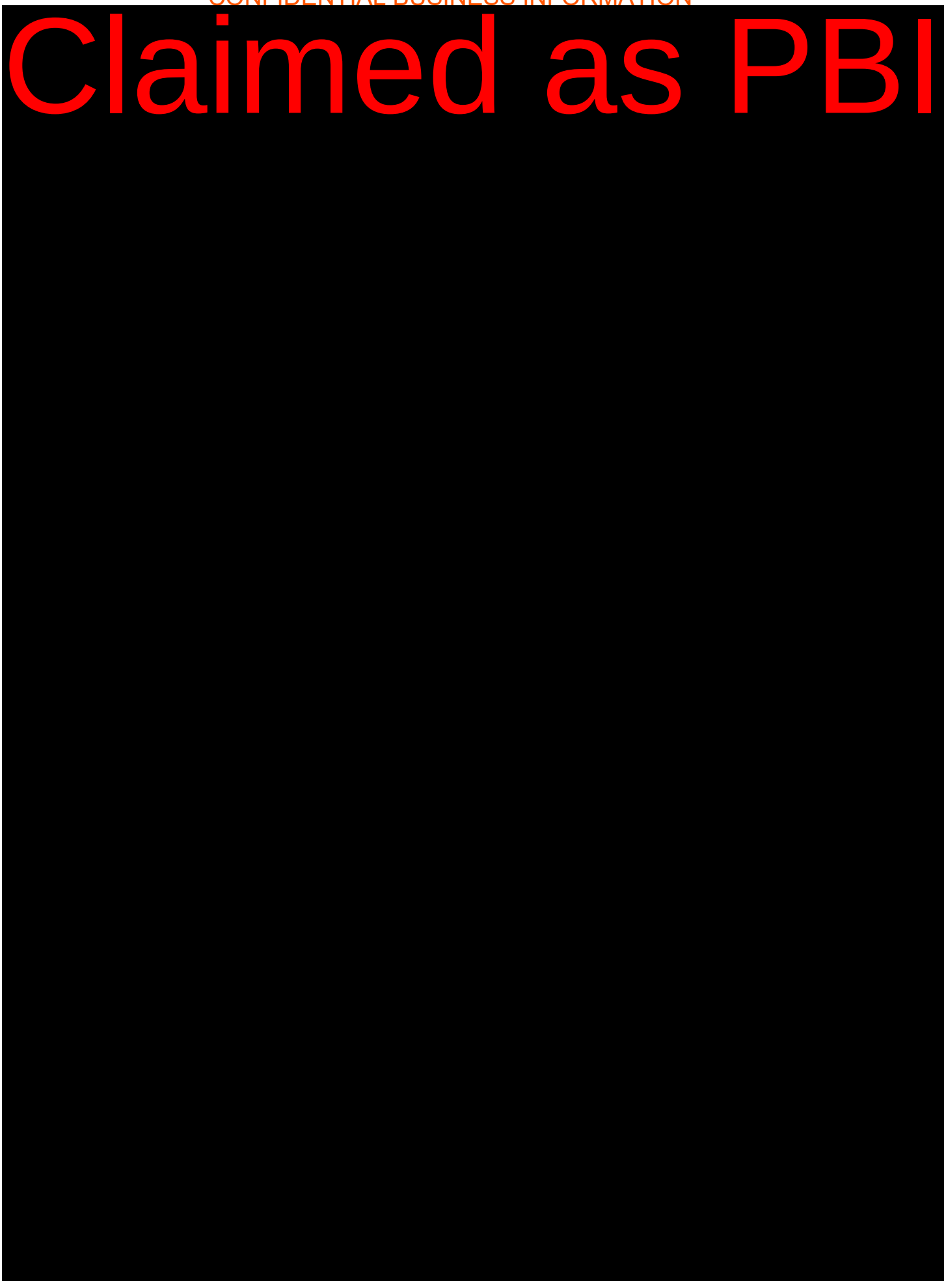

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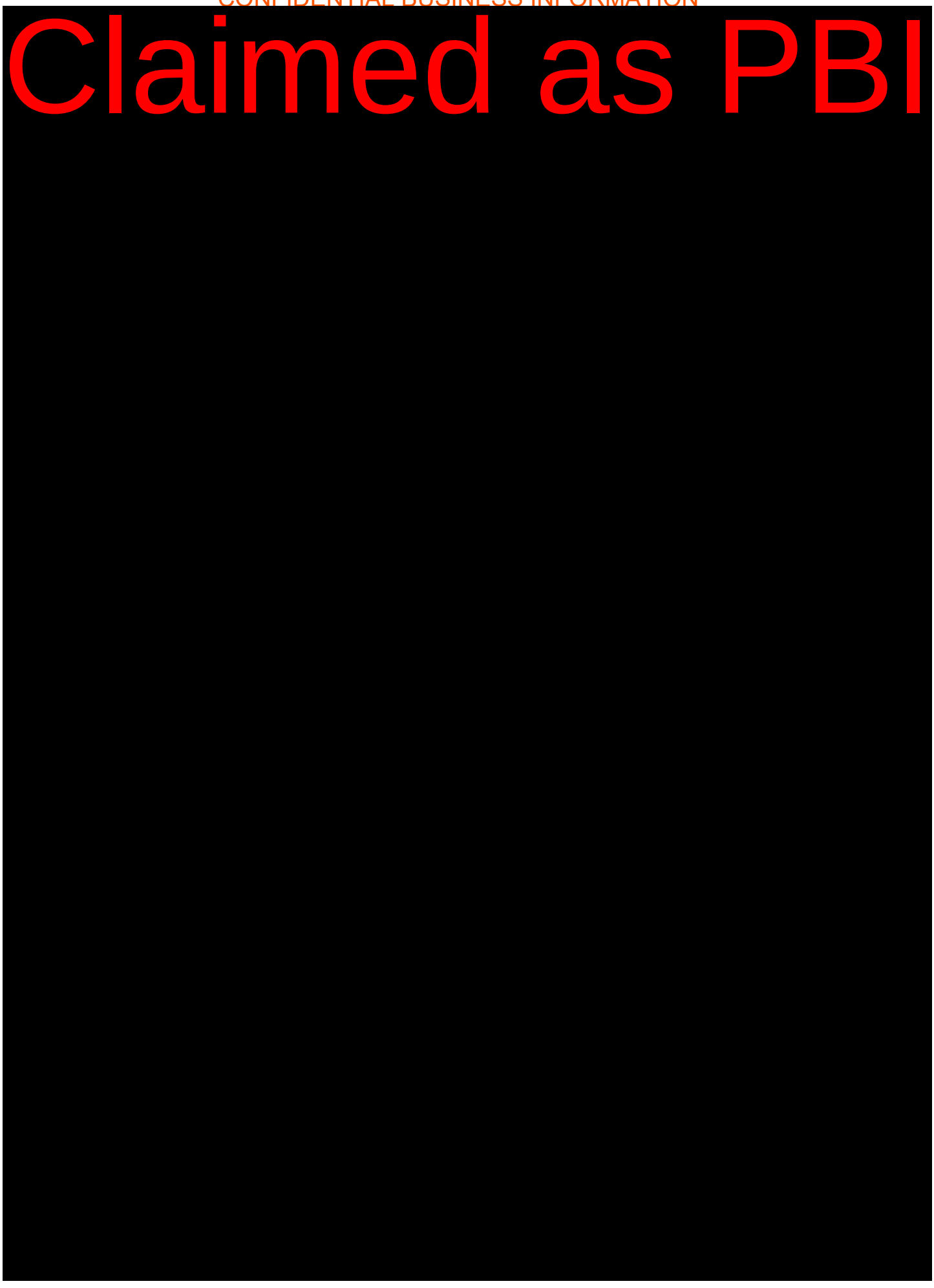

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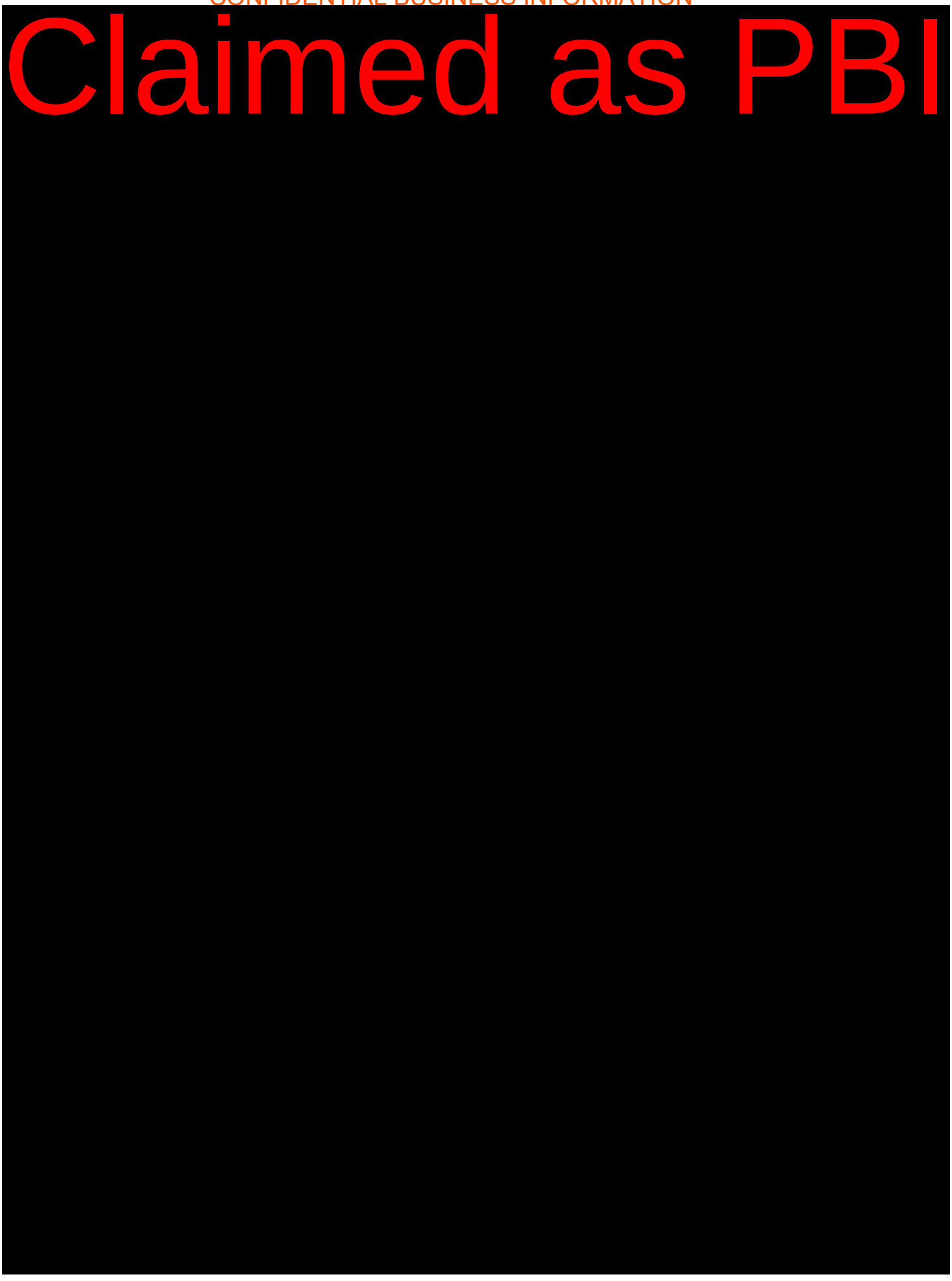

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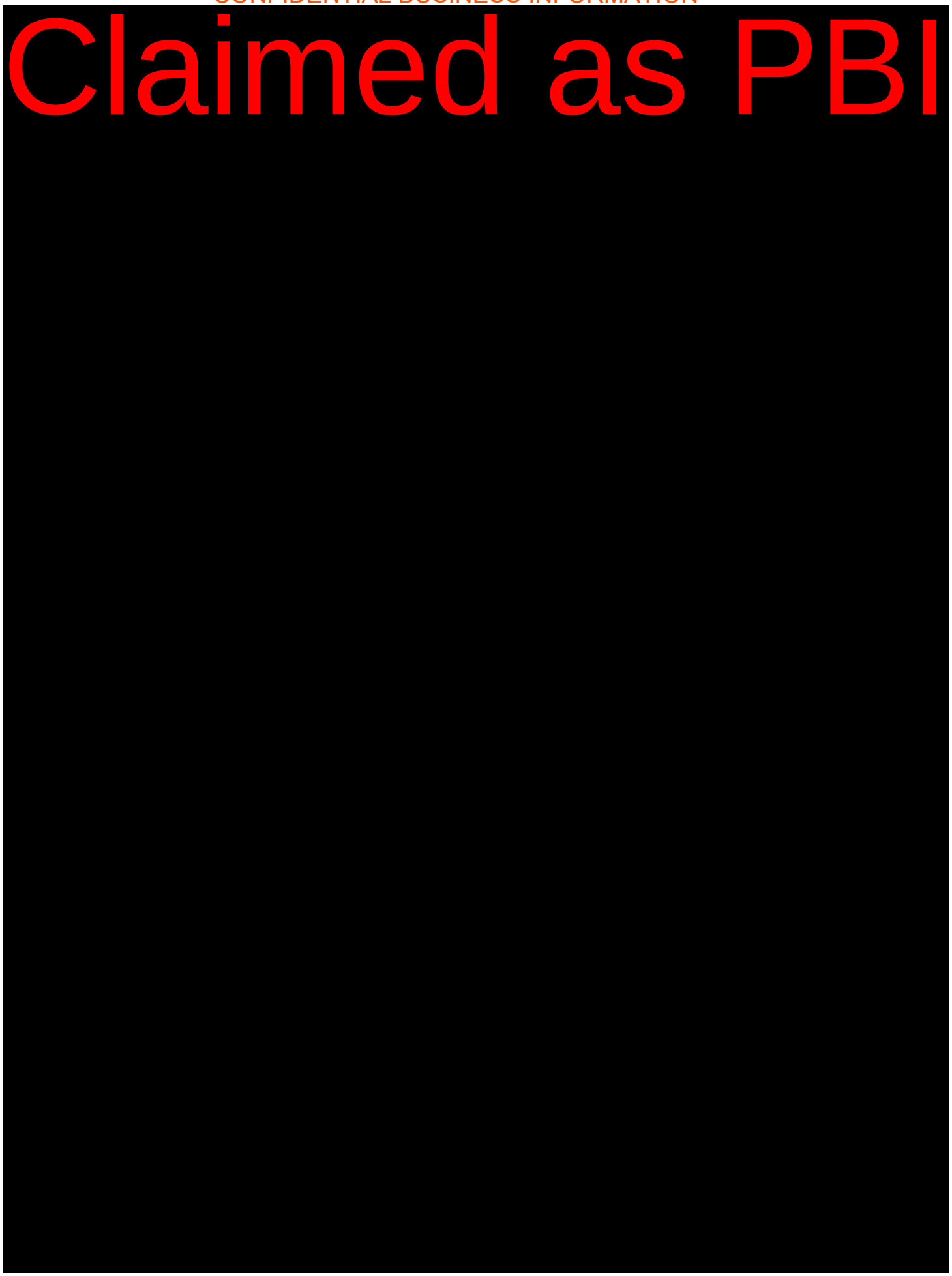

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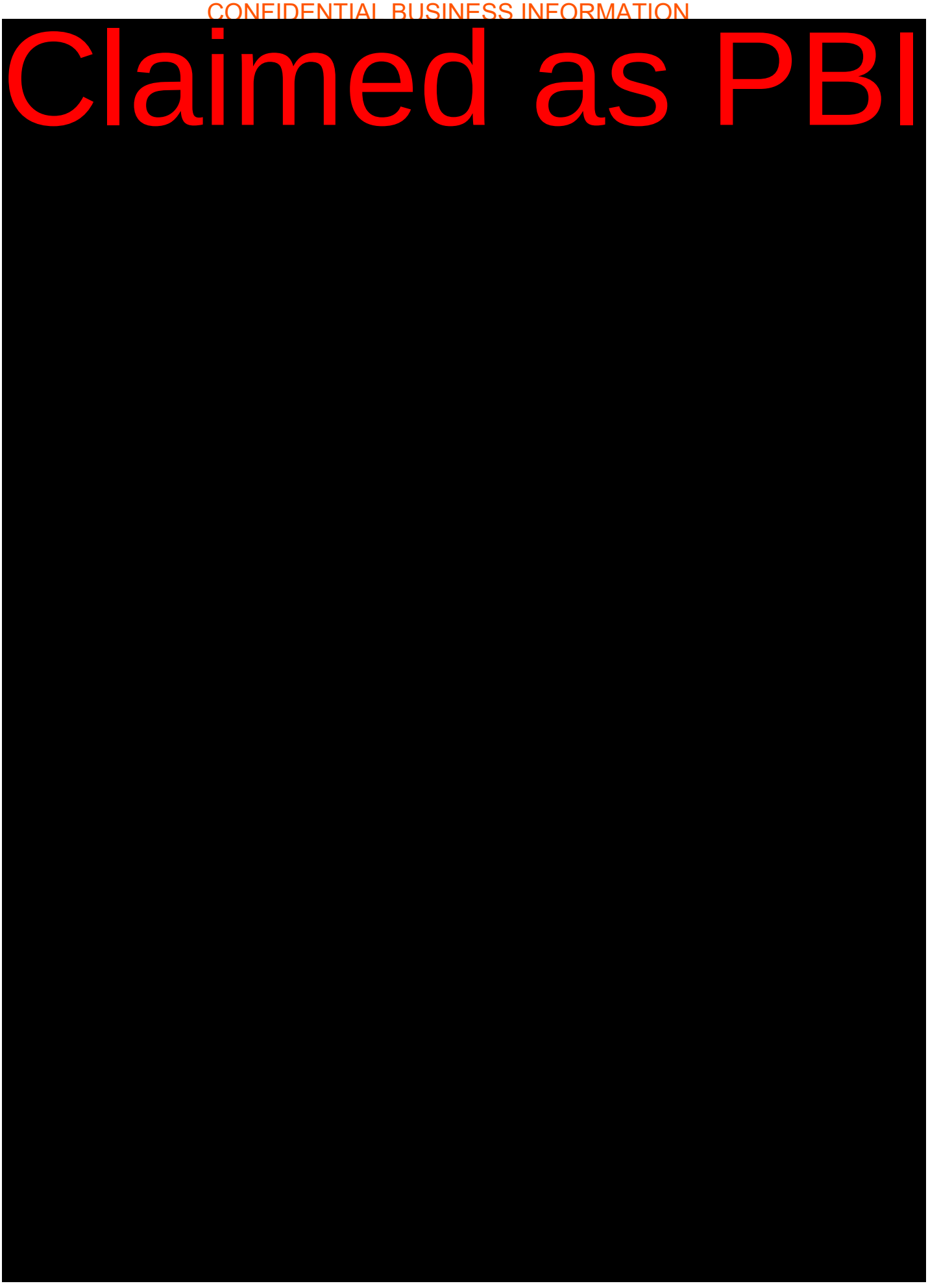

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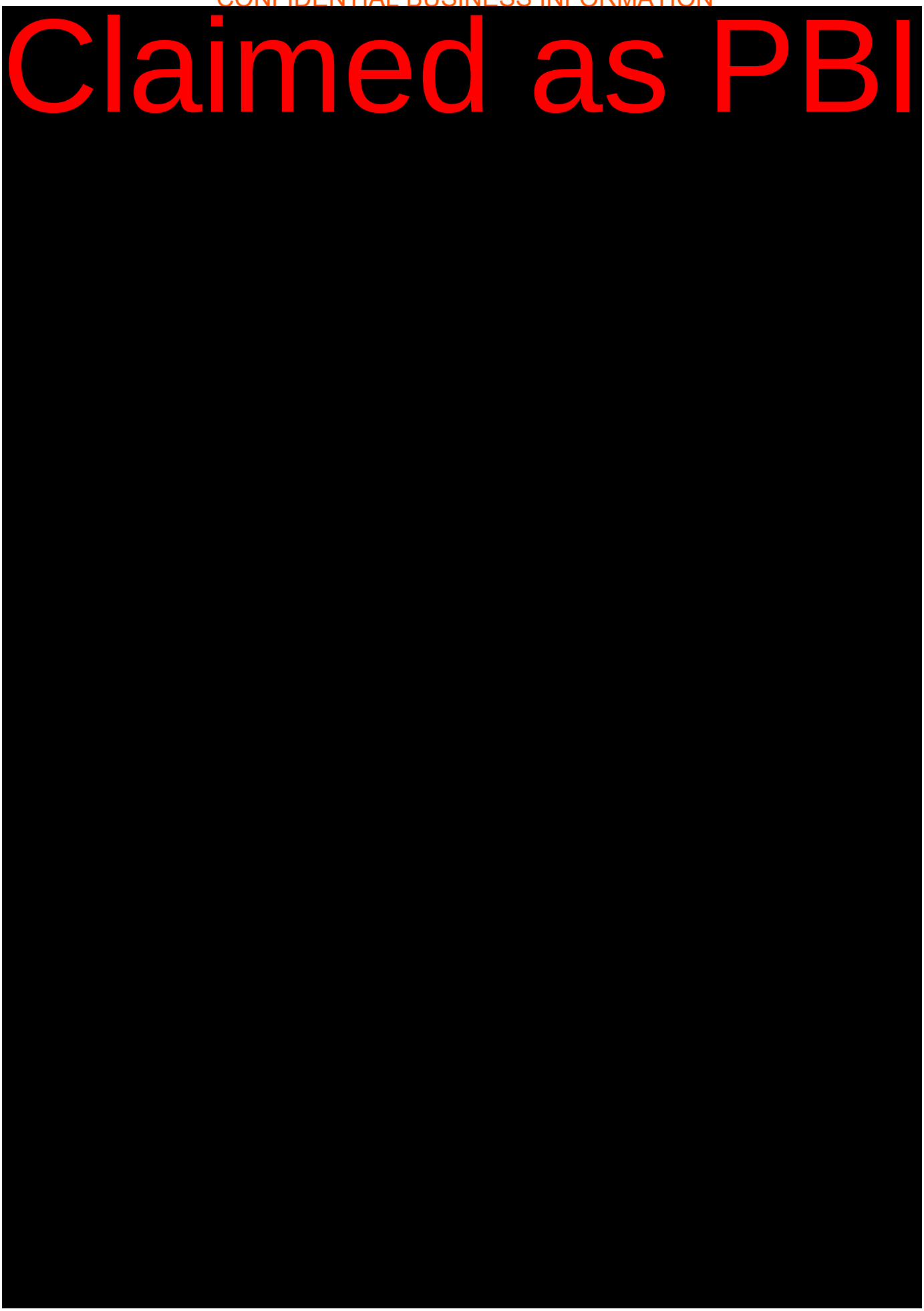

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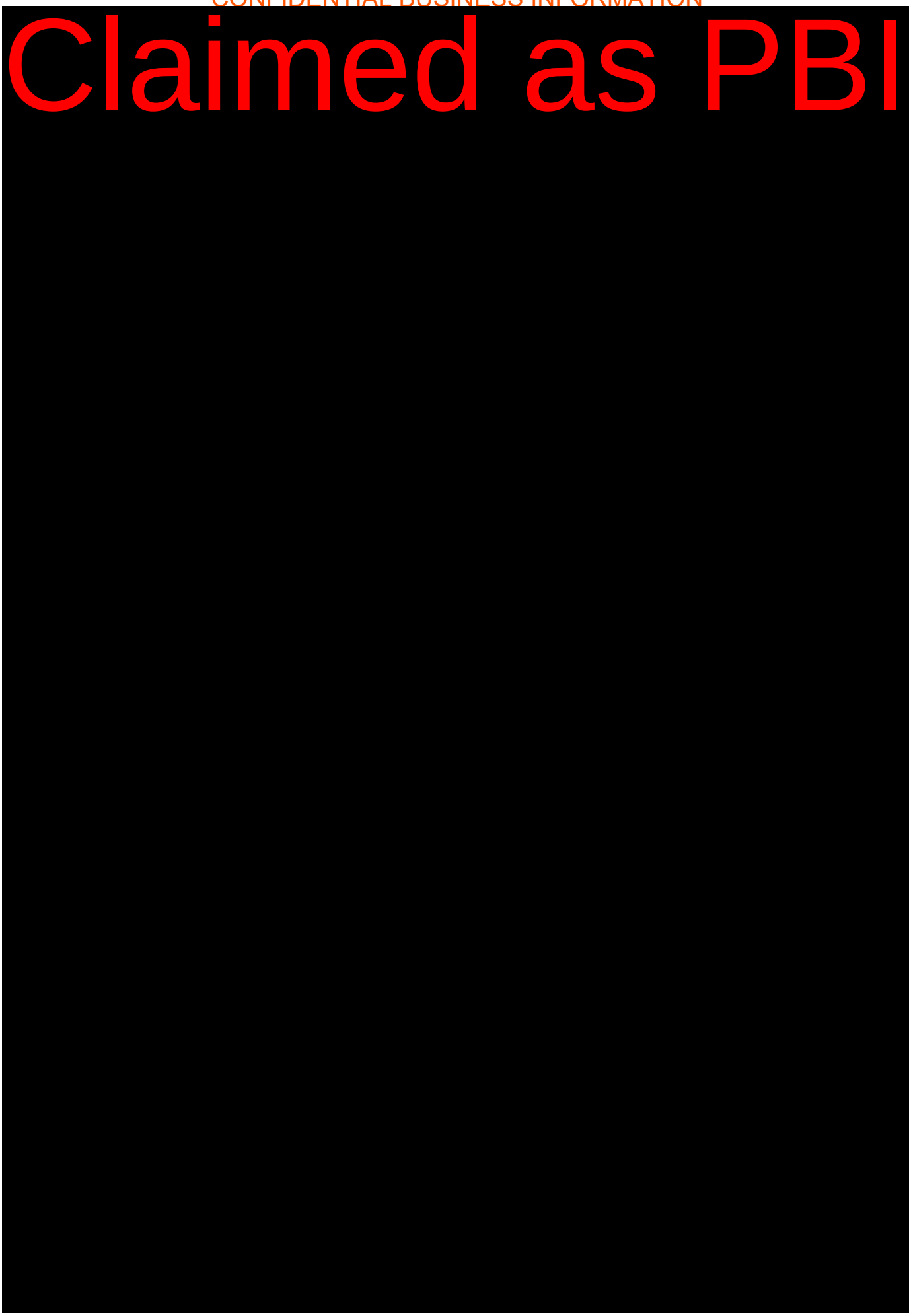

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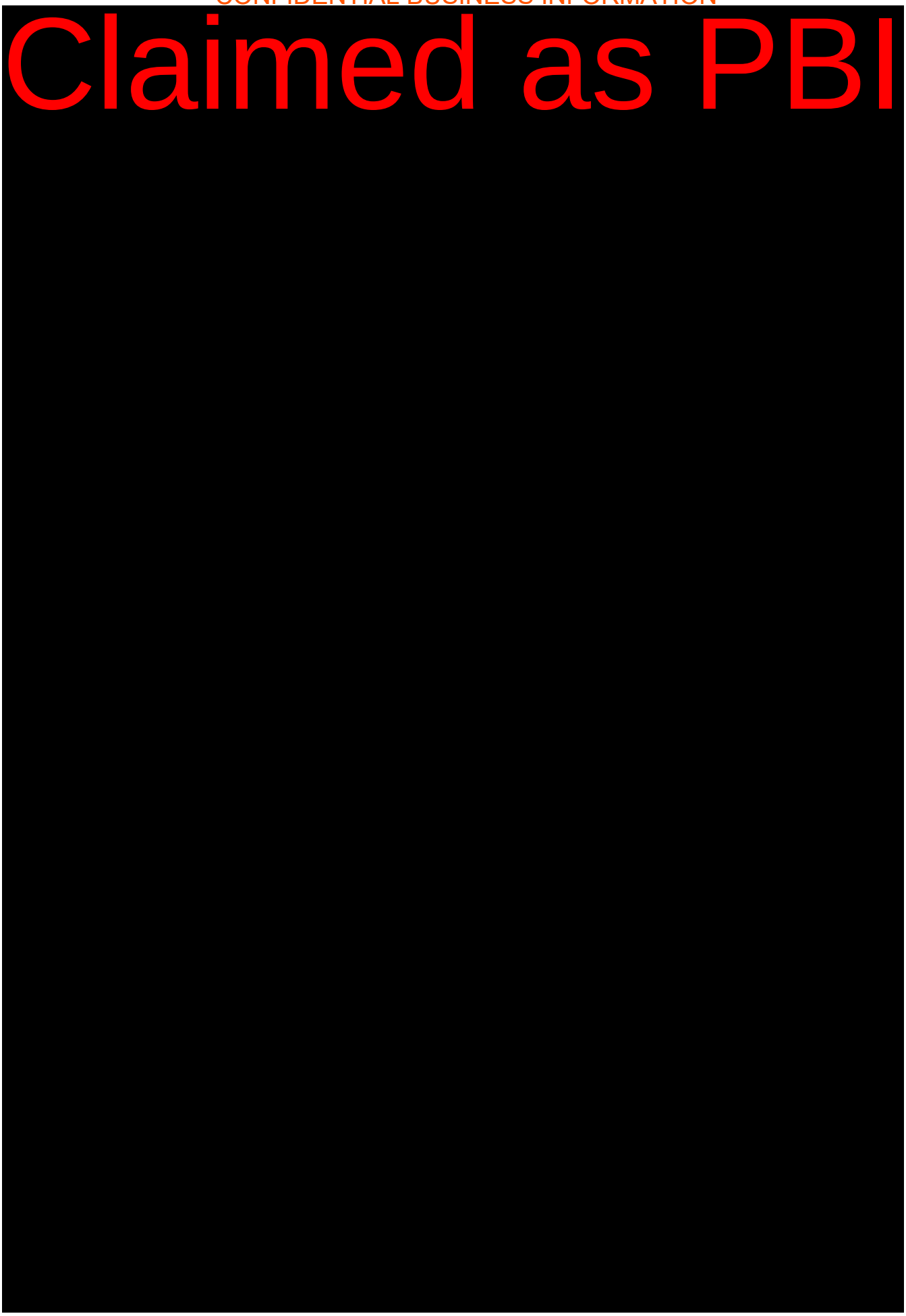

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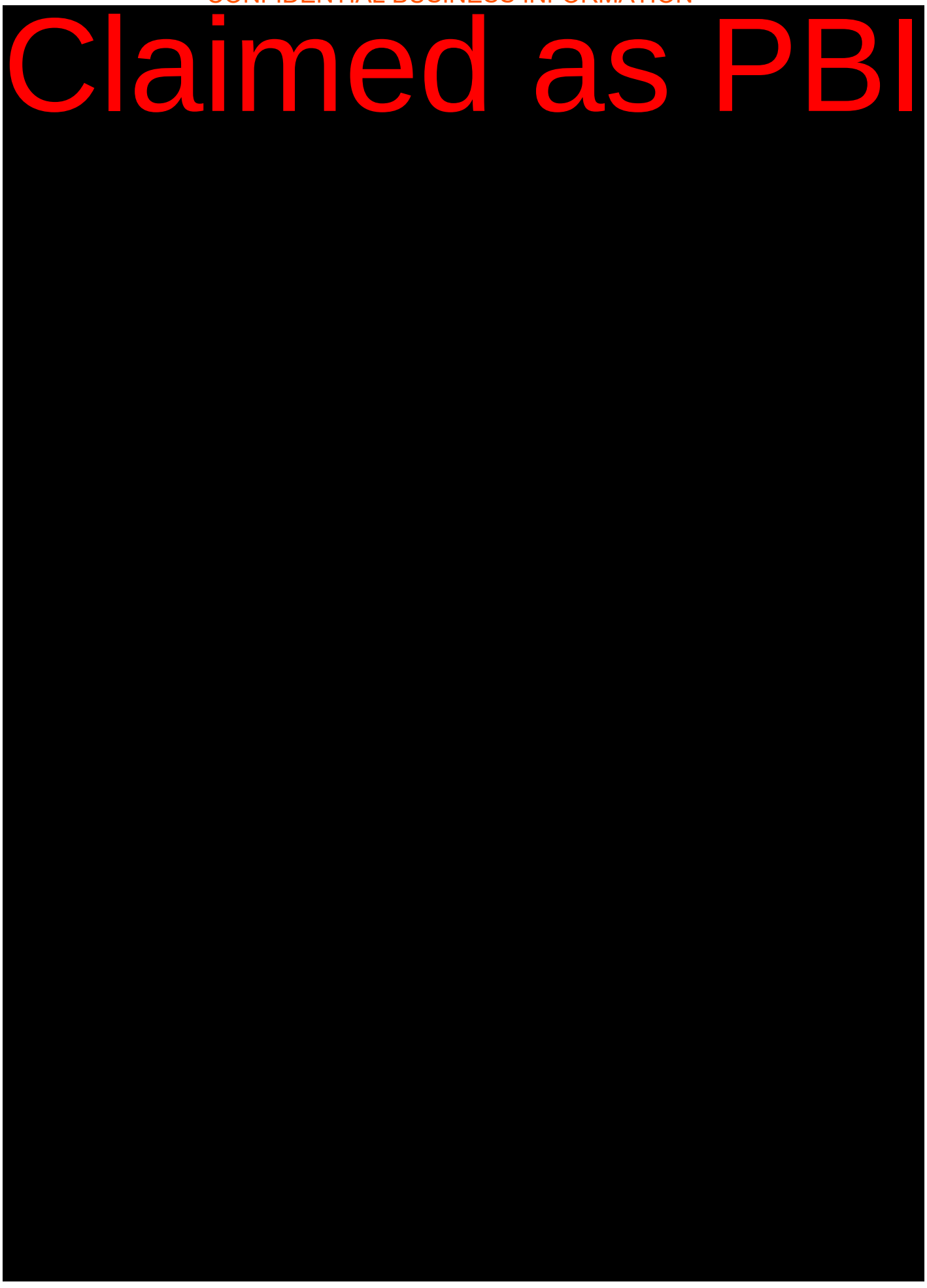

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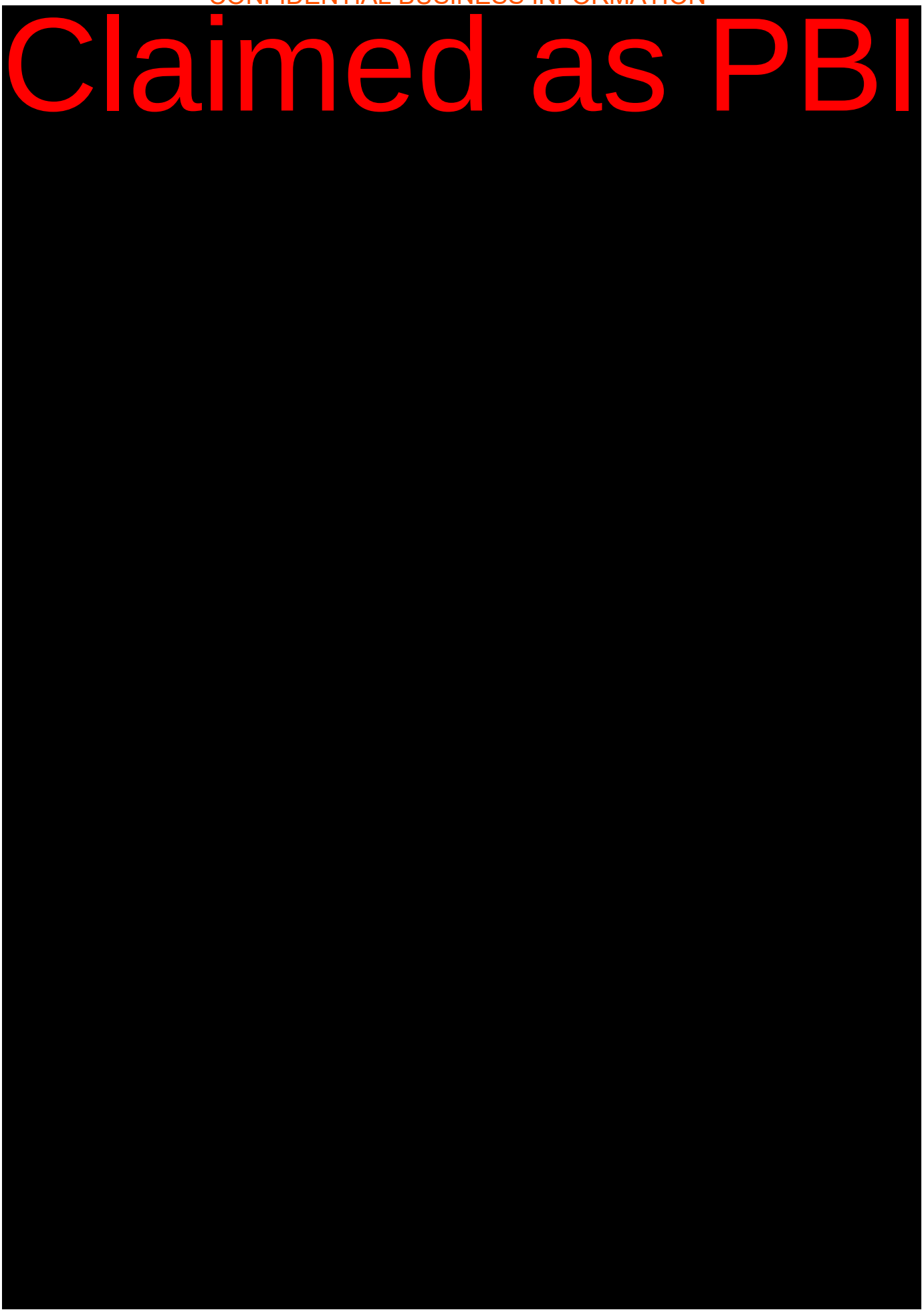

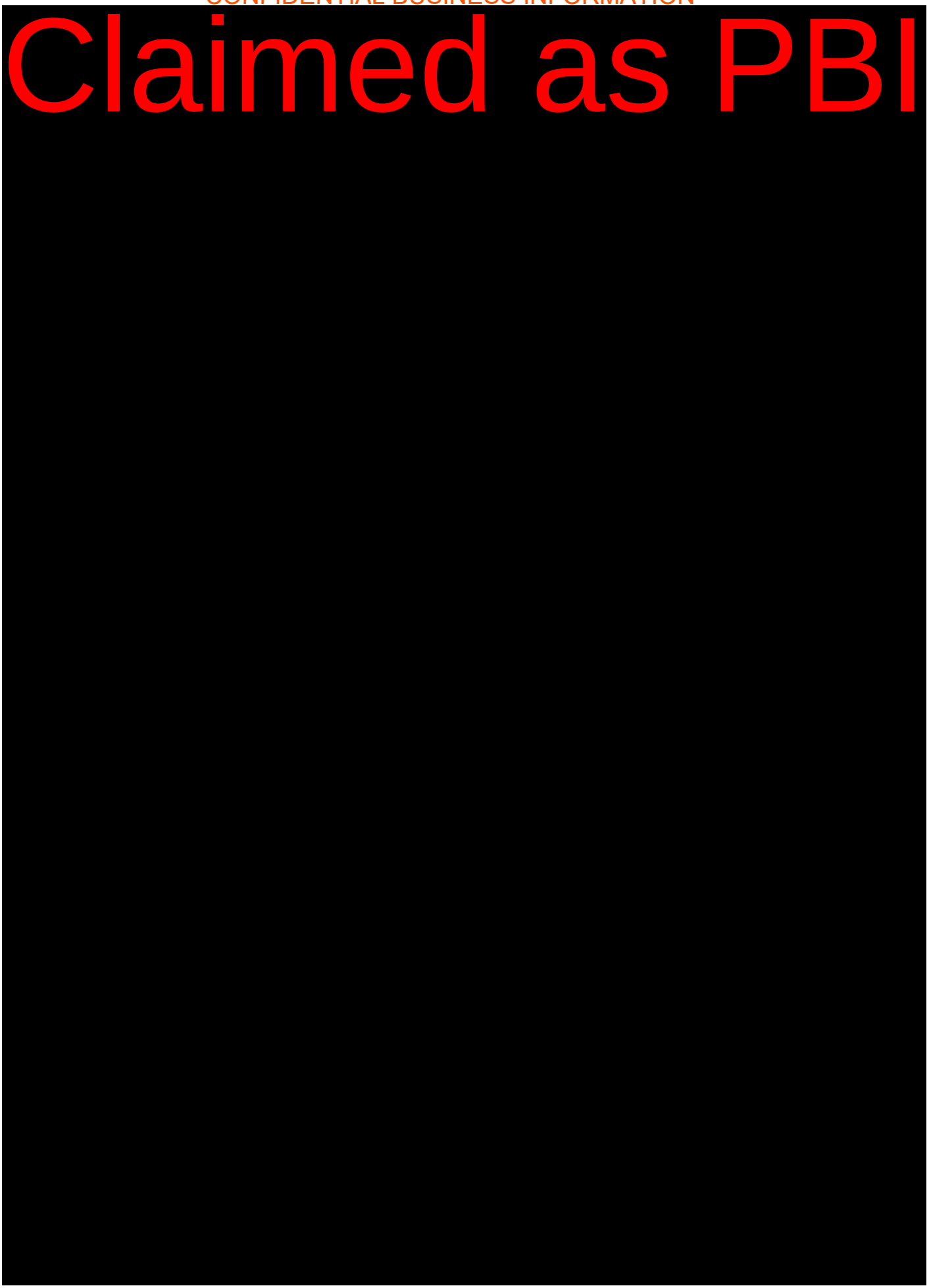
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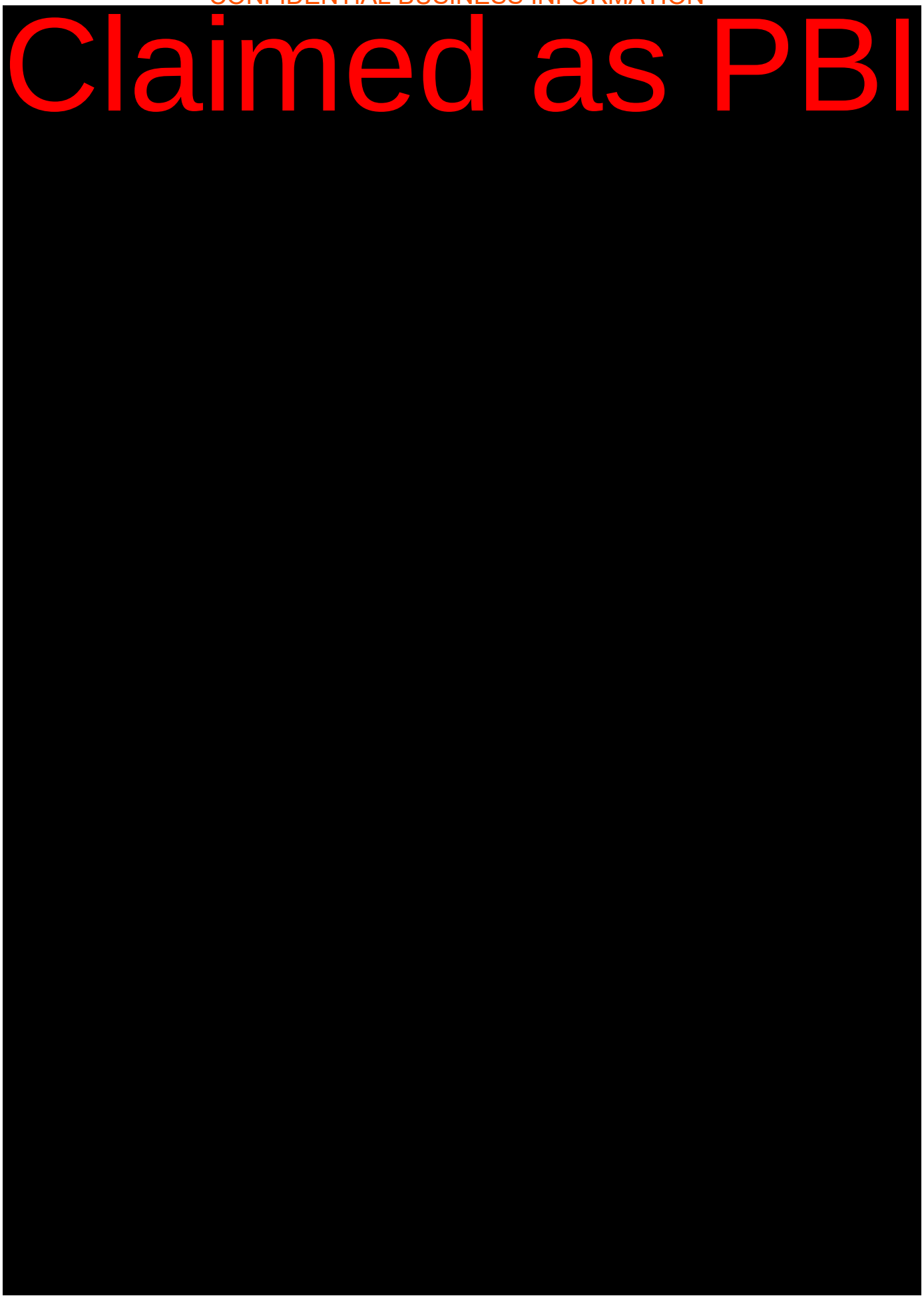

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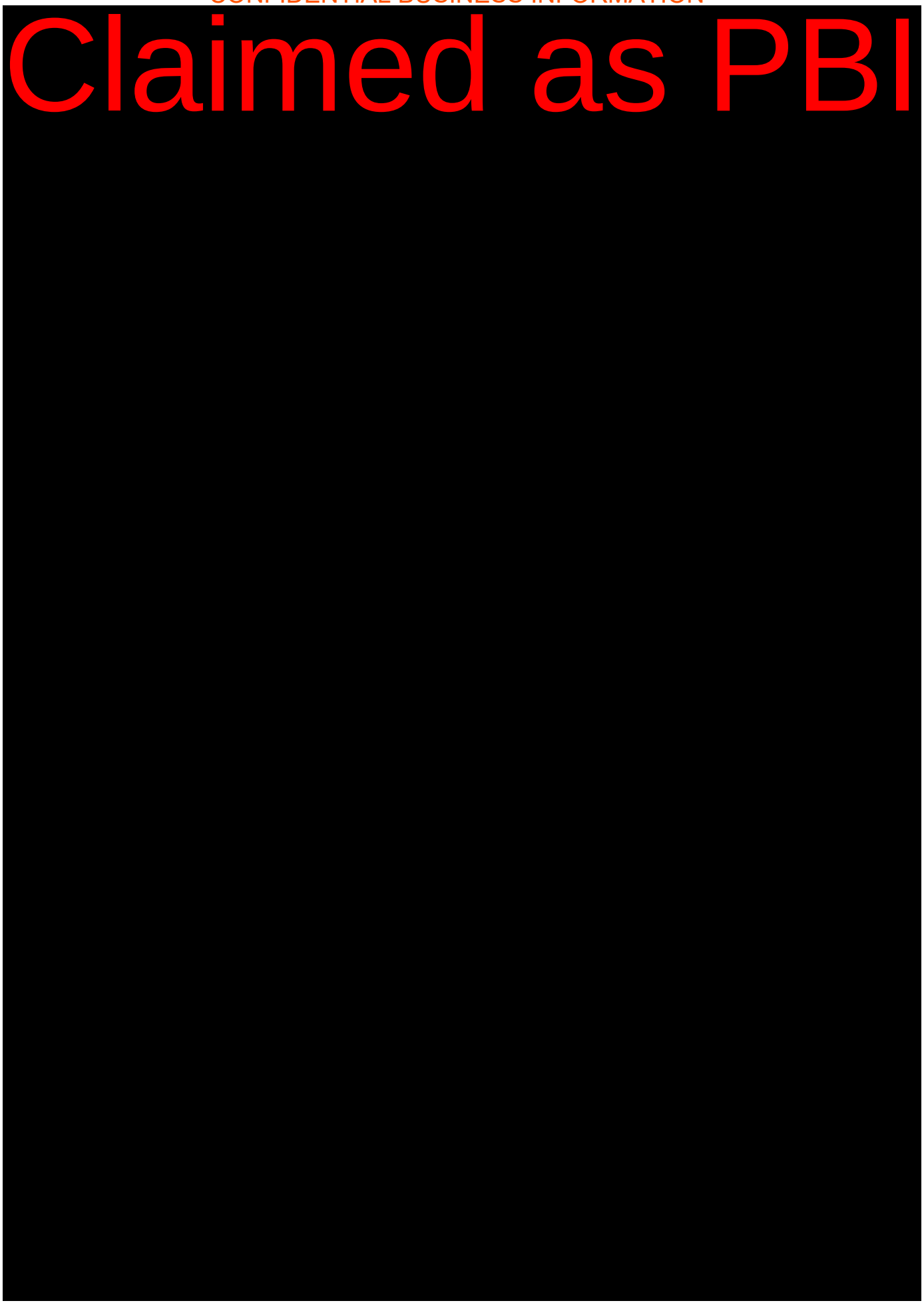

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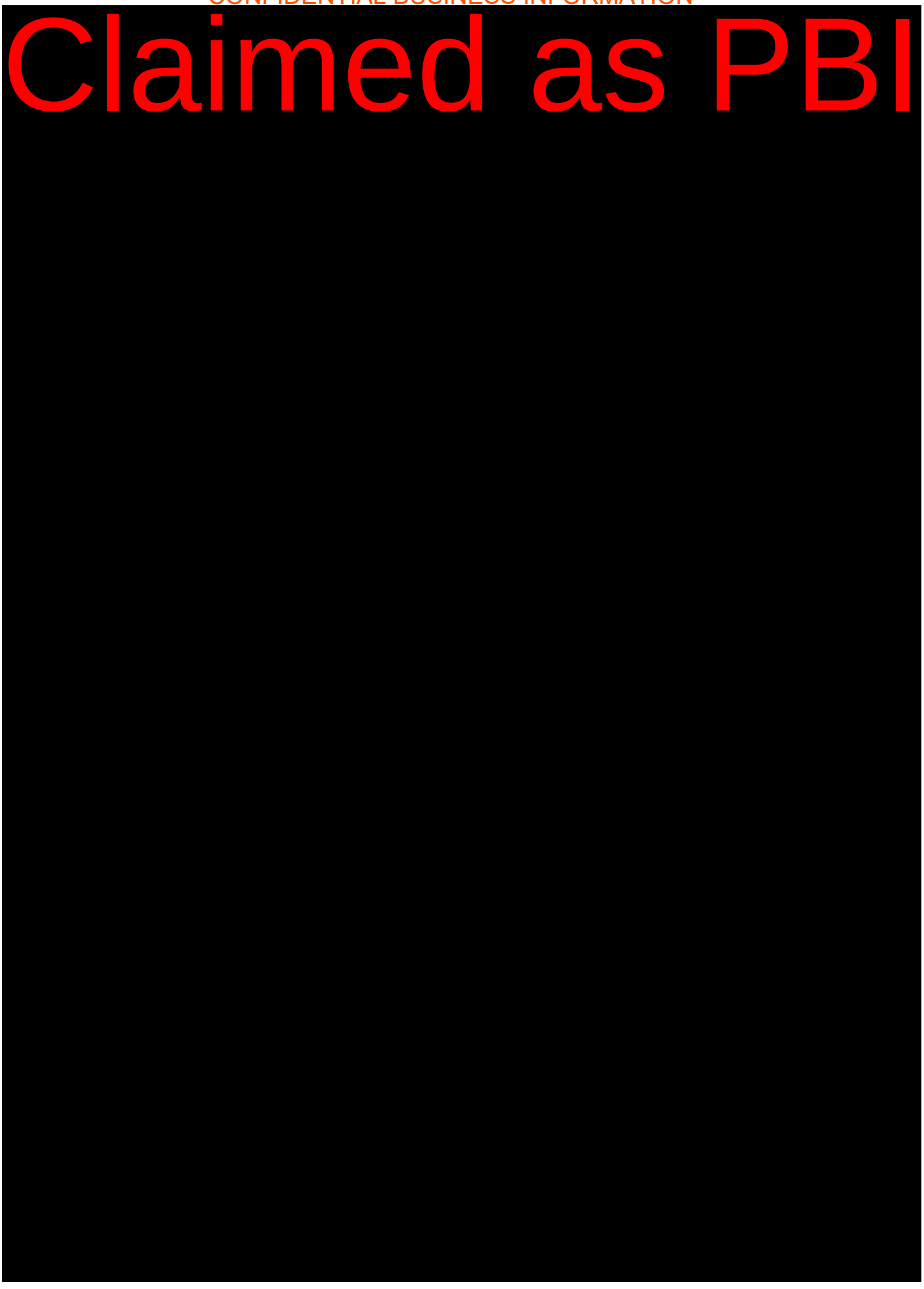

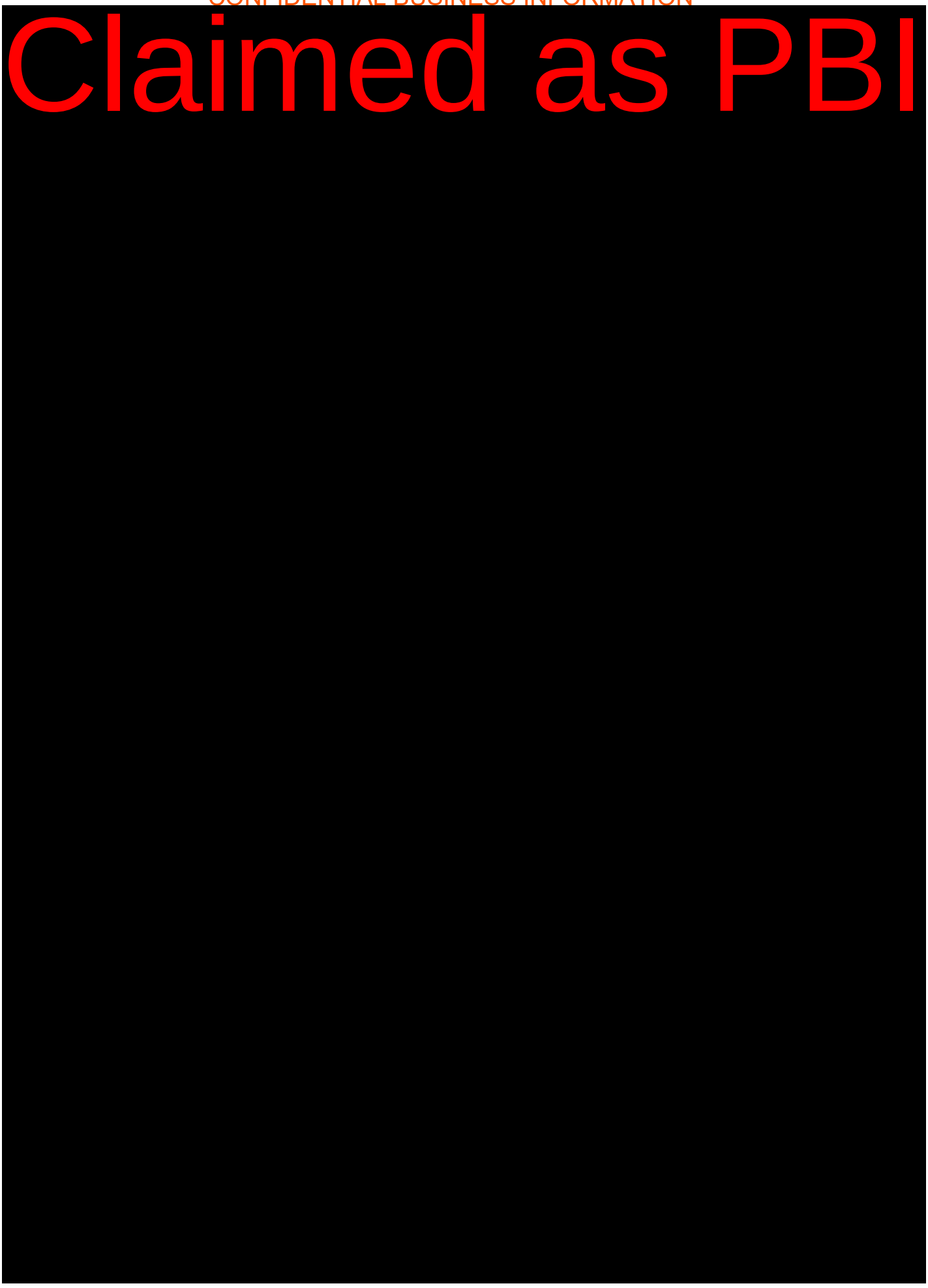
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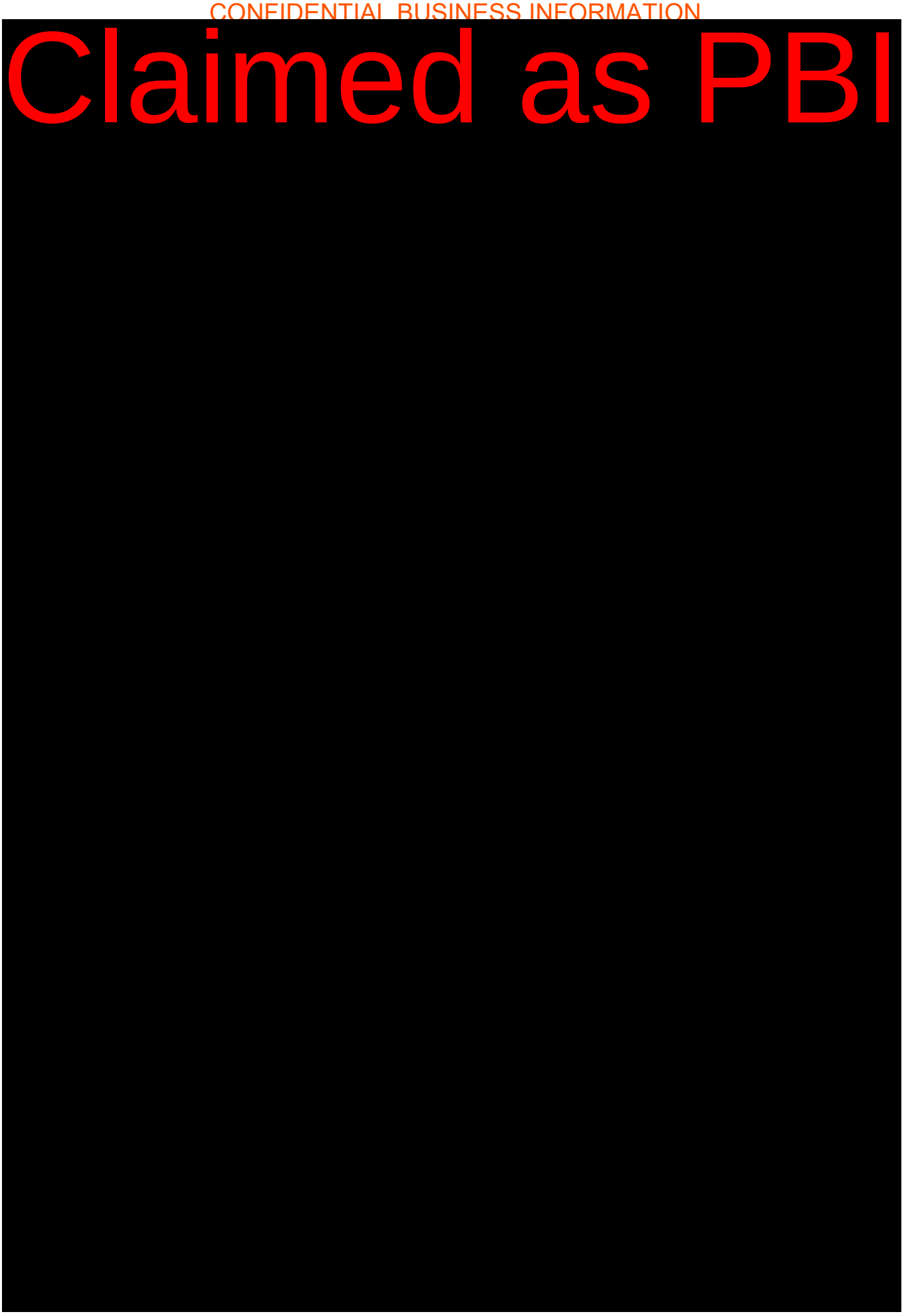

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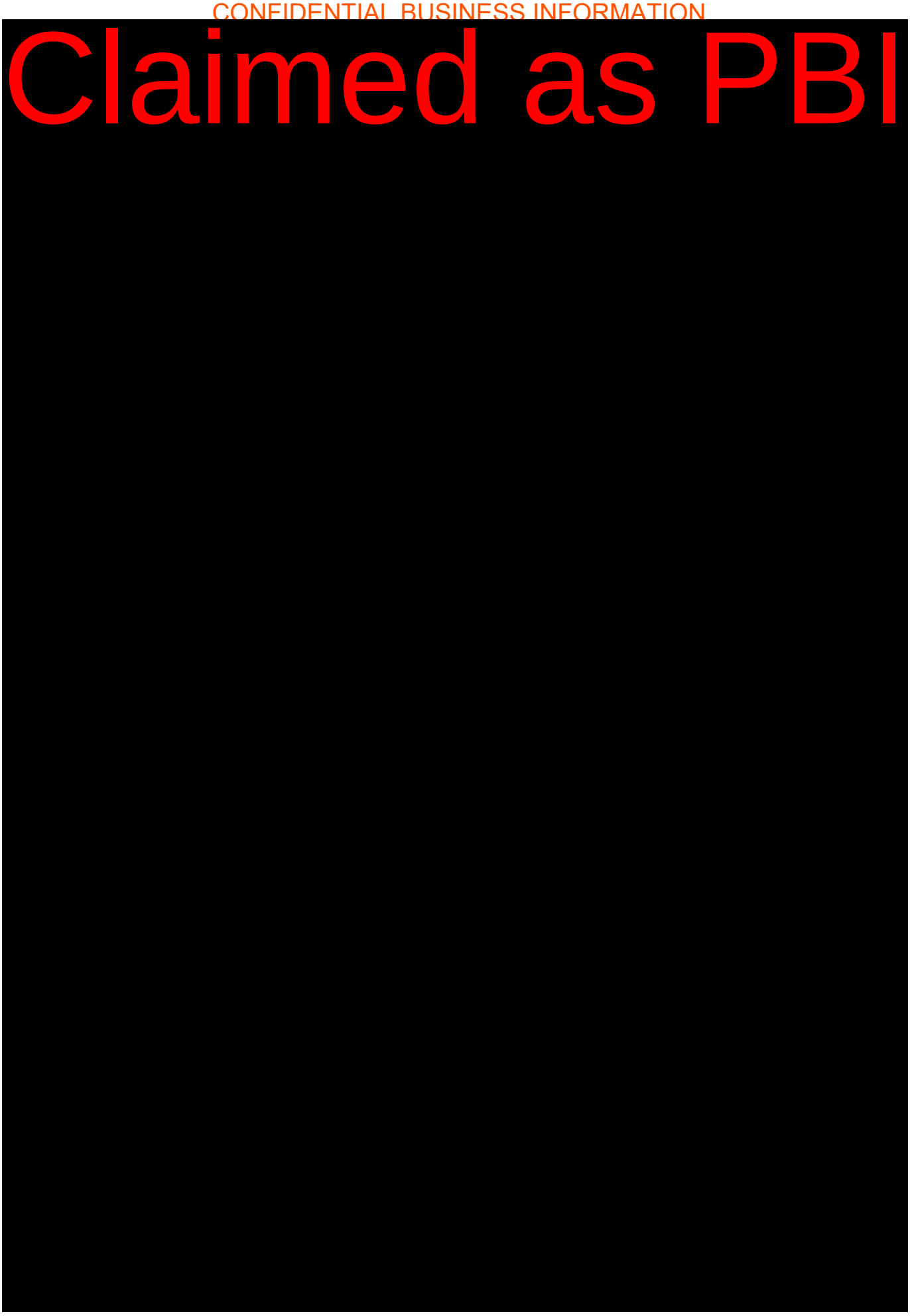

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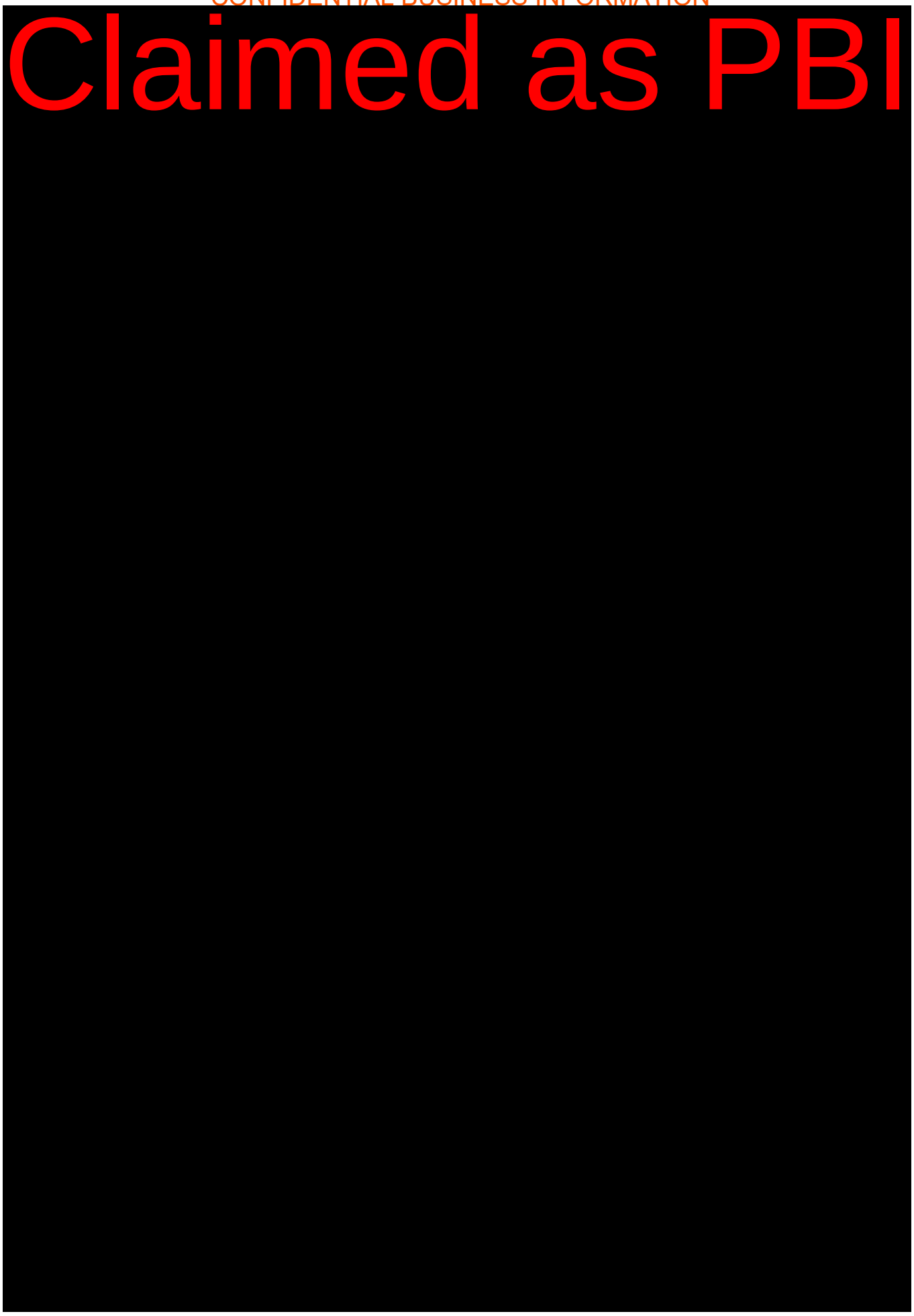

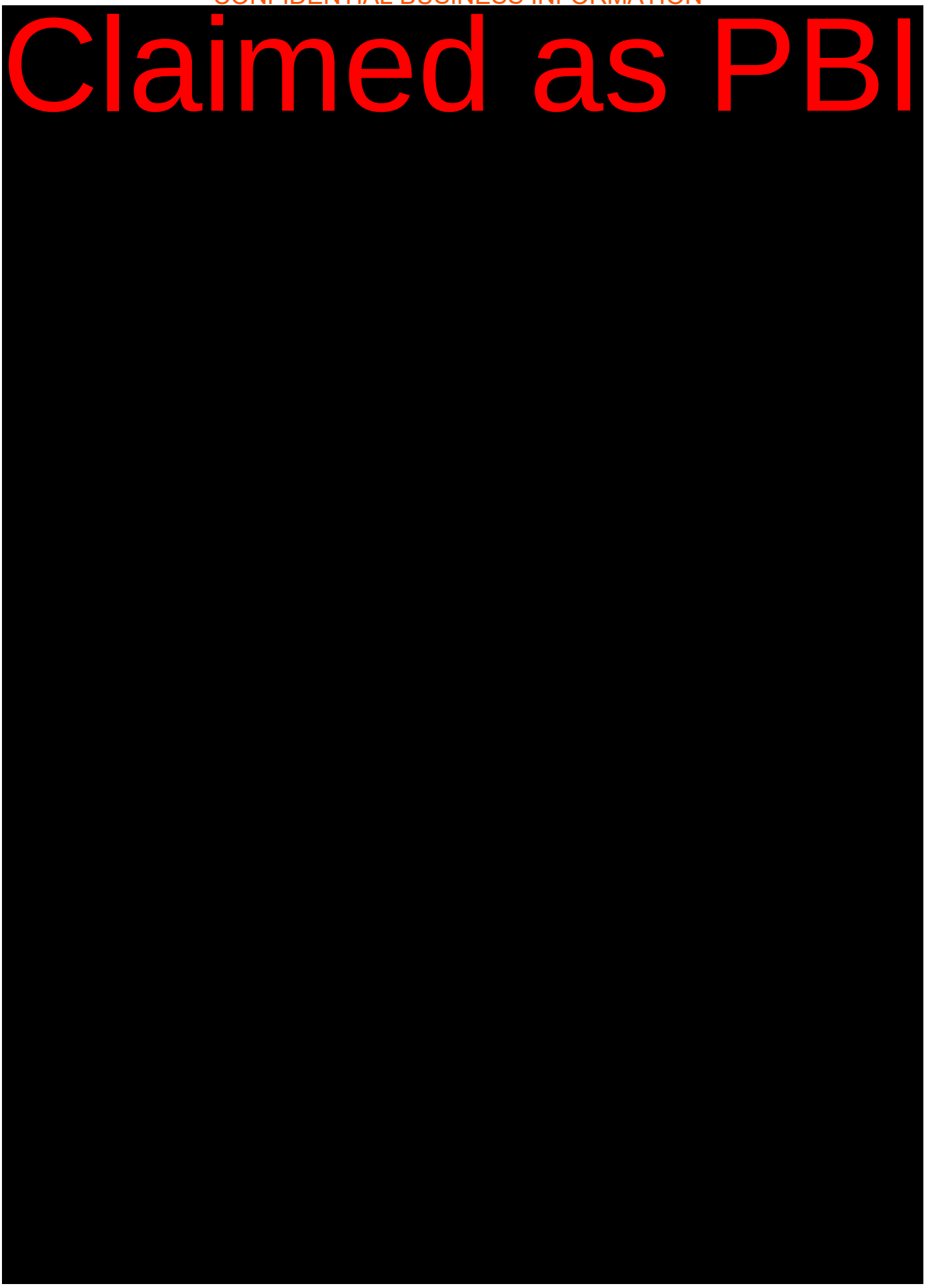
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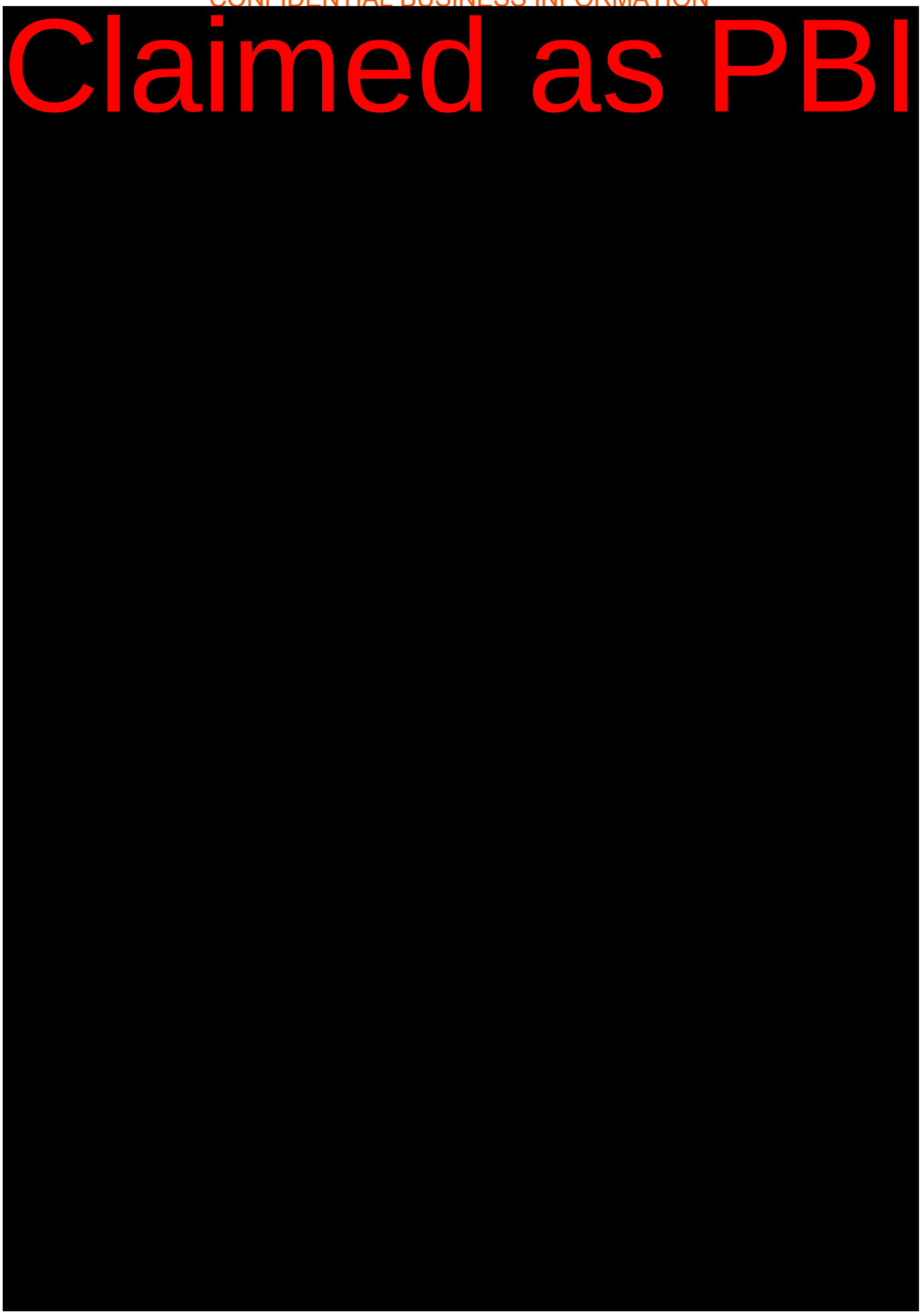

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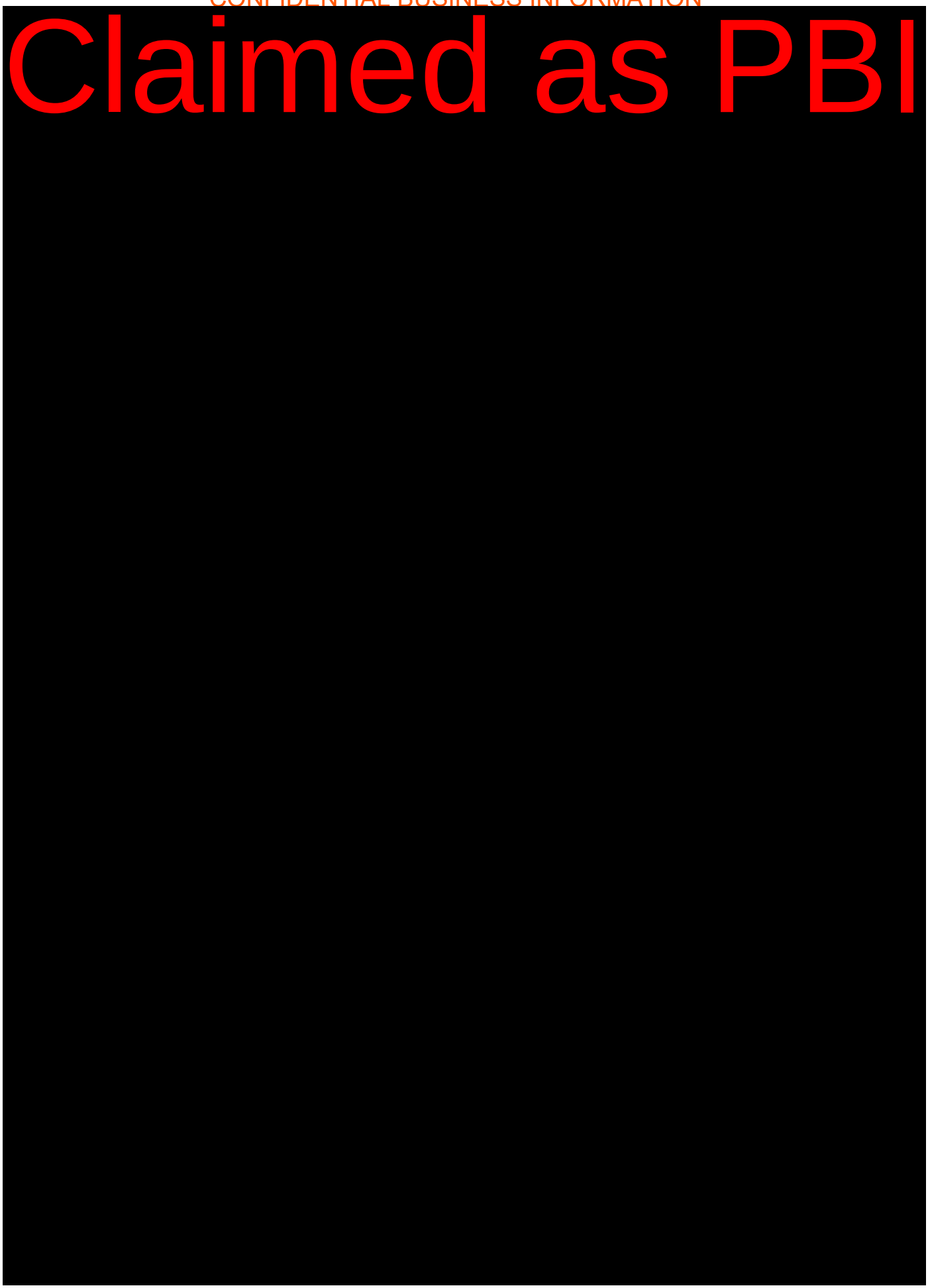

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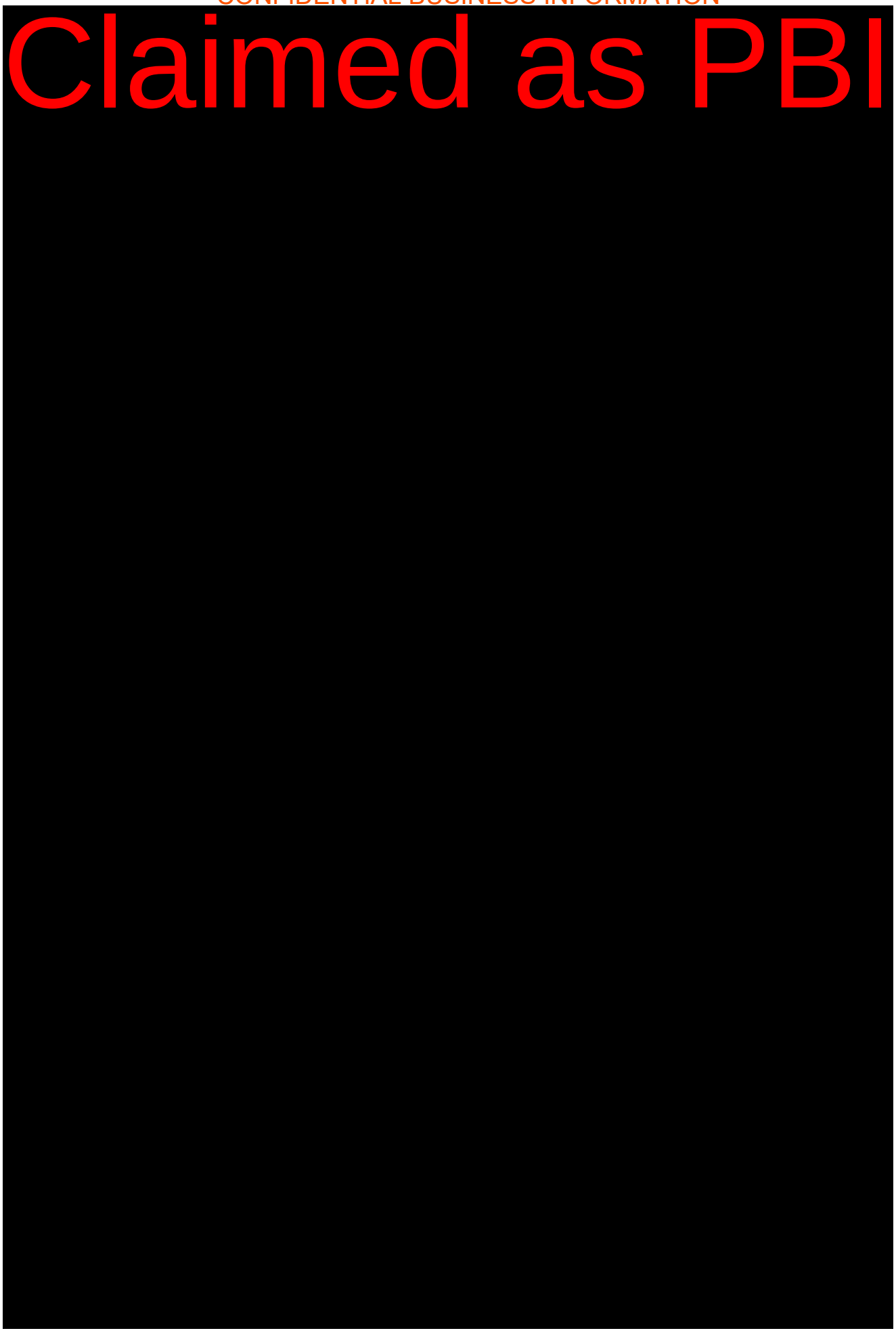

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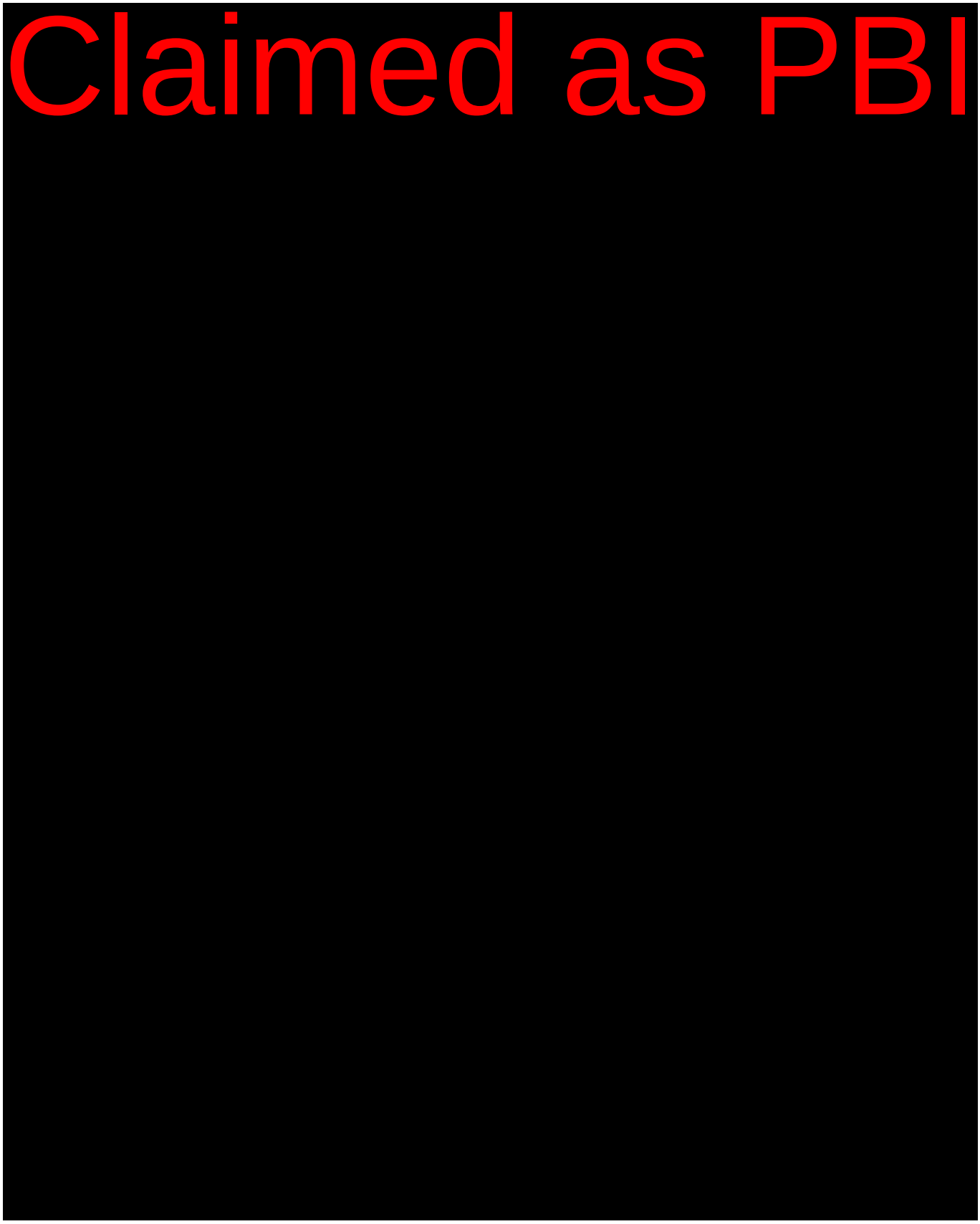
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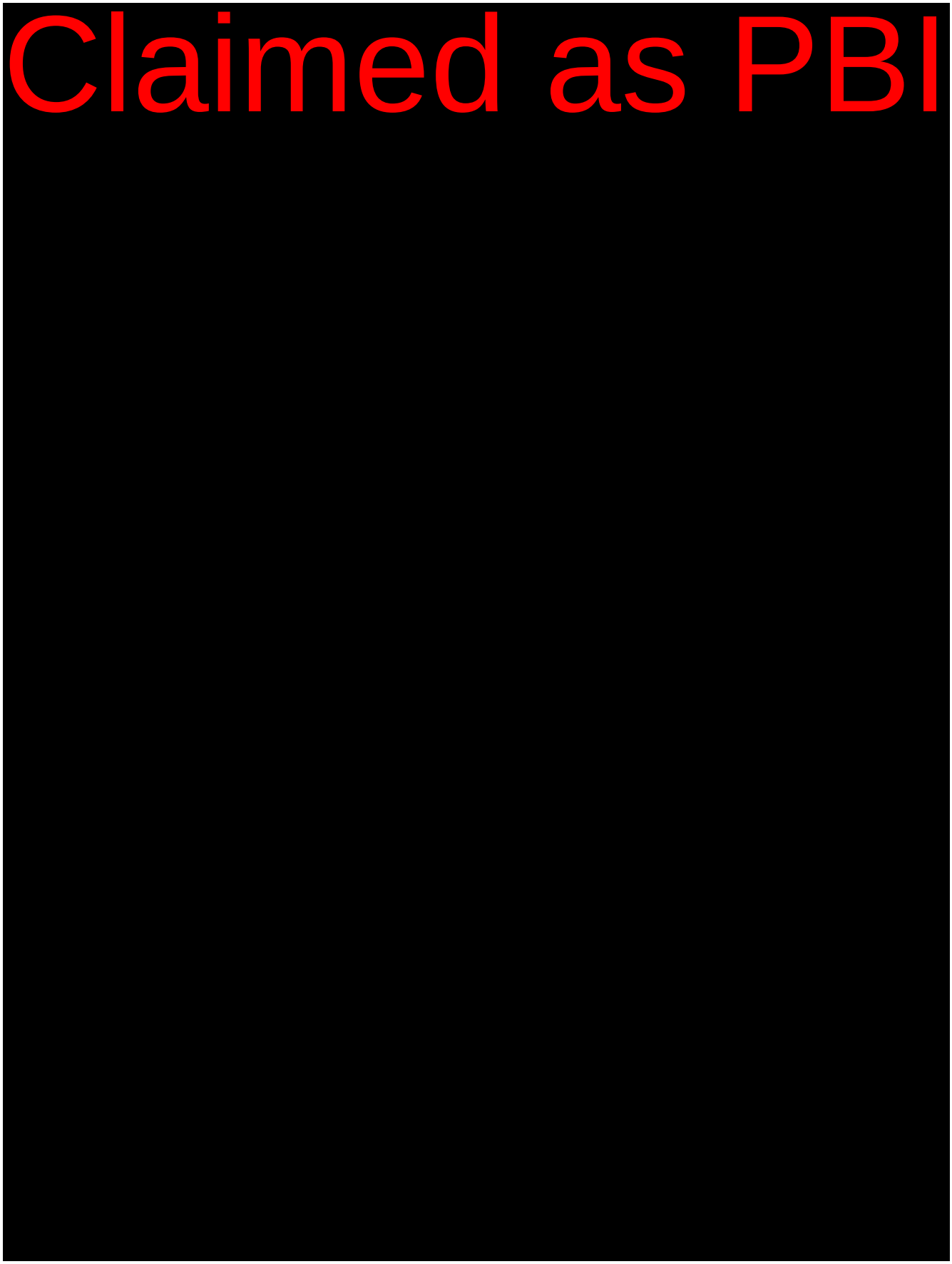
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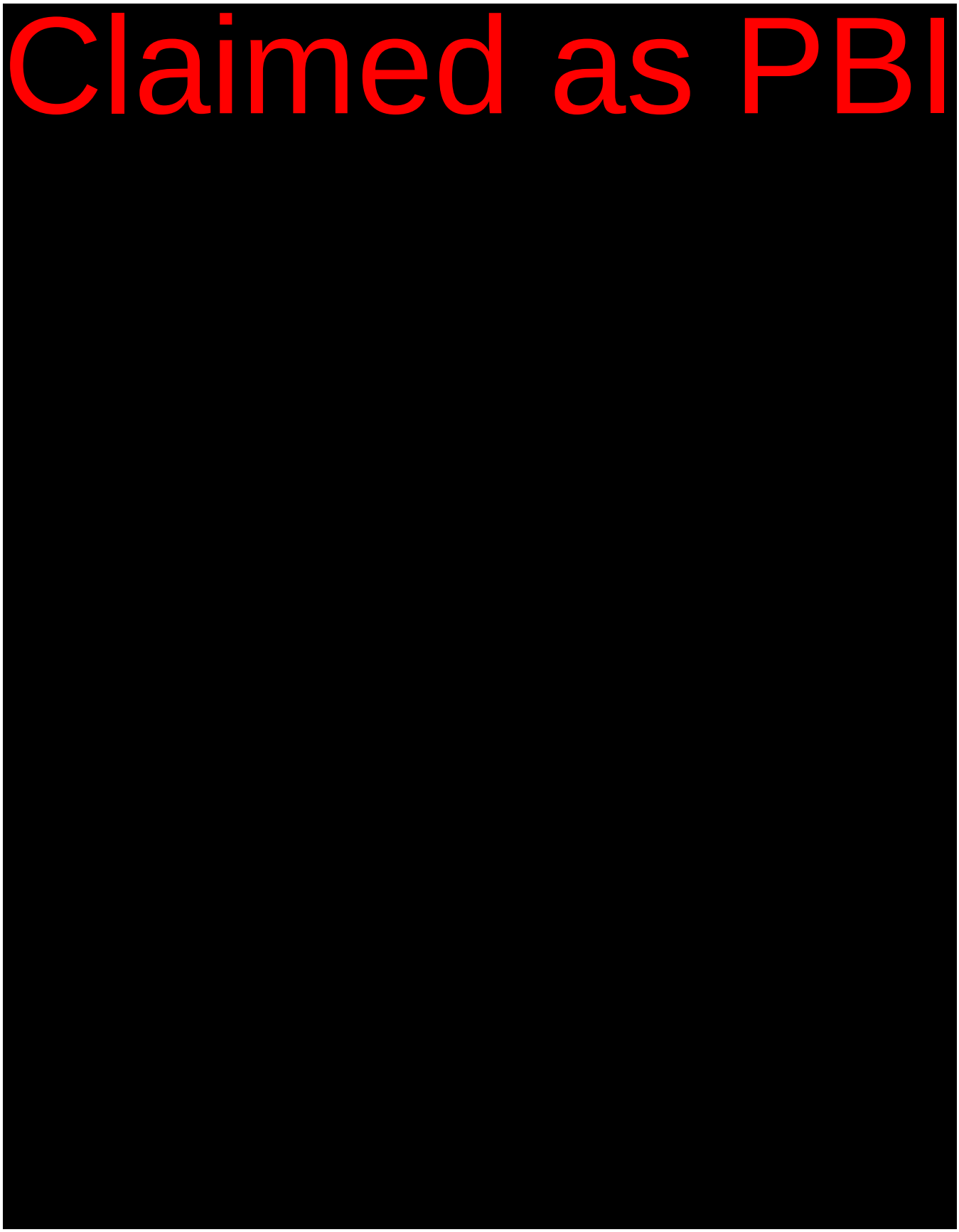
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Appendix F Testing and Monitoring

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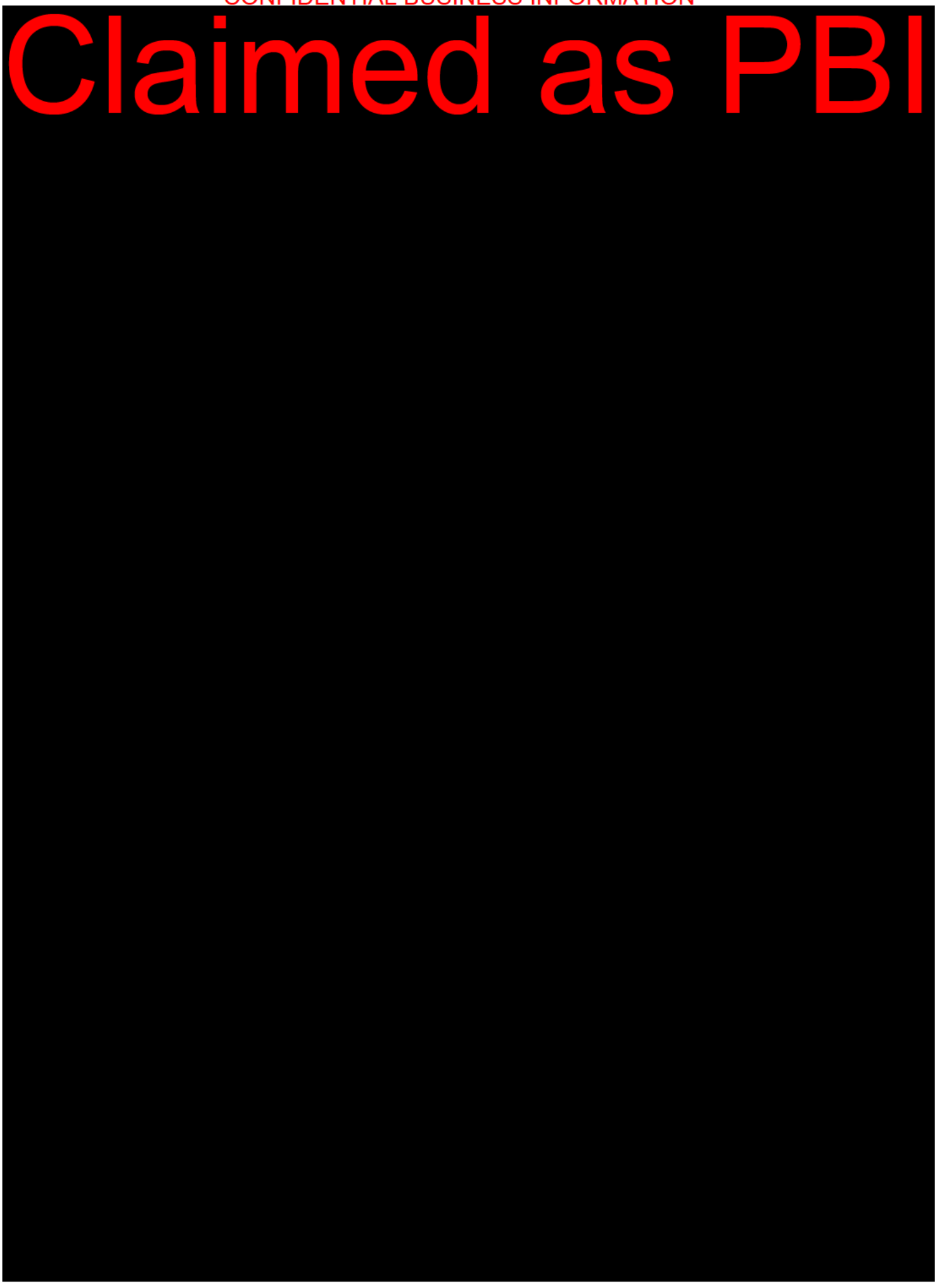

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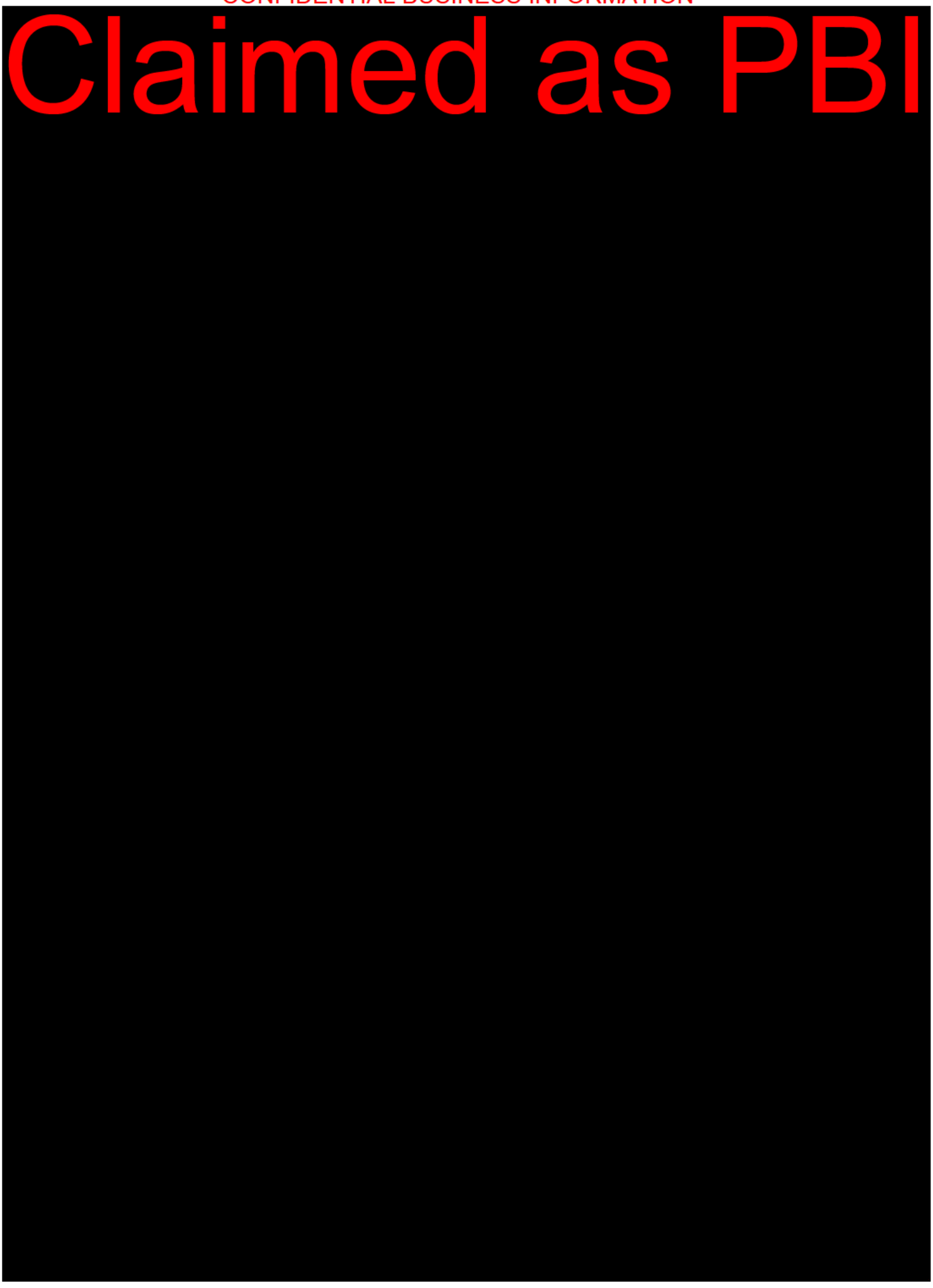

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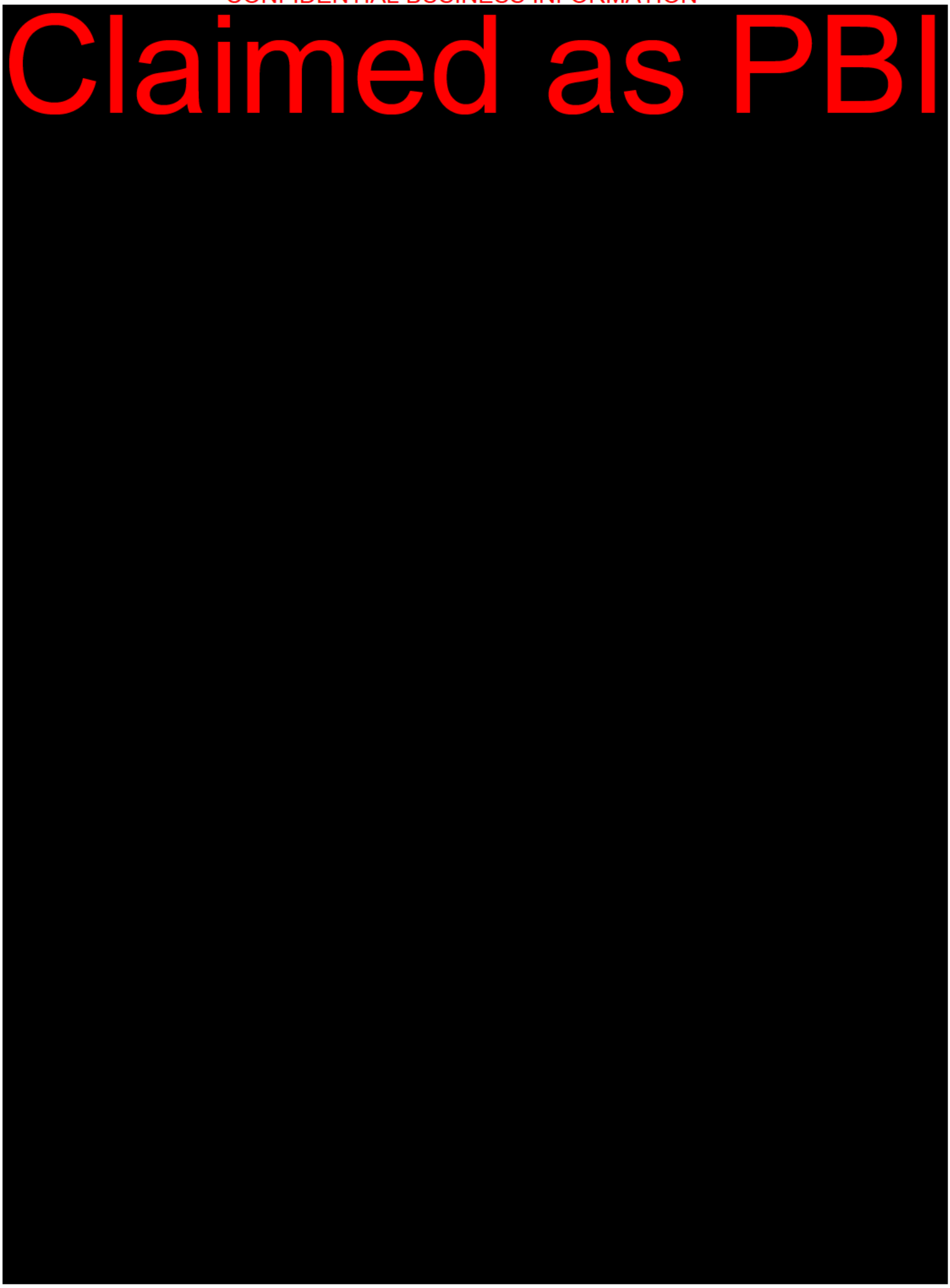

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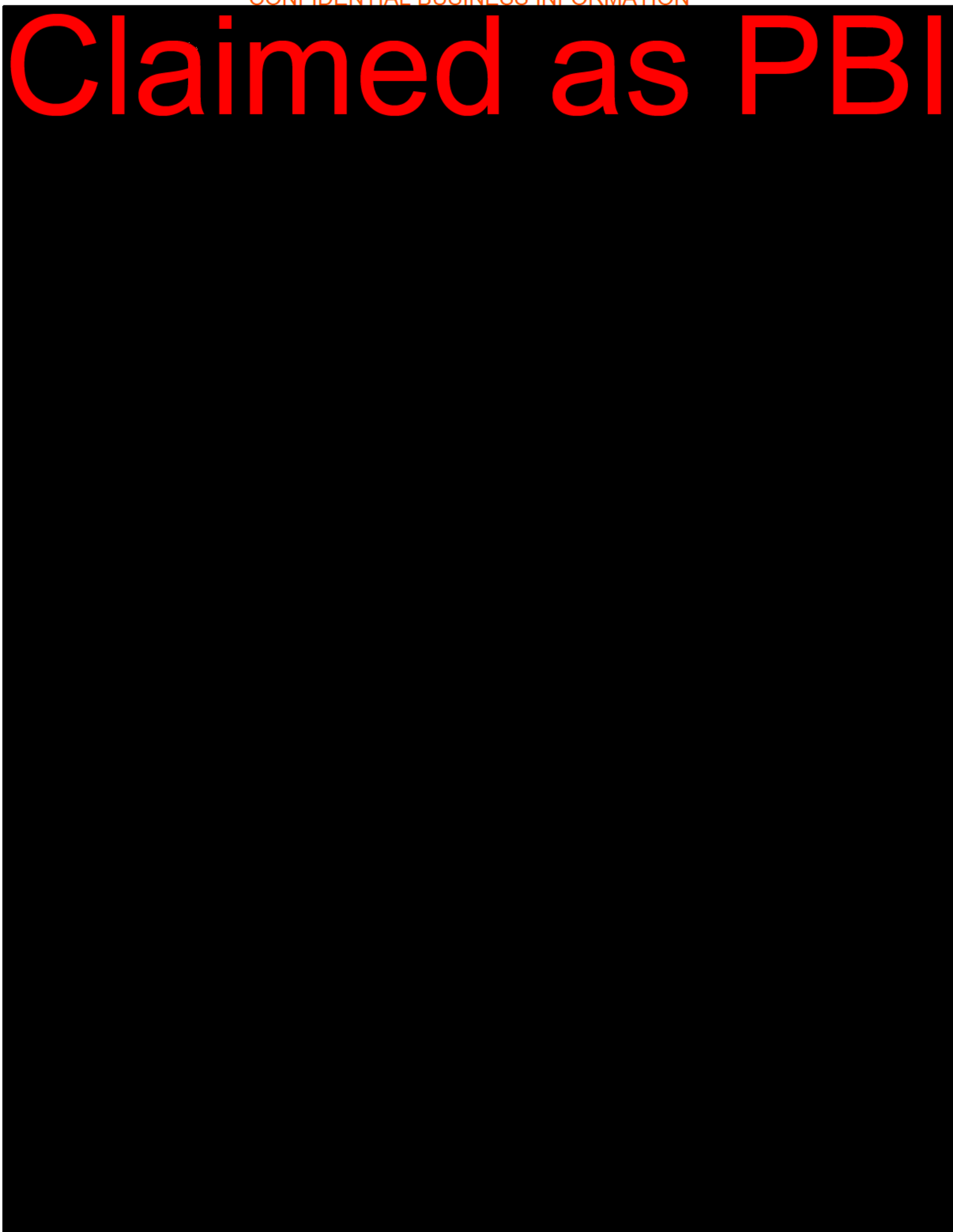

Appendix G FEMA Maps

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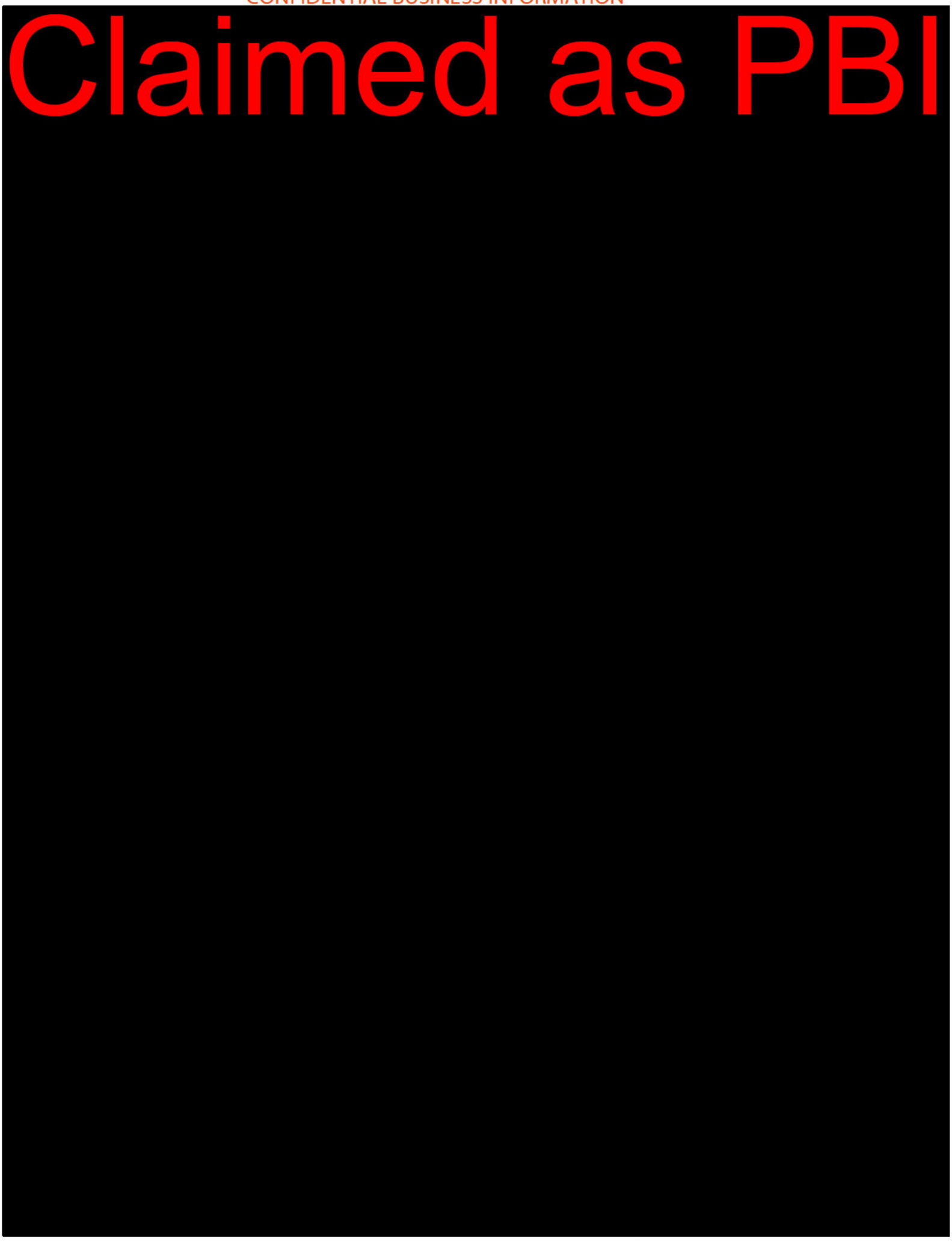

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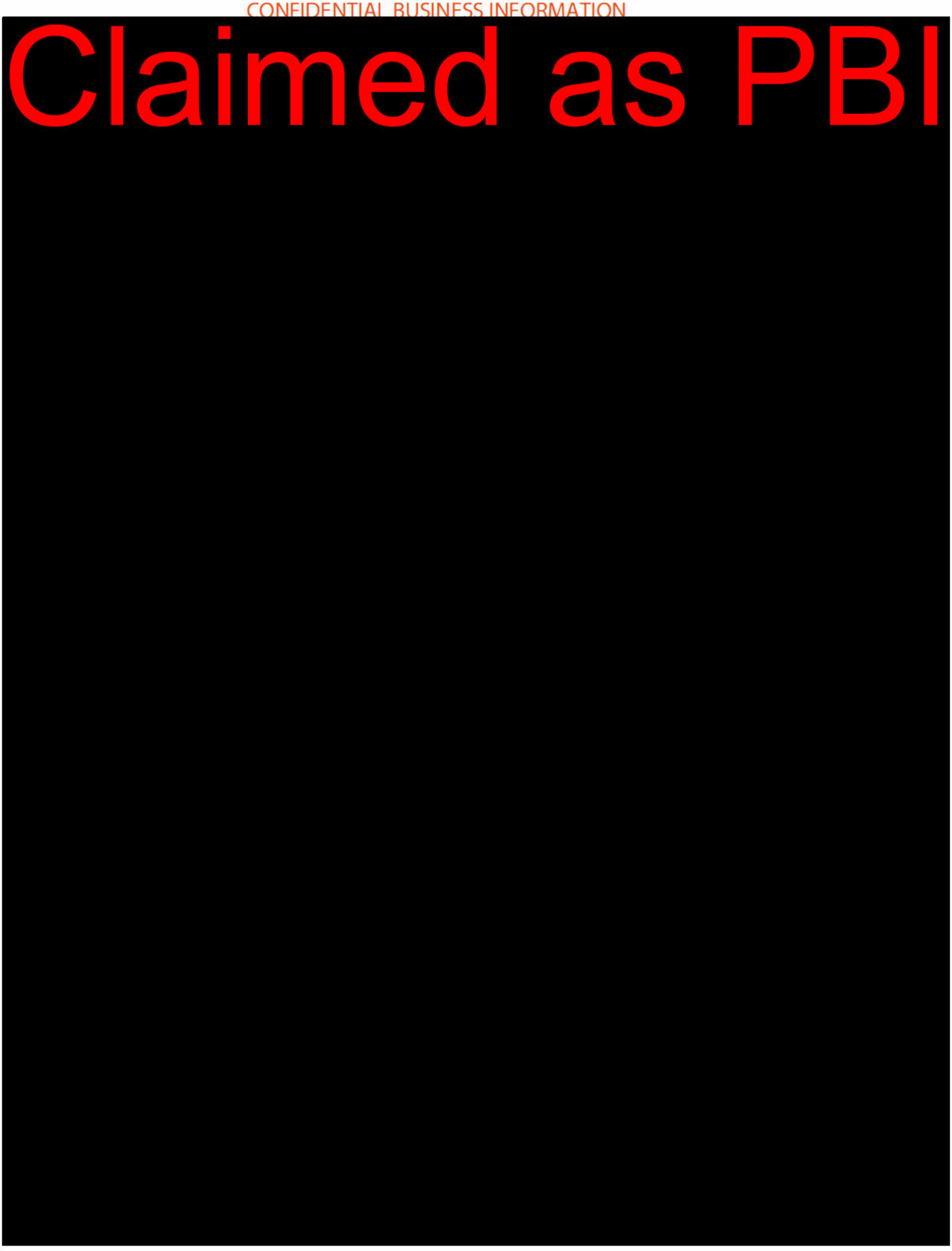

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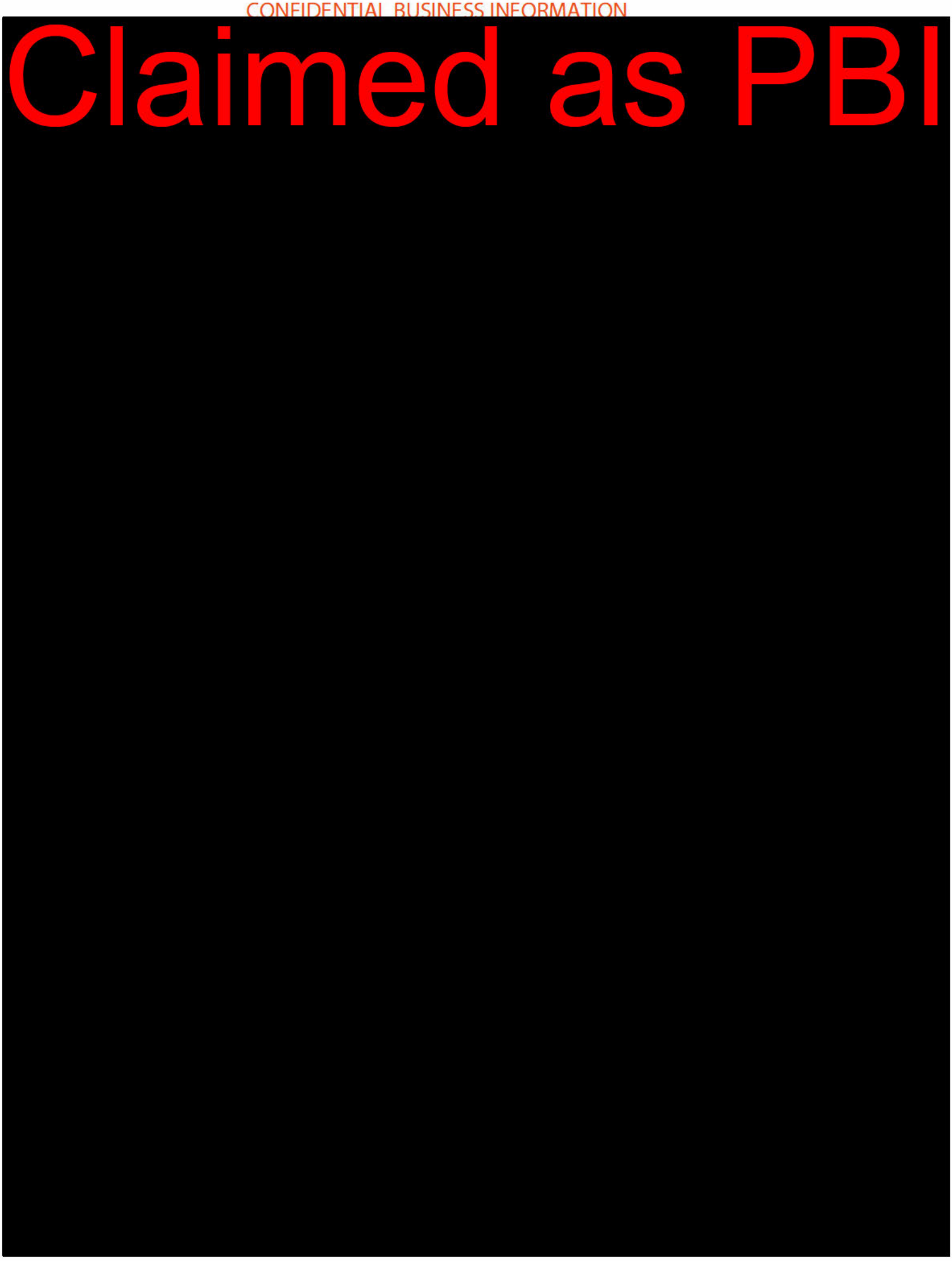

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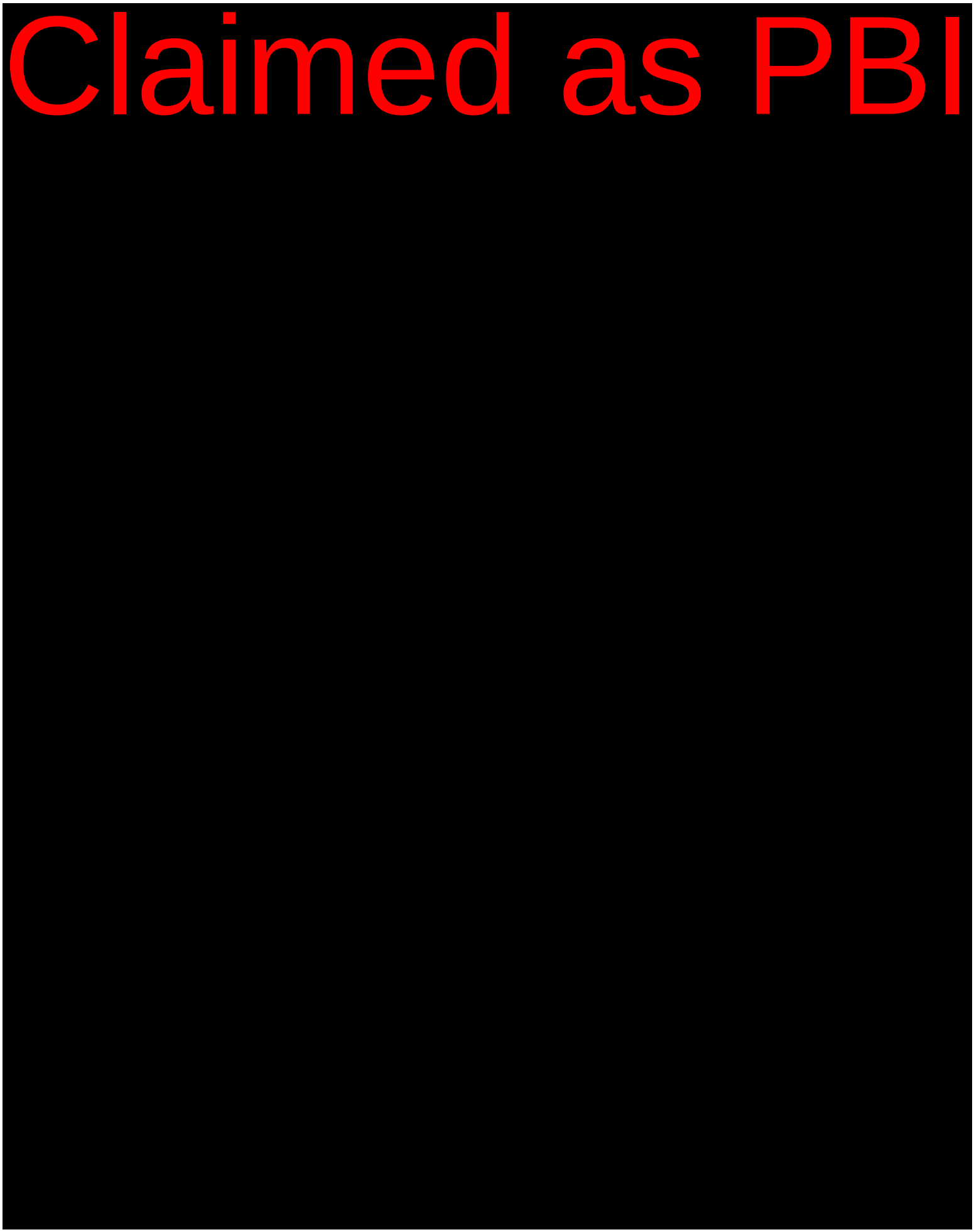
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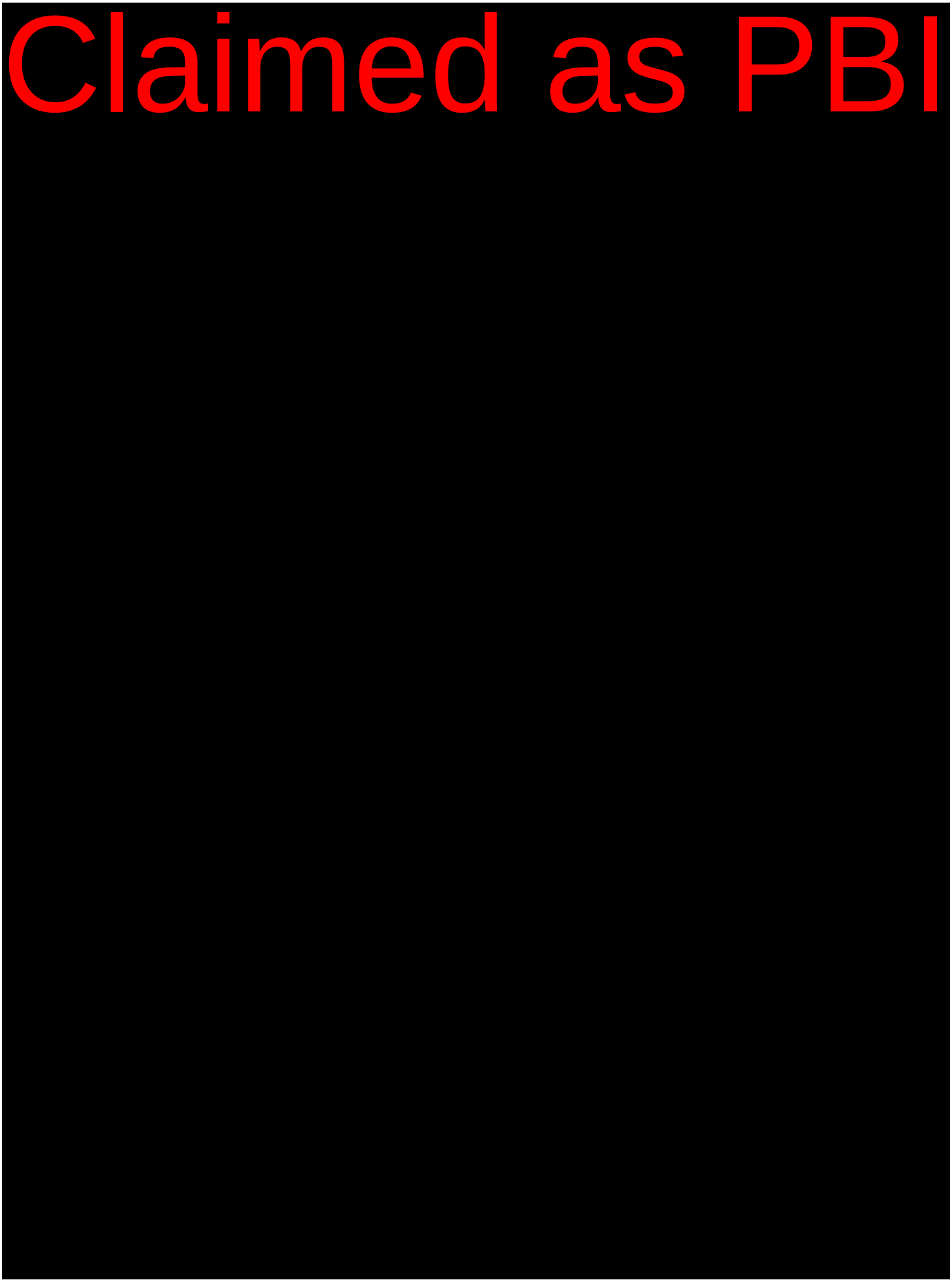
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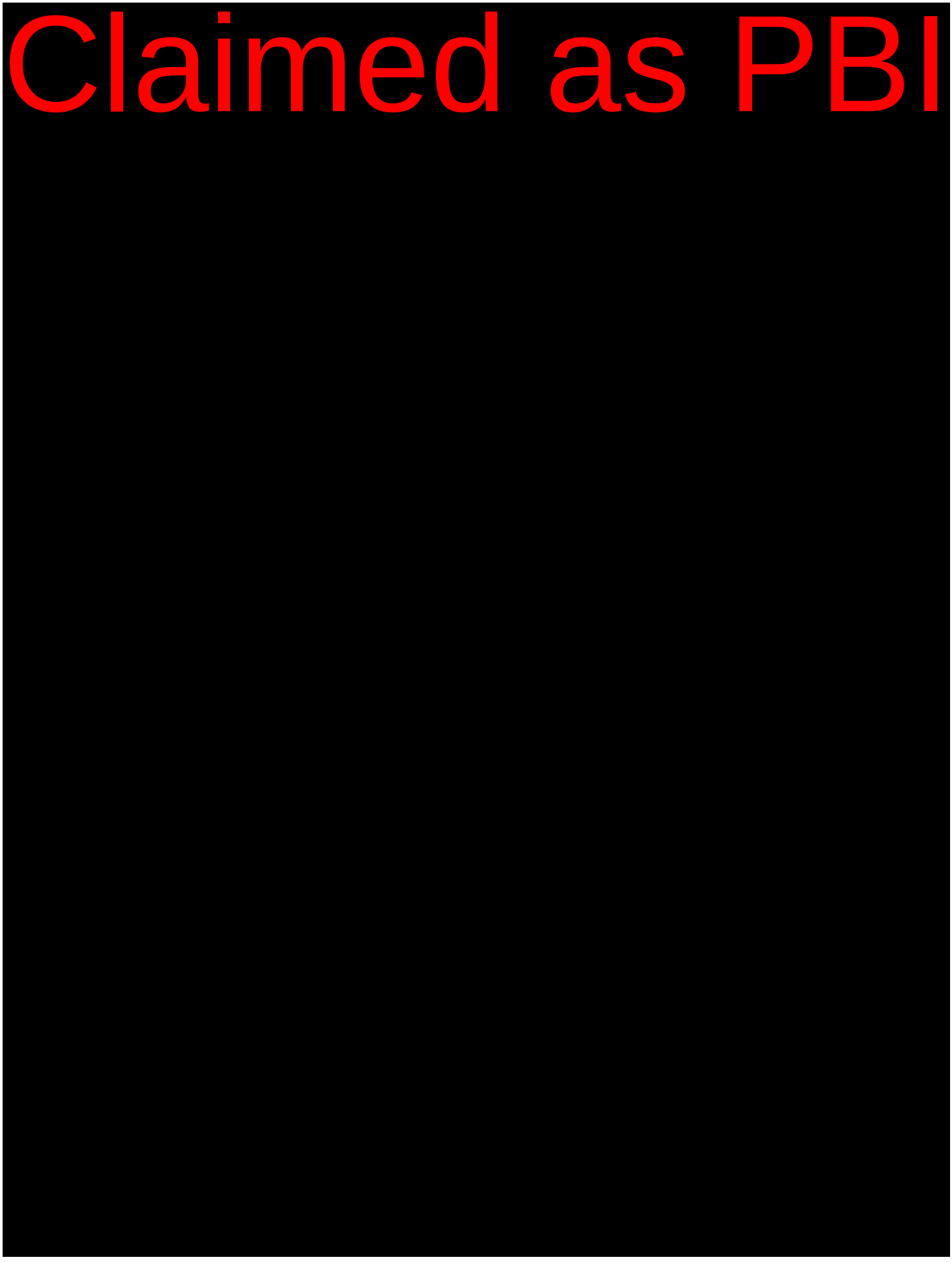
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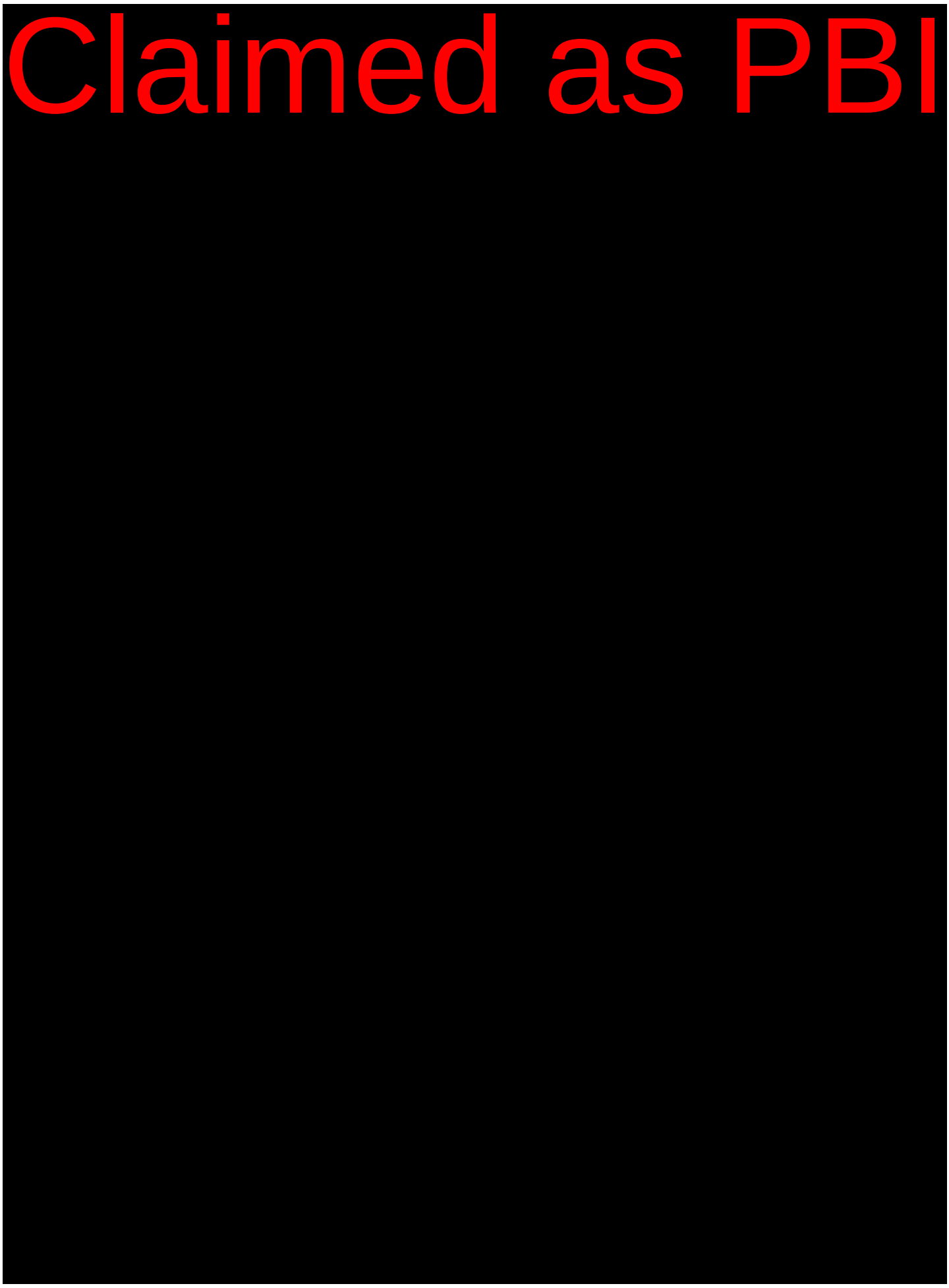
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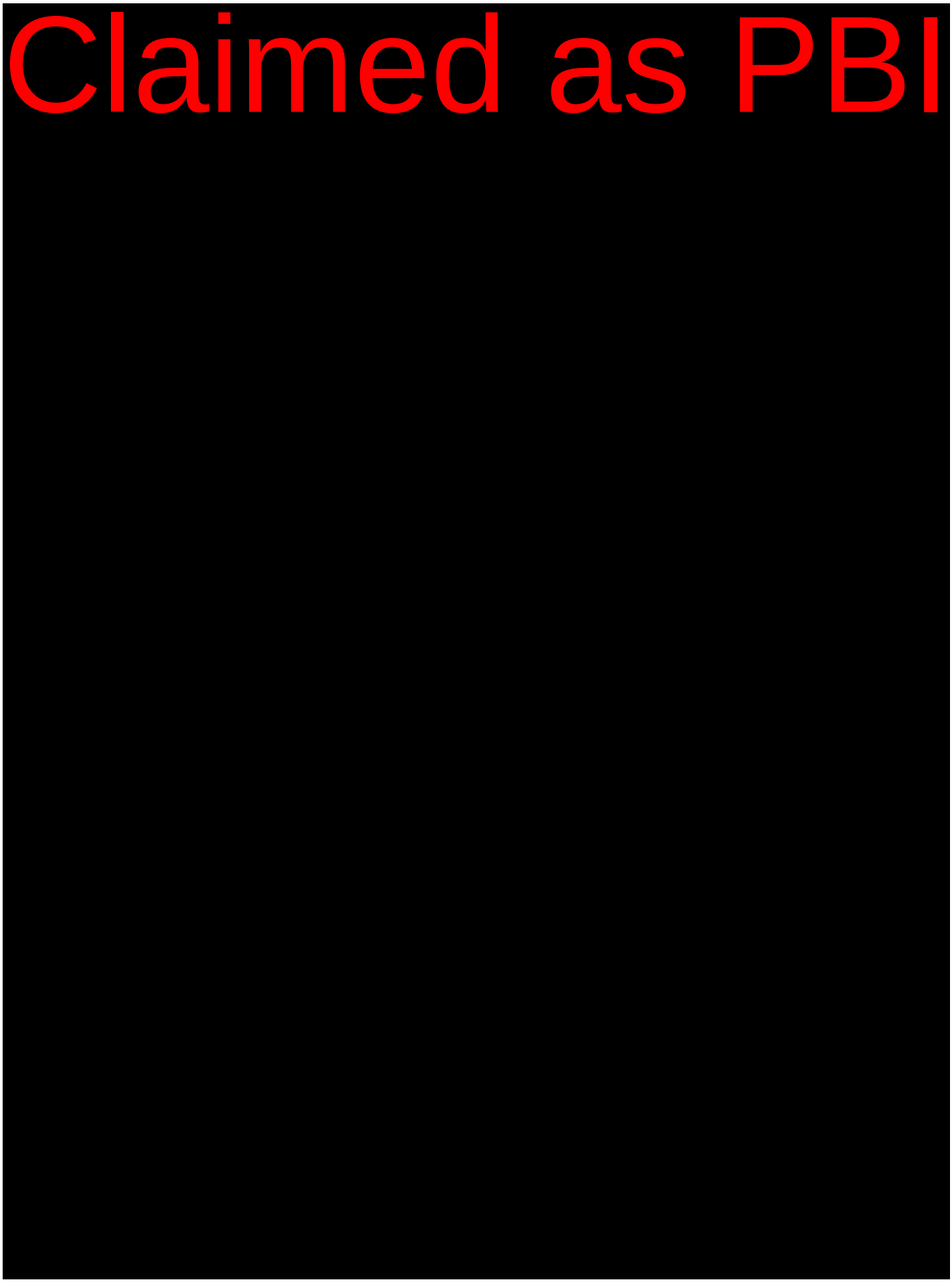
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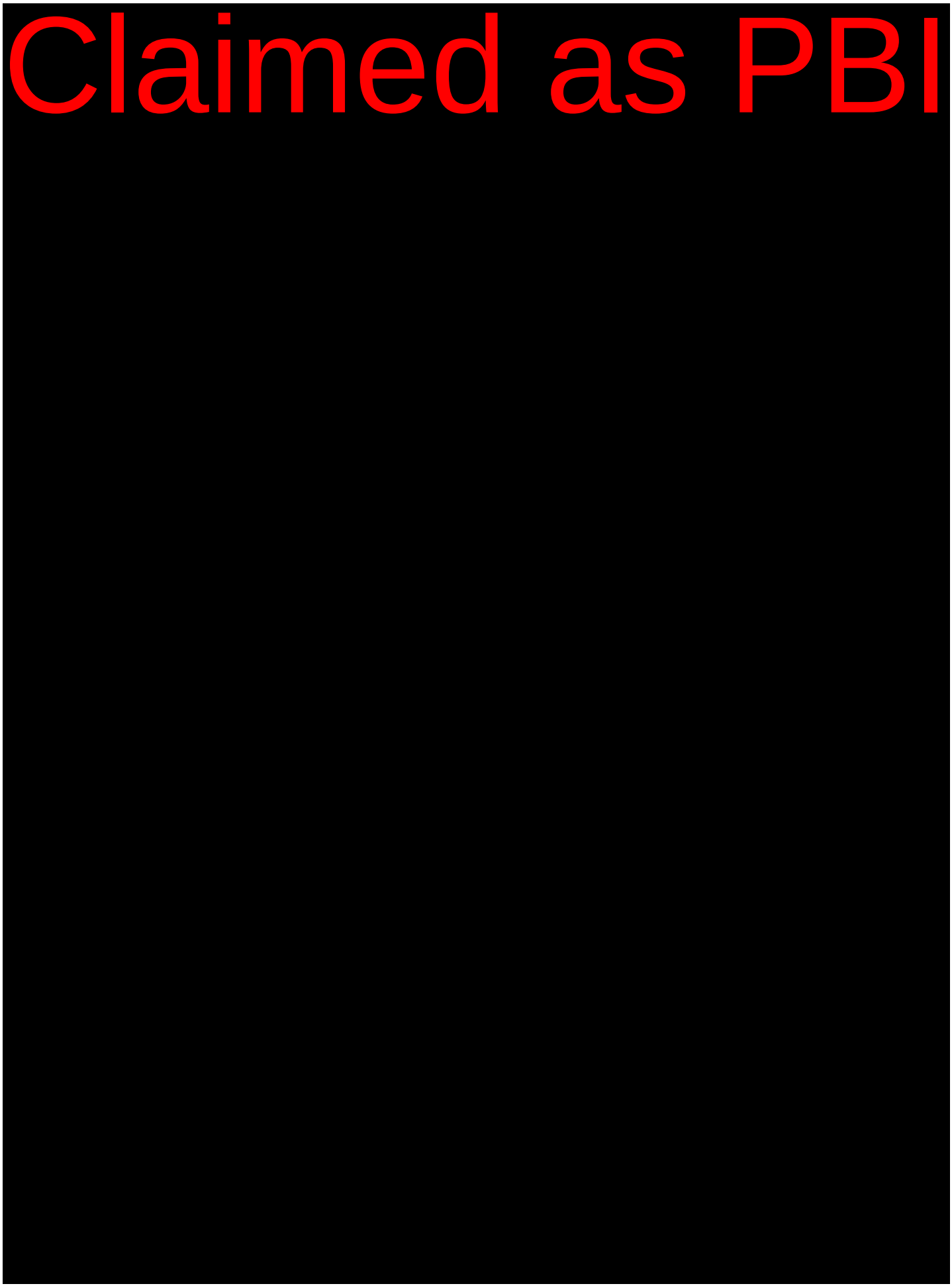
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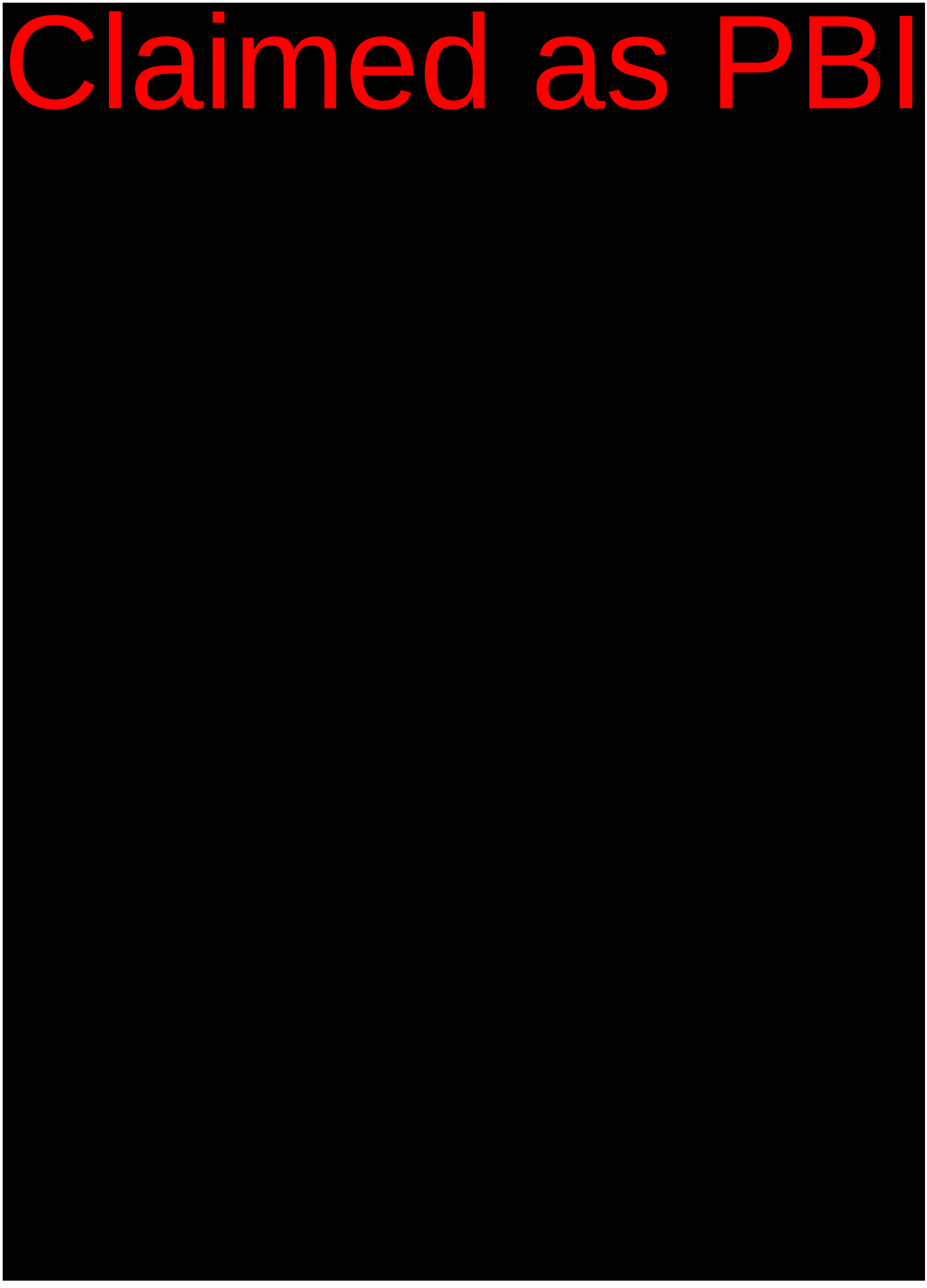
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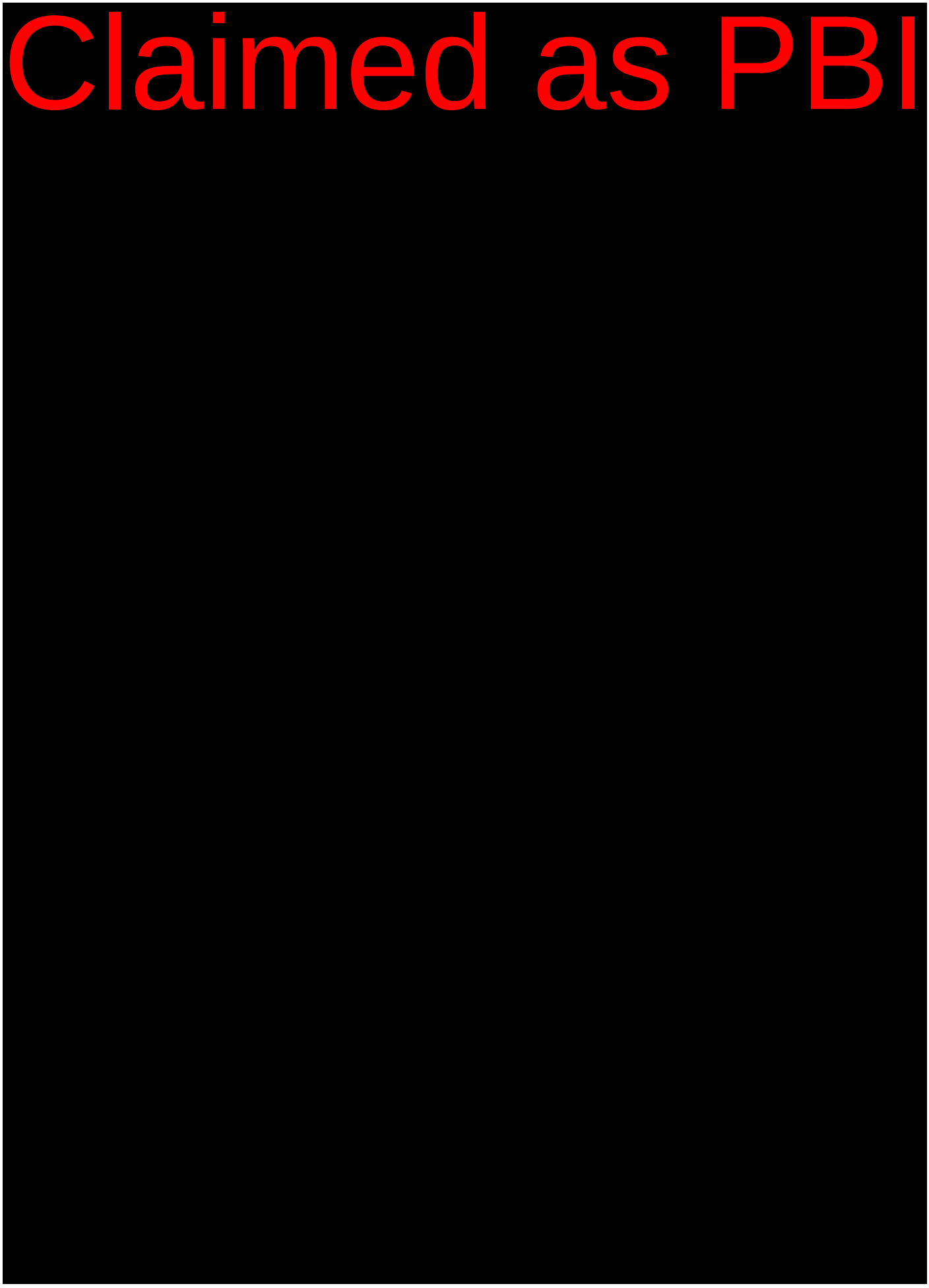
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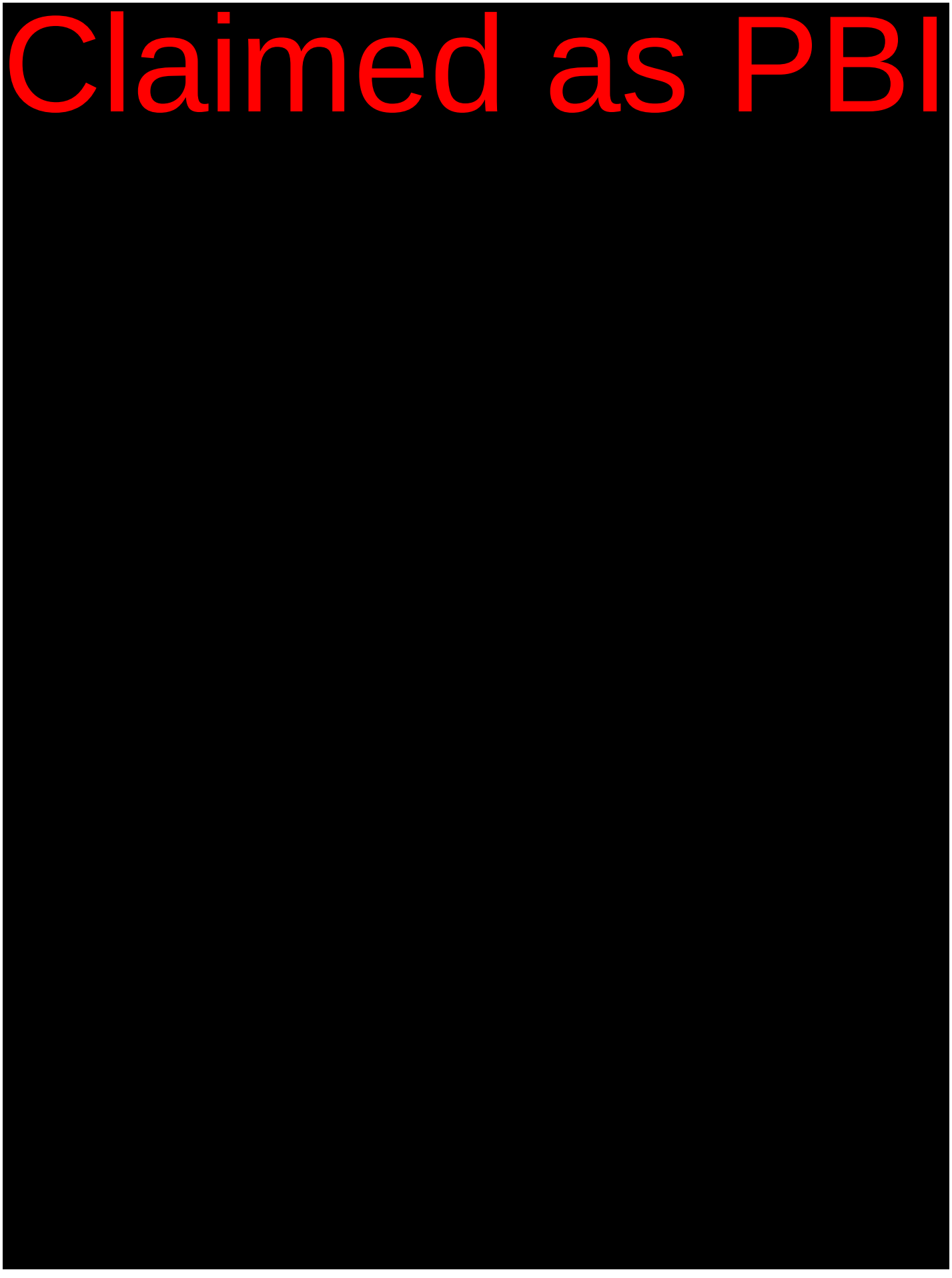
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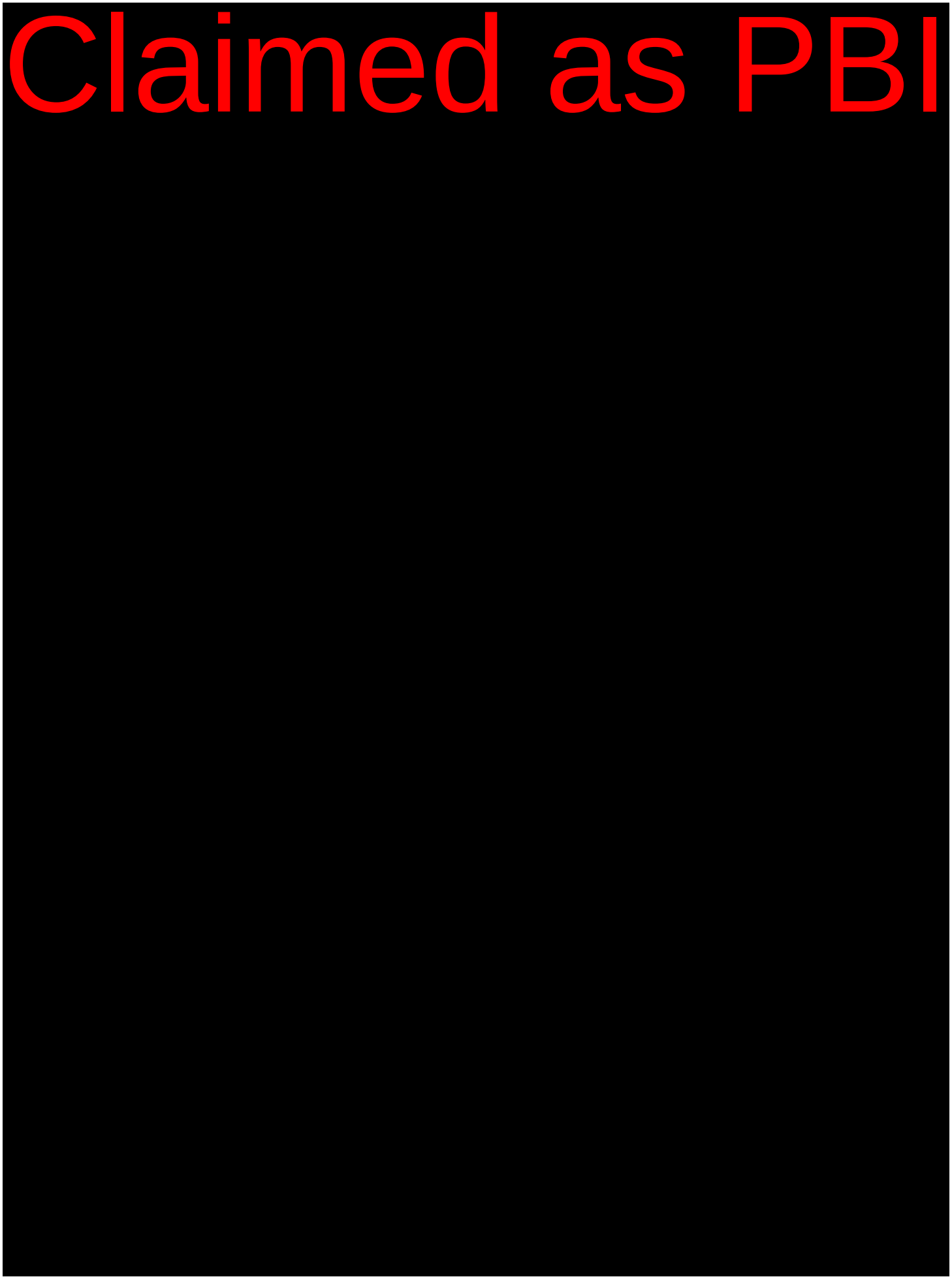
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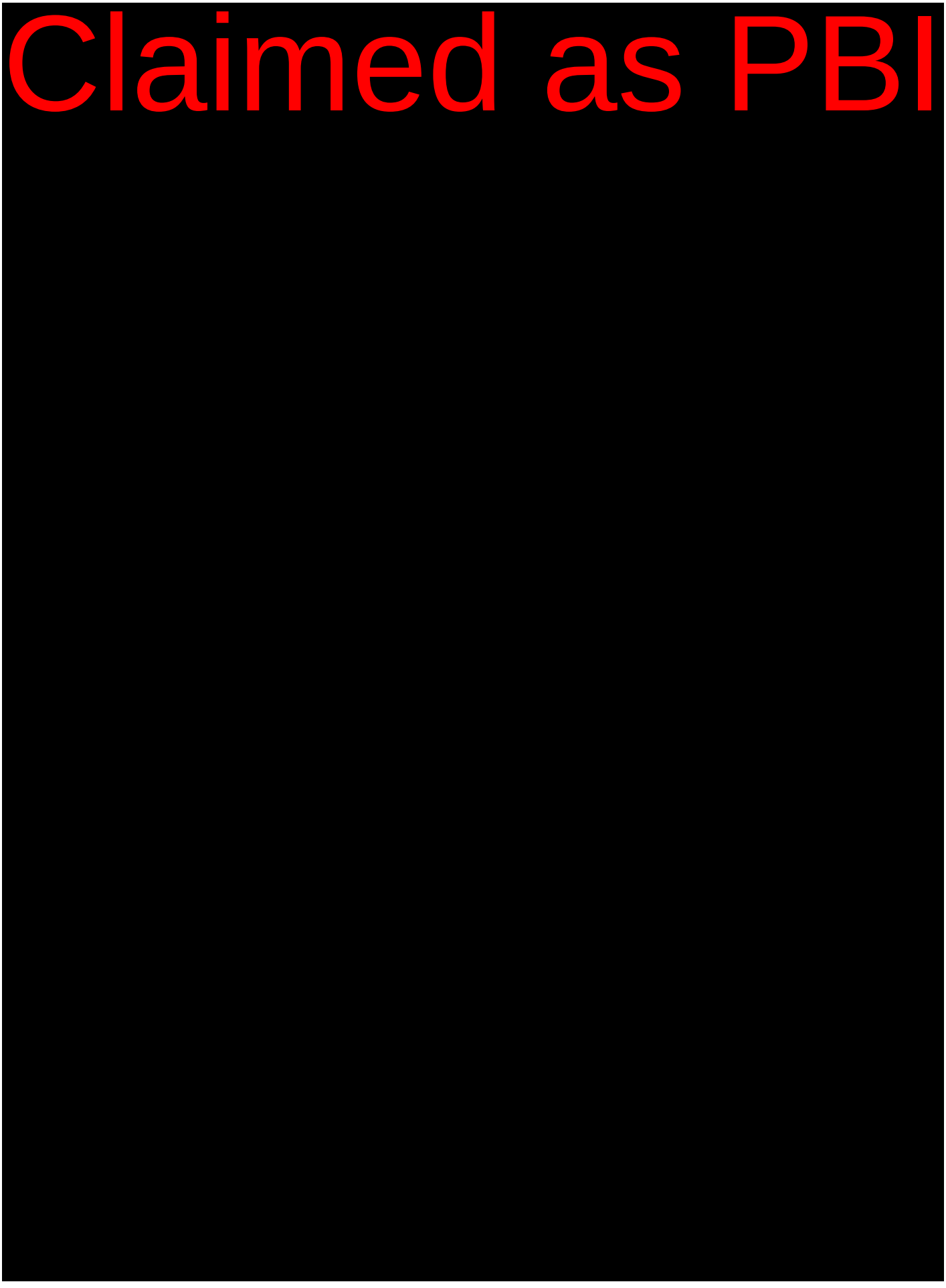
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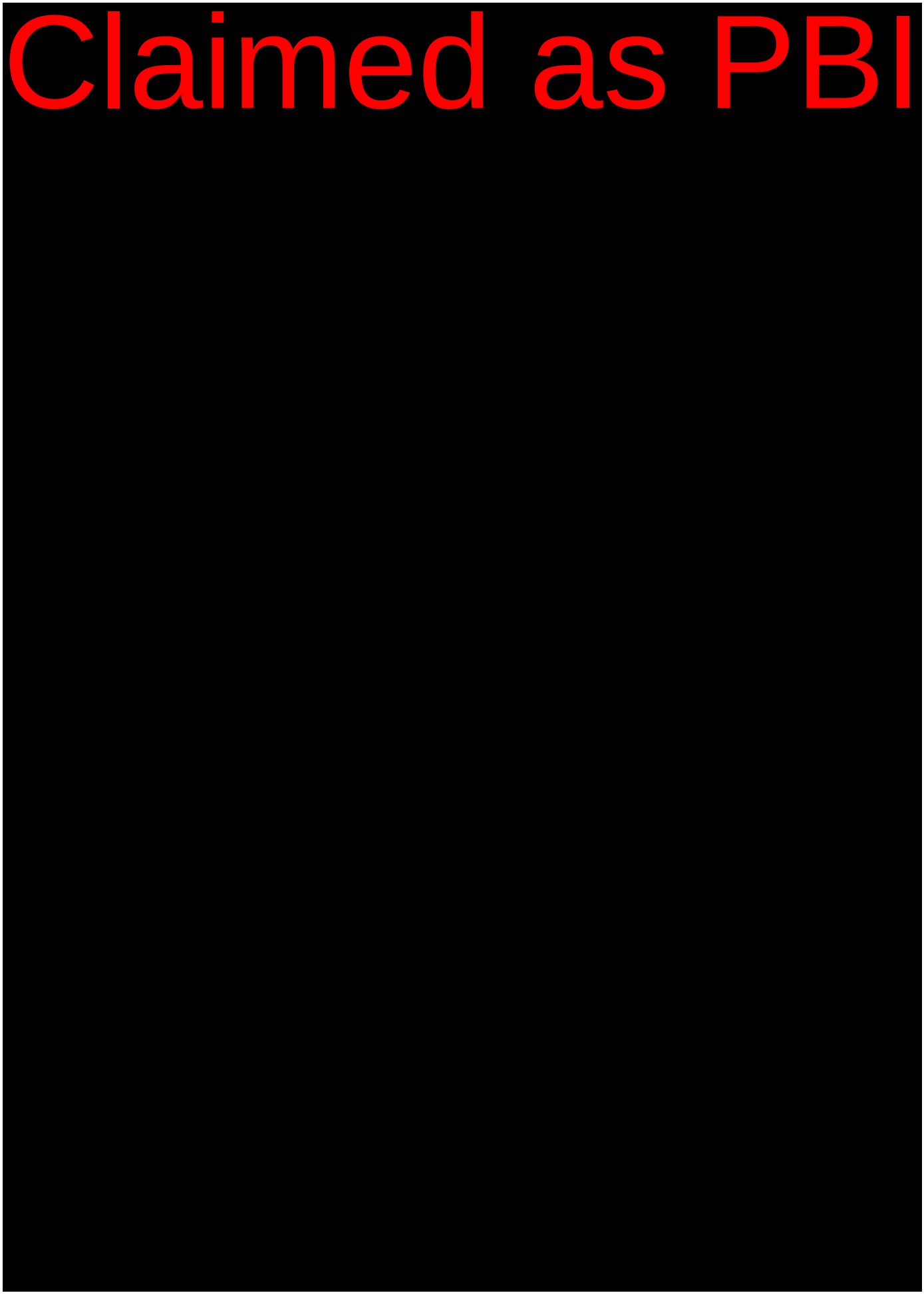
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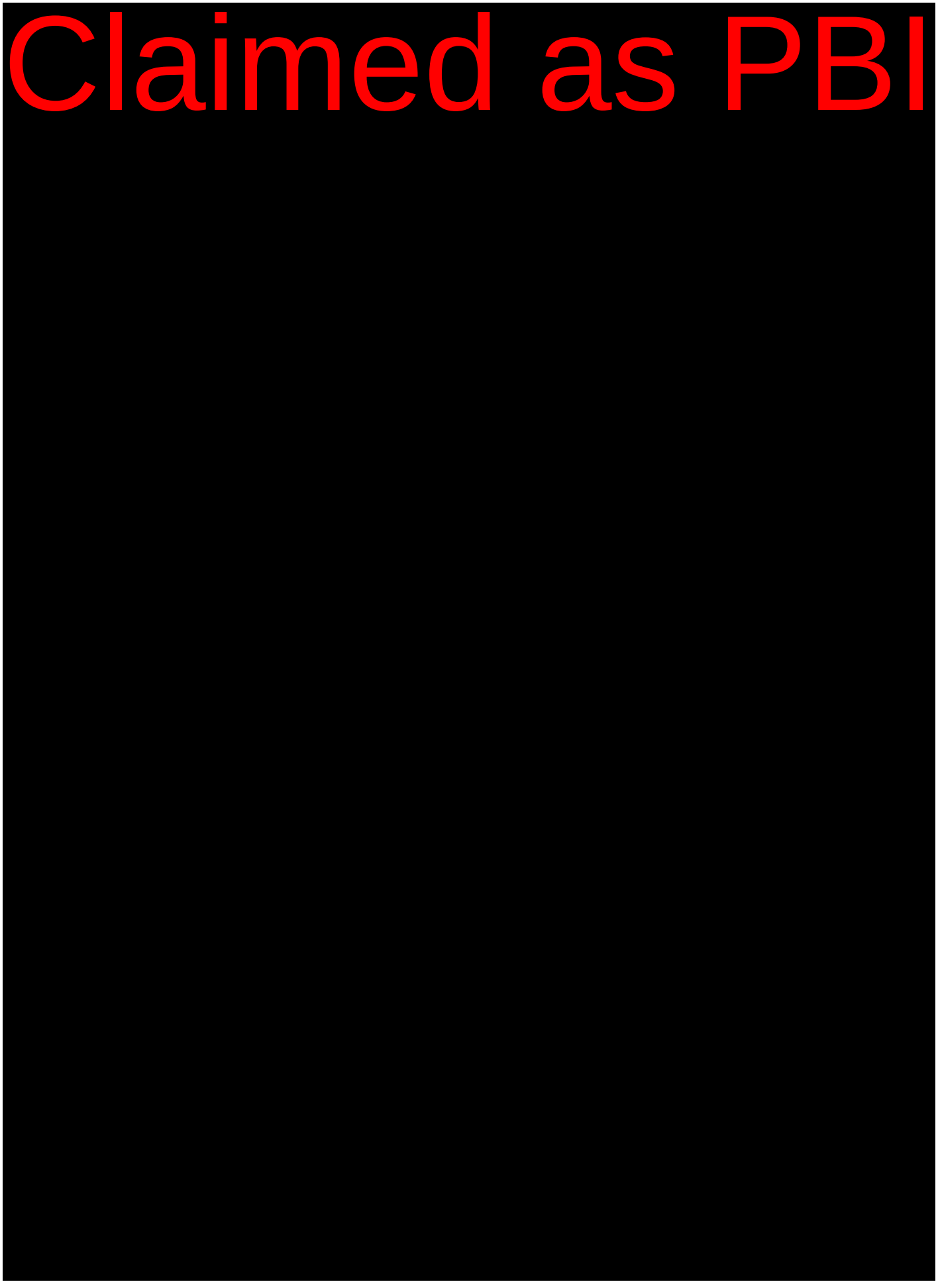
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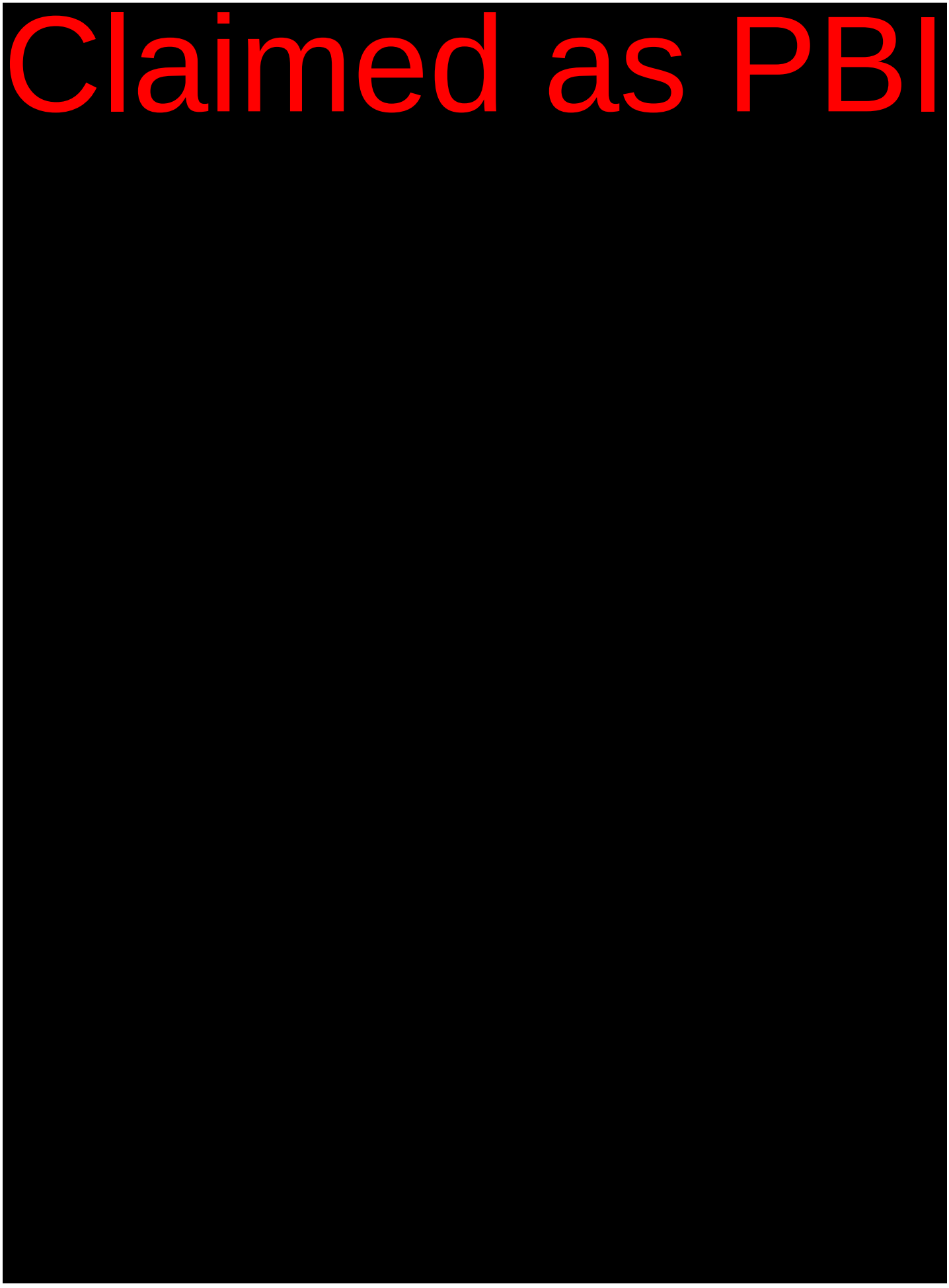
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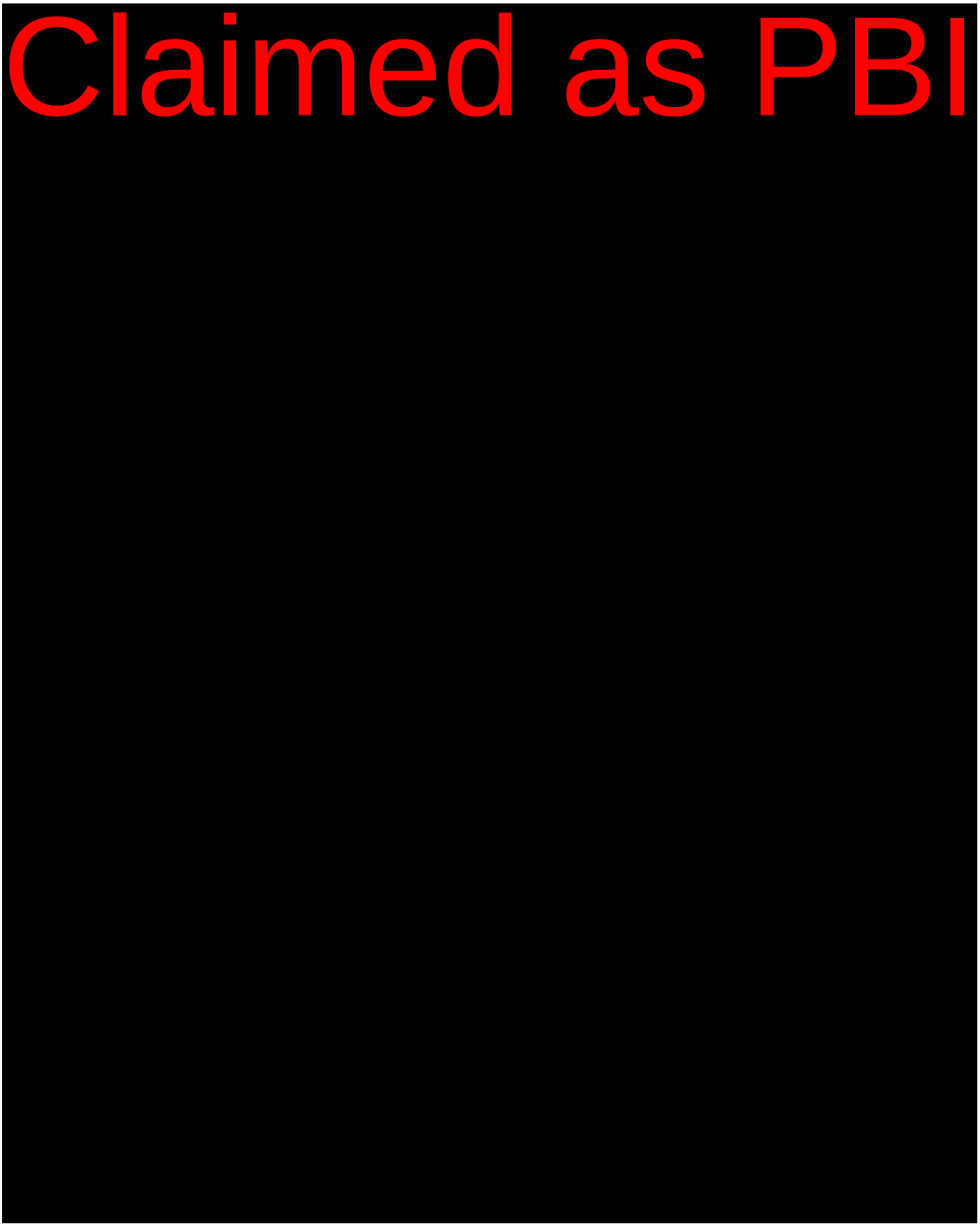
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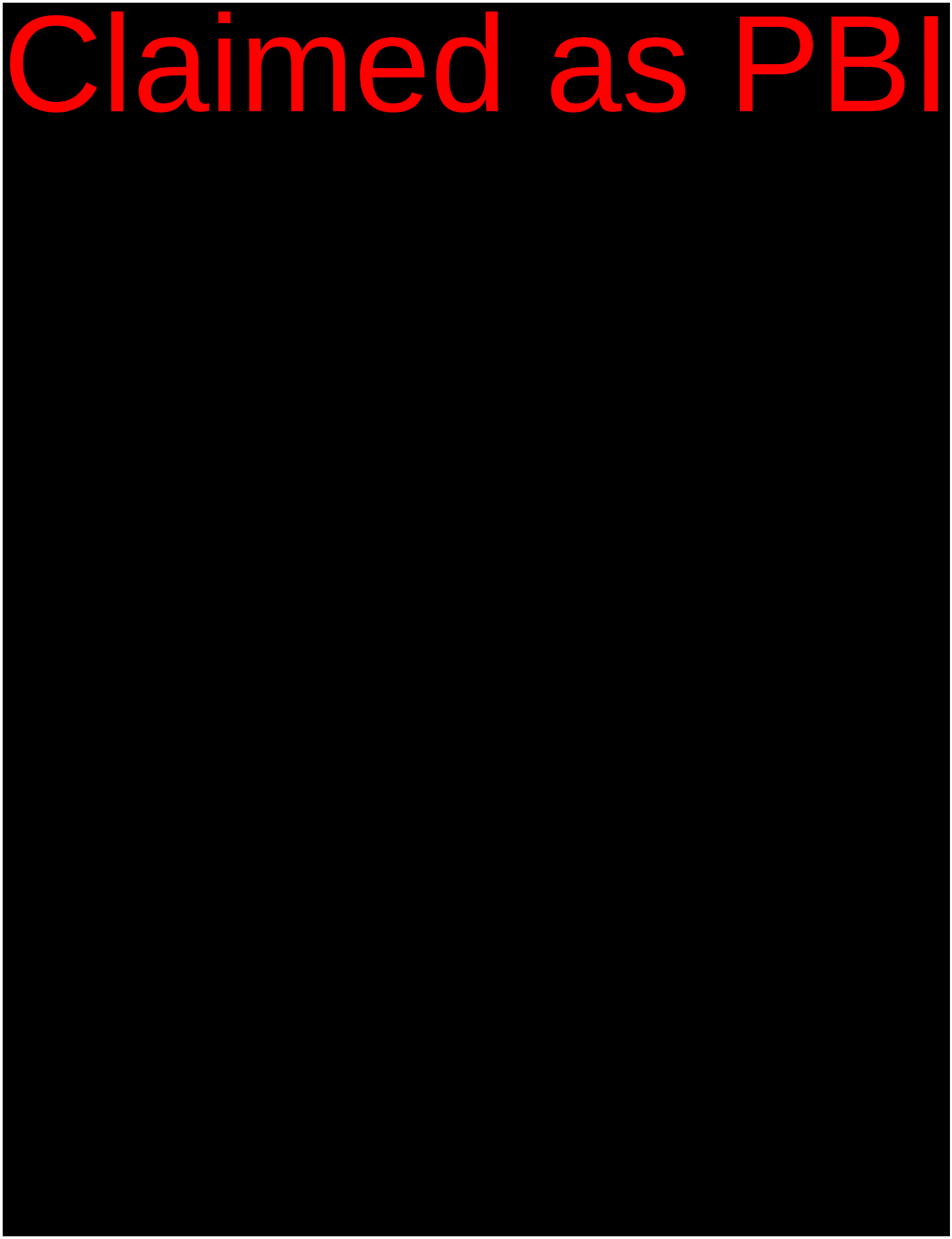
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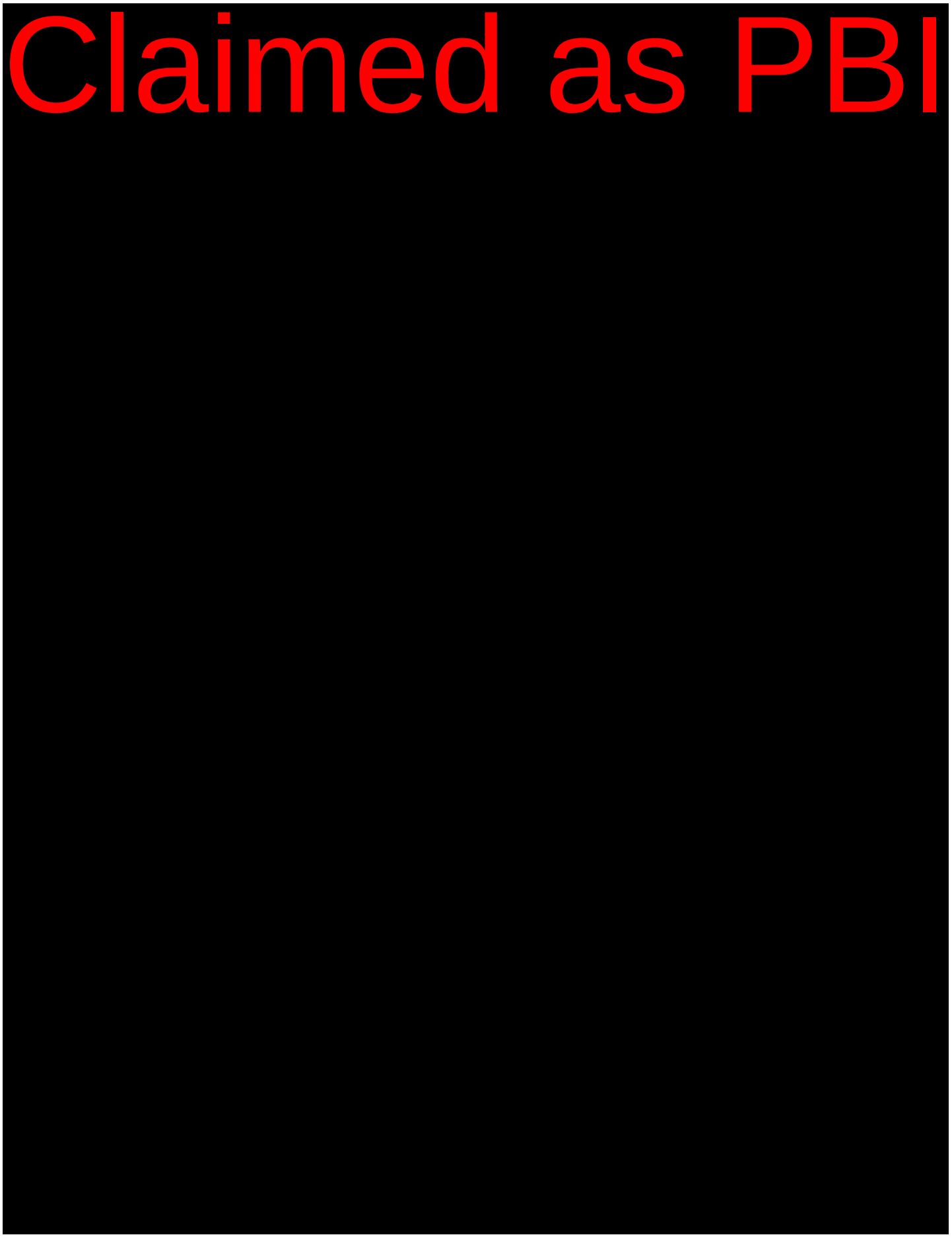
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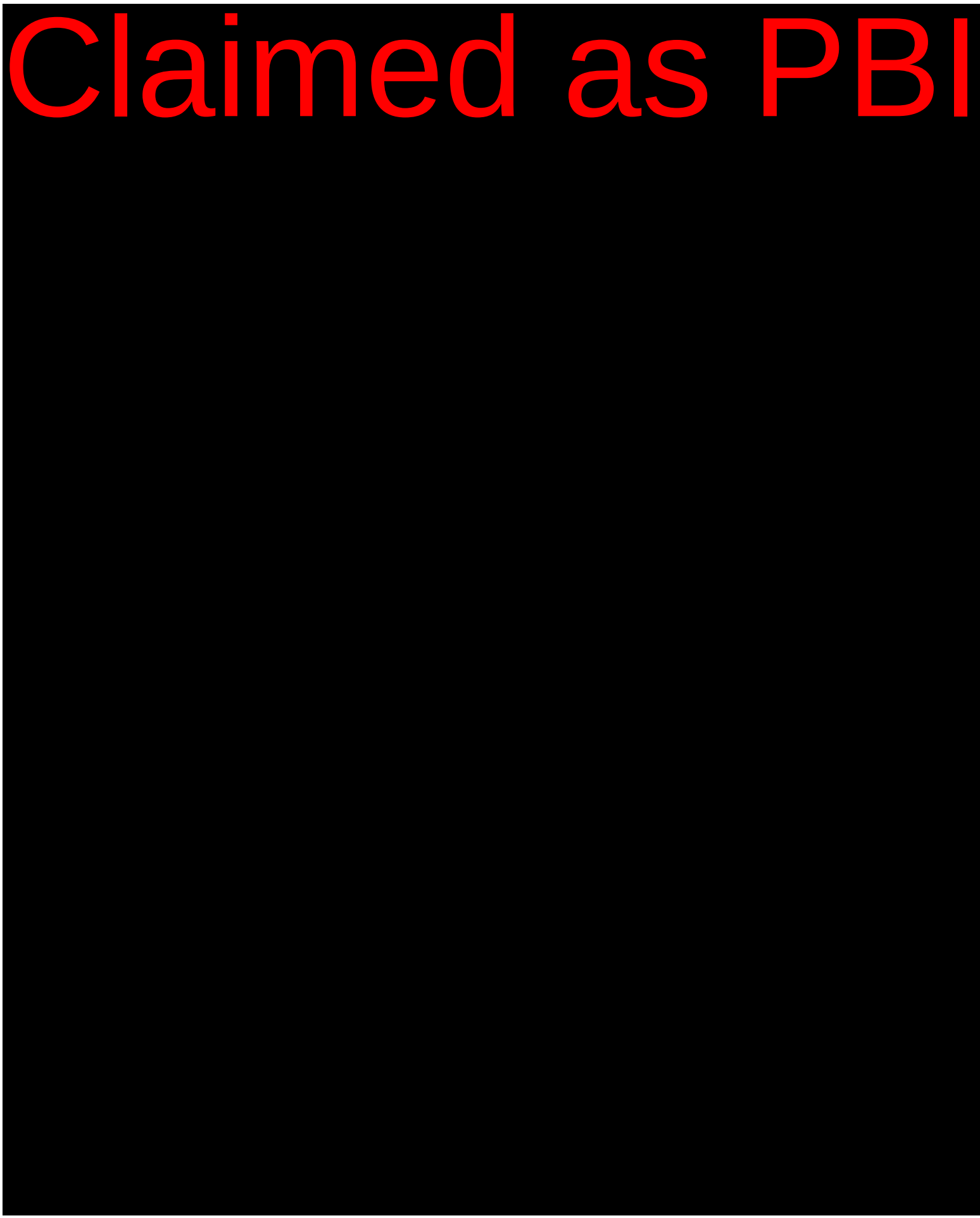
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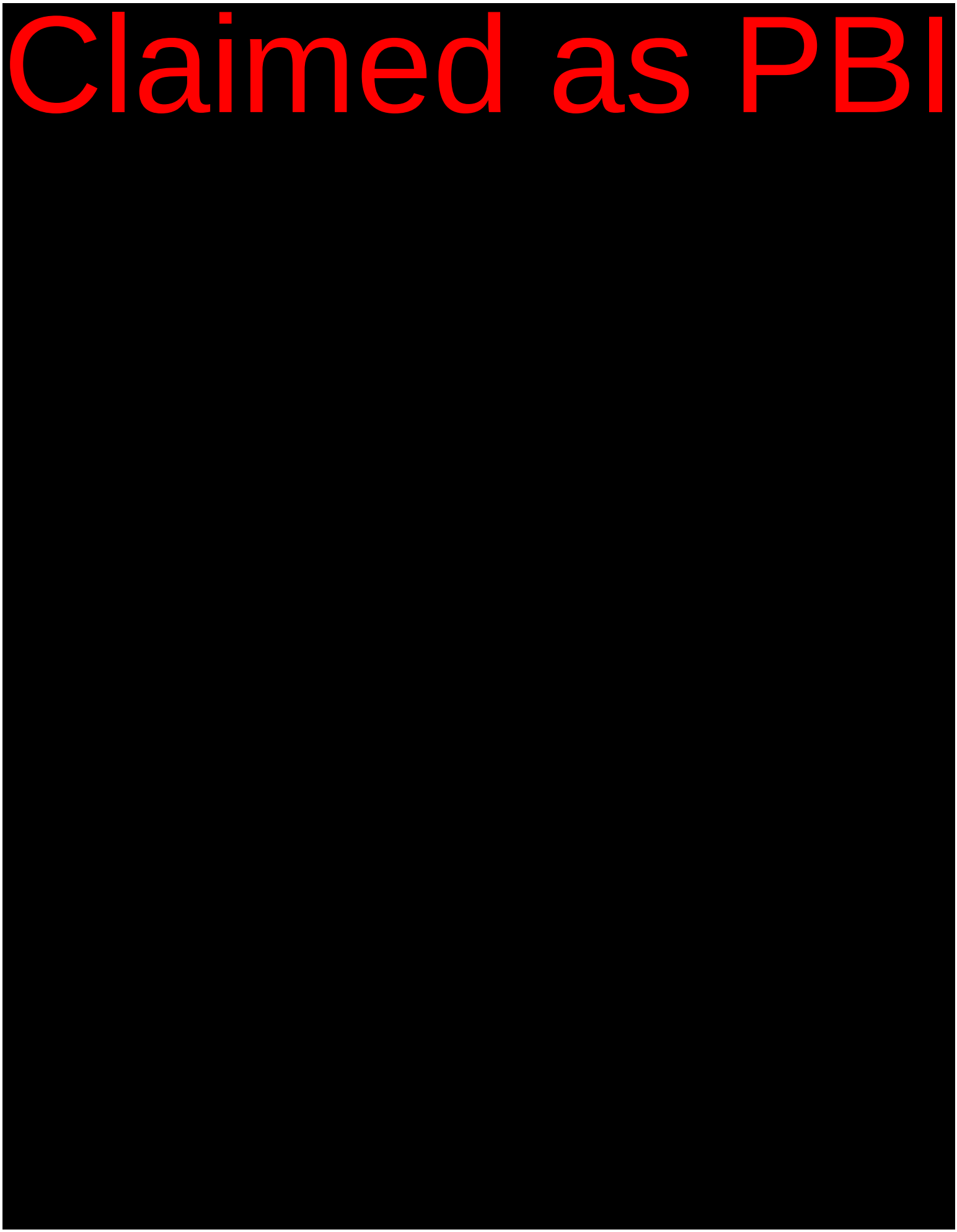
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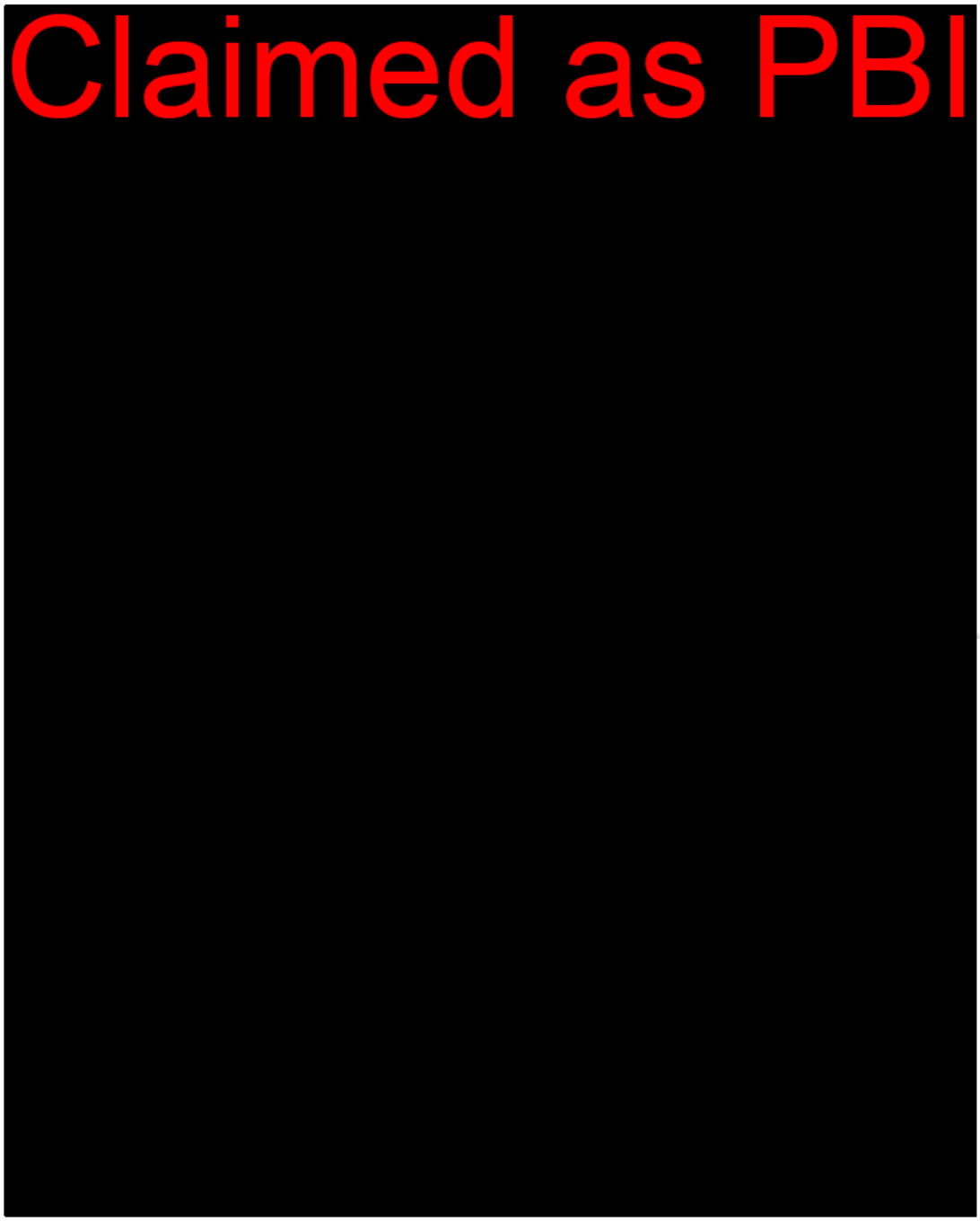
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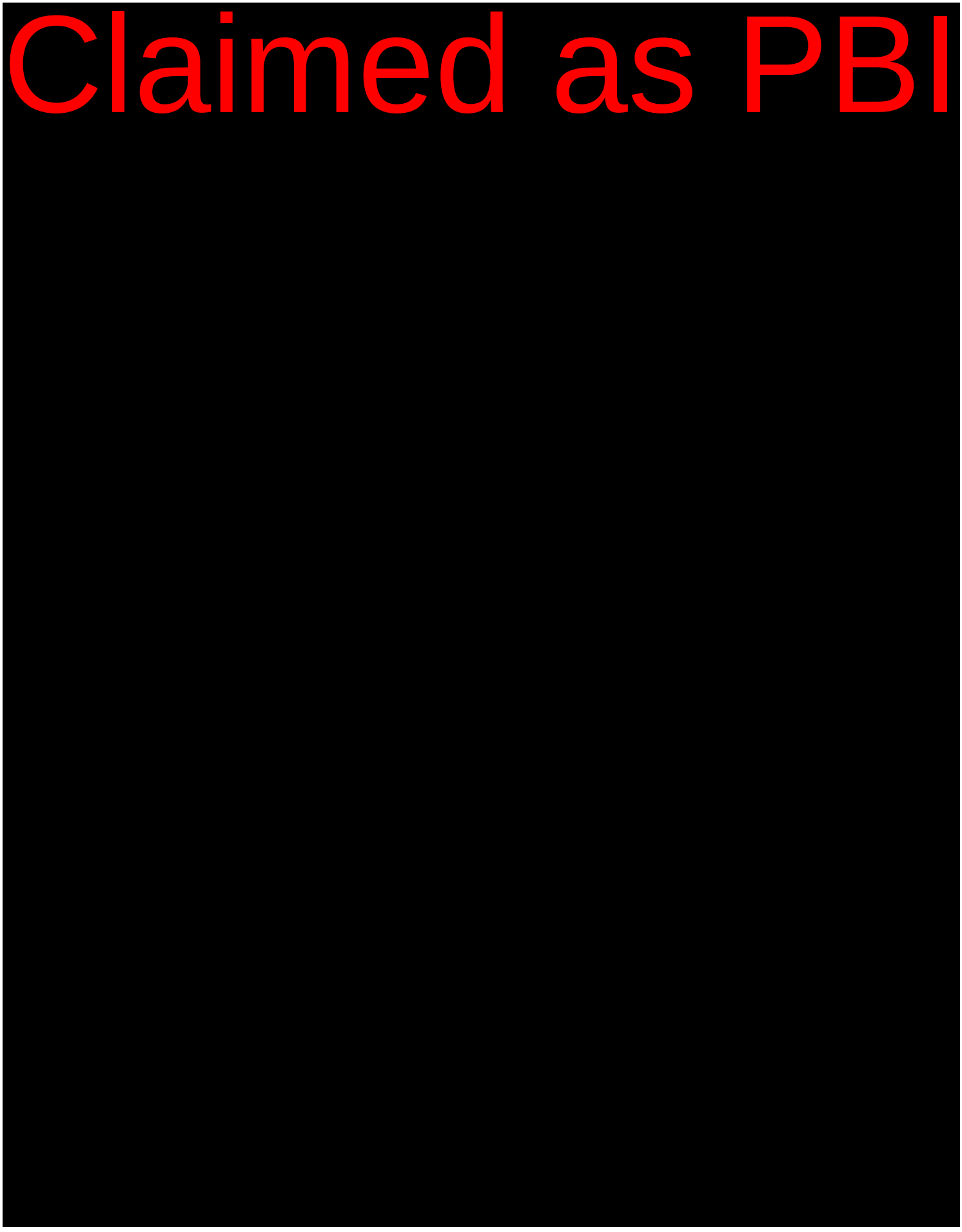
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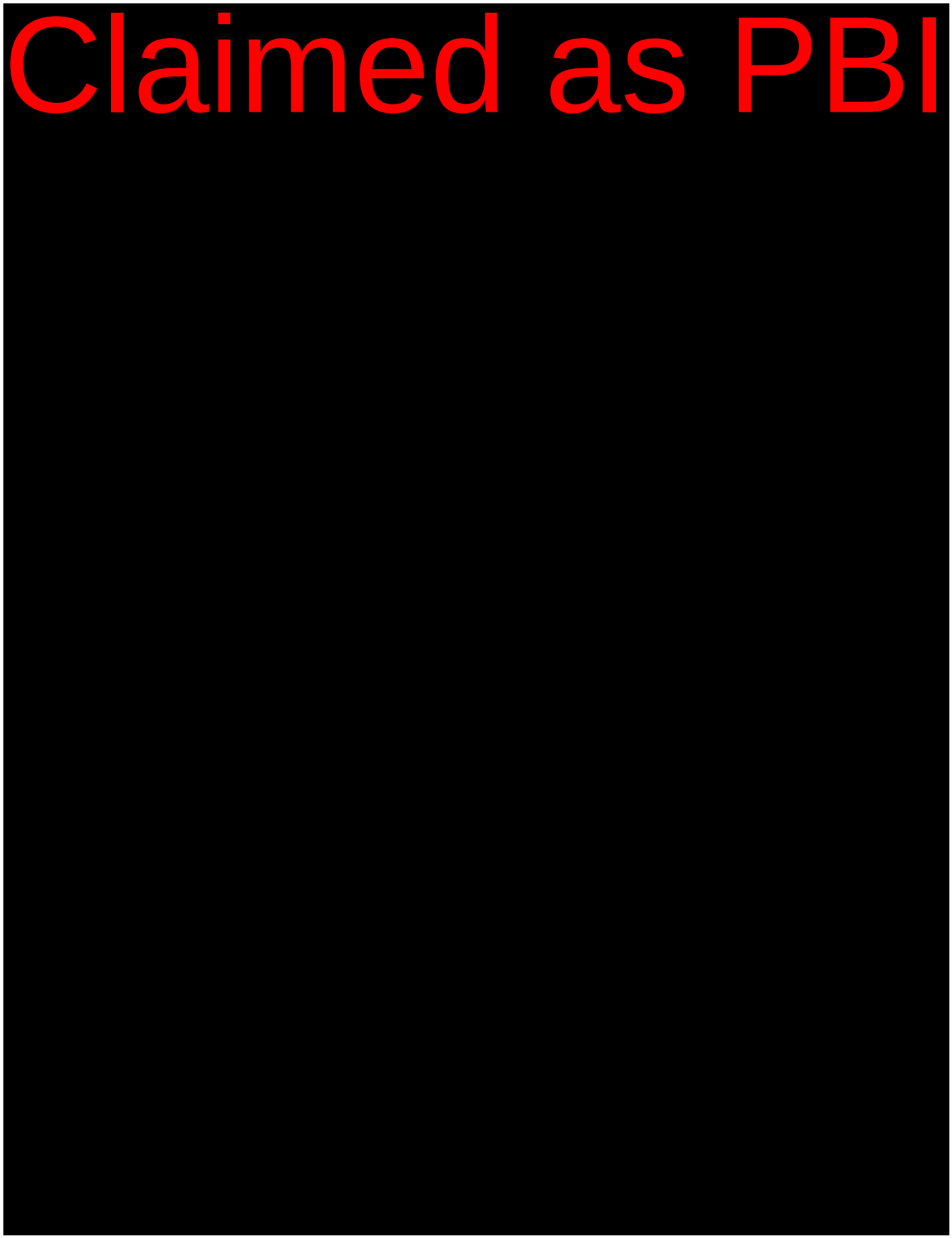
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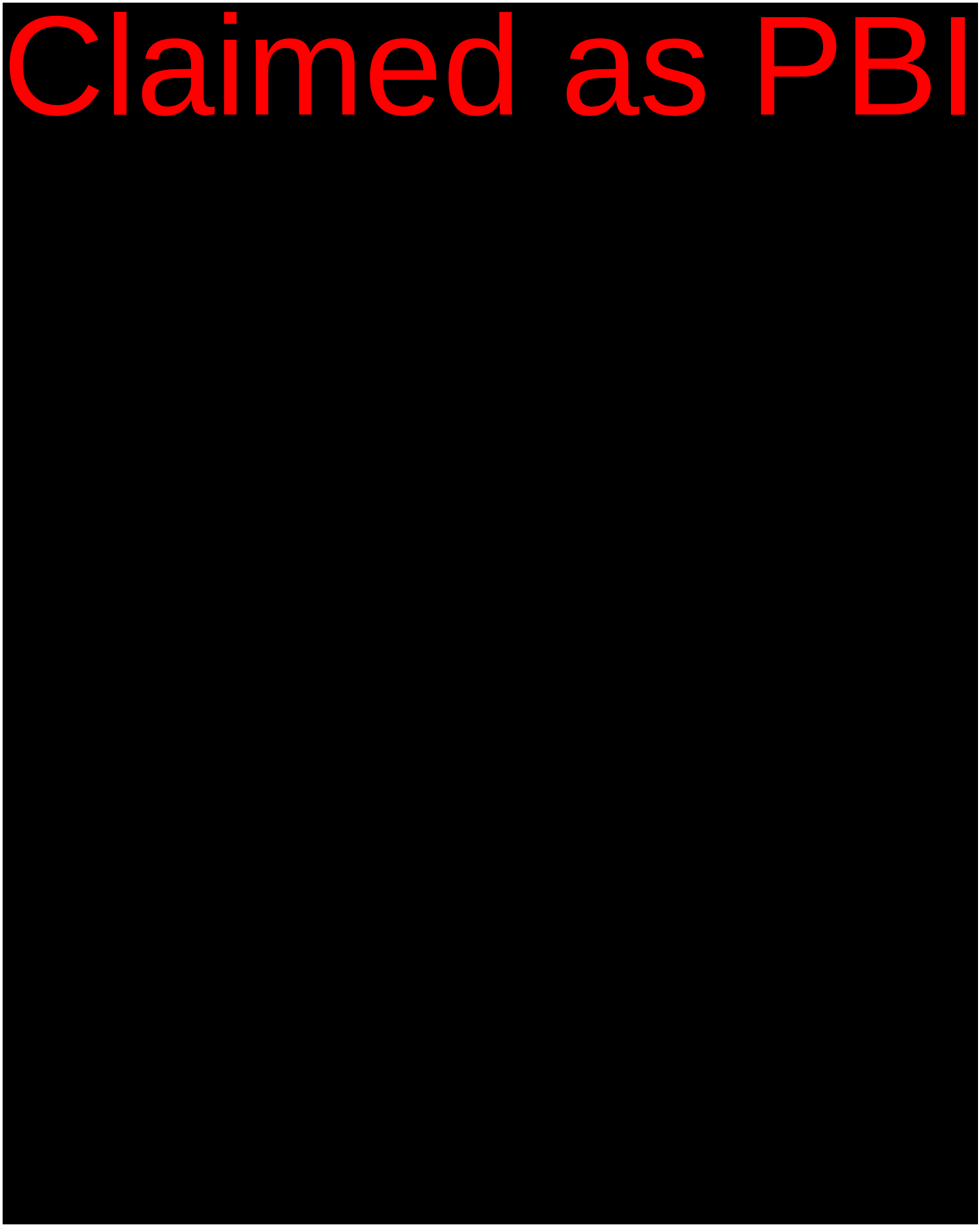
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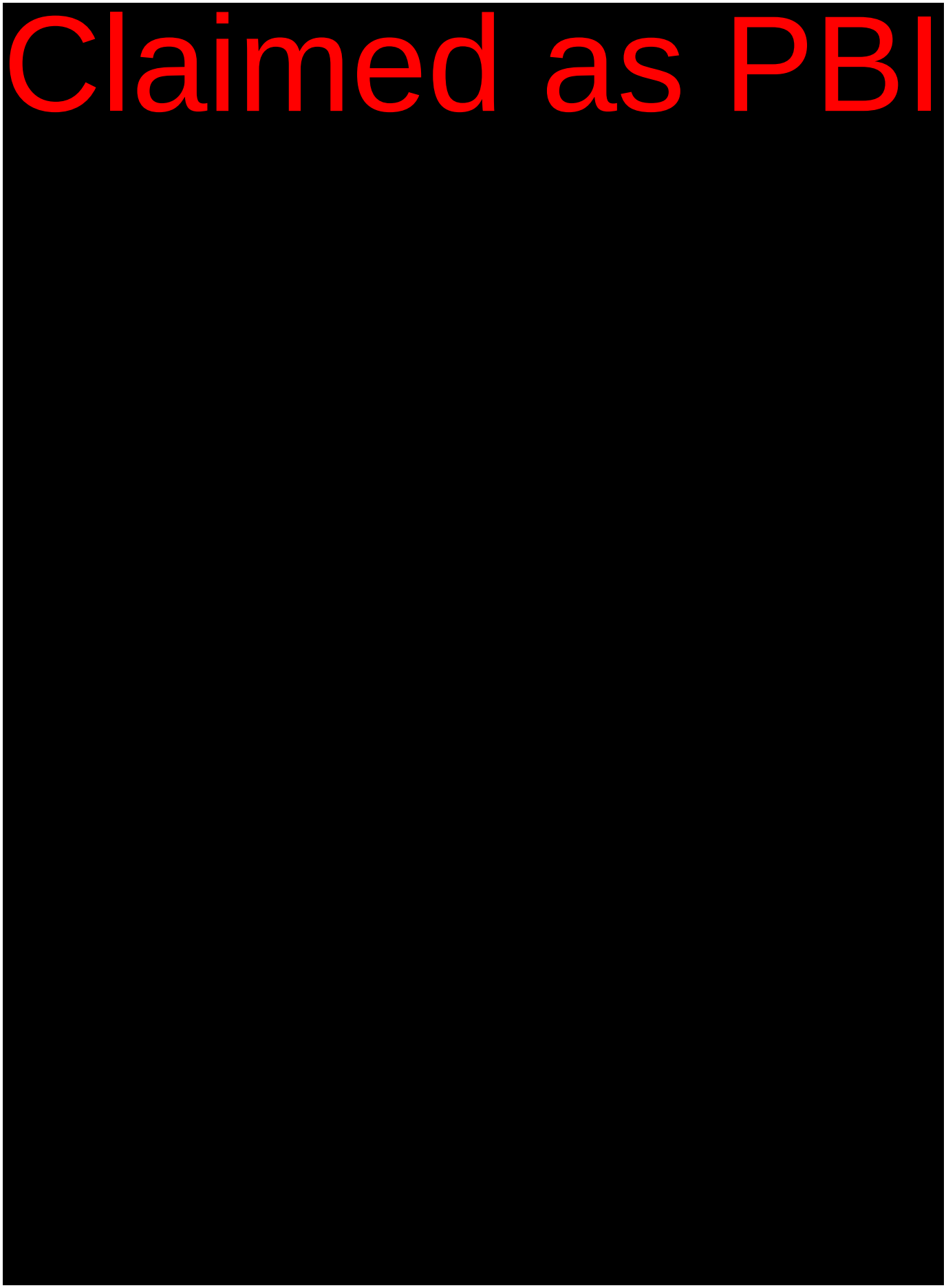
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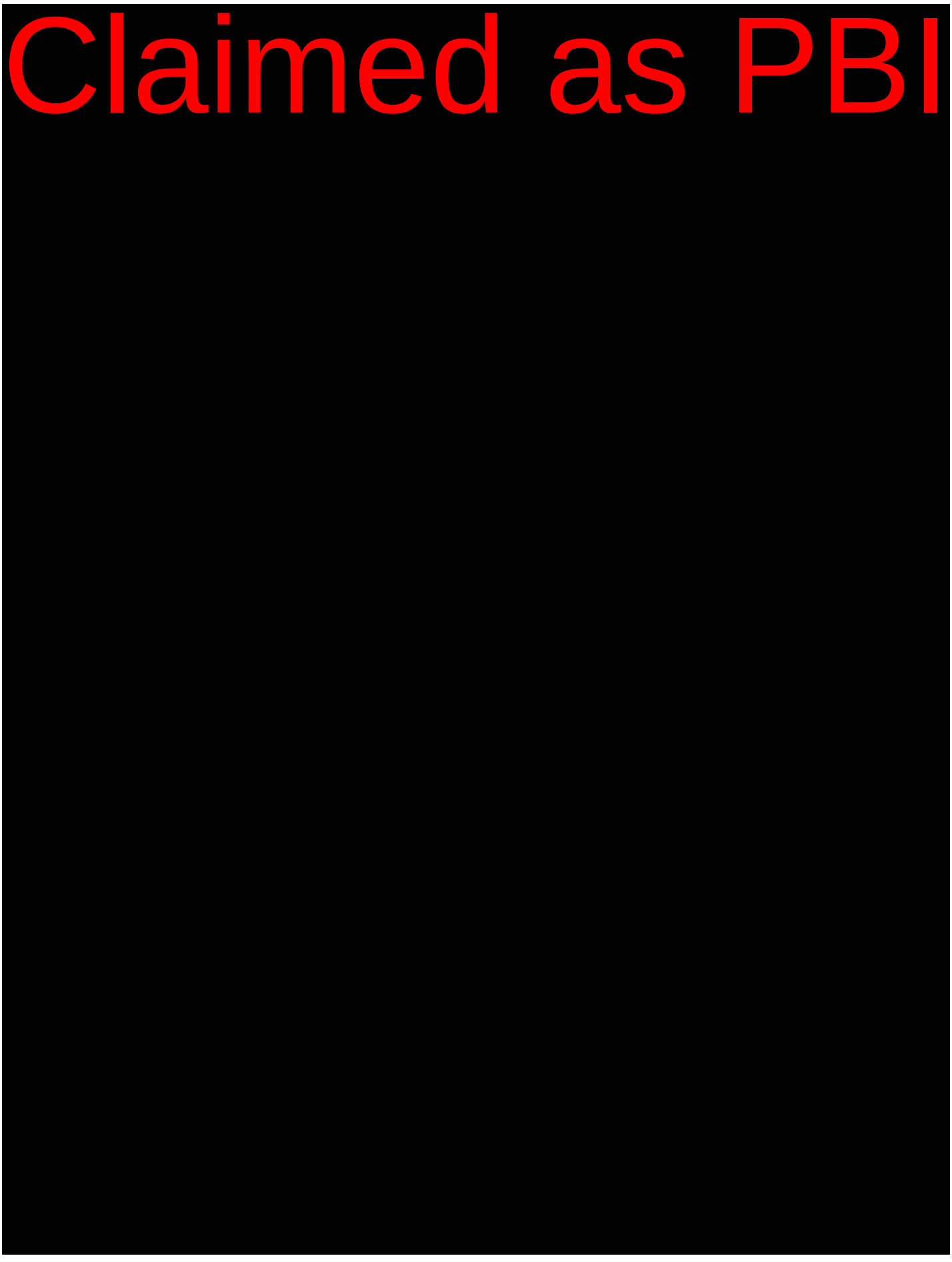
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Appendix K Environmental Justice

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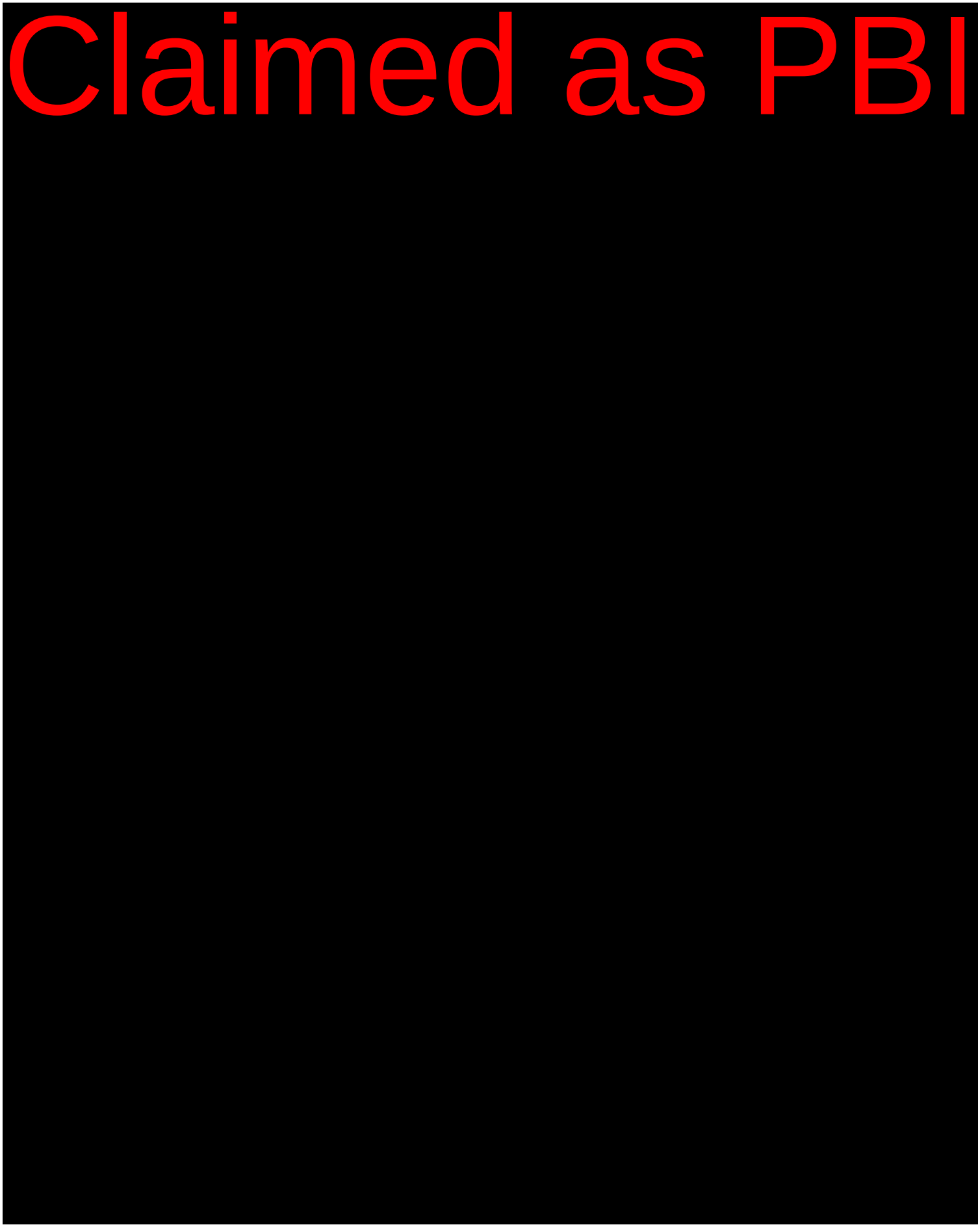

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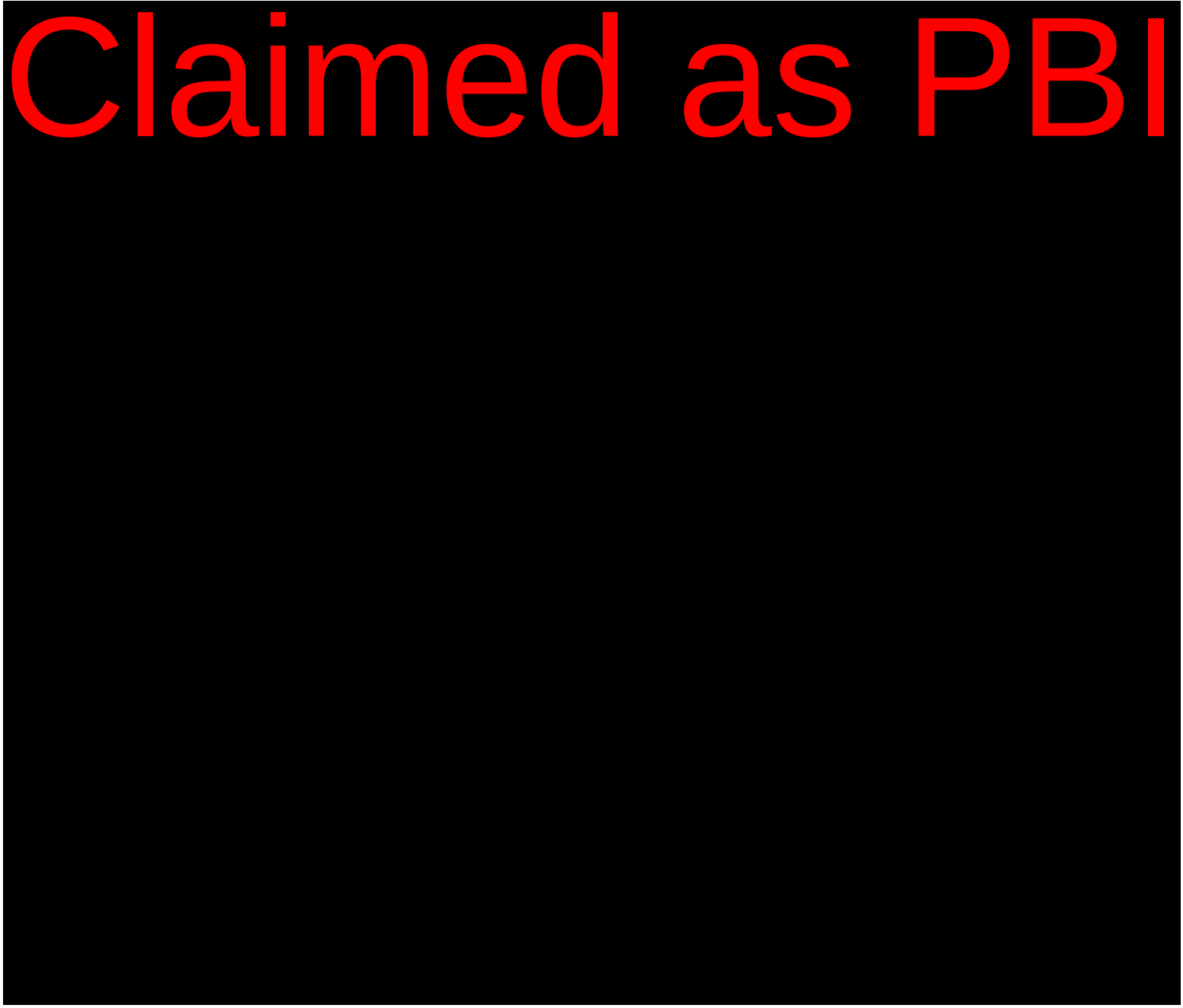

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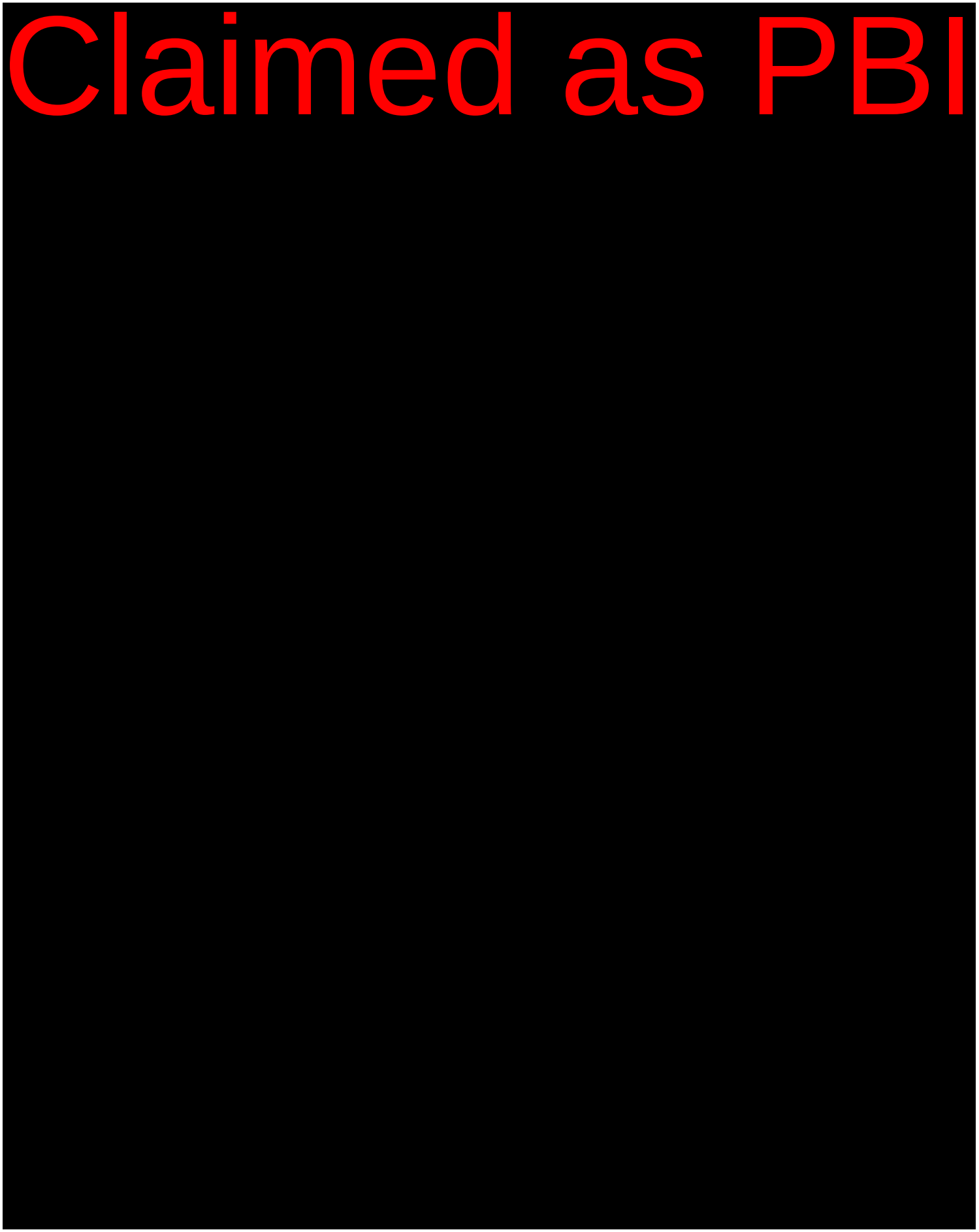

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Appendix L References

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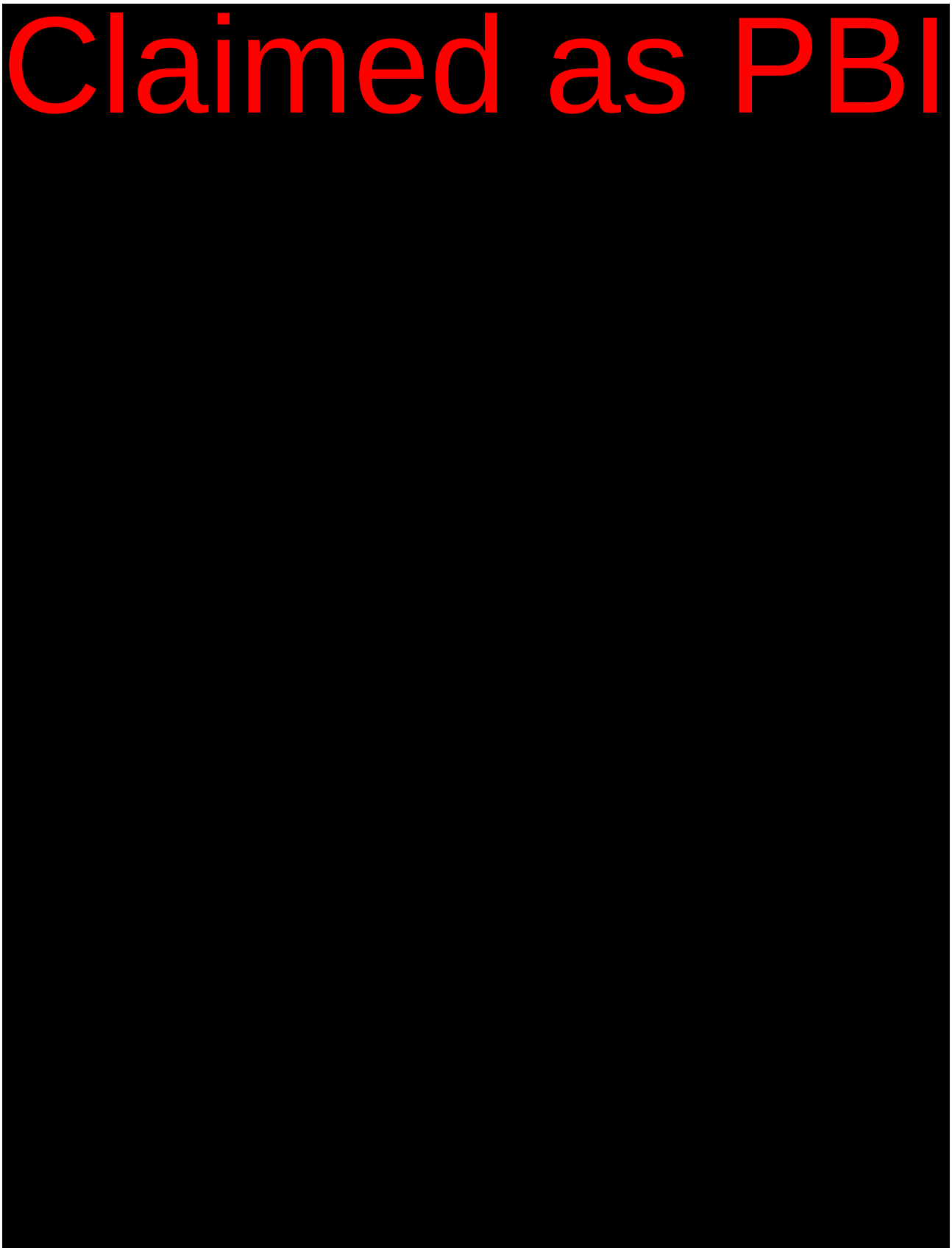
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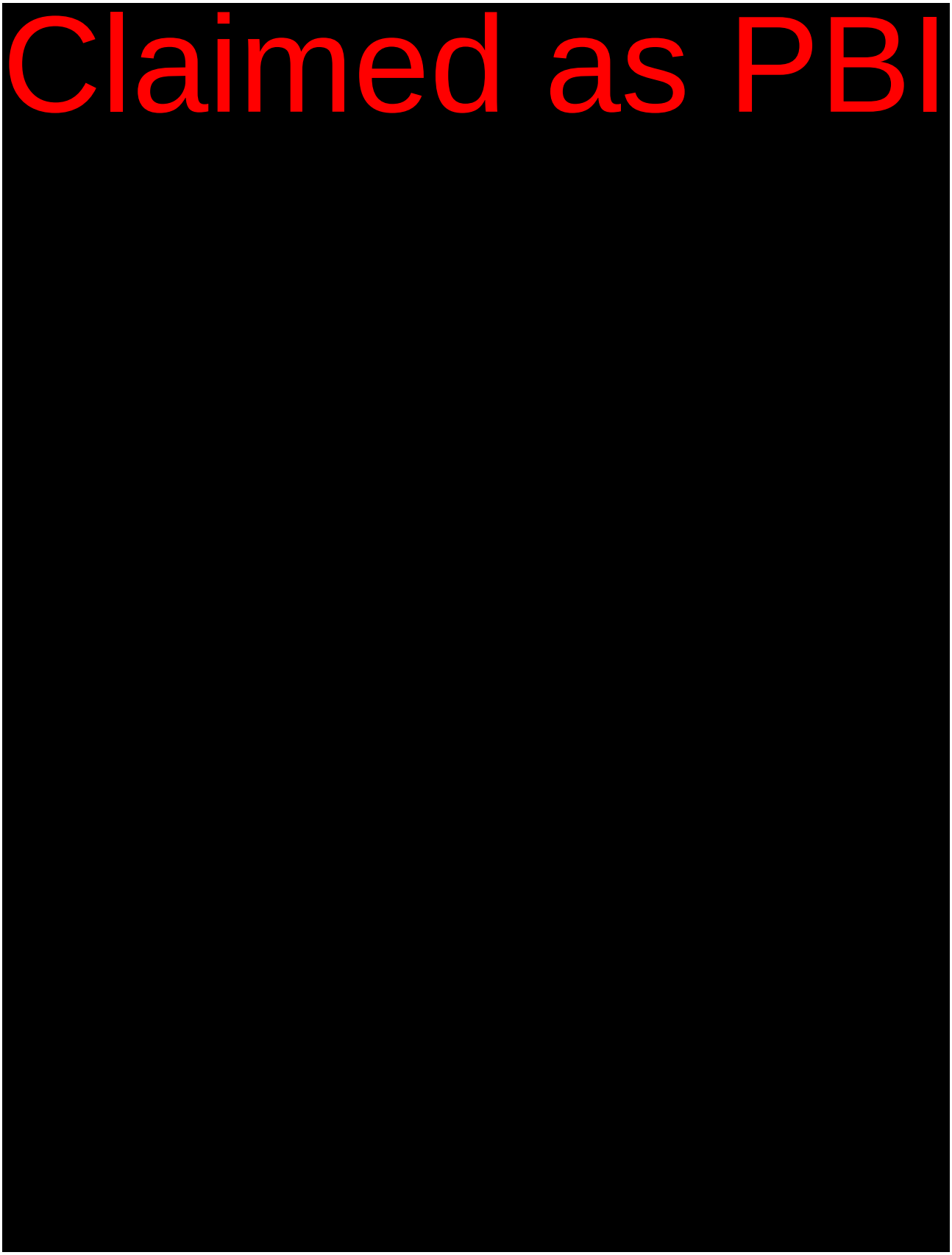
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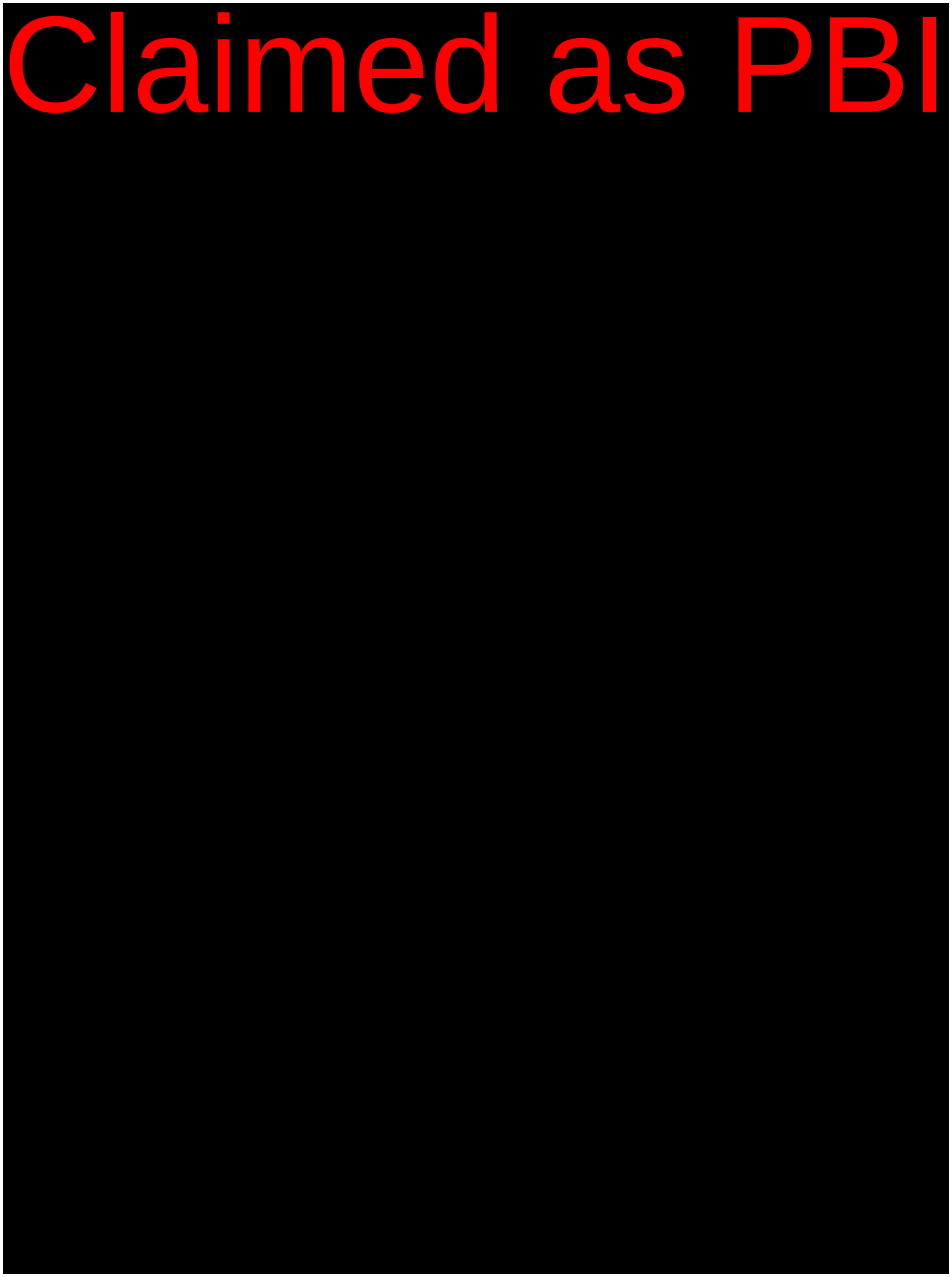
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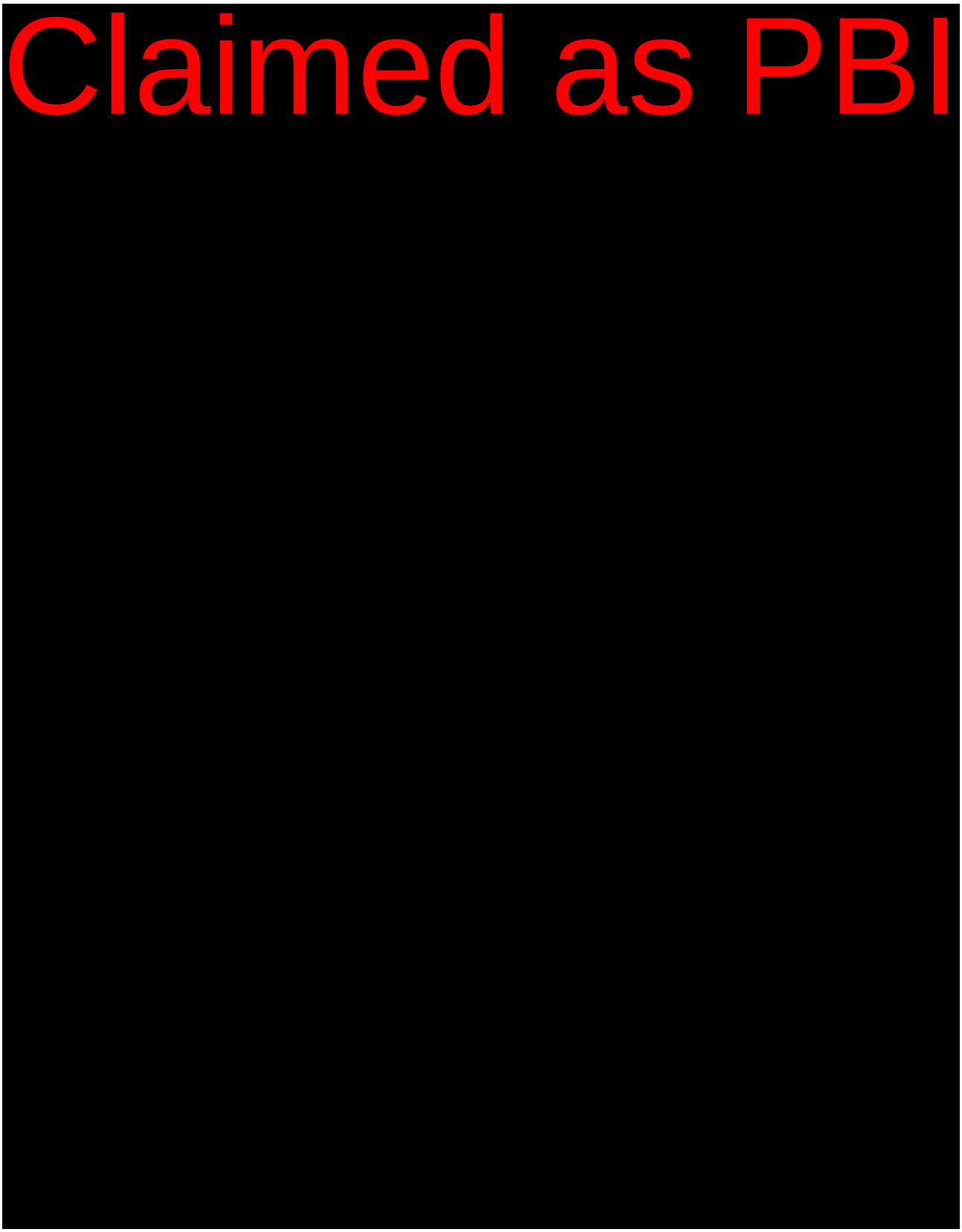
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