UNITED STATES GOVERNMENT MEMORANDUM

May 19, 2020

To: Public Information
From: Plan Coordinator, OLP, Plans Section (GM235D)

Subject: Public Information Copy of Plan

Control #	-	N-10110
Type	-	Initial Exploration Plan
Lease(s)	-	OCS-G35879 - Block 895 Green Canyon Area
Operator	-	BOE Exploration & Production LLC
Description	-	Subsea Wells A, B, C, and D

Attached is a copy of the subject plan.

It has been deemed submitted as of this date and is under review for approval.

Laura Christensen, Esq.
Plan Coordinator
Office of Leasing and Plans

BOE Exploration and Production / Initial EP N-10110

Revision Record

Appendix / Page	Plan Type	Revision Description
Appendix A / Form 137	Proprietary	Indicated TA of proposed wells
Appendix A / Page 2	Proprietary	Revision of storage tanks on proposed MODU types
Appendix J / Page 16	Proprietary	Included moonpool / entrapment-entanglement discussion
Appendix L / Page 18	Proprietary	Included moonpool / entrapment-entanglement discussion
Appendix A / Form 137	Public	Indicated TA of proposed wells
Appendix A / Page 2	Public	Revision of storage tanks on proposed MODU types
Appendix J / Page 16	Public	Included moonpool / entrapment-entanglement discussion
Appendix L / Page 18	Public	Included moonpool / entrapment-entanglement discussion

BOE Beacon OFFSHORE ENERGY

16564 E Brewster Rd, Ste 203
Covington, LA 70433

April 10, 2020

Bureau of Ocean Energy Management
Gulf of Mexico OCS Region Office
1201 Elmwood Park Boulevard
New Orleans, LA 70123

ATTN: Plans Section

BOE Exploration & Production has reviewed applicable regulations for the activities proposed in this plan and has included all relevant proprietary and public information and documentation regarding those activities.

The activities proposed in this plan are expected to commence on or around July 1, 2020.

BOE Exploration & Production has reviewed the document "Biological Opinion on the Federally Regulated Oil and Gas Program Activities in the Gulf of Mexico" published by the National Marine Fisheries Service (NMFS) on 3/13/2020 (**Consultation Tracking number:** FPR-2017-9234).

The opinion reviews the impact of Gulf of Mexico oil and gas operations on 10 Endangered Species Act listed species. Of the 10 species reviewed only the Gulf of Mexico Bryde's Whale is jeopardized. *" It is NMFS' biological opinion that the proposed action is likely to jeopardize the continued existence of the Gulf of Mexico Bryde's whale."*

The report contains an RPA – Reasonable and Prudent Alternative developed to avoid the likelihood of jeopardizing the continued existence of the Gulf of Mexico Bryde's whale. The RPA identifies the "Bryde's whale area" in section 8.1.2.1 Figure 96. "Figure 96 displays the proposed mitigation area displayed as a magenta polygon." Section 14.1 Proposed RPA - lists seven measures vessels must follow in this "Bryde's Whale Area", the RPA Conclusion (section 14.4) states.

The proposed oil and gas activities proposed in this permit (or plan) will utilize vessels that will not approach or transverse the Bryde's Whale area defined in the RPA. Thus these proposed activities would be in compliance with the RPA proposed in the NMFS Biological Opinion FPR-2017-9234.

16564 E Brewster Rd, Ste 203
Covington, LA 70433

Biological Opinion on BOEM Gulf of Mexico Oil and Gas Program | Tracking No. FPR-2017-9234

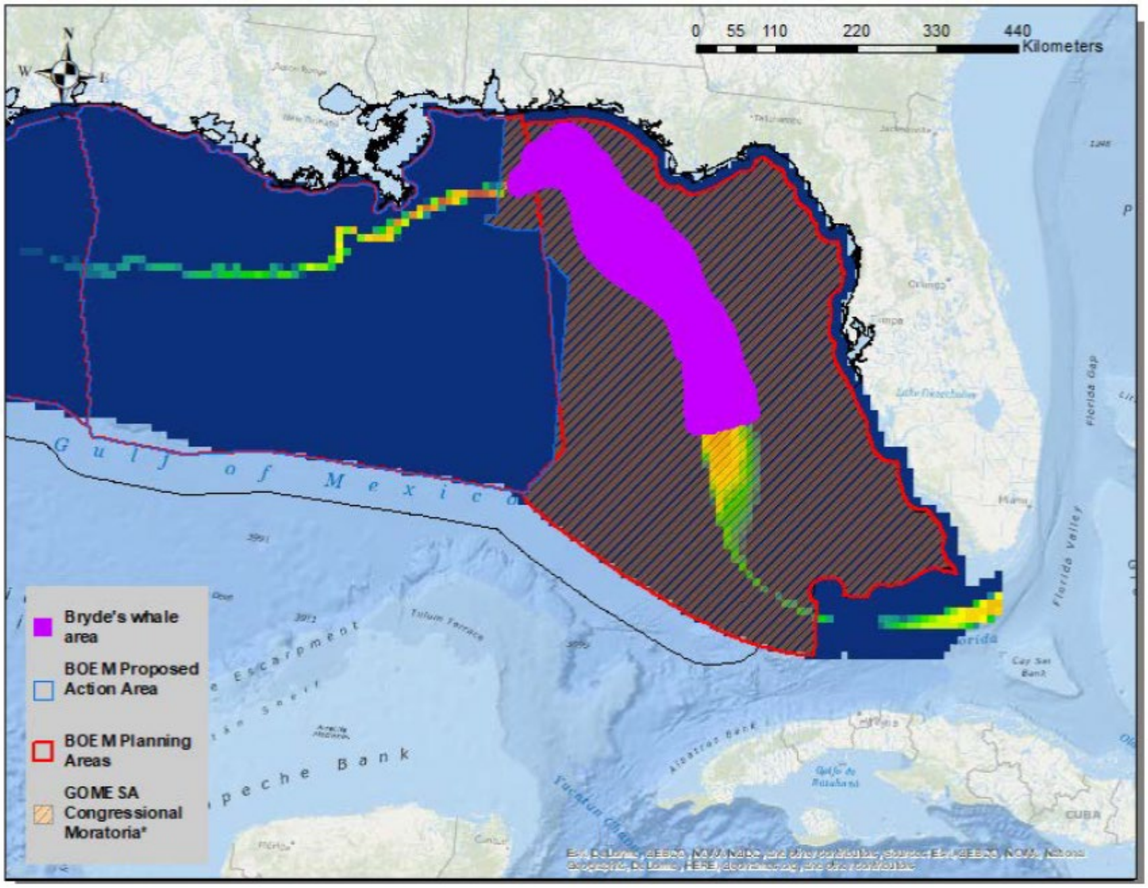


Figure 96. Image of the Bryde's whale area mitigation overlaying Roberts et al. (2016b) density model.

All questions and/or correspondence regarding this plan should be submitted to Brandon Hebert at 985.666.0143 or via email at bhebert@beaconoffshore.com.

Respectfully,

Brandon Hebert
Senior Regulatory Coordinator
Beacon Offshore Energy

INITIAL EXPLORATION PLAN

PUBLIC INFORMATION

Lease Number: OCS-G 35879

Area/Block: GC 895

Prospect: Highgarden

Well(s): A / B / C / D

BOE Exploration & Production (03572)
16564 E Brewster Rd, Ste 203
Covington, LA 70433

Submitted By:
Brandon Hebert
(985) 666-0143
bhebert@beaconoffshore.com

Estimated Start Date: July 1, 2020

APPENDIX A
PLAN CONTENTS

A) PLAN INFORMATION
Included in the attachments for this appendix is the OCS Plan Information Form 137, providing information on the activities proposed in this plan. Well locations proposed in this plan will be drilled and temporarily abandoned.

Houston Energy, LP is the current designated operator of Green Canyon 895, OCS-G 35879. BOEM-approved representatives of both BOE Exploration & Production, LLC and Houston Energy, LP have executed Form BOEM-1123, "Designation of Operator," for lease OCS-G 35879, designating BOE Exploration & Production, LLC as operator.

The status of previously proposed and approved activities in Exploration and/or Development Plans for this lease are as follows:

This is the first Exploration Plan submitted for the subject lease.

B) LOCATION
A map depicting the proposed surface and bottomhole location(s) and is included in the attachment(s) to this appendix of the proprietary information copy of this plan.

A map depicting the proposed surface location(s) is included in the attachment(s) to this appendix of the public information copy of this plan.

C) SAFETY AND POLLUTION PREVENTION FEATURES
BOE Exploration & Production proposes utilizing a drillship or dynamically positioned (DP) semisubmersible as its mobile offshore drilling unit to conduct the activities proposed in this plan. Rig specifications will be included in each Application for Permit to Drill.

Safety features on the drilling unit selected will include pollution prevention, well control, and blowout prevention equipment as described in Title 30 CFR Part 250, Subparts C, D, E, and G; and as further clarified by DOI Notices to Lessees, and current policy making invoked by the DOI, Environmental Protection Agency and the U.S. Coast Guard. A Safety and Environmental Management System that is consistent with Title 30 CFR Part 250 Subparts "O" and "S" will be in effect during the proposed operations. In addition, the Well Control System, consisting of subsea BOP equipment, BOP control system, choke and kill lines, choke manifold, mud-gas separator, circulation system and monitoring (PVT) equipment will be installed and available upon demand when the riser and BOP is attached to the well. The emergency systems consisting of secondary BOP activation equipment, firefighting and abandonment equipment utilized will meet or exceed the regulatory requirements of the DOI and USCG.

Pollution prevention measures will include the installation of curbs, gutters, drip pans, and drains on drilling deck areas to collect all contaminants and debris.

The drilling rig and each of the marine vessels servicing the rig and its operations will be equipped with all U.S. Coast Guard required navigational safety aids to alert ships of its presence in all weather conditions.

D) STORAGE TANKS AND/OR PRODUCTION VESSELS

The table below provides information on oil storage tanks with a capacity of 25 barrels or more that will be used to conduct the activities proposed in this plan.

Type of Storage Tank	Type of Facility	Tank Capacity (bbls)	Number of Tanks	Total Capacity (bbls)	Fluid Gravity (API)
Fuel Oil	Drillship	5514	2	11028	No. 2 Diesel
Fuel Oil	Drillship	12458	2	24916	No. 2 Diesel
Fuel Oil	Drillship	12065	2	24130	No. 2 Diesel
Fuel Oil	Drillship	640	2	1280	No. 2 Diesel
Fuel Oil	Drillship	480	3	1440	No. 2 Diesel
Fuel Oil	Drillship	80	1	80	No. 2 Diesel
Fuel Oil	DP Semisubmersible	4541	2	9082	No. 2 Diesel
Fuel Oil	DP Semisubmersible	3392	2	6784	No. 2 Diesel
Fuel Oil	DP Semisubmersible	629	1	629	No. 2 Diesel
Fuel Oil	DP Semisubmersible	164	1	164	No. 2 Diesel
Fuel Oil	DP Semisubmersible	30	1	30	No. 2 Diesel

E) POLLUTION PREVENTION

In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as the State of Florida is not an affected State.

F) ADDITIONAL MEASURES

BOE Exploration & Production will comply with regulations in 30 CFR Part 250 and will not take any additional measures beyond those stated in referenced regulations regarding safety, pollution prevention, and early spill detection measures.

G) SERVICE FEE

In accordance with 30 CFR 550.125, included in the attachments for this appendix is a copy of the pay.gov receipt for the required service fee for the activities proposed in this plan.

OCS PLAN INFORMATION FORM

OCS PLAN INFORMATION FORM

General Information

Type of OCS Plan:	X	Exploration Plan (EP)	Development Operations Coordination Document (DOCD)	

Company Name: BOE Exploration & Production LLC	BOEM Operator Number: 03572
Address: 16564 E Brewster Rd, Ste 203	Contact Person: Brandon Hebert
Covington, LA 70433	Phone Number: 985.666.0143
	E-Mail Address: bhebert@beaconoffshore.com

If a service fee is required under 30 CFR 550.125(a), provide the	Amount paid	$14,692	Receipt No.	26O63MD0

Project and Worst Case Discharge (WCD) Information

Lease(s): OCS-G 35879	Area: GC	Block(s): 895	Project Name (If Applicable): Highgarden

Objective(s)	X	Oil		Gas		Sulphur		Salt	Onshore Support Base(s): Port Fourchon, LA

Platform/Well Name: Loc A	Total Volume of WCD: 25,348,928 bbls	API Gravity: 31.6°
Distance to Closest Land (Miles): 136	Volume from uncontrolled blowout: 313,100 BOPD	

Have you previously provided information to verify the calculations and assumptions for your WCD?		Yes	X	No
If so, provide the Control Number of the EP or DOCD with which this information was provided				
Do you propose to use new or unusual technology to conduct your activities?		Yes	X	No
Do you propose to use a vessel with anchors to install or modify a structure?		Yes	X	No
Do you propose any facility that will serve as a host facility for deepwater subsea development?		Yes	X	No

Description of Proposed Activities and Tentative Schedule (Mark all that apply)

Proposed Activity	Start Date	End Date	No. of Days
Drill / TA Well Location A	07/01/2020	11/28/2020	150
Drill / TA Well Location B	01/01/2021	05/31/2021	150
Drill / TA Well Location C	01/01/2022	05/31/2022	150
Drill / TA Well Location D	01/01/2023	05/31/2023	150

Description of Drilling Rig

	Jackup	X	Drillship
	Gorilla Jackup		Platform rig
	Semisubmersible		Submersible
X	DP Semisubmersible		Other (Attach Description)
Drilling Rig Name (If Known):			

Description of Structure

	Caisson		Tension leg platform
	Fixed platform		Compliant tower
	Spar		Guyed tower
	Floating production system		Other (Attach Description)

Description of Lease Term Pipelines

From (Facility/Area/Block)	To (Facility/Area/Block)	Diameter (Inches)	Length (Feet)
N/A			

OCS PLAN INFORMATION FORM (CONTINUED)
Include one copy of this page for each proposed well/structure

Proposed Well/Structure Location							
Well or Structure Name/Number (If renaming well or structure, reference previous name): Loc A			Previously reviewed under an approved EP or DOCD?		Yes	X	No
Is this an existing well or structure?		Yes	X	No	If this is an existing well or structure, list the Complex ID or API No.		
Do you plan to use a subsea BOP or a surface BOP on a floating facility to conduct your proposed activities?				X	Yes		No
WCD info	For wells, volume of uncontrolled blowout (Bbls/day): 313,100		For structures, volume of all storage and pipelines (Bbls): N/A		API Gravity of fluid	31.6°	

	Surface Location	**Bottom-Hole Location (For Wells)**	**Completion (For multiple completions, enter separate lines)**
Lease No.	OCS-G 35879		OCS OCS
Area Name	Green Canyon		
Block No.	895		
Blockline Departures (in feet)	N/S Departure: F_S_L 2200.00'	N/S Departure: F ___L	N/S Departure: F____L N/S Departure: F____L N/S Departure: F____L
	E/W Departure: F_E_L 6940.00'	E/W Departure: F____L	E/W Departure: F____L E/W Departure: F____L E/W Departure: F____L
Lambert X-Y coordinates	X: 2,226,500.00	X:	X: X: X:
	Y: 9,823,000.00	Y:	Y: Y: Y:
Latitude/ Longitude	Latitude 27° 03' 31.6260" N	Latitude	Latitude Latitude Latitude
	Longitude 91° 11' 55.5170" W	Longitude	Longitude Longitude Longitude

Water Depth (Feet): 5584'	MD (Feet):	TVD (Feet):	MD (Feet): TVD (Feet): MD (Feet): TVD (Feet): MD (Feet): TVD (Feet):
Anchor Radius (if applicable) in feet: N/A			

Anchor Locations for Drilling Rig or Construction Barge (If anchor radius supplied above, not necessary)

Anchor Name or No.	**Area**	**Block**	**X Coordinate**	**Y Coordinate**	**Length of Anchor Chain on Seafloor**
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	

OCS PLAN INFORMATION FORM (CONTINUED)

Proposed Well/Structure Location

Well or Structure Name/Number (If renaming well or structure, reference previous name): Loc B	Previously reviewed under an approved EP or DOCD?		Yes	X	No

Is this an existing well or structure?		Yes	X	No	If this is an existing well or structure, list the Complex ID or API No.	

Do you plan to use a subsea BOP or a surface BOP on a floating facility to conduct your proposed activities?	X	Yes		No

WCD info	For wells, volume of uncontrolled blowout (Bbls/day): 313,100	For structures, volume of all storage and pipelines (Bbls): N/A	API Gravity of fluid	31.6°

	Surface Location	**Bottom-Hole Location (For Wells)**	**Completion (For multiple completions, enter separate lines)**
Lease No.	OCS-G 35879		OCS OCS
Area Name	Green Canyon		
Block No.	895		
Blockline Departures (in feet)	N/S Departure: F_S_L 3960.00’	N/S Departure: F ____L	N/S Departure: F____L N/S Departure: F____L N/S Departure: F____L
	E/W Departure: F_E_L 5890.00’	E/W Departure: F____L	E/W Departure: F____L E/W Departure: F____L E/W Departure: F____L
Lambert X-Y coordinates	X: 2,227,550.00	X:	X: X: X:
	Y: 9,824,760.00	Y:	Y: Y: Y:
Latitude/ Longitude	Latitude 27° 03’ 48.9052” N	Latitude	Latitude Latitude Latitude
	Longitude 91° 11’ 43.6254” W	Longitude	Longitude Longitude Longitude

Water Depth (Feet): 5572’	MD (Feet):	TVD (Feet):	MD (Feet): MD (Feet): MD (Feet):	TVD (Feet): TVD (Feet): TVD (Feet):
Anchor Radius (if applicable) in feet: N/A				

Anchor Locations for Drilling Rig or Construction Barge (If anchor radius supplied above, not necessary)

Anchor Name or No.	**Area**	**Block**	**X Coordinate**	**Y Coordinate**	**Length of Anchor Chain on Seafloor**
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	

OCS PLAN INFORMATION FORM (CONTINUED)

Proposed Well/Structure Location							
Well or Structure Name/Number (If renaming well or structure, reference previous name): Loc C		Previously reviewed under an approved EP or DOCD?			Yes	X	No
Is this an existing well or structure?		Yes	X	No	If this is an existing well or structure, list the Complex ID or API No.		
Do you plan to use a subsea BOP or a surface BOP on a floating facility to conduct your proposed activities?				X	Yes		No
WCD info	For wells, volume of uncontrolled blowout (Bbls/day): 313,100		For structures, volume of all storage and pipelines (Bbls): N/A		API Gravity of fluid	31.6°	

	Surface Location	Bottom-Hole Location (For Wells)	Completion (For multiple completions, enter separate lines)
Lease No.	OCS-G 35879		OCS OCS
Area Name	Green Canyon		
Block No.	895		
Blockline Departures (in feet)	N/S Departure: F_S_L 5942.00'	N/S Departure: F ___L	N/S Departure: F____L N/S Departure: F____L N/S Departure: F____L
	E/W Departure: F_E_L 5101.00'	E/W Departure: F____L	E/W Departure: F____L E/W Departure: F____L E/W Departure: F____L
Lambert X-Y coordinates	X: 2,228,339.00	X:	X: X: X:
	Y: 9,826,742.00	Y:	Y: Y: Y:
Latitude/ Longitude	Latitude 27° 04' 8.4195" N	Latitude	Latitude Latitude Latitude
	Longitude 91° 11' 34.5842" W	Longitude	Longitude Longitude Longitude

Water Depth (Feet): 5596'	MD (Feet):	TVD (Feet):	MD (Feet): MD (Feet): MD (Feet):	TVD (Feet): TVD (Feet): TVD (Feet):
Anchor Radius (if applicable) in feet: N/A				

Anchor Locations for Drilling Rig or Construction Barge (If anchor radius supplied above, not necessary)

Anchor Name or No.	Area	Block	X Coordinate	Y Coordinate	Length of Anchor Chain on Seafloor
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	

OCS PLAN INFORMATION FORM (CONTINUED)

Proposed Well/Structure Location					
Well or Structure Name/Number (If renaming well or structure, reference previous name): Loc D			Previously reviewed under an approved EP or DOCD?	Yes	X No
Is this an existing well or structure?	Yes	X No	If this is an existing well or structure, list the Complex ID or API No.		
Do you plan to use a subsea BOP or a surface BOP on a floating facility to conduct your proposed activities?				X Yes	No
WCD info	For wells, volume of uncontrolled blowout (Bbls/day): 313,100		For structures, volume of all storage and pipelines (Bbls): N/A	API Gravity of fluid	31.6°

	Surface Location		**Bottom-Hole Location (For Wells)**		**Completion (For multiple completions, enter separate lines)**	
Lease No.	OCS-G 35879				OCS OCS	
Area Name	Green Canyon					
Block No.	895					
Blockline Departures (in feet)	N/S Departure: F_N_L 3815.00'		N/S Departure: F____L		N/S Departure: F____L N/S Departure: F____L N/S Departure: F____L	
	E/W Departure: F_E_L 4910.00'		E/W Departure: F____L		E/W Departure: F____L E/W Departure: F____L E/W Departure: F____L	
Lambert X-Y coordinates	X: 2,228,530.00		X:		X: X: X:	
	Y: 9,832,825.00		Y:		Y: Y: Y:	
Latitude/ Longitude	Latitude 27° 05' 08.6280" N		Latitude		Latitude Latitude Latitude	
	Longitude 91° 11' 31.5050" W		Longitude		Longitude Longitude Longitude	
Water Depth (Feet): 5442'			MD (Feet):	TVD (Feet):	MD (Feet): MD (Feet): MD (Feet):	TVD (Feet): TVD (Feet): TVD (Feet):
Anchor Radius (if applicable) in feet: N/A						

Anchor Locations for Drilling Rig or Construction Barge (If anchor radius supplied above, not necessary)

Anchor Name or No.	Area	Block	X Coordinate	Y Coordinate	Length of Anchor Chain on Seafloor
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	
			X =	Y =	

OCS PLAN INFORMATION FORM (CONTINUED)

Paperwork Reduction Act of 1995 Statement: The Paperwork Reduction Act of 1995 (44 U.S.C. 2501 et seq.) requires us to inform you that BOEM collects this information as part of an applicant's Exploration Plan or Development Operations Coordination Document submitted for BOEM approval. We use the information to facilitate our review and data entry for OCS plans. We will protect proprietary data according to the Freedom of Information Act and 30 CFR 550.197. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid Office of Management and Budget Control Number. Responses are mandatory (43 U.S.C. 1334). The public reporting burden for this form is included in the burden for preparing Exploration Plans and Development Operations Coordination Documents. We estimate that burden to average 600 hours with an accompanying EP, or 700 hours with an accompanying DPP or DOCD, including the time for reviewing instructions, gathering and maintaining data, and completing and reviewing the forms associated with subpart B. Direct comments regarding the burden estimate or any other aspect of this form to the Information Collection Clearance Officer, Bureau of Ocean Energy Management, 45600 Woodland Road, Sterling, Virginia 20166.

SERVICE FEE RECEIPT

Brandon Hebert

From: notification@pay.gov
Sent: Wednesday, March 11, 2020 4:15 PM
To: Brandon Hebert
Subject: Pay.gov Payment Confirmation: BOEM Exploration Plan - BF

CAUTION: This email is from an external source.

An official email of the United States government

Pay.gov

Your payment has been submitted to Pay.gov and the details are below. If you have any questions regarding this payment, please contact Brenda Dickerson at (703) 787-1617 or BseeAccountsReceivable@bsee.gov.

Application Name: BOEM Exploration Plan - BF
Pay.gov Tracking ID: 26O63MD0
Agency Tracking ID: 75973686206
Transaction Type: Sale
Transaction Date: 03/11/2020 05:15:11 PM EDT
Account Holder Name: Eva Gravouilla
Transaction Amount: $14,692.00
Card Type: Visa
Card Number: ************5796

Region: Gulf of Mexico
Contact: Brandon Hebert 985-666-0143
Company Name/No: BOE Exploration & Production LLC, 03572
Lease Number(s): 35879, , , ,
Area-Block: Green Canyon GC, 895: , : , : , : ,
Surface Locations: 4

THIS IS AN AUTOMATED MESSAGE. PLEASE DO NOT REPLY.

APPENDIX B
GENERAL INFORMATION

A) APPLICATIONS & PERMITS

Listed in the table below are the applications and/or permits that are required to be filed prior to conducting the activities proposed in this plan:

Application/Permit	Issuing Agency	Status
Application for Permit to Drill (APD)	BSEE	Pending
Application for Permit to Modify (APM)	BSEE	Pending

B) DRILLING FLUIDS

In accordance with BOEM guidance, the required drilling fluid information has been incorporated into the Waste & Discharge tables which are included in the attachment(s) to the Waste & Discharge Information appendix.

C) PRODUCTION

In accordance with NTL 2008-G04, this information is not applicable as this is an Exploration Plan.

D) OIL CHARACTERISTICS

In accordance with NTL 2008-G04, this information is not applicable as this is an Exploration Plan.

E) NEW OR UNUSUAL TECHNOLOGY

BOE Exploration & Production does not plan to use new or unusual technology to carry out the activities proposed in this plan. Further, no new or unusual technology will be utilized in the event of oil spill prevention, response or cleanup. The best available and safest technologies, as referred to in 30 CFR 250, will be incorporated as standard operating procedures to the extent that are practical and applicable.

F) BONDING STATEMENT

The bond requirements for the activities and facilities proposed in this plan are satisfied by a $3,000,000 area-wide bond, furnished and maintained according to 30 CFR Part 556, Subpart I, and NTL No. 2015-N04, “General Financial Assurance;” and additional security under 30 CFR Part 556, Subpart I, and NTL 2016-N01, “Requiring Additional Security.”

G) OIL SPILL FINANCIAL RESPONSIBILITY

BOE Exploration & Production, BOEM company number 03572, will demonstrate oil spill financial responsibility for the activities/facilities proposed in this plan in accordance with 30 CFR Part 553 and NTL 2008-N05, "Guidelines for Oil Spill Financial Responsibility for Covered Facilities."

H) DEEPWATER WELL CONTROL STATEMENT

BOE Exploration & Production (03572) has the financial capability to drill a relief well and conduct other emergency well control operations.

I) SUSPENSION OF PRODUCTION

In accordance with NTL 2008-G04, this information is not applicable as this is an Exploration Plan.

J) BLOWOUT SCENARIO

Information required by 30 CFR 550.243 (h) and referenced in NTL No. 2015-N01, “Information Requirements for Exploration Plans, Development and Production Plans, and Development Operations Coordination Documents on the OCS" are included in the attachments to this appendix.

BLOWOUT SCENARIO

BLOWOUT SCENARIO

The following attachment provides a blowout scenario description, information regarding any oil spill, WCD results and assumptions of potential spill and additional measures taken by BOE Exploration & Production (BOE) first enhance the ability to prevent a blowout and secondly to manage a blowout scenario if it occurs.

INFORMATION REQUIREMENTS

PROPOSED PROSPECT INFORMATION

Well Surface Location	WD	X (NAD 27)	Y (NAD 27)	Latitude	Longitude
GC 895 A*	5584	2226500.00	9823000.00	27°03'31.6260"N	91°11'55.5170"W
GC 895 B	5572	2227550.00	9824760.00	27°03'48.9052"N	91°11'43.6254"W
GC 895 C	5596	2228339.00	9826742.00	27°04'8.4195"N	91°11'34.5842"W
GC 895 D	5442	228530.00	9832825.00	27°05'08.6280"N	91°11'31.5050"W

* Plan WCD Well

INFORMATION REQUIREMENTS

A) Blowout scenario

The proposed GC 895 wells to be drilled to potential outlined in the Geological and Geophysical Information Section of this plan utilizing a typical subsea wellhead system, conductor, surface and intermediate casing strings and a MODU rig with marine riser and a subsea BOP system. A hydrocarbon influx and a well control event occurring from the objective sand is modeled with no drill pipe or obstructions in the wellbore followed by a full failure of the subsea BOP's (i.e. BOPS elements provide no restriction) and loss of well control at the seabed. The simulated flow and worst case discharge (WCD) results for all wells and the highest WCD is used for this unrestricted blowout scenario.

B) Estimated flow rate of the potential blowout

Category	
Type of Activity	Drilling
Facility Location (area / block)	GC 895 (surface location)
Facility Designation	MODU
Distance to Nearest Shoreline (nautical miles)	136 miles
Uncontrolled Blowout (Volume per day)	313,100 BOPD
Type of Fluid	Crude (31.6 API oil)

C) Total volume and maximum duration of the potential blowout

Duration of Flow (days)	**99** days total (see Relief Well Response Estimate below)
Total Volume of Spill (bbls)	**~25,348** MMBO based on **99** days of uncontrolled flow based on simulator models

WCD volume is generated using geologic maps to drive OOIP volumes. In the event of a worst case discharge situation, there will be some gradual depletion in the reservoir. As a result, the well will gradually decline in production based on the transient reservoir model. The reported worst case discharge is based on these model assumptions rather than the WCD rate multiplied times the estimated relief well days.

D) Assumptions and calculations used in determining the worst case discharge

Submitted separately in the Proprietary Copy of this Plan - Omitted from Public Information Copies

E) Potential for the well to bridge over

Mechanical failure/collapse of the borehole in a blowout scenario is influenced by several factors including in-situ stress, rock strength and fluid velocities at the sand face. Given the substantial fluid velocities inherent in the WCD, and the scenario as defined where the formation is not supported by a cased and cemented wellbore, it is likely that the borehole will fall/collapse/bridge over within a span of a few days, significantly reducing the outflow of the rates. However, for this blowout scenario, no bridging is considered.

F) Likelihood for intervention to stop blowout

The likelihood of surface intervention to stop a blowout is based on some of the following equipment specific to potential MODU's to be contracted for this well. It is reasonable to assume that the sooner BOE is able to respond to the initial blowout, the better likelihood there is to control and contain the event due to reduced pressures at the wellhead, less exposure to well fluids to eroding and compromising the well control equipment, and less exposure of hydrocarbons to the surface and greater probability of safeguarding personnel and equipment in an emergency situation. This equipment includes:

- Secondary Acoustic BOP Control System – typically fitted on DP MODU's presently operating in the GOM. This system has the ability to communicate and function specific BOP controls from the surface in the event of a failure of the primary umbilical control system. This system typically can establish BOP controls from the surface acoustic system package on the rig or by deploying a second acoustic package from a separate vessel of opportunity. This system may not be included on all MODU's such as 4th generation moored rigs. This system is typically configured to function the following:

    - Blind/;shear ram close
    - Pipe ram close
    - LMRP disconnect

- ROV Intervention BOP Control System – includes one or more ROV intervention panels mounted on the subsea BOP's located on the seabed allows a ROV utilizing standard ROV stabs to access and function the specific BOP controls. These functions will be tested at the surface as part of the required BOP stump test and selectively at the seafloor to ensure proper functionality. These function include the following (at a minimum):

    - Blind/shear ram close
    - Pipe ram close
    - LMRP disconnect
    - WH disconnect

- Deadman / Autoshear function – typically fitted on DP MODU's and but to be on all MODU's operating in the GOM according to new requirements, this equipment allows for an automated pre-programmed sequence of functions to close the casing shear rams and the blind/shear rams in the event of an inadvertent or emergency disconnect of the LMRP or loss of both hydraulic and electrical supply from the surface control system.

In the event that the intervention systems for the subsea BOP's fail, BOE will initiate call out of a secondary containment / surface intervention system supported by the HWCG well containment company of which BOE is a member. This system incorporates a capping stacks capable of being deployed from the back of a vessel of opportunity equipped with an ROV, or from the Helix Q4000 or Q5000 DP MODU. Based on the potential wellbore integrity concerns, a cap and flow system can be deployed from a range of vessels. This system is capable of handling flowback volumes of up to 130,000 bbls of fluid per day and 220 MMSCF of gas per day. The vertical intervention work is contingent upon the condition of the blowing out well and what equipment is intact to access the wellbore for kill or containment operations The available intervention equipment may also require modifications based on actual wellbore conditions. Standard equipment is available through the HWCG equipment to fit the wellhead and BOP stack profiles used for the drilling of the above mentioned well.

G) Availability of rig to drill relief well, rig constraints and timing of rigs

In the event of a blowout scenario that does not involve loss or damage to the rig such as an inadvertent disconnect of the BOP's, then the existing contracted rig may be available for drilling the relief well and vertical intervention work. If the blowout scenario involves damage to the rig or loss of the BOP's and riser, a replacement rig or rigs will be required.

With the current activity level in the GOM, 20 to 25 deepwater MODU'S are potentially available to support the relief well drilling operations. Rig share and resource sharing agreements are in place between members of the HWCG as well as the larger Gulf of Mexico Operators Rig Share Agreement . BOE is a member of both groups. The ability to negotiate and contract an appropriate rig or rigs to drill relief wells is highly probable in a short period of time. If the rig or rigs are operating, the time to properly secure the well and mobe the rig to the relief well site location is estimated to be about 14 days. Dynamically positioned (DP) MODU's would be the preferred option due to the logistical advantage versus a moored MODU which may add complications due to the mooring spread.

Most 4th, 5th and 6th generation drill ships or semi-submersible rigs in the USGOM would be suitable to drill a relief well. Therefore, the rig choice would be first available, quickest to mobilize and move into position offsetting the blow out well. A relief well would be drilled from an open water location about 1500' south to southwest of the blowout well. The final rig location will be influenced by operator, contractor, BSEE and depth of intersect to insure safety of all personnel and equipment involved in the relief well effort.

<u>VESSELS OF OPPORTUNITY</u>

Based on the water depth restrictions for the proposed locations the following "Vessels of Opportunity" are presently available for utilization for intervention and containment and relief well operations. These may include service vessels and drilling rigs capable of working in the potential water depths and may include moored vessels and dynamically positioned vessels. The specific conditions of the intervention or relief well operations will dictate the "best fit" vessel to efficiently perform the desired results based on the blowout scenario. The list included below illustrates specific option that may vary according to the actual timing / availability at the time the vessels are needed.

OPERATION	SPECIFIC VESSEL OF OPPORTUNITY

Intervention and Containment	• Helix Q4000 (DP Semi) • Helix Q5000 (DP Semi)
Relief Well Drilling Rigs	• BOE has contractual agreements in place with HWCG, a GOM Rig Share group – these agreements give BOE access to any MODU operating in GOM
ROV / Multi-Purpose Service Vessels	• Oceaneering (numerous DP ROV vessels) • HOS Achiever, Iron Horse 1 and 2 (DP MPSV) • Helix Pipe Lay Vessel (equipped w/ 6" PL – 75,000') • Other ROV Vessels – (Chouest, HOS, Fugro, Subsea 7)
Shuttle Tanker / Barge Support	• American Eagle Tankers (AET)

H) Measures taken to enhance ability to prevent blowout

The measures to enhance the ability to prevent or reduce the likelihood of a blowout are largely based on proper planning and communication, identification of potential hazards, training and experience of personnel, use of good oil field practices and proper equipment that is properly maintained and inspected for executing drilling operations of the proposed well or wells to be drilled.

When planning and designing the well, ample time is spent analyzing offset data, performing any needed earth modeling and identifying any potential drilling hazards or well specific conditions to safeguard the safety of the crews when well construction operations are underway. Once the design criteria and well design is established, the well design is modeled for the lifecycle of the wellbore to ensure potential failure modes are eliminated. A minimum of 2 independent barriers for both internal and external flow paths in addition to proper positive and negative testing of the barriers is part of BOE's design and testing protocol.

The proper training of crew members and awareness to identify and handle well control event is the best way prevent a blowout incident. Contractor's personnel and service personnel training requirements are verified per regulatory requirements. Drills are performed frequently to verify crew training and improve reaction times.

Good communication between rig personnel, office support personnel is critical to the success of the operations. Pre-spud meetings are conducted with rig crews and service providers to discuss, inform and as needed improve operations and well plans for safety and efficiency considerations. Daily meetings are conducted to discuss planning and potential hazards to ensure state of preparedness and behavior is enforced to create an informed and safe culture for the operations. Any changes in the planning and initial approved wellbore design is incorporated and communicated in a Management of Change (MOC) process to ensure continuity for all personnel.

Use of established good oil field practices that safeguard crews and equipment are integrated to incorporate BOE's, the contractor and service provider policies.

Additional personnel and equipment will be used as needed to elevate awareness and provide real time monitoring of well conditions while drilling such as MWD/LWD/PWD tools used in the bottom hole assemblies. The tool configuration for each open hole section varies to optimize information gathered including the use of Formation-Pressure-While-Drilling (FPWD) tools to establish real time formation pressures and to be used to calibrates pore pressure models while drilling. Log information and pressure data is used by the drilling engineers, geologist and pore pressure engineers to maintain well control and reduced potential events such as well control events and loss circulation events.

Onsite Mud loggers continuously monitor return drilling fluids, drill gas levels and cuttings as well as surface mud volumes and flow rates, rate of penetration and lithology/paleo to aid in understanding trends and geology being drilled. Remote monitoring of real time drilling parameters and evaluation of geologic markers and pore pressure indicators is used to identify potential well condition changes.

Proper equipment maintenance and inspection program for same to before the equipment is required. Programmed equipment inspections and maintenance will be performed to ensure the equipment operability and condition. Operations will cease as needed in order to ensure equipment and well conditions are maintained and controlled for the safety of personnel, rig and subsurface equipment and the environment.

I) Measures to conduct effective and early intervention in the event of a blowout

The following is provided to demonstrate the potential time needed for performing secondary intervention and drilling of a relief well to handle potential worst case discharge for the proposed prospect. Specific plans are integrated into the HWCG procedures to be approved and submitted with the Application for Permit to Drill. Equipment availability, backup equipment and adaptability to the potential scenarios will need to be addressed based on the initial site assessment of the seafloor conditions for intervention operations. Relief well equipment such as backup wellhead equipment and tubulars will be available in BOE’s inventory for immediate deployment as needed to address drilling the relief well(s).

SITE SPECIFIC PROPOSED RELIEF WELL AND INTERVENTION PLANNING

No platform was considered for drilling relief wells for this location due to location, water depth and lack of appropriate platform within the area. For this reason a moored or DP MODU will be preferred / required.

RELIEF WELL RESPONSE TIME ESTIMATE

OPERATION	TIME ESTIMATE (DAYS)
IMMEDIATE RESPONSE • safeguard personnel, render first-aid • make initial notifications • implement short term intervention (if possible) • implement spill control • develop Initial Action Plan	1
INTERIM REPSONSE • establish Onsite Command Center and Emergency Management Team • assess well control issues • mobilize people and equipment (Helix DW Containment System) • implement short term intervention and containment (if possible) • develop Intervention Plan • initiate relief well planning • continue spill control measures	4
INTERVENTION AND CONTAIMENT OPERATIONS • mobilize equipment and initiate intervention and containment operations • perform TA operations and mobilize relief wells rig(s) • finalize relief well plans, mobilize spud equipment, receive approvals	14

• continue spill control measures	
RELIEF WELL(S) OPERATIONS • continue intervention and containment measures • continue spill control measures • drill relief well (s)	60
PERFORM HYDRAULIC KILL OPERATIONS / SECURE BLOWNOUT WELL • continue intervention and containment measures • continue spill control measures • perform hydraulic kill operations, monitor well, secure well	20
ESTIMATED TOTAL DAYS OF UNCONTROLLED FLOW	**99**
SECURE RELIEF WELL(S) / PERFORM P&A / TA OPERATIONS / DEMOBE	30
TOTAL DAYS	**129**

APPENDIX C
GEOLOGICAL & GEOPHYSICAL INFORMATION

A) GEOLOGICAL DESCRIPTION
PROPRIETARY INFORMATION

B) STRUCTURE CONTOUR MAPS
Current structure maps drawn to the top of each prospective hydrocarbon sand, showing the location of the proposed well(s) and location(s) of geological cross-sections are included in the attachment(s) to this appendix of the proprietary information copy of this plan.

C) INTERPRETED 2D/3D SEISMIC CROSS SECTIONS
An interpreted 2D/3D seismic line cross section map is included for the proposed well(s) in the attachment(s) to this appendix of the proprietary information copy of this plan.

D) GEOLOGICAL STRUCTURE CROSS SECTIONS
Geological structure cross-section markers showing the key horizons and objective sands for the proposed well(s) location is included in the attachment(s) to this appendix of the proprietary information copy of this plan.

E) SHALLOW HAZARDS REPORT
A shallow hazard report incorporating Green Canyon 895 was submitted to BOEM under separate cover (Echo Offshore Report No. 17-022-50/1115). An archaeological report incorporating Green Canyon 988, OCS-G 35417, was submitted to BOEM under separate cover (Echo Offshore Report No. 17-021-41).

F) SHALLOW HAZARDS ASSESSMENT
An assessment of any seafloor and subsurface geological and manmade features and conditions that may adversely affect drilling operations for the proposed well(s) is included in the attachment(s) to this appendix.

G) HIGH RESOLUTION SEISMIC LINES
High-resolution seismic lines for the proposed well(s) are included in the attachment(s) to this appendix of the proprietary information copy of this plan

H) STRATIGRAPHIC COLUMN
A stratigraphic column from the seafloor to the proposed total depth of the proposed well(s) is included in the attachment(s) to this appendix of the proprietary information copy of this plan.

I) TIME VS DEPTH TABLES
A time vs. depth table is included in the attachment(s) to this appendix of the proprietary information copy of this plan

J) GEOCHEMICAL INFORMATION
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as the subject area is within the boundaries of the Gulf of Mexico.

K) FUTURE G&G ACTIVITIES
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as the subject area is within the boundaries of the Gulf of Mexico.

SHALLOW HAZARDS ASSESSMENT

Well Clearance Letter for
BOE Exploration & Production LLC
Public Copy

Project:
Block GC895, Offshore Gulf of Mexico

Description:
Proposed GC895-A Well Location

Project Number:
20-012-31/2018-103

Report Status:
Final

REPORT AUTHORIZATION AND DISTRIBUTION

Compilation	Geophysics	L Fuentes
Authorization	Geophysics	…………………… A R Haigh
	Quality Assurance	…………………… Matt Keith

Revision	**Date**	**Title**
0	March 02, 2020	Final

Distribution

One digital copy (PDF)

BOE Exploration & Production LLC
300 Holiday Square Blvd,
Suite 100
Covington, LA 70433

For the attention of
Eva Gravouilla

Public Copy

Eva Gravouilla
BOE Exploration & Production LLC
300 Holiday Square Blvd,
Suite 100
Covington, LA 70433

Dear Mrs. Gravouilla:

Echo Offshore, LLC appreciates the opportunity to submit this Well Clearance letter based on a 3D geohazard assessment covering Block GC895, Green Canyon protraction area. This assessment was prepared utilizing 3D seismic data originally provided by Houston Energy, LP, in compliance with NTL Nos. 2008-G05, 2008-G04, and 2009-G40, by the Bureau of Ocean Energy Management (BOEM), Gulf of Mexico Region. BOE Exploration & Production LLC is now the operator of the lease and has requested that Echo Offshore provide this assessment of the referenced proposed well location.

This report has been prepared with due care, diligence, and with the skill reasonably expected of a reputable contractor experienced in the types of work, carried out under the contract. As such, the findings in this report are based on an interpretation of data which is a matter of opinion on which professionals may differ and, unless clearly stated, is not a recommendation of any course of action.

Please be aware that further distribution of this report, in whole or part, or the use of the data for a purpose not expressly stated within the contractual work scope is at the client's sole risk, and it is recommended that this disclaimer be included in any such distribution.

If we can be of further assistance, or if you have any questions, please do not hesitate to call.

We sincerely appreciate this opportunity to be of service to you.

Very truly yours,

C. D. Schempf, Jr.

C. D. Schempf, Jr.
President

MK for CDS

Location Map

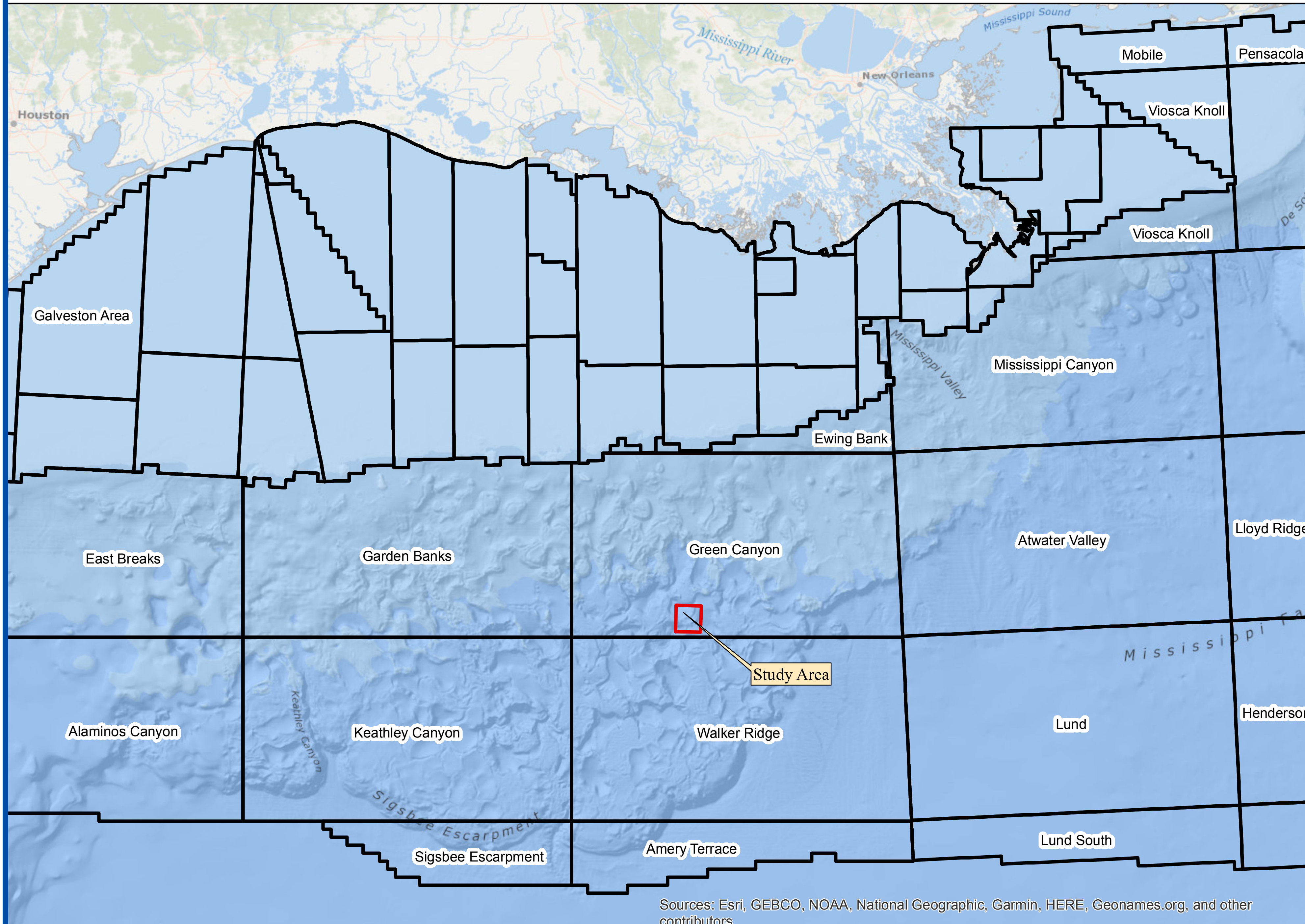


TABLE OF CONTENTS

LIST OF FIGURES

WELL CLEARANCE LETTER – PROPOSED GC895-A WELL LOCATION

Public Copy

March 02, 2020
Bureau of Ocean Energy Management (MS 5230)
Gulf of Mexico OCS Region
1201 Elmwood Park Blvd.
New Orleans, LA 70123-2394

RE: **BOE Exploration & Production LLC**
Proposed GC895-A
Block 895, Green Canyon
Offshore Gulf of Mexico
OCS-G-35879

Echo Offshore, LLC was contracted by BOE Exploration & Production LLC, to prepare a Well Clearance Letter for the proposed GC895-A well in Block 895, Green Canyon Area (OCS-G-35879). This letter addresses seafloor and shallow geologic conditions that may impact exploratory drilling operations within 2,000ft of the proposed well site. The depth limit of this site clearance assessment is at -8,792ft below sea surface (3,208ft below seafloor). BOE Exploration & Production LLC plans to operate from a dynamically positioned drilling module; therefore, an anchoring assessment is not required. Relevant letter-size chart extracts, and data examples are presented with this Well Clearance Letter, plus annotated data examples of the two nearest intersecting inlines and crosslines, the nearest sub-bottom profiler transect line, and the side-scan sonar mosaic. This site clearance assessment is primarily based on the interpretation of an AUV data set for seafloor and shallow soils and a 3D seismic data set for deeper geology. This assessment is based on the area specific hazard assessment that has been produced under separate cover (Houston Energy – Gardline Surveys Inc. Report No. 11115).

AUV Archaeological Investigation. The proposed activities occur within an area of the outer continental shelf defined by BOEM as having a moderate archaeological resource potential (see NTL No. 2011-JOINT-G01). An archaeological investigation was performed across the wellsite area by Echo Offshore on Nov. 21-27, 2017 using AUV geophysical data. An archaeological assessment of the proposed well location based on this data set has been prepared.

3D Geophysical Survey. The 3D seismic dataset is of good quality and suitable for shallow hazard assessment. Inlines are oriented northeast to southwest, have a numerical increment of one, and exhibit a line spacing of 98.42ft. Crosslines are oriented northwest to southeast, have a numerical increment of four and exhibit a line spacing of 82.02ft. Sample rate of the data was 4ft, and record length is 60,000ft.

The data presents an acceptable frequency response across the upper one second below seafloor, with an equivalent effective frequency range at 50% power of 55-85Hz (Figure 11). The data exhibits a dominant frequency in the upper one second of approximately 70Hz plus significant higher usable frequencies, resulting in a mean vertical resolvability of typically 20ft and a layer detectability of 5ft.

Several data types were provided, within two surveys: E Wave and E Octopus. The E Octopus survey data was used primarily, and is characterized by the following collection and processing parameters and history, based on the survey collection and processing phases:

- Modern WAZ data
- Spec. data widely licensed by many companies for exploration
- Using highest frequency product available "High-resolution sediment flood", after 3 iterations of multiazimuth sediment tomography
- E-Octopus VII:
  - Shot 2010, Processed 2011
- E-Octopus II
  - Shot 2008, Processed 2008
- E-Octopus III
  - Shot 2009, Processed 2009
- Note that E-Oct II and III were merged together by WesternGeco

E-Octopus VII

Acquisition Parameters

Recording System: Q-Marine*

Energy Source: Single Source; 8,475 in.^{3}

Line Orientation: NE/SW

Source Depth: 12m

Streamer Configuration: Multi-streamer: 10 X 7,000m cables

Streamer Depth: 12m

Maximum Offset: 8,600m

Sample Rate: 2ms

Record Length: 14s

DGF Receiver Interval: 12.5m

Recording Bin Dimensions: 6.25 X60m

Acquisition Completed: April 2010

Processing Flow

Q* point-receiver seismic acquisition and processing methodology

Digital group forming (DGF): output 12.5m

Navigation merge

Calibrated marine source designature

Anomalous amplitude attenuation

Water velocity correction

3D GSMP demultiple

3 iterations of multiazimuth sediment tomography

High-resolution sediment flow (pick top of salt 1)

Salt flood 1(pick bottom salt 1)

Salt body 1 (pick top of salt 2)

Salt flood 1(pick bottom salt 2)

Salt body 2

Subsalt tomography (using ample gathers)

Full salt velocity models

RTM (Reverse Time Migration) and Kirchhoff migration

Processing completed: December 2011

E-Octopus I & II

Acquisition Parameters

Recording System: Q-Marine*

Energy Source: Single Source; 8,475 in.^{3}

Line Orientation: NE/SW

Source Depth: 10m

Streamer Configuration: Multi-streamer: 10 X 7,000m cables

Streamer Depth: 12m

Maximum Offset: 9,600m

Sample Rate: 2ms

Record Length: 14s

DGF Receiver Interval: 12.5m

Recording Bin Dimensions: 6.25 X60m

Acquisition Completed: Phase I December 2006; Phase II: December 2008

Processing Flow

Q* point-receiver seismic acquisition and processing methodology

Digital group forming (DGF): output 12.5m

Navigation merge

Calibrated marine source designature

Anomalous amplitude attenuation

Water velocity correction

Inverse Q: phase only

WEM demultiple

3 iterations of multiazimuth sediment tomography (incorporating anistrophy)

High-resolution sediment flow (pick top of salt 1)

Salt flood 1(pick bottom salt 1)

Salt body 1 (pick top of salt 2)

Salt flood 1(pick bottom salt 2)

Salt body 2

Subsalt tomography (using ample gathers)

Full salt velocity models

Final WEM (Wave Equation Migration) 25Hz

Processing completed: Phase I: April 2008; Phase II: December 2008

E-Octopus III

Acquisition Parameters
Recording System: Q-Marine*
Energy Source: Single Source; 8,475 in.^{3}
Line Orientation: NE/SW
Source Depth: 10m
Streamer Configuration: Multi-streamer: 10 X 7,000m cables
Streamer Depth: 12m
Maximum Offset: 8,600m
Sample Rate: 2ms
Record Length: 14s
DGF Receiver Interval: 12.5m
Recording Bin Dimensions: 6.25 X60m
Acquisition Completed: Phase I December 2008

Processing Flow
Q* point-receiver seismic acquisition and processing methodology
Digital group forming (DGF): output 12.5m
Navigation merge
Calibrated marine source designature
Anomalous amplitude attenuation
Water velocity correction
Inverse Q: phase only
WEM demultiple
3 iterations of multiazimuth sediment tomography (incorporating anistrophy)
High-resolution sediment flow (pick top of salt 1)
Salt flood 1(pick bottom salt 1)
Salt body 1 (pick top of salt 2)
Salt flood 1(pick bottom salt 2)
Salt body 2
Subsalt tomography (using ample gathers)
Full salt velocity models
Final WEM (Wave Equation Migration) 25Hz
Processing completed: May 2009

Spectral whitening was applied to the data set as a post-processing technique to optimize interpretability.

In summary, and with reference to NTL No. 2008-G04 and 2008-G05, the following statements are applicable to the seismic data:

In summary and with reference to NTL No. 2008-G04:

a) The data provides imaging of sufficient resolution of the shallow section allowing a clear analysis of the shallow conditions.
b) The data can be loaded to a workstation at 16-bit resolution or greater and is unscaled.
c) There is no trace or sample decimation.
d) The sample interval and bin size are maintained throughout the assessment area.

e) The data possess a frequency content of 50Hz or higher at 50% power in the first second below seafloor.
f) Seafloor reflection is free of gaps and is defined by a wavelet of stable shape and phase, allowing auto-tracking of the seafloor event with minimum user intervention and guidance.
g) There are no significant acquisition artifacts throughout the dataset.
h) Merge points in the data are marked by no time shifts and very minimal amplitude changes and are not a detriment to interpretation.
i) Processed bin sizes are 98.42ft x 82.02ft.
j) The sample rate of the data is 4ft.
k) There is no significant multiple energy.

1. LOCATION COORDINATES

1.1 Proposed GC895-A Well Location (OCS-G-35879).

<table>
<tr><th colspan="8">Proposed GC895-A Well Location</th></tr>
<tr><td colspan="8">Location Coordinates</td></tr>
<tr><td colspan="5">NAD 27 Datum - Clarke 1866 Ellipsoid</td><td colspan="3">UTM Zone 15 - CM 93° West</td></tr>
<tr><td>Latitude</td><td>27°</td><td>03’</td><td>31.626”</td><td>North</td><td>Easting</td><td>2,226,500</td><td>US ft E</td></tr>
<tr><td>Longitude</td><td>91°</td><td>11’</td><td>55.517</td><td>West</td><td>Northing</td><td>9,823,000</td><td>US ft N</td></tr>
<tr><td>FEL Green Canyon 895</td><td>6,940ft</td><td>US ft</td><td colspan="2">Inline</td><td colspan="3">5232</td></tr>
<tr><td>FSL Green Canyon 895</td><td>2,200ft</td><td>US ft</td><td colspan="2">Crossline</td><td colspan="3">39025</td></tr>
<tr><td>Water Depth: -5,584 ft.</td><td colspan="7">Slope: 3.3° WSW</td></tr>
<tr><td>Nearest Shoreline</td><td colspan="7">118 Nautical Miles @ 06.47°</td></tr>
<tr><td>Nearest Manned Platform</td><td colspan="3">A-Constitution TLP in GC680</td><td colspan="4">19.23 Nautical Miles @ 23.5°</td></tr>
</table>

2. VELOCITY DATA

2.1 Seafloor Depth

Seafloor depth around the proposed well was derived from multibeam echosounder data acquired as part of an AUV geophysical investigation over approximately 15.3 square miles of blocks GC895 & GC939.

2.2 Sub-seafloor Depth

3D seismic data was provided as a depth volume; therefore, no depth conversion was required.

3. SEAFLOOR CONDITIONS

3.1 Seafloor Depth

Water depth at the Proposed GC895-A well location is -5,584ft below sea surface (Figure 1). The seafloor slopes to the WNW at 3.3°.

3.2 Seafloor Morphology and Man-Made Features

The proposed GC895-A well location is in the south-central part of block GC895.

Side-scan sonar data indicates the proposed well is located on an area of smooth seafloor interpreted as clays and silts with no significant variations within 2,000ft (Figure 6).

A thin ENE/WSW trending debris flow, originating from a possible fluid expulsion feature several thousand feet to the southeast, occurs 960ft to the southeast of the proposed location. This feature does not present a problem or hazard to the proposed location. No other natural seafloor features were observed within a 2,000ft radius (Figure 6).

In accordance with NTL stipulations for archaeological resources, an archeological survey was performed in the study area in November 2017. Several targets were identified within the study area. A side-scan target (Target #2) occurs approximately 606ft to the southeast of the proposed well. **No features of archaeological resources were identified within 2,000ft of the proposed well location**. All targets are interpreted as modern anthropogenic debris.

There are no anomalous seafloor amplitudes indicative of hydrocarbon macroseep observed within a 2,000ft radius of the proposed location (Figure 3). **No features or areas that could support high-density sensitive sessile benthic communities are located within 2,000ft of any mud or cuttings discharge location.** The nearest area with the potential for benthic communities occurs 2,145ft to the east.

4. SUB-SEAFLOOR CONDITIONS

4.1 Geology and Lithology

The sub-seafloor geology has been divided into seven Units, A, B, C, D, E, F, and G, separated by Horizons, H10, H20, H30, H40, H50, H60, and Top of salt (Figures 8 through 10). Top of salt is the depth limit of investigation.

4.2 Unit A

The lithology within Unit A from seafloor to -5,854ft below sea surface (270ft below seafloor) is characterized by well-layered, low and slightly moderate-amplitude reflectors interpreted as clays and silts with occasional sand interbeds. A <10ft thick sand interbed is located near the base of Unit A at -5,778ft below sea surface (194ft below seabed). Minor drilling fluid circulation and wellbore stability problems are possible at the level of the sand interbed.

Sub bottom profiler data shows the upper part of Unit A consists of predominantly clays and silts (Figure 7).

No risk of gas or shallow water flow is interpreted within Unit A at the location. Nearest risk of gas is located 1,128ft to the southwest with no connectivity to the proposed well location.

Unit A appears conducive to conductor jetting with no hardgrounds or problems interpreted.

Horizon H10 marks the base of Unit A occurring at -5,854ft below sea surface (270ft below seafloor).

4.3 Unit B

Unit B, from -5,854ft to -6,122ft below sea surface (270ft to 538ft below seafloor), is characterized by well-layered, low- moderate-amplitude reflectors interpreted as clays, silts, and occasional sands.

No risk of gas is predicted within Unit B at the proposed well location or within 2,000ft of the proposed well.

The well-path will not traverse any faults within Unit B.

Horizon H20 marks the base of Unit B occurring at -6,122ft below sea surface (538ft below seafloor).

4.4 Unit C

The well-path will not traverse Unit C which is absent due to salt uplift.

4.5 Unit D

Unit D between -6,122ft below sea surface (538ft below seabed) to -7,402ft below sea surface (1,818ft below seabed) is interpreted as a higher energy mass-transport deposit, characterized by semi-continuous and discontinuous variable amplitude reflectors interpreted as clays, silts, and several sands. Sand interbeds within this interval may have been rapidly deposited with inadequate dewatering time and the proposed well is located within a regional sand fairway that occupies most of the study area (Figure 5).

Several wells in the Green Canyon protraction area experienced shallow water flow risk but these are at least 15miles to the northeast of the proposed well. At the proposed well location some minor sand interbeds are considered probable and therefore a **Slight Shallow Water Flow Risk** is assigned throughout Unit D.

In addition, due to the increased potential for encountering poorly consolidated granular material in Unit D, minor drilling fluid circulation and wellbore stability problems may also occur within Unit D.

The well-path will not traverse any predicted risk of gas anomalies within Unit D, however, several risk of gas hazards occur within 2,000ft of the proposed well. The closest occurs 1,200ft to the NNE associated with a fault. The anomaly occurs on the northeast side of the fault and is disconnected from the proposed well location.

A vertical borehole will penetrate two faults within Unit D at -6,323ft below sea surface (739ft below seabed) and at -7,263ft below sea surface (1,679ft below seabed). The shallower fault is minor, exhibiting only around 10ft of throw. Minor drilling fluid circulation and wellbore stability problems may occur in association with the shallower fault. The deeper fault is larger, exhibiting around 35ft of throw and downward connectivity to top of salt and upward connectivity to at or near seafloor. Given this setting, in addition to minor drilling fluid and wellbore stability problems, the connectivity to near seafloor may result in additional drilling fluid circulation problems if pressures over hydrostatic are exerted by the drilling fluid column.

Horizon H40 marks the base of Unit D at -7,402ft below sea surface (1,818ft below seafloor).

4.6 Unit E

Unit E, from -7,402ft to -7,676ft below sea surface (1,818ft to 2,092ft below seafloor), is characterized by slightly-chaotic, low and occasional moderate-amplitude reflectors interpreted as clays and silts with several sands. Minor drilling fluid circulation and wellbore stability problems may occur within Unit E.

No risk of gas is predicted within Unit E at the proposed well or within 2,000ft.

The well-path will not traverse any faults within Unit E.

Horizon H50 marks the base of this unit and the base of this interpretation at -7,676ft below sea surface (2,092ft below seafloor).

4.7 Unit F

Unit F, from -7,676ft to -8,375ft below sea surface (2,092ft to 2,791ft below seafloor), is characterized by slightly-chaotic, low-amplitude reflectors interpreted as clays and silts with occasional sands.

No risk of gas is predicted within Unit F at the proposed well or within 2,000ft.

The well-path will not traverse any faults within Unit F.

Horizon H60 marks the base of this unit and the base of this interpretation at -8,375ft below sea surface (2,791ft below seafloor).

4.8 Unit G

Unit G, from -8,375ft to -8,792ft below sea surface (2,791ft to 2,823ft below seafloor), is characterized by slightly-chaotic, low and occasional moderate-amplitude reflectors interpreted as clays and silts with several sands. Minor drilling fluid circulation and minor wellbore stability problems may occur within this interval.

No risk of gas is predicted within Unit G at the proposed well or within 2,000ft.

The well-path will traverse a fault, exhibiting around 30ft of throw, within Unit G at -8,407ft below sea surface (2,823ft below seabed). The fault is limited in upward and downward connectivity but may still induce minor drilling fluid circulation and wellbore stability problems.

Top of Salt marks the base of this unit and the base of this interpretation at -8,792ft below sea surface (3,208ft below seafloor).

4.9 Shallow Gas Assessment

No risk of gas is interpreted at the proposed well location.

4.10 Shallow Water Flow Assessment

Throughout Unit D, a **Slight Shallow Water Flow Risk** is interpreted from -6,122ft to -7,402ft below sea surface (538ft to 1,275ft below seafloor).

5. CONCLUSIONS AND RECOMMENDATIONS

- Seafloor

  No drilling hazards or problems are interpreted at seafloor.

  No features of potential biological or archaeological significance were identified within 2,000ft of the proposed well location.

  A side-scan sonar target (Target #2) occurs approximately 652ft to the southeast of the proposed well.

- Unit A

  Minor wellbore stability and drilling fluid circulation problems are possible at the level of a <10ft thick sand interbed at -5,778ft below sea surface (194ft below seabed).

- Unit B

  None Predicted.

- Unit D

  Throughout Unit D, a **Slight Shallow Water Flow Risk** is interpreted from -6,122ft to -7,402ft below sea surface (538ft to 1,818ft below seafloor). Appropriate drilling methodology should be applied to contain with a short-lived, non-persistent water flow event. Additionally, minor drilling and wellbore stability problems are possible within this interval.

  A vertical borehole will penetrate two faults within Unit D at -6,323ft below sea surface (739ft below seabed) and at -7,263ft below sea surface (1,679ft below seabed). Minor drilling fluid circulation and wellbore stability problems may occur in association with the shallower fault. Additional drilling fluid circulation problems may occur at the level of the deeper fault if pressures over hydrostatic are exerted by the drilling fluid column. Casing seats should avoid all fault intersections as formation integrity could be compromised.

- Unit E

  Minor drilling and wellbore stability problems are possible within Unit E.

- Unit F

  None drilling hazards or problems are interpreted.

- Unit G

  Minor drilling and wellbore stability problems are possible within Unit G.

  The well-path will traverse a fault within Unit G at -8,407ft below sea surface (2,823ft below seabed). Minor wellbore stability and drilling fluid circulation problems may occur at the level of the fault. Casing seats should avoid all fault intersections as formation integrity could be compromised.

We appreciate the opportunity to work with you on this project and look forward to continuing as your geohazards consultants. Please contact us if you have any questions or if we can be of further assistance.

Sincerely,
Echo Offshore, LLC

Andrew Haigh
Geophysical Manager
Ocean Geo Solutions, Inc

Matt Keith
Quality Assurance
Echo Offshore, LLC

Copies Submitted: One digital copy (PDF) to Eva Gravouilla at BOE Exploration & Production LLC.

Attachments:

Proposed GC895-A Well Location

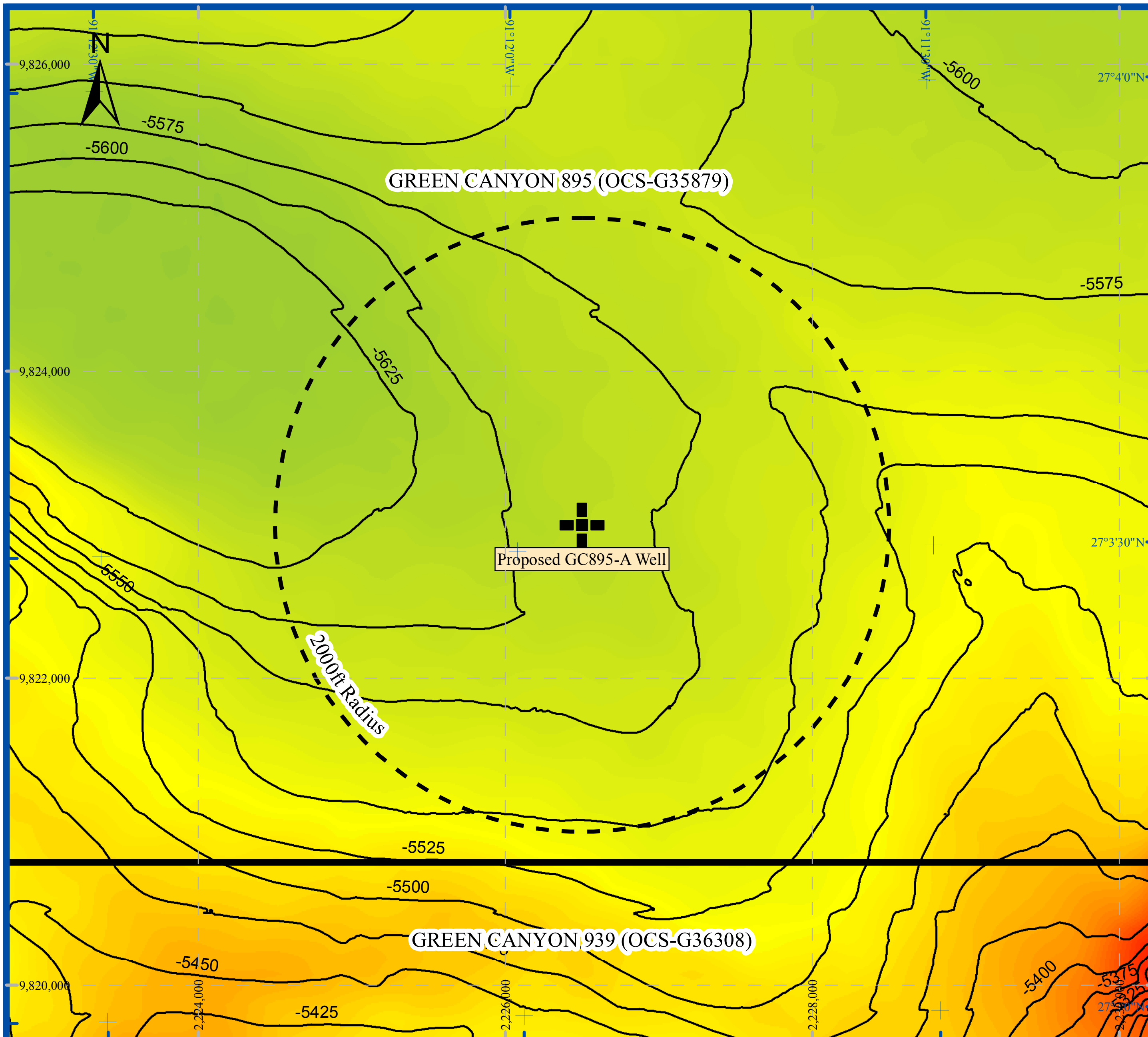
Seafloor Depth Extract

Seafloor Morphology Extract

Seafloor Amplitude Extract

Geohazard Summary Extract

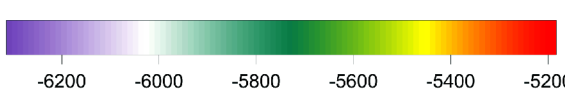
Sand Lithology Extract-Unit D



Seabed Depth Extract

Proposed GC895-A Well Location
(2,226,500ft E / 9,823,000ft N)

-5575 Depth in feet below sea surface to seabed contoured at 25ft intervals



Seabed Depth (Feet)

Chart Scale 1" = 1,000'

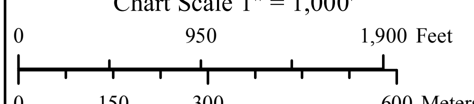
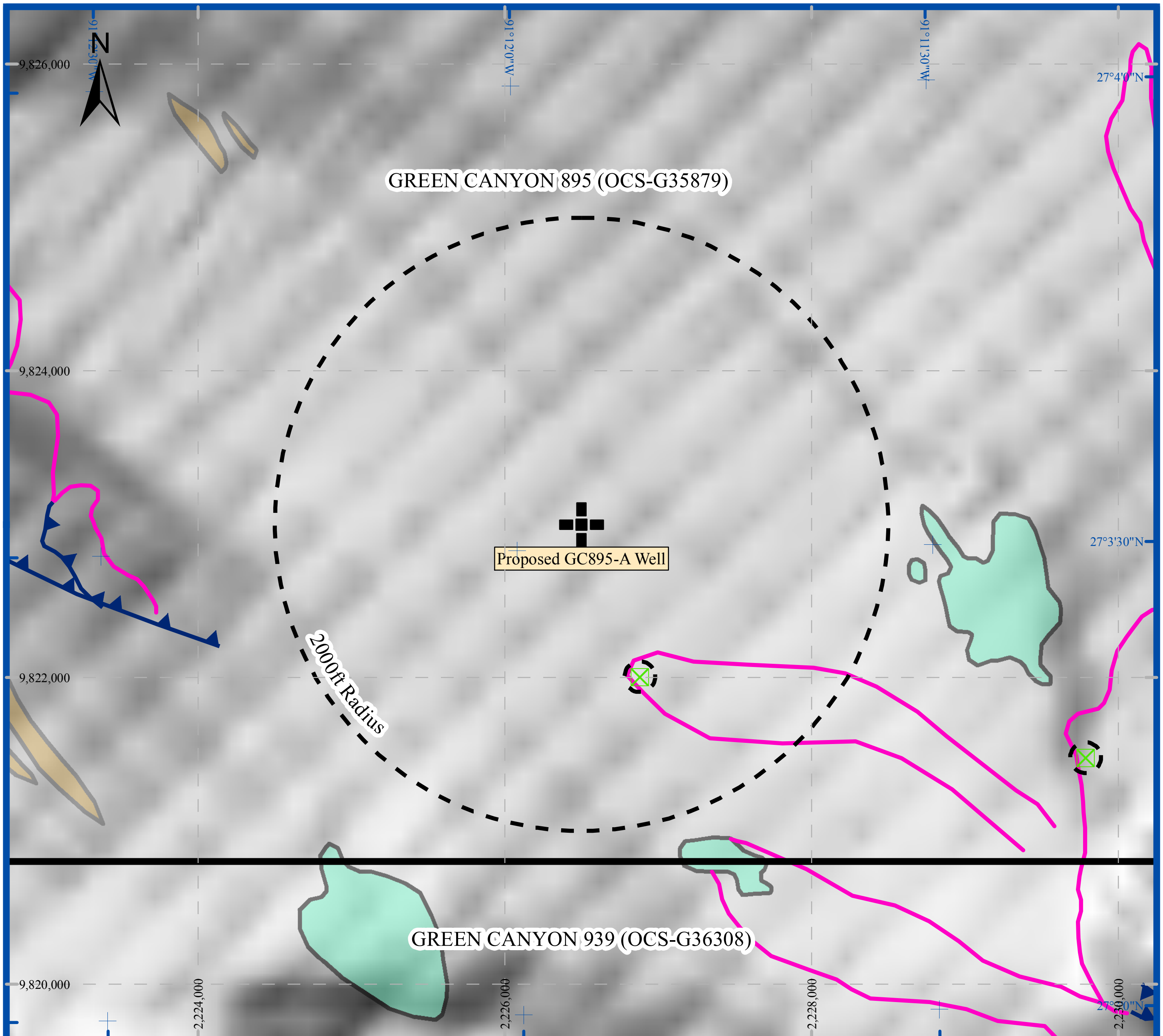


Figure 1
(GC895-A)



Seabed Morphology Extract

Proposed GC895-A Well Location
(2,226,500ft E / 9,823,000ft N)

Seabed failure scarps

Area of mass transport deposits

Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.

Seabed furrow area

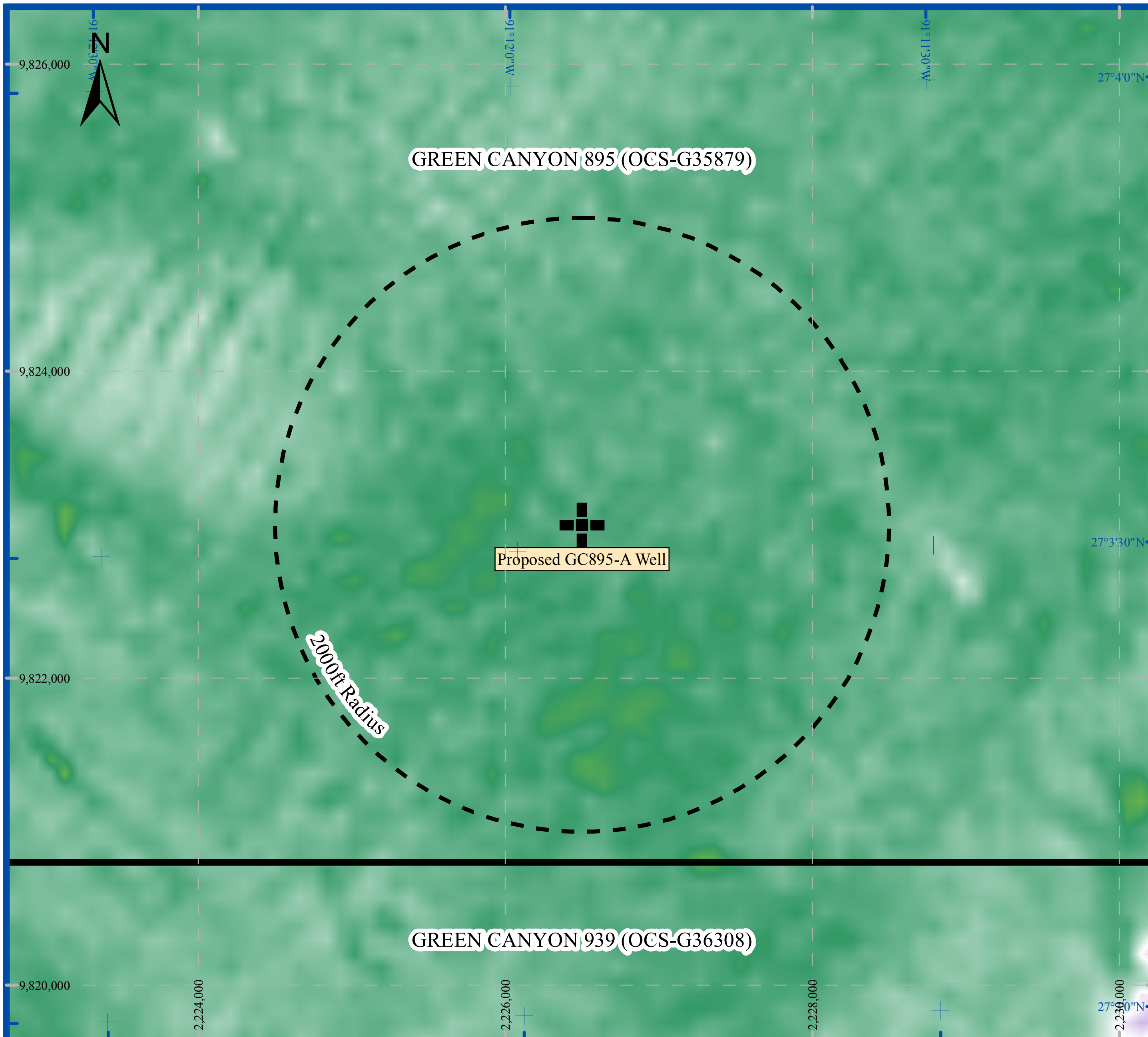
Side-scan sonar contact with 100ft exclusion zone

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 2
(GC895-A)



Seabed Amplitude Extract

Proposed GC895-A Well Location
(2,226,500ft E / 9,823,000ft N)

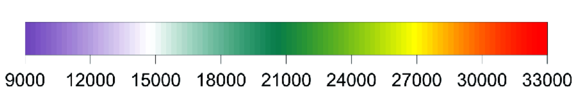


Chart Scale 1" = 1,000'

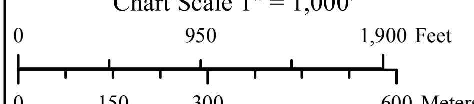
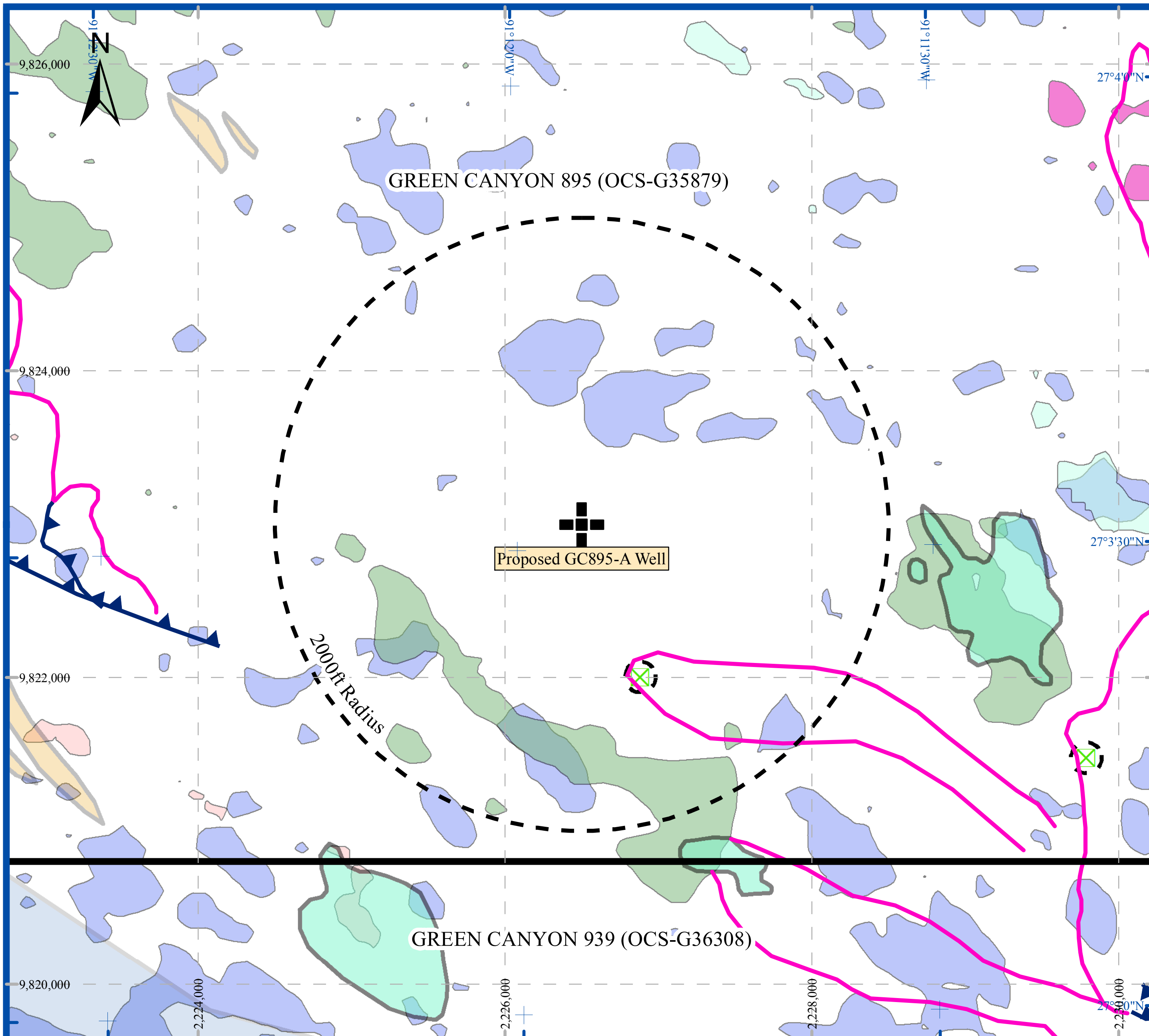


Figure 3
(GC895-A)



Geohazard Summary Extract

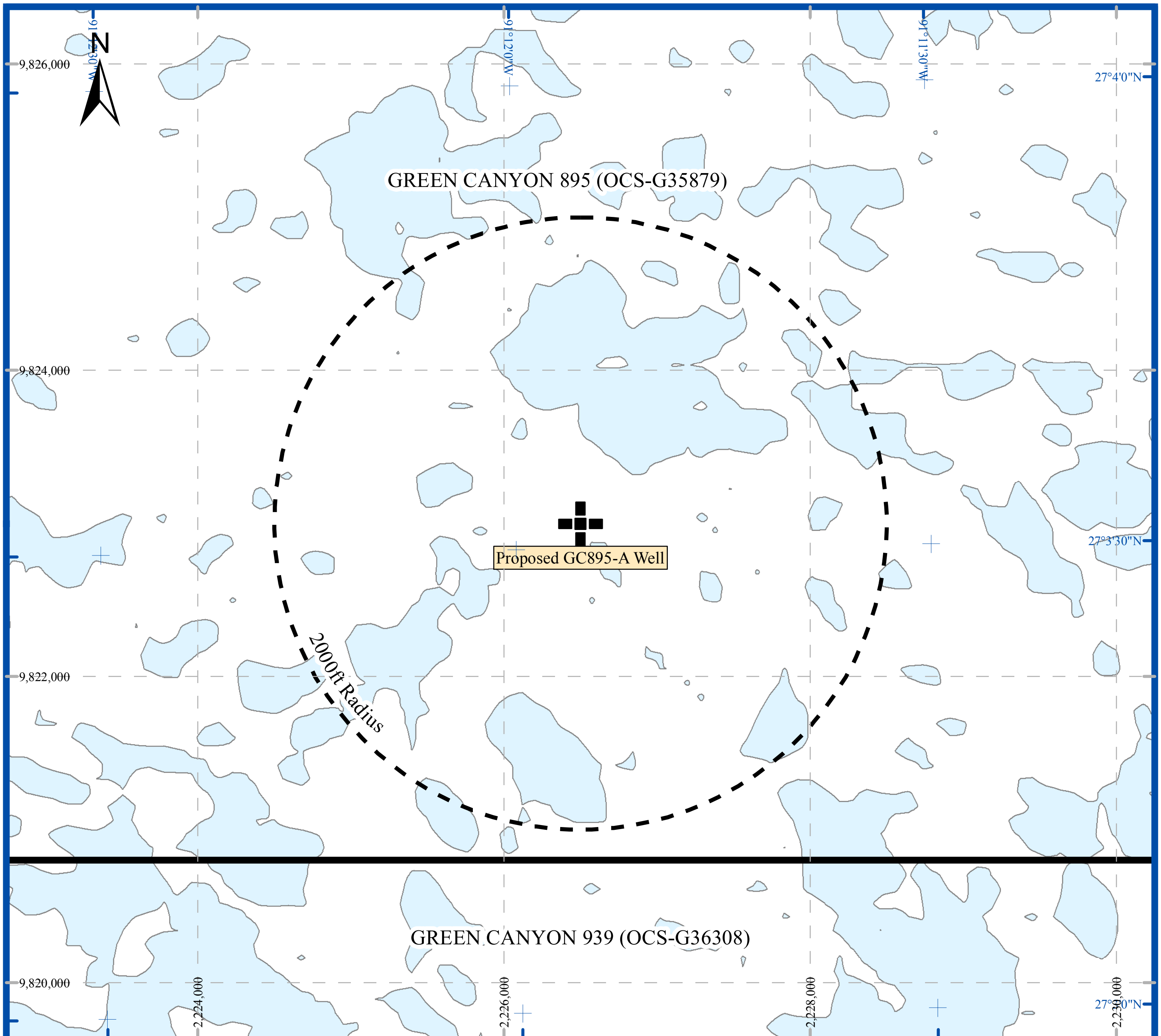
- Proposed GC895-A Well Location (2,226,500ft E / 9,823,000ft N)
- Seabed failure scarps
- Area of mass transport deposits
- Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.
- Seabed furrow area
- Side-scan sonar contact with 100ft exclusion zone
- Slight and Moderate Risk of Gas within Unit A
- Slight, Moderate, and High Risk of Gas within Unit B
- Slight, Moderate, and High Risk of Gas within Unit C
- Moderate and High Risk of Gas within Unit D
- Slight Risk of Gas within Unit F

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 4
(GC895-A)



Sand-Prone Lithology Extract (Unit D)

Proposed GC895-A Well Location
(2,226,500ft E / 9,823,000ft N)

Predicted sands within Unit D

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 5
(GC895-A)

Well Clearance Letter for
BOE Exploration & Production LLC
Public Copy

Project:
Block GC895, Offshore Gulf of Mexico

Description:
Proposed GC895-B Well Location

Project Number:
20-012-31/2018-104

Report Status:
Final

REPORT AUTHORIZATION AND DISTRIBUTION

Compilation	Geophysics	L Fuentes
Authorization	Geophysics	………………… A R Haigh
	Quality Assurance	………………… Matt Keith

Revision	**Date**	**Title**
0	March 2, 2020	Final

Distribution

One digital copy (PDF)

BOE Exploration & Production LLC
300 Holiday Square Blvd,
Suite 100
Covington, LA 70433

For the attention of
Eva Gravouilla

Public Copy

Eva Gravouilla
BOE Exploration & Production LLC
300 Holiday Square Blvd,
Suite 100
Covington, LA 70433

Dear Mrs. Gravouilla:

Echo Offshore, LLC appreciates the opportunity to submit this Well Clearance letter based on a 3D geohazard assessment covering Block GC895, Green Canyon protraction area. This assessment was prepared utilizing 3D seismic data originally provided by Houston Energy, LP, in compliance with NTL Nos. 2008-G05, 2008-G04, and 2009-G40, by the Bureau of Ocean Energy Management (BOEM), Gulf of Mexico Region. BOE Exploration & Production LLC is now the operator of the lease and has requested that Echo Offshore provide this assessment of the referenced proposed well location.

This report has been prepared with due care, diligence, and with the skill reasonably expected of a reputable contractor experienced in the types of work, carried out under the contract. As such, the findings in this report are based on an interpretation of data which is a matter of opinion on which professionals may differ and, unless clearly stated, is not a recommendation of any course of action.

Please be aware that further distribution of this report, in whole or part, or the use of the data for a purpose not expressly stated within the contractual work scope is at the client's sole risk, and it is recommended that this disclaimer be included in any such distribution.

If we can be of further assistance, or if you have any questions, please do not hesitate to call.

We sincerely appreciate this opportunity to be of service to you.

Very truly yours,

C. D. Schempf, Jr.

C. D. Schempf, Jr.
President

MK for CDS

Location Map

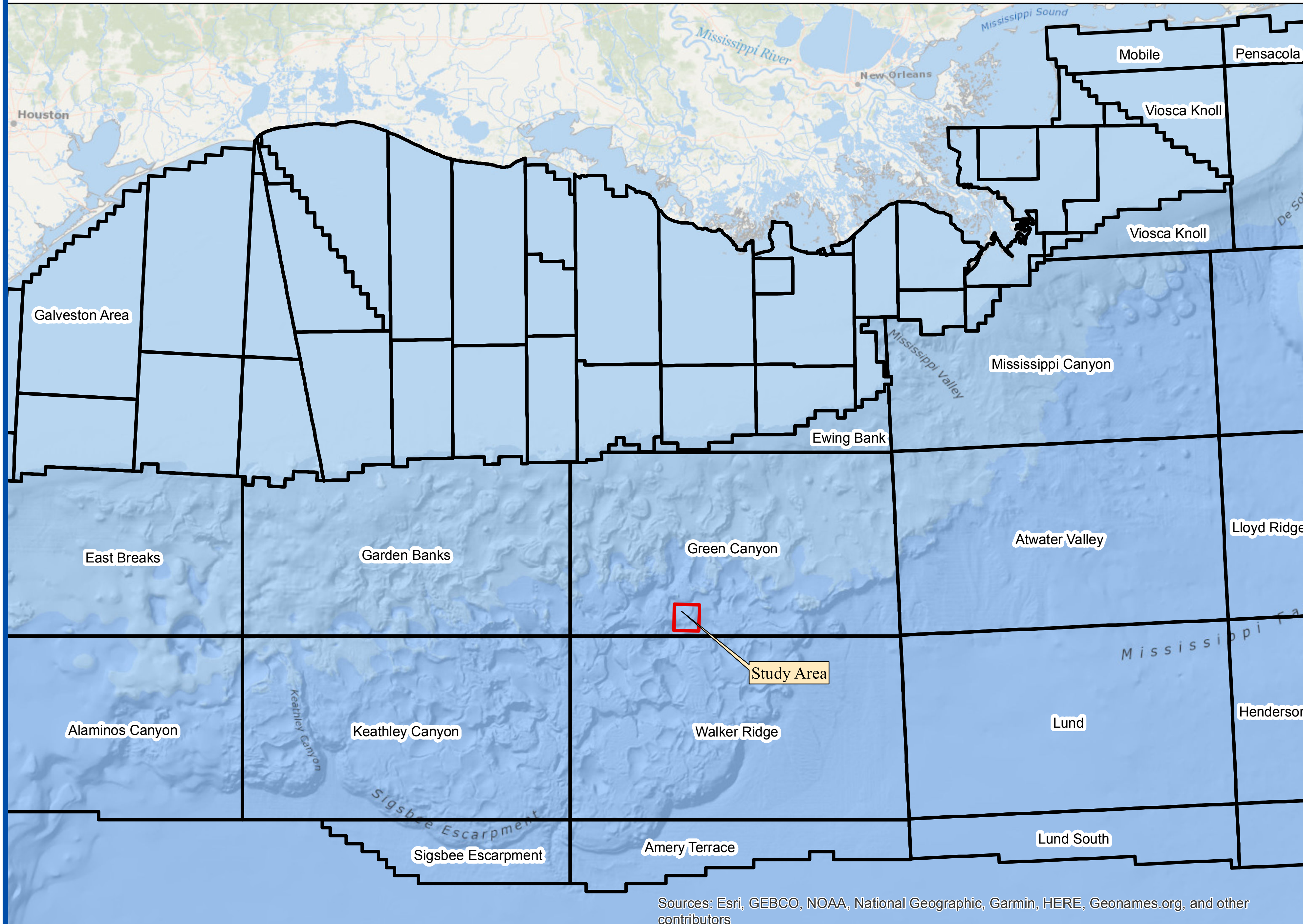


TABLE OF CONTENTS

LIST OF FIGURES

WELL CLEARANCE LETTER – PROPOSED GC895-B WELL LOCATION
PUBLIC COPY

March 02, 2020
Bureau of Ocean Energy Management (MS 5230)
Gulf of Mexico OCS Region
1201 Elmwood Park Blvd.
New Orleans, LA 70123-2394

RE: **BOE Exploration & Production LLC**
Proposed GC895-B
Block 895, Green Canyon
Offshore Gulf of Mexico
OCS-G-35879

Echo Offshore, LLC was contracted by BOE Exploration & Production LLC, to prepare a Well Clearance Letter for the proposed GC895-B well in Block 895, Green Canyon Area (OCS-G-35879). This letter addresses seafloor and shallow geologic conditions that may impact exploratory drilling operations within 2,000ft of the proposed well site. The depth limit of this site clearance assessment is at -8,710ft below sea surface (3,138ft below seafloor). BOE Exploration & Production LLC plans to operate from a dynamically positioned drilling module; therefore, an anchoring assessment is not required. Relevant letter-size chart extracts, data examples are presented with this Well Clearance Letter, plus annotated data examples of the two nearest intersecting inlines and crosslines, the nearest sub-bottom profiler transect line, and the side-scan sonar mosaic. This site clearance assessment is primarily based on the interpretation of and AUV data set for seafloor and shallow soils and a 3D seismic data set for deeper geology. This assessment is based on the area specific hazard assessment that has been produced under separate cover (Houston Energy – Gardline Surveys Inc. Report No. 11115).

AUV Archaeological Investigation. The proposed activities occur within an area of the outer continental shelf defined by BOEM as having a moderate archaeological resource potential (see NTL No. 2011-JOINT-G01). An archaeological investigation was performed across the wellsite area by Echo Offshore on Nov. 21-27, 2017 using AUV geophysical data. An archaeological assessment of the proposed well location based on this data set has been prepared.

3D Geophysical Survey. The 3D seismic dataset is of good quality and suitable for shallow hazard assessment. Inlines are oriented northeast to southwest, have a numerical increment of one, and exhibit a line spacing of 98.42ft. Crosslines are oriented northwest to southeast, have a numerical increment of four and exhibit a line spacing of 82.02ft. Sample rate of the data was 4ft, and record length is 60,000ft.

The data presents an acceptable frequency response across the upper one second below seafloor, with an equivalent effective frequency range at 50% power of 55-85Hz (Figure 11). The data exhibits a dominant frequency in the upper one second of approximately 70Hz plus significant higher usable frequencies, resulting in a mean vertical resolvability of typically 20ft and a layer detectability of 5ft.

Several data types were provided, within two surveys: E Wave and E Octopus. The E Octopus survey was used primarily, and is characterized by the following collection and processing parameters and history, based on the survey collection and processing phases:

- Modern WAZ data
- Spec. data widely licensed by many companies for exploration
- Using highest frequency product available "High-resolution sediment flood", after 3 iterations of multiazimuth sediment tomography
- E-Octopus VII:
  - Shot 2010, Processed 2011
- E-Octopus II
  - Shot 2008, Processed 2008
- E-Octopus III
  - Shot 2009, Processed 2009
- Note that E-Oct II and III were merged together by WesternGeco

E-Octopus VII

Acquisition Parameters

Recording System: Q-Marine*

Energy Source: Single Source; 8,475 in.^{3}

Line Orientation: NE/SW

Source Depth: 12m

Streamer Configuration: Multi-streamer: 10 X 7,000m cables

Streamer Depth: 12m

Maximum Offset: 8,600m

Sample Rate: 2ms

Record Length: 14s

DGF Receiver Interval: 12.5m

Recording Bin Dimensions: 6.25 X60m

Acquisition Completed: April 2010

Processing Flow

Q* point-receiver seismic acquisition and processing methodology

Digital group forming (DGF): output 12.5m

Navigation merge

Calibrated marine source designature

Anomalous amplitude attenuation

Water velocity correction

3D GSMP demultiple

3 iterations of multiazimuth sediment tomography

High-resolution sediment flow (pick top of salt 1)

Salt flood 1(pick bottom salt 1)

Salt body 1 (pick top of salt 2)

Salt flood 1(pick bottom salt 2)

Salt body 2

Subsalt tomography (using ample gathers)

Full salt velocity models

RTM (Reverse Time Migration) and Kirchhoff migration

Processing completed: December 2011

E-Octopus I & II

Acquisition Parameters

Recording System: Q-Marine*

Energy Source: Single Source; 8,475 in.^{3}

Line Orientation: NE/SW

Source Depth: 10m

Streamer Configuration: Multi-streamer: 10 X 7,000m cables

Streamer Depth: 12m

Maximum Offset: 9,600m

Sample Rate: 2ms

Record Length: 14s

DGF Receiver Interval: 12.5m

Recording Bin Dimensions: 6.25 X60m

Acquisition Completed: Phase I December 2006; Phase II: December 2008

Processing Flow

Q* point-receiver seismic acquisition and processing methodology

Digital group forming (DGF): output 12.5m

Navigation merge

Calibrated marine source designature

Anomalous amplitude attenuation

Water velocity correction

Inverse Q: phase only

WEM demultiple

3 iterations of multiazimuth sediment tomography (incorporating anistrophy)

High-resolution sediment flow (pick top of salt 1)

Salt flood 1(pick bottom salt 1)

Salt body 1 (pick top of salt 2)

Salt flood 1(pick bottom salt 2)

Salt body 2

Subsalt tomography (using ample gathers)

Full salt velocity models

Final WEM (Wave Equation Migration) 25Hz

Processing completed: Phase I: April 2008; Phase II: December 2008

E-Octopus III

Acquisition Parameters

Recording System: Q-Marine*
Energy Source: Single Source; 8,475 $in.^3$
Line Orientation: NE/SW
Source Depth: 10m
Streamer Configuration: Multi-streamer: 10 X 7,000m cables
Streamer Depth: 12m
Maximum Offset: 8,600m
Sample Rate: 2ms
Record Length: 14s
DGF Receiver Interval: 12.5m
Recording Bin Dimensions: 6.25 X60m
Acquisition Completed: Phase I December 2008

Processing Flow

Q* point-receiver seismic acquisition and processing methodology
Digital group forming (DGF): output 12.5m
Navigation merge
Calibrated marine source designature
Anomalous amplitude attenuation
Water velocity correction
Inverse Q: phase only
WEM demultiple
3 iterations of multiazimuth sediment tomography (incorporating anistrophy)
High-resolution sediment flow (pick top of salt 1)
Salt flood 1(pick bottom salt 1)
Salt body 1 (pick top of salt 2)
Salt flood 1(pick bottom salt 2)
Salt body 2
Subsalt tomography (using ample gathers)
Full salt velocity models
Final WEM (Wave Equation Migration) 25Hz
Processing completed: May 2009

Spectral whitening was applied to the data set as a post-processing technique to optimize interpretability.

In summary, and with reference to NTL No. 2008-G04 and 2008-G05, the following statements are applicable to the seismic data:

In summary and with reference to NTL No. 2008-G04:

a) The data provides imaging of sufficient resolution of the shallow section allowing a clear analysis of the shallow conditions.
b) The data can be loaded to a workstation at 16-bit resolution or greater and is unscaled.
c) There is no trace or sample decimation.
d) The sample interval and bin size are maintained throughout the assessment area.

e) The data possess a frequency content of 50Hz or higher at 50% power in the first second below seafloor.

f) Seafloor reflection is free of gaps and is defined by a wavelet of stable shape and phase, allowing auto-tracking of the seafloor event with minimum user intervention and guidance.

g) There are no significant acquisition artifacts throughout the dataset.

h) Merge points in the data are marked by no time shifts and very minimal amplitude changes and are not a detriment to interpretation.

i) Processed bin sizes are 98.42ft x 82.02ft.

j) The sample rate of the data is 4ft.

k) There is no significant multiple energy.

1. LOCATION COORDINATES

1.1 Proposed GC895-B Well Location (OCS-G-35879).

Proposed GC895-B Well Location							
Location Coordinates							
NAD 27 Datum - Clarke 1866 Ellipsoid					UTM Zone 15 - CM 93° West		
Latitude	27°	03'	48.905"	North	Easting	2,227,550	US ft E
Longitude	91°	11'	43.625	West	Northing	9,824,760	US ft N
FEL Green Canyon 895		5,890ft		US ft	Inline	5227	
FSL Green Canyon 895		3,960ft		US ft	Crossline	39121	
Water Depth: -5,572 ft.		Slope: 2.1° northeast					
Nearest Shoreline		118 Nautical Miles @ 06.47°					
Nearest Manned Platform		A-Constitution TLP in GC680			18.83 Nautical Miles @ 23.5°		

2. VELOCITY DATA

2.1 Seafloor Depth

Seafloor depth around the proposed well was derived from multibeam echosounder data acquired as part of an AUV geophysical investigation over approximately 15.3 square miles of blocks GC895 & GC939.

2.2 Sub-seafloor Depth

3D seismic data was provided as a depth volume; therefore, no depth conversion was required.

3. SEAFLOOR CONDITIONS

3.1 Seafloor Depth

Water depth at the Proposed GC895-B well location is -5,572ft below sea surface (Figure 1). The seafloor slopes to the northeast at 2.1°.

3.2 Seafloor Morphology and Man-Made Features

The proposed GC895-B well location is in the east-central part of block GC895.

Side-scan sonar data indicates the proposed well is located on an area of smooth seafloor interpreted as clays and silts with no significant variations within 2,000ft. No major seabed features were identified within 2,000ft (Figure 6).

In accordance with NTL stipulations for archaeological resources, an archeological survey was performed in the study area in November 2017. Several targets were identified within the study area. No side scan targets occur within 2,000ft of the proposed well. **No features of archaeological resources were identified within 2,000ft of the proposed well location**. All targets are interpreted as modern anthropogenic debris.

There are no anomalous seafloor amplitudes indicative of hydrocarbon macroseep observed within a 2,000ft radius of the proposed location (Figure 3). **No features or areas that could support high-density sensitive sessile benthic communities are located within 2,000ft of any mud or cuttings discharge location.** The nearest area with the potential for benthic communities occurs 2,015ft to the southeast.

4. SUB-SEAFLOOR CONDITIONS

4.1 Geology and Lithology

The sub-seafloor geology has been divided into seven Units, A, B, C, D, E, F, and G, separated by Horizons, H10, H20, H30, H40, H50, H60, and Top of salt (Figures 8 through 10). Top of Salt is the depth limit of investigation.

4.2 Unit A

The lithology within Unit A from seafloor to -5,842ft below sea surface (270ft below seafloor) is characterized by well-layered, low and slightly moderate-amplitude reflectors interpreted as clays and silts with occasional sand interbeds.

Seismic data profiler shows the upper part of Unit A consists of clays and silts overlying a well-layered stratum interpreted as clays and silts (Figure 7).

No risk of gas or shallow water flow is interpreted within Unit A at the location. Nearest risk of gas is located 1,615ft to the northeast with no connectivity to the proposed well location.

Unit A appears conducive to conductor jetting.

Horizon H10 marks the base of Unit A occurring at -5,842ft below sea surface (270ft below seafloor).

4.3 Unit B

Unit B, from -5,842ft to -6,344ft below sea surface (270ft to 772ft below seafloor), is characterized by well-layered and slightly chaotic, low and occasional moderate-amplitude reflectors interpreted as clays, silts, and occasional sands.

No risk of gas is predicted within Unit B at the proposed well location or within 2,000ft of the proposed well.

The well-path will not traverse any faults within Unit B.

Horizon H20 marks the base of Unit B occurring at -6,344ft below sea surface (772ft below seafloor).

4.4 Unit C

The well-path will not traverse Unit C which is absent due to salt uplift.

4.5 Unit D

Unit D between -6,344ft below sea surface (722ft below seabed) to -7,587ft below sea surface (2,015ft below seabed) is interpreted as a higher energy mass-transport deposit, characterized by semi-continuous and discontinuous variable amplitude reflectors interpreted as clays, silts, and several sands. Sand interbeds within this interval may have been rapidly deposited with inadequate dewatering time and the proposed well is located within a regional sand fairway that occupies most of the study area (Figure 5).

Several wells in the Green Canyon protraction area experienced shallow water flow risk but these are at least 15miles to the northeast of the proposed well. At the proposed well location some minor sand interbeds are considered probable and therefore a **Slight Shallow Water Flow Risk** is assigned throughout Unit D.

In addition, due to the increased potential for encountering poorly consolidated granular material in Unit D, minor drilling fluid circulation and wellbore stability problems may also occur within Unit D.

The well-path will not traverse any predicted risk of gas anomalies within Unit D, however, several risk of gas hazards occur within 2,000ft of the proposed well. The closest occurs 410ft northwest. This anomaly is interpreted as a slight risk of gas associated with a sandy interbed / lens. The anomaly is downdip of location, but there is possible connectivity of the sand interbed to the proposed well location. Although this sand interbed does not present direct hydrocarbon indicators at the well location, **Drilling Caution** should be considered at this level (-6,440ft below sea surface, 868ft below seabed).

A vertical borehole will penetrate two faults within Unit D at -6,786ft below sea surface (1,214ft below seabed) and at -7,063ft below sea surface (1,491ft below seabed). Both faults are relatively minor, and exhibit around 20ft of throw. Minor drilling fluid circulation and wellbore stability problems may occur in association with the faults.

Horizon H40 marks the base of Unit D at -7,587ft below sea surface (2,015ft below seafloor).

A fault occurs at the level of Horizon H40 at -7,587ft below sea surface (2,015ft below seafloor) exhibiting an estimated 40ft of throw. This fault is connected upwards to near seabed levels. Given this setting, drilling fluid circulation problems may occur if pressures over hydrostatic are exerted by the drilling fluid column. Minor wellbore stability problems may occur in association with the fault.

4.6 Unit E

Unit E, from -7,587ft to -7,809ft below sea surface (2,015ft to 2,237ft below seafloor), is characterized by slightly chaotic, low and occasional moderate-amplitude reflectors interpreted as clays and silts with occasional sands.

No drilling hazards or problems are interpreted within Unit E.

The well-path will not traverse any faults within Unit E.

Horizon H50 marks the base of this unit and the base of this interpretation at -7,809ft below sea surface (2,237ft below seafloor).

4.7 Unit F

Unit F, from -7,809ft to -8,388ft below sea surface (2,237ft to 2,816ft below seafloor), is characterized by slightly chaotic, low-amplitude reflectors interpreted as clays and silts with occasional sands.

No drilling hazards or problems are interpreted within Unit F.

Horizon H60 marks the base of this unit and the base of this interpretation at -8,388ft below sea surface (2,816ft below seafloor).

4.8 Unit G

Unit G, from -8,388ft to -8,710ft below sea surface (2,816ft to 3,138ft below seafloor), is characterized by slightly chaotic, low and occasional moderate-amplitude reflectors interpreted as clays and silts with occasional sands.

No drilling hazards or problems are interpreted within Unit G.

Top of Salt marks the base of this unit and the base of this interpretation at -8,710ft below sea surface (3,138ft below seafloor).

4.9 Shallow Gas Assessment

Although there are no anomalies indicative of shallow gas at the proposed well location, a sand interbed within Unit D, occurring at -6,440ft below sea surface (868ft below seabed) is connected to an anomaly considered a Slight Risk of Gas 410ft to the northwest.

4.10 Shallow Water Flow Assessment

Throughout Unit D a **Slight Shallow Water Flow Risk** is interpreted from -6,344ft to -7,587ft below sea surface (772ft to 2,015ft below seafloor).

5. CONCLUSIONS AND RECOMMENDATIONS

- Seafloor

  No drilling hazards or problems are interpreted at seafloor.

  No features of potential biological or archaeological significance were identified within 2,000ft of the proposed well location.

  No side-scan sonar targets were identified within 2,000ft of the proposed well.

- Unit A

  No drilling hazards or problems interpreted.

- Unit B

  No drilling hazards or problems interpreted.

- Unit D

  A sand interbed, estimated to be around 20ft thick, within Unit D, occurring at -6,440ft below sea surface (868ft below seabed) is connected to an anomaly considered a Slight Risk of Gas 410ft to the northwest. **Drilling Caution** is advised.

  Throughout Unit D, a **Slight Shallow Water Flow Risk** is interpreted from -6,344ft to -7,587ft below sea surface (772ft to 2,015ft below seafloor). Appropriate drilling methodology should be applied to contain a short-lived, non-persistent water flow event. Additionally, minor drilling and wellbore stability problems are possible.

  A vertical borehole will penetrate two faults within Unit D at -6,786ft below sea surface (1,214ft below seabed) and at -7,063ft below sea surface (1,491ft below seabed). Minor drilling fluid circulation and wellbore stability problems may occur in association with the faults.

  A larger fault occurs at the level of Horizon H40 at -7,587ft below sea surface (2,015ft below seafloor). This fault is connected to near seabed and drilling fluid circulation problems may occur if pressures over hydrostatic are exerted by the drilling fluid column. In addition, minor wellbore stability problems may occur. Casing seats should avoid all fault intersections as formation integrity could be compromised.

- Unit E

  No drilling hazards or problems are interpreted.

- Unit F

  No drilling hazards or problems are interpreted

- Unit G

  No drilling hazards or problems are interpreted

We appreciate the opportunity to work with you on this project and look forward to continuing as your geohazards consultants. Please contact us if you have any questions or if we can be of further assistance.

Sincerely,
Echo Offshore, LLC

Andrew Haigh
Geophysical Manager
Ocean Geo Solutions, Inc

Matt Keith
Quality Assurance
Echo Offshore, LLC

Copies Submitted: One digital copy (PDF) to Eva Gravouilla at BOE Exploration & Production LLC.

Attachments:

Proposed GC895-B Well Location

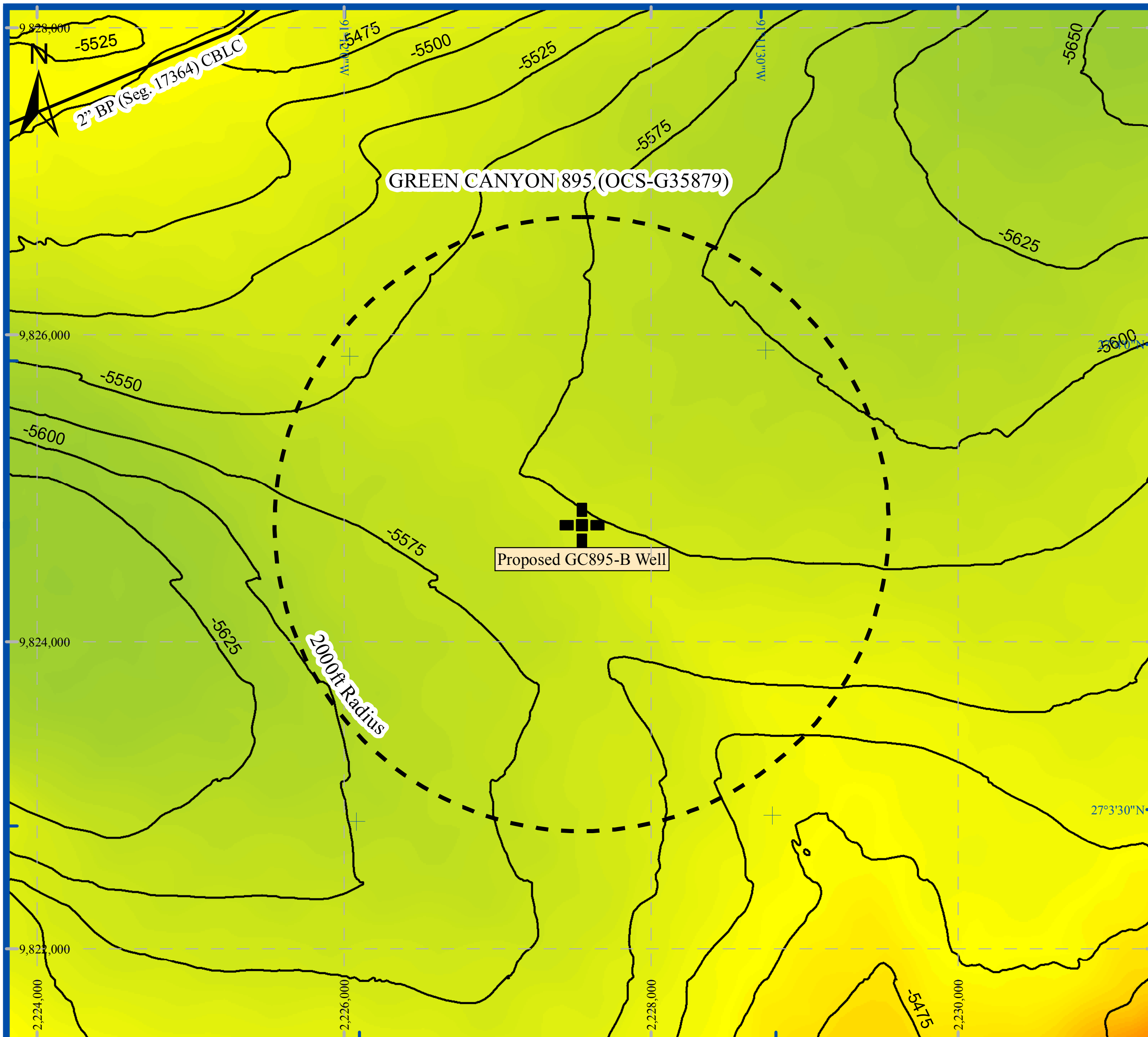
Seafloor Depth Extract

Seafloor Morphology Extract

Seafloor Amplitude Extract

Geohazard Summary Extract

Sand Lithology Extract-Unit D



Seabed Depth Extract

Proposed GC895-B Well Location
(2,227,550ft E / 9,824,760ft N)

Existing infastructure

-5575 Depth in feet below sea surface to seabed contoured at 25ft intervals

Seabed Depth (Feet)

Chart Scale 1" = 1,000'

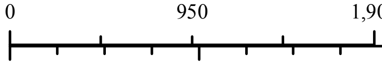
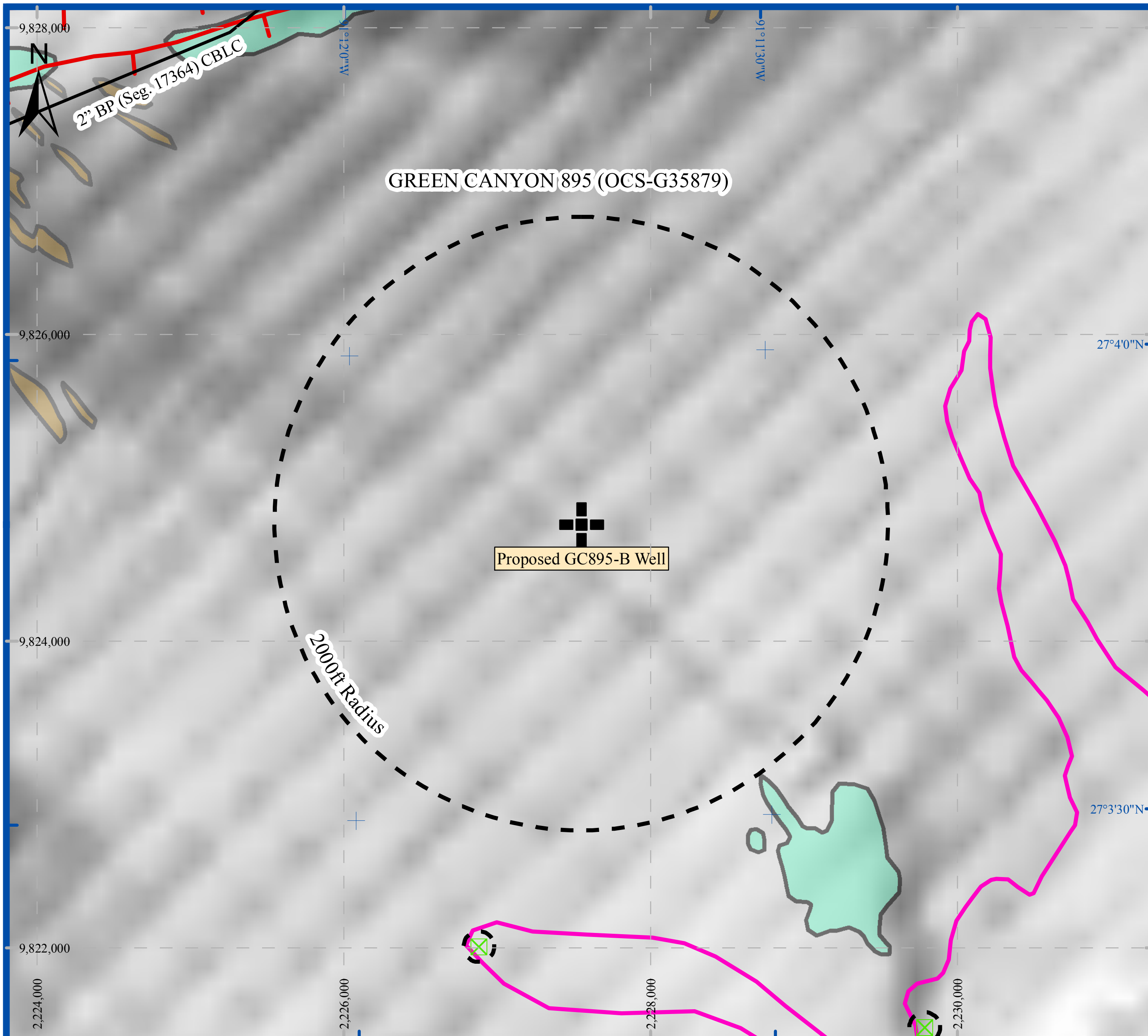


Figure 1
(GC895-B)



Seabed Morphology Extract

Proposed GC895-B Well Location
(2,227,550ft E / 9,824,760ft N)

Existing infastructure

Area of mass transport deposits

Seabed fault identified in AUV multibeam bathymetry data. Tick shows downthrown side

Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.

Seabed furrow area

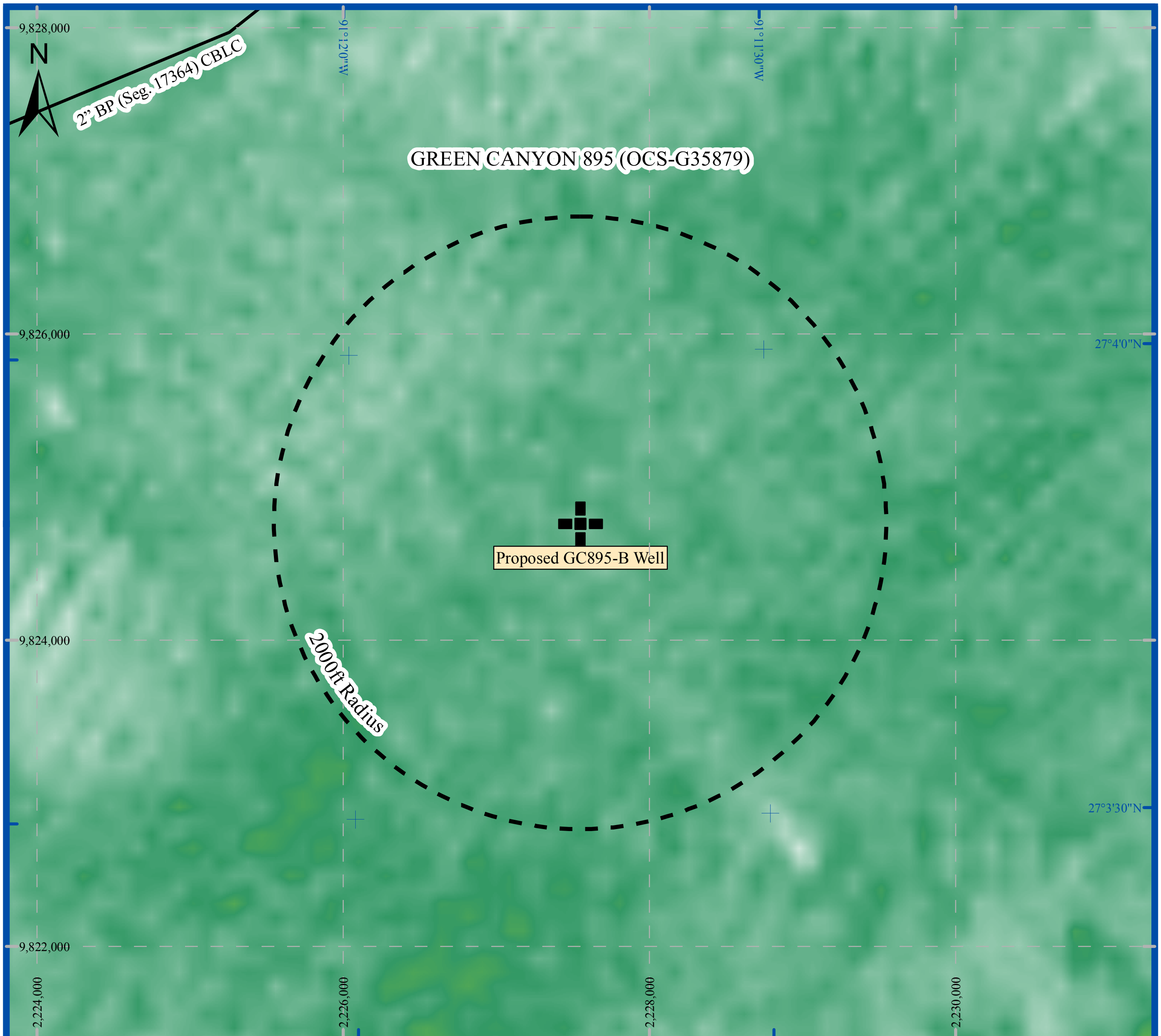
Side-scan sonar contact with 100ft exclusion zone

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 2
(GC895-B)



Seabed Amplitude Extract

Proposed GC895-B Well Location
(2,227,550ft E / 9,824,760ft N)

Existing infastructure

9000 12000 15000 18000 21000 24000 27000 30000 33000

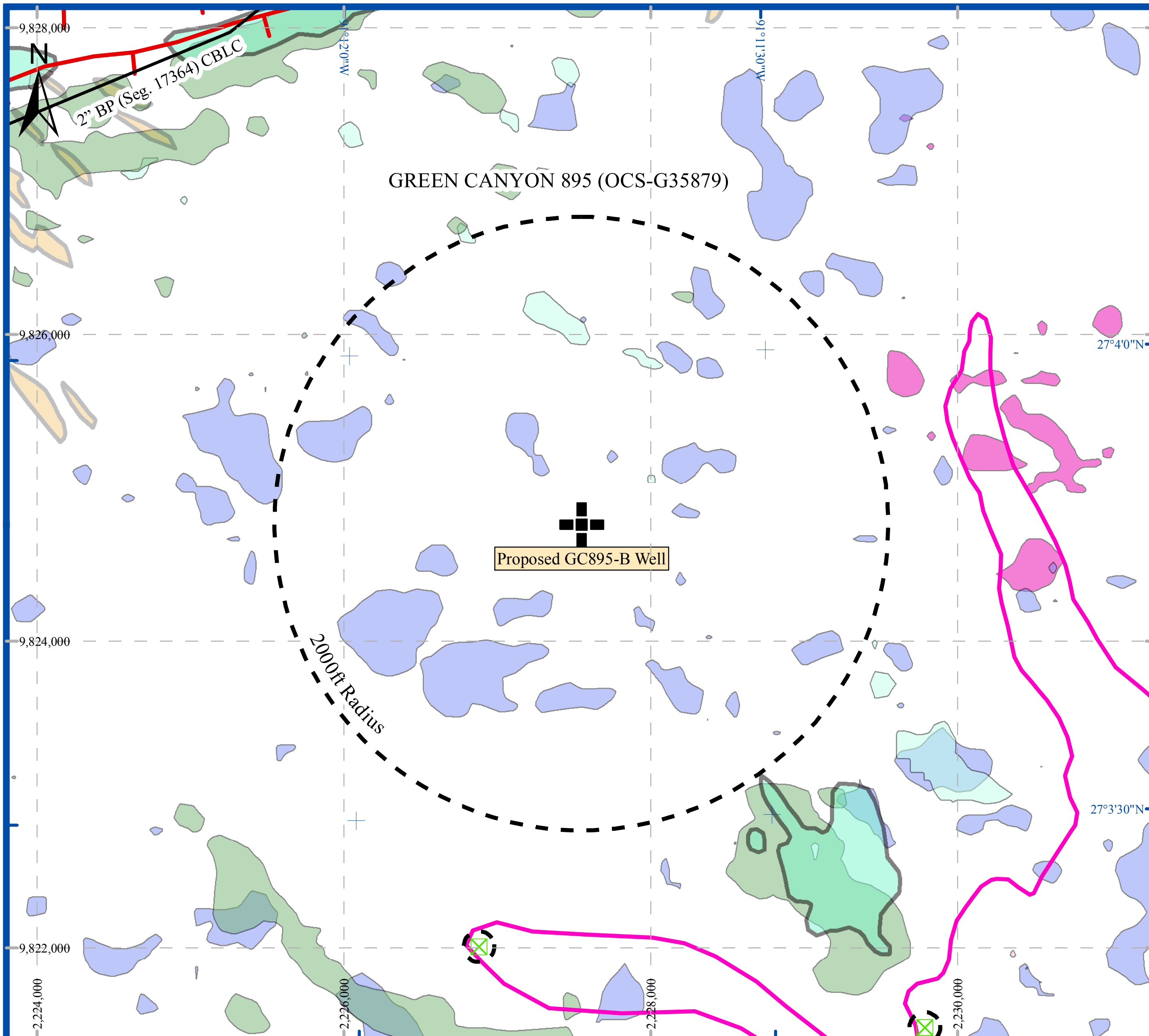
Relative Seabed Amplitude

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 3
(GC895-B)



Geohazard Summary Extract

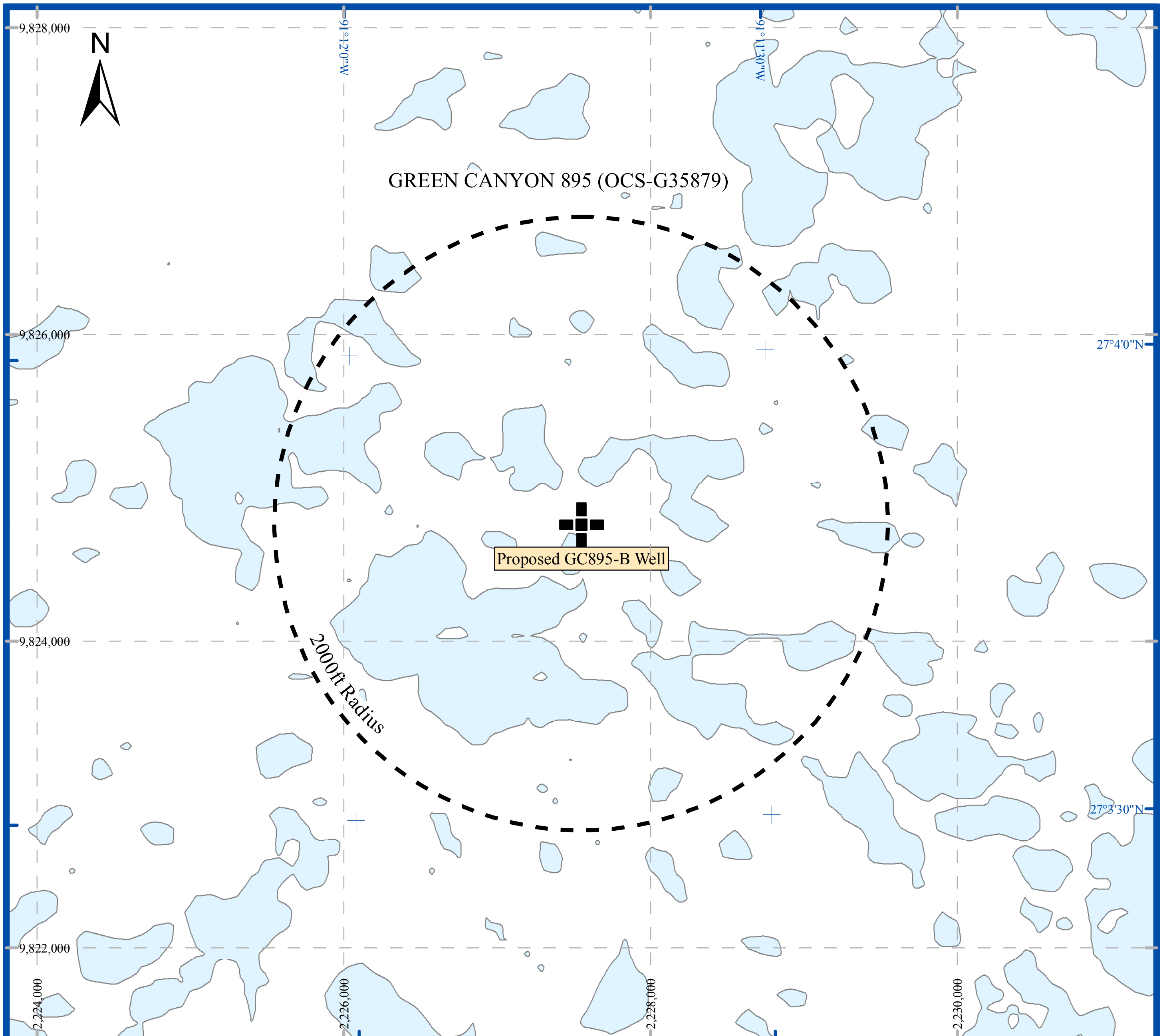
- Proposed GC895-B Well Location (2,227,550ft E / 9,824,760ft N)
- Existing infastructure
- Area of mass transport deposits
- Seabed fault identified in AUV multibeam bathymetry data. Tick shows downthrown side
- Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.
- Seabed furrow area
- Side-scan sonar contact with 100ft exclusion zone
- Slight and Moderate Risk of Gas within Unit A
- Slight, Moderate, and High Risk of Gas within Unit B
- Slight, Moderate, and High Risk of Gas within Unit C
- Slight, Moderate, and High Risk of Gas within Unit D
- Slight Risk of Gas within Unit F

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 4
(GC895-B)



Sand-Prone Lithology Extract (Unit D)

Proposed GC895-B Well Location
(2,227,550ft E / 9,824,760ft N)

Predicted sands within Unit D

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 5
(GC895-B)

Well Clearance Letter for
BOE Exploration & Production LLC
Public Copy

Project:
Block GC895, Offshore Gulf of Mexico

Description:
Proposed GC895-C Well Location

Project Number:
20-012-31/2020-243

Report Status:
Final

REPORT AUTHORIZATION AND DISTRIBUTION

Compilation	Geophysics	L Fuentes
Authorization	Geophysics	………………… A R Haigh
	Quality Assurance	………………… Matt Keith

Revision	**Date**	**Title**
0	March 02, 2020	Final

Distribution

One digital copy (PDF)

BOE Exploration & Production LLC
300 Holiday Square Blvd,
Suite 100
Covington, LA 70433

For the attention of
Eva Gravouilla

Public Copy

Eva Gravouilla
BOE Exploration & Production LLC
300 Holiday Square Blvd,
Suite 100
Covington, LA 70433

Dear Mrs. Gravouilla:

Echo Offshore, LLC appreciates the opportunity to submit this Well Clearance letter based on a 3D geohazard assessment covering Block GC895, Green Canyon protraction area. This assessment was prepared utilizing 3D seismic data originally provided by Houston Energy LP, in compliance with NTL Nos. 2008-G05, 2008-G04, and 2009-G40, by the Bureau of Ocean Energy Management (BOEM), Gulf of Mexico Region. BOE Exploration & Production LLC is now the operator of the lease and has requested that Echo Offshore provide this assessment of the referenced proposed well location.

This report has been prepared with due care, diligence, and with the skill reasonably expected of a reputable contractor experienced in the types of work, carried out under the contract. As such, the findings in this report are based on an interpretation of data which is a matter of opinion on which professionals may differ and, unless clearly stated, is not a recommendation of any course of action.

Please be aware that further distribution of this report, in whole or part, or the use of the data for a purpose not expressly stated within the contractual work scope is at the client's sole risk, and it is recommended that this disclaimer be included in any such distribution.

If we can be of further assistance, or if you have any questions, please do not hesitate to call.

We sincerely appreciate this opportunity to be of service to you.

Very truly yours,

C. D. Schempf, Jr.

C. D. Schempf, Jr.
President

MK for CDS

Location Map

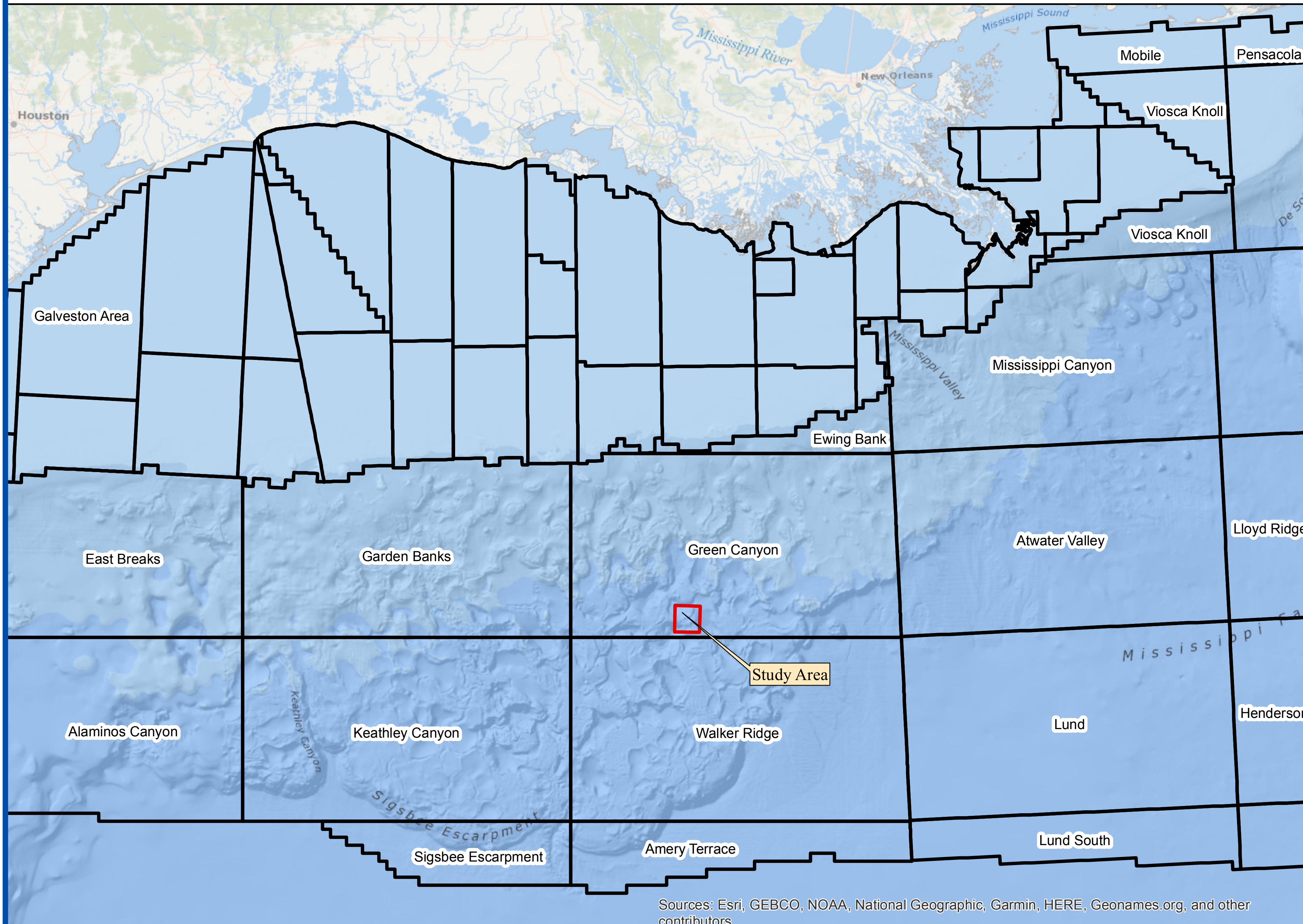


TABLE OF CONTENTS

LIST OF FIGURES

WELL CLEARANCE LETTER – PROPOSED GC895-C WELL LOCATION

PUBLIC COPY

March 02, 2020
Bureau of Ocean Energy Management (MS 5230)
Gulf of Mexico OCS Region
1201 Elmwood Park Blvd.
New Orleans, LA 70123-2394

RE: **BOE Exploration & Production LLC**
Proposed GC895-C
Block 895, Green Canyon
Offshore Gulf of Mexico
OCS-G-35879

Echo Offshore, LLC was contracted by BOE Exploration & Production LLC, to prepare a Well Clearance Letter for the proposed GC895-C well in Block 895, Green Canyon Area (OCS-G-35879). This letter addresses seafloor and shallow geologic conditions that may impact exploratory drilling operations within 2,000ft of the proposed well site. The depth limit of this site clearance assessment is at -8,218ft below sea surface (2,622ft below seafloor). BOE Exploration & Production LLC plans to operate from a dynamically positioned drilling module; therefore, an anchoring assessment is not required. Relevant letter-size chart extracts, data examples are presented with this Well Clearance Letter, plus annotated data examples of the two nearest intersecting inlines and crosslines, the nearest sub-bottom profiler transect line, and the side-scan sonar mosaic. This site clearance assessment is primarily based on the interpretation of an AUV data set for seafloor and shallow soils and a 3D seismic data set for deeper geology. This assessment is based on the area specific hazard assessment that has been produced under separate cover (Houston Energy – Gardline Surveys Inc. Report No. 11115).

AUV Archaeological Investigation. The proposed activities occur within an area of the outer continental shelf defined by BOEM as having a moderate archaeological resource potential (see NTL No. 2011-JOINT-G01). An archaeological investigation was performed across the wellsite area by Echo Offshore on Nov. 21-27, 2017 using AUV geophysical data.

3D Geophysical Survey. The 3D seismic dataset is of good quality and suitable for shallow hazard assessment. Inlines are oriented northeast to southwest, have a numerical increment of one, and exhibit a line spacing of 98.42ft. Crosslines are oriented northwest to southeast, have a numerical increment of four and exhibit a line spacing of 82.02ft. Sample rate of the data was 4ft, and record length is 60,000ft.

The data presents an acceptable frequency response across the upper one second below seafloor, with an equivalent effective frequency range at 50% power of 55-85Hz (Figure 11). The data exhibits a dominant frequency in the upper one second of approximately 70Hz plus significant higher usable frequencies, resulting in a mean vertical resolvability of typically 20ft and a layer detectability of 5ft.

Several data types were provided, within two surveys: E Wave and E Octopus. The E Octopus survey was used primarily, and is characterized by the following collection and processing parameters and history, based on the survey collection and processing phases:

- Modern WAZ data
- Spec. data widely licensed by many companies for exploration
- Using highest frequency product available "High-resolution sediment flood", after 3 iterations of multiazimuth sediment tomography
- E-Octopus VII:
  - Shot 2010, Processed 2011
- E-Octopus II
  - Shot 2008, Processed 2008
- E-Octopus III
  - Shot 2009, Processed 2009
- Note that E-Oct II and III were merged together by WesternGeco

E-Octopus VII

Acquisition Parameters

Recording System: Q-Marine*

Energy Source: Single Source; 8,475 in.^{3}

Line Orientation: NE/SW

Source Depth: 12m

Streamer Configuration: Multi-streamer: 10 X 7,000m cables

Streamer Depth: 12m

Maximum Offset: 8,600m

Sample Rate: 2ms

Record Length: 14s

DGF Receiver Interval: 12.5m

Recording Bin Dimensions: 6.25 X60m

Acquisition Completed: April 2010

Processing Flow

Q* point-receiver seismic acquisition and processing methodology

Digital group forming (DGF): output 12.5m

Navigation merge

Calibrated marine source designature

Anomalous amplitude attenuation

Water velocity correction

3D GSMP demultiple

3 iterations of multiazimuth sediment tomography

High-resolution sediment flow (pick top of salt 1)

Salt flood 1(pick bottom salt 1)

Salt body 1 (pick top of salt 2)

Salt flood 1(pick bottom salt 2)

Salt body 2

Subsalt tomography (using ample gathers)

Full salt velocity models

RTM (Reverse Time Migration) and Kirchhoff migration

Processing completed: December 2011

E-Octopus I & II

Acquisition Parameters
Recording System: Q-Marine*
Energy Source: Single Source; 8,475 in.^{3}
Line Orientation: NE/SW
Source Depth: 10m
Streamer Configuration: Multi-streamer: 10 X 7,000m cables
Streamer Depth: 12m
Maximum Offset: 9,600m
Sample Rate: 2ms
Record Length: 14s
DGF Receiver Interval: 12.5m
Recording Bin Dimensions: 6.25 X60m
Acquisition Completed: Phase I December 2006; Phase II: December 2008

Processing Flow
Q* point-receiver seismic acquisition and processing methodology
Digital group forming (DGF): output 12.5m
Navigation merge
Calibrated marine source designature
Anomalous amplitude attenuation
Water velocity correction
Inverse Q: phase only
WEM demultiple
3 iterations of multiazimuth sediment tomography (incorporating anistrophy)
High-resolution sediment flow (pick top of salt 1)
Salt flood 1(pick bottom salt 1)
Salt body 1 (pick top of salt 2)
Salt flood 1(pick bottom salt 2)
Salt body 2
Subsalt tomography (using ample gathers)
Full salt velocity models
Final WEM (Wave Equation Migration) 25Hz
Processing completed: Phase I: April 2008; Phase II: December 2008

E-Octopus III

<u>Acquisition Parameters</u>
Recording System: Q-Marine*
Energy Source: Single Source; 8,475 in.^{3}
Line Orientation: NE/SW
Source Depth: 10m
Streamer Configuration: Multi-streamer: 10 X 7,000m cables
Streamer Depth: 12m
Maximum Offset: 8,600m
Sample Rate: 2ms
Record Length: 14s
DGF Receiver Interval: 12.5m
Recording Bin Dimensions: 6.25 X60m
Acquisition Completed: Phase I December 2008

<u>Processing Flow</u>
Q* point-receiver seismic acquisition and processing methodology
Digital group forming (DGF): output 12.5m
Navigation merge
Calibrated marine source designature
Anomalous amplitude attenuation
Water velocity correction
Inverse Q: phase only
WEM demultiple
3 iterations of multiazimuth sediment tomography (incorporating anistrophy)
High-resolution sediment flow (pick top of salt 1)
Salt flood 1(pick bottom salt 1)
Salt body 1 (pick top of salt 2)
Salt flood 1(pick bottom salt 2)
Salt body 2
Subsalt tomography (using ample gathers)
Full salt velocity models
Final WEM (Wave Equation Migration) 25Hz
Processing completed: May 2009

Spectral whitening was applied to the data set as a post-processing technique to optimize interpretability.

In summary, and with reference to NTL No. 2008-G04 and 2008-G05, the following statements are applicable to the seismic data:

In summary and with reference to NTL No. 2008-G04:

a) The data provides imaging of sufficient resolution of the shallow section allowing a clear analysis of the shallow conditions.
b) The data can be loaded to a workstation at 16-bit resolution or greater and is unscaled.
c) There is no trace or sample decimation.
d) The sample interval and bin size are maintained throughout the assessment area.

e) The data possess a frequency content of 50Hz or higher at 50% power in the first second below seafloor.

f) Seafloor reflection is free of gaps and is defined by a wavelet of stable shape and phase, allowing auto-tracking of the seafloor event with minimum user intervention and guidance.

g) There are no significant acquisition artifacts throughout the dataset.

h) Merge points in the data are marked by no time shifts and very minimal amplitude changes and are not a detriment to interpretation.

i) Processed bin sizes are 98.42ft x 82.02ft.

j) The sample rate of the data is 4ft.

k) There is no significant multiple energy.

1. LOCATION COORDINATES

1.1 Proposed GC895-C Well Location (OCS-G-35879).

Proposed GC895-C Well Location							
Location Coordinates							
NAD 27 Datum - Clarke 1866 Ellipsoid					UTM Zone 15 - CM 93° West		
Latitude	27°	04’	08.419”	North	Easting	2,228,339	US ft E
Longitude	91°	11’	34.584	West	Northing	9,826,742	US ft N
FEL Green Canyon 895	5,101ft	US ft	Inline	5218			
FSL Green Canyon 895	5,942ft	US ft	Crossline	39221			
Water Depth: -5,596 ft.	Slope: 2.0° SW						
Nearest Shoreline	118 Nautical Miles @ 06.47°						
Nearest Manned Platform	A-Constitution TLP in GC680	18.83 Nautical Miles @ 23.5°					

2. VELOCITY DATA

2.1 Seafloor Depth

Seafloor depth around the proposed well was derived from multibeam echosounder data acquired as part of an AUV geophysical investigation over approximately 15.3 square miles of blocks GC895 & GC939.

2.2 Sub-seafloor Depth

3D seismic data was provided as a depth volume; therefore, no depth conversion was required.

3. SEAFLOOR CONDITIONS

3.1 Seafloor Depth

Water depth at the Proposed GC895-C well location is -5,596ft below sea surface (Figure 1). The seafloor slopes to the southeast at 2.0°.

3.2 Seafloor Morphology and Man-Made Features

The proposed GC895-C well location is in the east-central part of block GC895.

Side-scan sonar data indicates the proposed well is located on an area of smooth seafloor interpreted as clays and silts. A small seabed furrow occurs 1,293ft to the north of the proposed well. A seabed fault is located 1,872ft to the north. No other major seabed features were identified within 2,000ft of the proposed well (Figure 6).

In accordance with NTL stipulations for archaeological resources, an archeological survey was performed in the study area in November 2017. Several targets were identified within the study area. No side scan targets occur within 2,000ft of the proposed well. **No features of archaeological resources were identified within 2,000ft of the proposed well location**. All targets are interpreted as modern anthropogenic debris.

There are no anomalous seafloor amplitudes indicative of hydrocarbon macroseep observed within a 2,000ft radius of the proposed location (Figure 3). **No features or areas that could support high-density sensitive sessile benthic communities are located within 2,000ft of any mud or cuttings discharge location.** The nearest area with the potential for benthic communities **occurs** approximately 2,027ft to the northwest.

4. SUB-SEAFLOOR CONDITIONS

4.1 Geology and Lithology

The sub-seafloor geology has been divided into seven Units, A, B, C, D, E, F, and G, separated by Horizons, H10, H20, H30, H40, H50, H60, and Top of salt (Figures 8 through 10). Top of Salt is the depth limit of investigation.

4.2 Unit A

The lithology within Unit A from seafloor to -6,006ft below sea surface (410ft below seafloor) is characterized by well-layered, low and slightly moderate-amplitude reflectors interpreted as clays and silts with and increased possibility for minor thin sand interbeds.

Sub bottom profiler data shows the upper part of Unit A consists of predominantly clays and silts (Figure 7).

No risk of gas or shallow water flow is interpreted within Unit A at the location. Nearest risk of gas is located 474ft to the south, presenting as a minor amplitude anomaly that is up-dip from the proposed location. This anomaly is likely lithological and not connected to the proposed well location.

Unit A appears conducive to conductor jetting, though the possibility for minor sandy interbeds may make the jetting conditions a little more variable.

Horizon H10 marks the base of Unit A occurring at -6,006ft below sea surface (410ft below seafloor).

4.3 Unit B

Unit B, from -6,006ft to -6,600ft below sea surface (410ft to 1,004ft below seafloor), is characterized by well-layered and slightly chaotic, low and occasional moderate-amplitude reflectors interpreted as clays, silts, and occasional sands.

No risk of gas is predicted within Unit B at the proposed well location or within 2,000ft of the proposed well.

The well-path will traverse a fault within Unit B at -6,432ft below sea surface (836ft below seabed) exhibiting around 15ft of throw. Minor drilling fluid circulation and wellbore stability problems may occur in association with the fault.

Horizon H20 marks the base of Unit B occurring at -6,600ft below sea surface (1,004ft below seafloor).

4.4 Unit C

The lithology within Unit C from 6,600ft below sea surface (1,004ft below seabed) to 6,702ft below sea surface (1,074ft below seabed) presents as slightly chaotic, low-amplitude reflectors interpreted as clays, silts, and occasional sands.

No risk of gas is predicted within Unit C at the proposed well location. Nearest risk of gas occurs 962ft to SSW with no connectivity to the proposed well location.

The well-path will traverse a minor fault within Unit C at -6,670ft below sea surface (1,074ft below seabed) exhibiting around 15ft of throw. Minor drilling fluid circulation and wellbore stability problems may occur in association with the fault.

Horizon H30 marks the base of Unit C occurring at -6,702ft below sea surface (1,106ft below seafloor).

4.5 Unit D

Unit D from -6,702ft to -7,819ft below sea surface (1,106ft to 2,091ft below seafloor) is interpreted as a higher energy mass-transport deposit, characterized by semi-continuous and discontinuous variable amplitude reflectors interpreted as clays, silts, and several sands. Sand interbeds within this interval may have been rapidly deposited with inadequate dewatering time. The proposed well is located within a regional sand fairway that occupies most of the study rea (Figure 5). Several wells in the Green Canyon protraction area experienced shallow water flow risk but these are at least 15miles to the northeast of the proposed well. However, at the proposed well location seismic data indicates a lesser sand content in the upper part of Unit D and a **Slight Shallow Water Flow Risk** is still assigned throughout this upper interval. Due to the increased potential for encountering poorly consolidated granular material in Unit D, minor drilling fluid circulation and wellbore stability problems may also occur within this upper interval.

The well-path will not traverse any predicted risk of gas anomalies within Unit D, still several risk of gas hazards occurs within 2,000ft of the proposed well. The closest is 305ft to the south and is considered a Slight Risk of Gas. The anomaly is up-dip of the proposed well location, and the downdip extension of the sand interbed associated with the anomaly just reaches the proposed well location but no indication of gas is observed. Anomalies to the northeast are considered a Moderate Risk of Gas with a closest approach of 320ft ENE, these anomalies are separated from the proposed well location by a fault that bounds the southwest side of the anomalies.

A vertical borehole will penetrate two faults within Unit D at -7,062ft below sea surface (1,466ft below seabed) and at -7,687ft below sea surface (2,091ft below seabed). These faults exhibit throws of 30ft and 50ft respectively but are not connected to deeper anomalies or upwards to seafloor. Minor drilling fluid circulation and wellbore stability problems may occur in association with the faults.

Horizon H40 marks the base of Unit D at -7,819ft below sea surface (2,223ft below seafloor).

4.6 Unit E

Unit E, from -7,819ft to -7,971ft below sea surface (2,223ft to 2,375ft below seafloor), is characterized by slightly chaotic, low amplitude reflectors interpreted as clays and silts with occasional sands.

No risk of gas is predicted within Unit E at the proposed well or within 2,000ft.

The well-path will not traverse any faults within Unit E.

Horizon H50 marks the base of this unit and the base of this interpretation at -7,971ft below sea surface (2,375ft below seafloor).

4.7 Unit F

Unit F, from -7,971ft to -8,167ft below sea surface (2,375ft to 2,571ft below seafloor), is characterized by slightly chaotic, low-amplitude reflectors interpreted as clays and silts with occasional sands.

No risk of gas is predicted within Unit F at the proposed well. Nearest risk of gas anomaly is located 1,476ft to the northeast and not connected to the proposed well location.

The well-path will not traverse any faults within Unit F.

Horizon H60 marks the base of this unit and the base of this interpretation at -8,167ft below sea surface (2,571ft below seafloor).

4.8 Unit G

Unit G, from -8,167ft to -8,218ft below sea surface (2,571ft to 2,622ft below seafloor), is characterized by slightly-chaotic, low and occasional moderate-amplitude reflectors interpreted as clays and silts with occasional sands.

No risk of gas is predicted within Unit G at the proposed well or within 2,000ft.

The well-path will not traverse any faults within Unit G.

Top of Salt marks the base of this unit and the base of this interpretation at -8,218ft below sea surface (2,622ft below seafloor).

4.9 Shallow Gas Assessment

No shallow gas is interpreted at the proposed well location.

4.10 Shallow Water Flow Assessment

Throughout Unit D, a **Slight Shallow Water Flow Risk** is interpreted from -6,702ft to -7,819ft below sea surface (1,106ft to 2,223ft below seafloor).

5. CONCLUSIONS AND RECOMMENDATIONS

- Seafloor

  No major drilling hazards or problems are predicted at seafloor.

  No features of potential biological or archaeological significance were identified within 2,000ft of the proposed well location.

  No side-scan targets were identified within 2,000ft of the proposed well.

- Unit A

  No drilling hazards or problems are interpreted.

- Unit B

  The well-path will traverse a fault within Unit B at -6,432ft below sea surface (836ft below seabed). Minor drilling fluid circulation and wellbore stability problems may occur in association with the fault. Casing seats should avoid all fault intersections as formation integrity could be compromised.

- Unit C

  The well-path will traverse a fault within Unit C at -6,670ft below sea surface (1,074ft below seabed). Minor drilling fluid circulation and wellbore stability problems may occur in association with the fault. Casing seats should avoid all fault intersections as formation integrity could be compromised.

- Unit D

  Within the Unit D, a **Slight Shallow Water Flow Risk** is interpreted from -7,062ft below sea surface (1,466ft below seabed) to -7,819ft below sea surface (2,223ft below seabed). Appropriate drilling methodology should be applied to contain a possible non-persistent water flow event.

  A vertical borehole will penetrate two faults within Unit D at -7,062ft below sea surface (1,466ft below seabed) and at -7,687ft below sea surface (2,091ft below seabed). Minor drilling fluid circulation and wellbore stability problems may occur in association with the faults. Minor drilling fluid circulation and wellbore stability problems may occur in association with the faults. Casing seats should avoid all fault intersections as formation integrity could be compromised.

- Unit E

  No drilling hazards or problems interpreted.

- Unit F

  No drilling hazards or problems interpreted.

- Unit G

  No drilling hazards or problems interpreted.

We appreciate the opportunity to work with you on this project and look forward to continuing as your geohazards consultants. Please contact us if you have any questions or if we can be of further assistance.

Sincerely,
Echo Offshore, LLC

Andrew Haigh	Matt Keith
Geophysical Manager	Quality Assurance
Ocean Geo Solutions, Inc	Echo Offshore, LLC

Copies Submitted: One digital copy (PDF) to Eva Gravouilla at BOE Exploration & Production LLC.

Attachments:

Proposed GC895-C Well Location

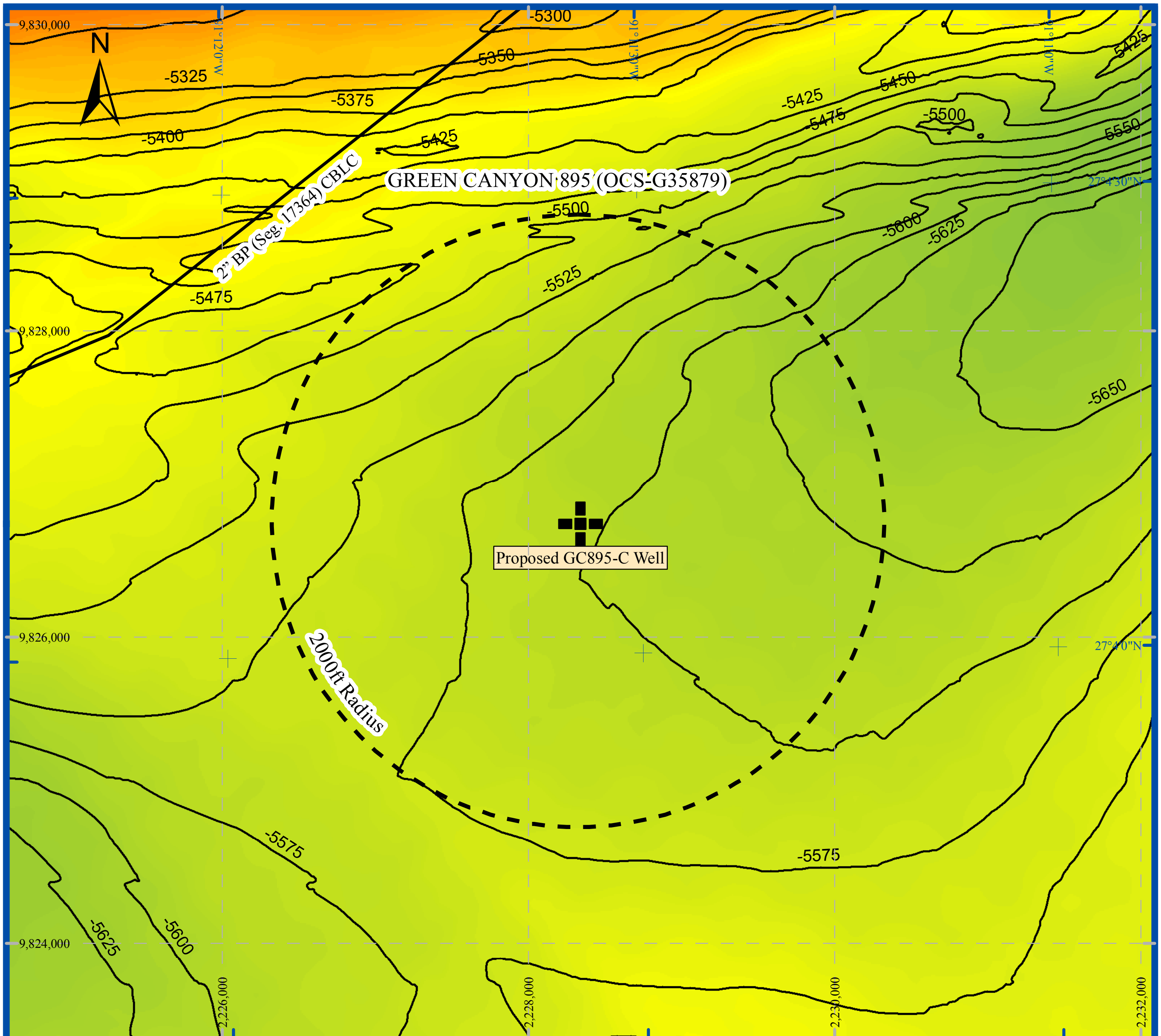
Seafloor Depth Extract

Seafloor Morphology Extract

Seafloor Amplitude Extract

Geohazard Summary Extract

Sand Lithology Extract-Unit D



Seabed Depth Extract

Proposed GC895-C Well Location (2,228,339ft E / 9,826,742ft N)

Existing infastructure

-5600 Depth in feet below sea surface to seabed contoured at 25ft intervals

Seabed Depth (Feet)

Chart Scale 1" = 1,000'

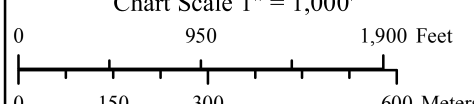
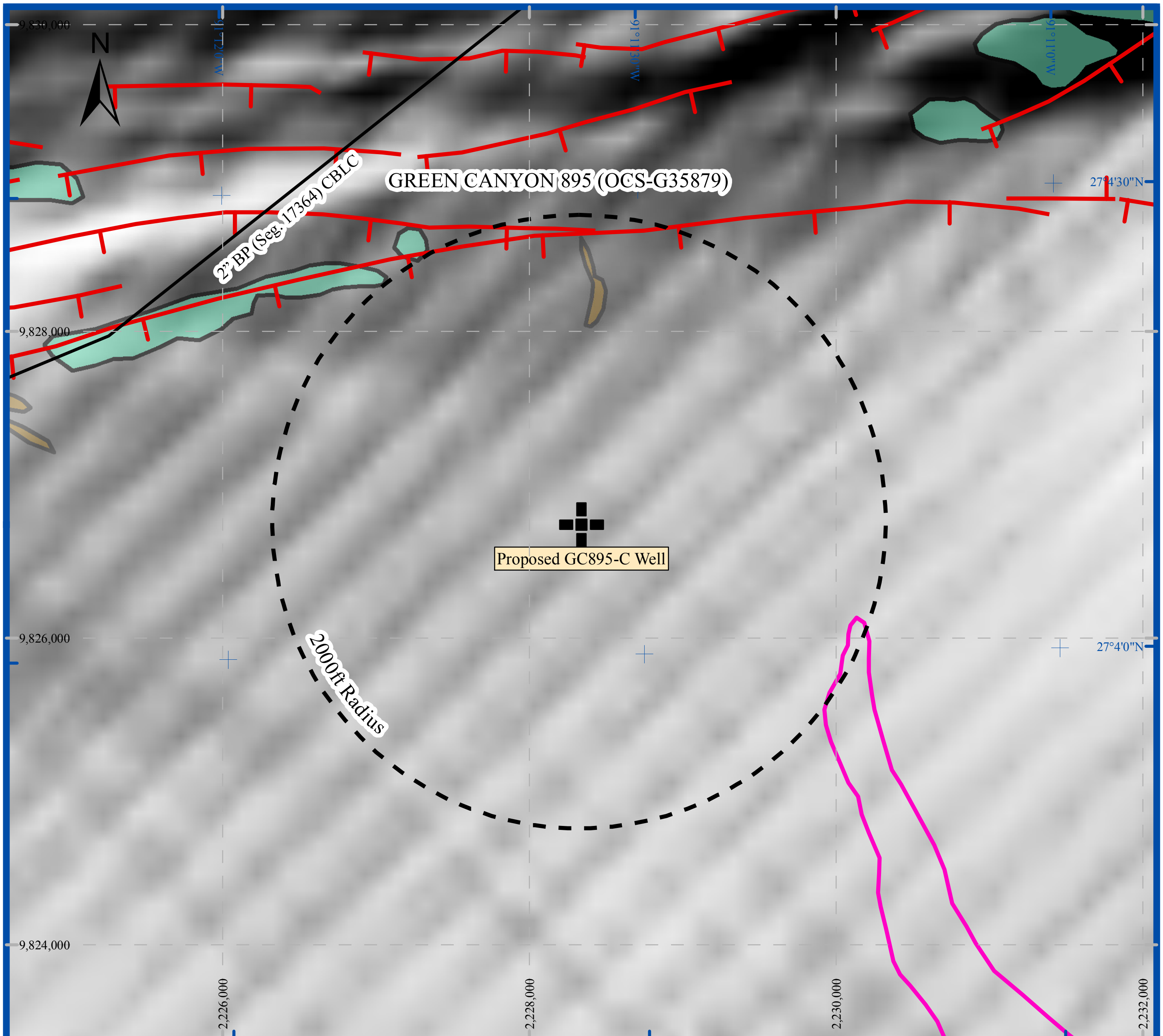


Figure 1
(GC895-C)



Seabed Morphology Extract

Proposed GC895-C Well Location
(2,228,339ft E / 9,826,742ft N)

Existing infastructure

Area of mass transport deposits

Seabed fault identified in AUV multibeam bathymetry data. Tick shows downthrown side

Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.

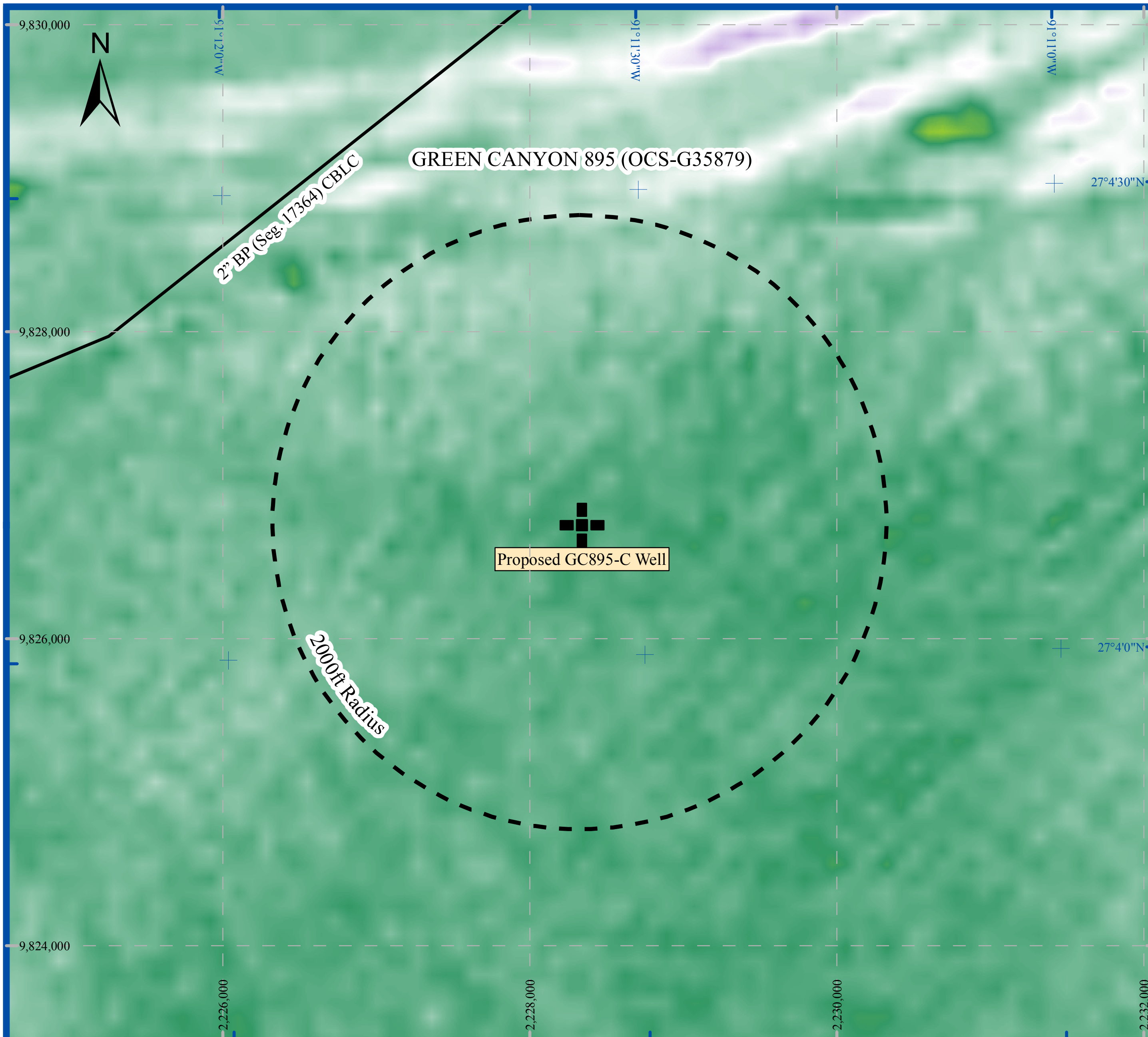
Seabed furrow area

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 2
(GC895-C)



Seabed Amplitude Extract

Proposed GC895-C Well Location
(2,228,339ft E / 9,826,742ft N)

Existing infastructure

9000 12000 15000 18000 21000 24000 27000 30000 33000

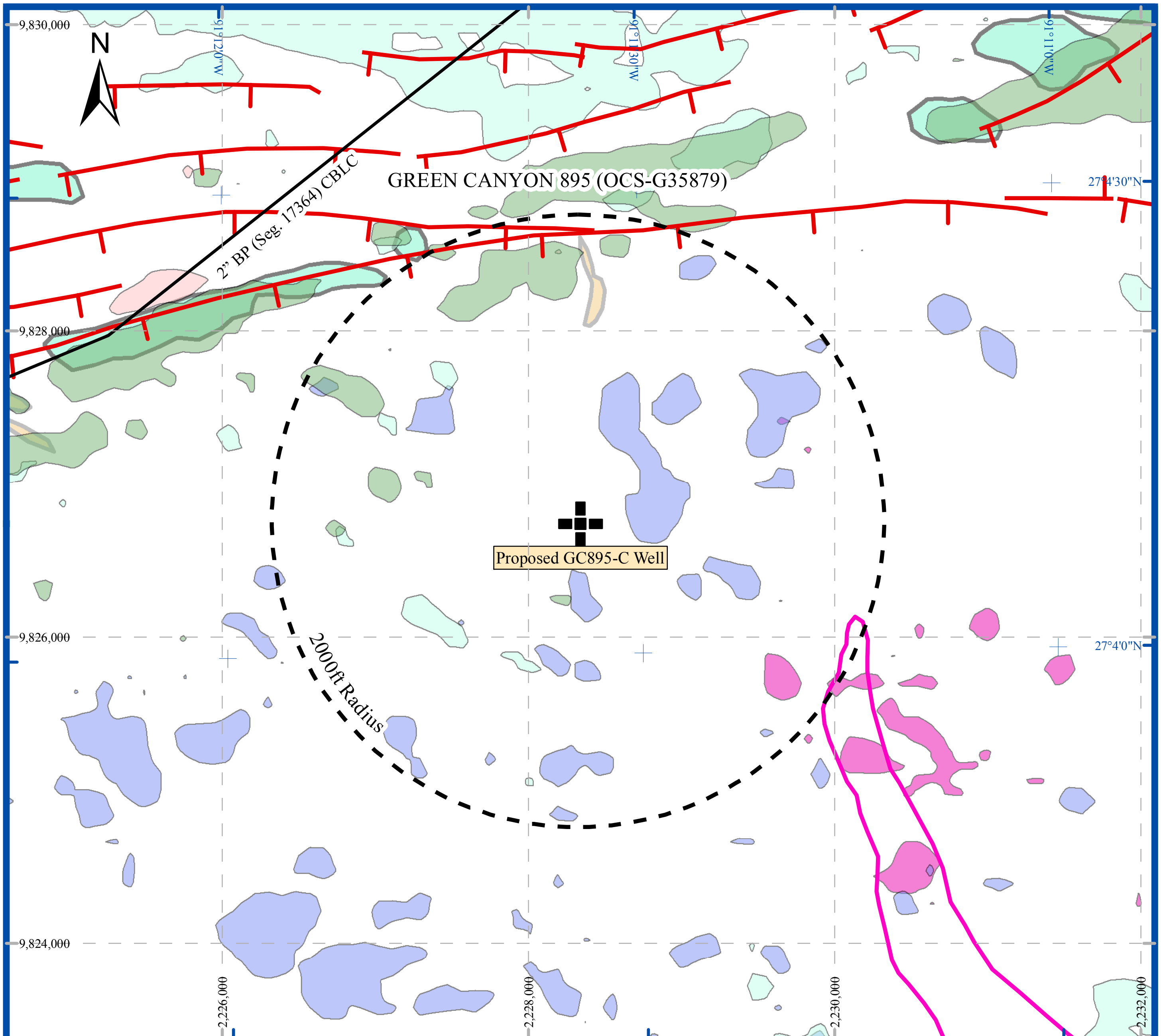
Relative Seabed Amplitude

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 3
(GC895-C)



Geohazard Summary Extract

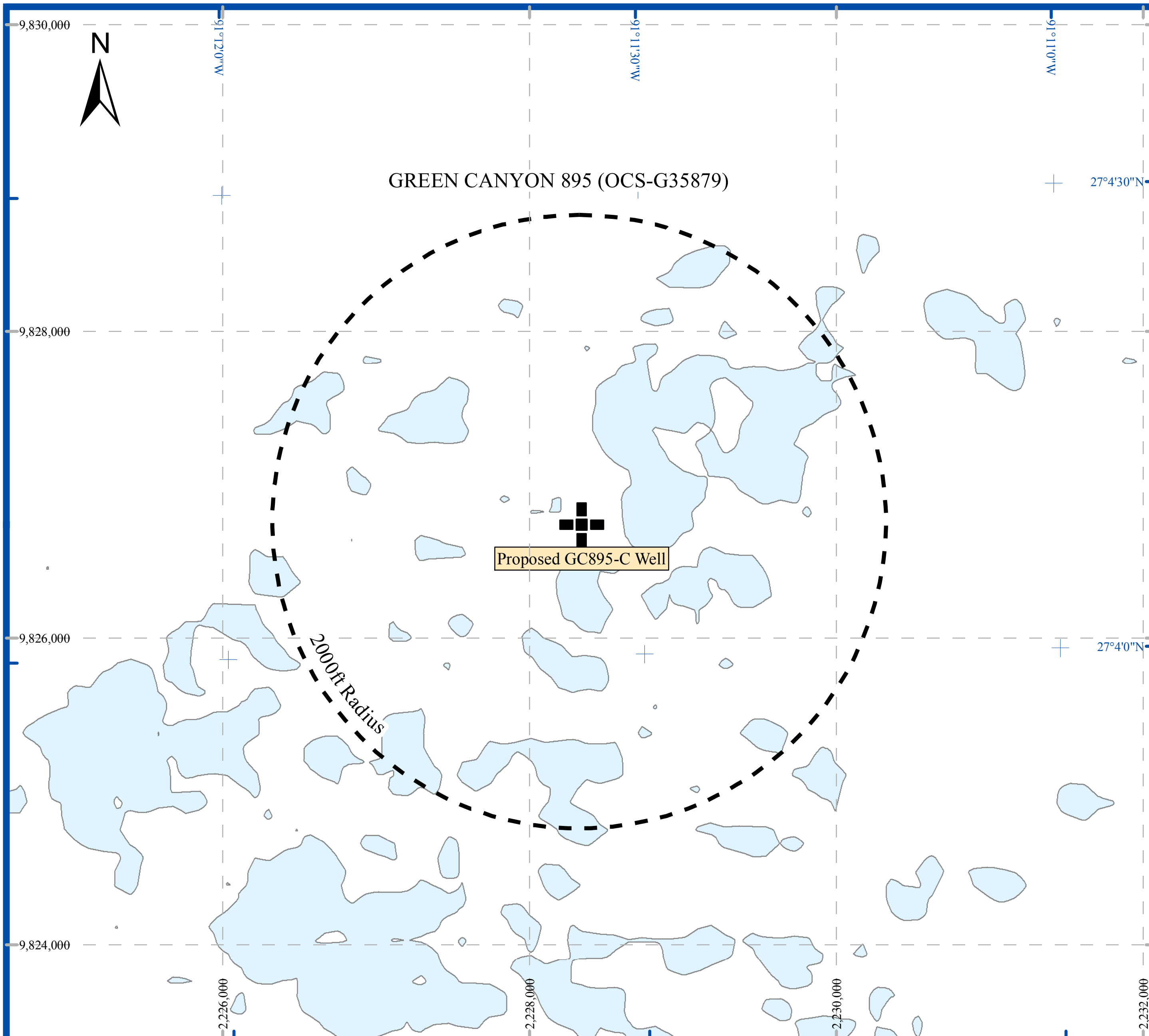
- Proposed GC895-C Well Location (2,228,339ft E / 9,826,742ft N)
- Existing infastructure
- Area of mass transport deposits
- Seabed fault identified in AUV multibeam bathymetry data. Tick shows downthrown side
- Seabed furrow area
- Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.
- Slight and High Risk of Gas within Unit A
- Slight, Moderate, and High Risk of Gas within Unit B
- Slight, Moderate, and High Risk of Gas within Unit C
- Slight, Moderate, and High Risk of Gas within Unit D
- Slight Risk of Gas within Unit F

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 4
(GC895-C)



Sand-Prone Lithology Extract (Unit D)

Proposed GC895-C Well Location
(2,228,339ft E / 9,826,742ft N)

Predicted sands within Unit D

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 5
(GC895-C)

Well Clearance Letter for
BOE Exploration & Production LLC
Public Copy

Project:
Block GC895, Offshore Gulf of Mexico

Description:
Proposed GC895-D Well Location

Project Number:
20-012-31/2020-244

Report Status:
Final

REPORT AUTHORIZATION AND DISTRIBUTION

Compilation	Geophysics	L Fuentes
Authorization	Geophysics	A.R.K …………………
	Quality Assurance	………………… Matt Keith

Revision	**Date**	**Title**
0	March 2, 2020	Final

Distribution

One digital copy (PDF)

BOE Exploration & Production LLC
300 Holiday Square Blvd,
Suite 100
Covington, LA 70433

For the attention of
Eva Gravouilla

Public Copy

Eva Gravouilla
BOE Exploration & Production LLC
300 Holiday Square Blvd,
Suite 100
Covington, LA 70433

Dear Mrs. Gravouilla:

Echo Offshore, LLC appreciates the opportunity to submit this Well Clearance letter based on a 3D geohazard assessment covering Block GC895, Green Canyon protraction area. This assessment was prepared utilizing 3D seismic data provided by Houston Energy, LP, in compliance with NTL Nos. 2008-G05, 2008-G04, and 2009-G40, by the Bureau of Ocean Energy Management (BOEM), Gulf of Mexico Region. BOE Exploration & Production LLC is now the operator of the lease and has requested that Echo Offshore provide this assessment of the referenced proposed well location.

This report has been prepared with due care, diligence, and with the skill reasonably expected of a reputable contractor experienced in the types of work, carried out under the contract. As such, the findings in this report are based on an interpretation of data which is a matter of opinion on which professionals may differ and, unless clearly stated, is not a recommendation of any course of action.

Please be aware that further distribution of this report, in whole or part, or the use of the data for a purpose not expressly stated within the contractual work scope is at the client's sole risk, and it is recommended that this disclaimer be included in any such distribution.

If we can be of further assistance, or if you have any questions, please do not hesitate to call.

We sincerely appreciate this opportunity to be of service to you.

Very truly yours,

C. D. Schempf, Jr.

C. D. Schempf, Jr.
President

MK for CDS

Location Map

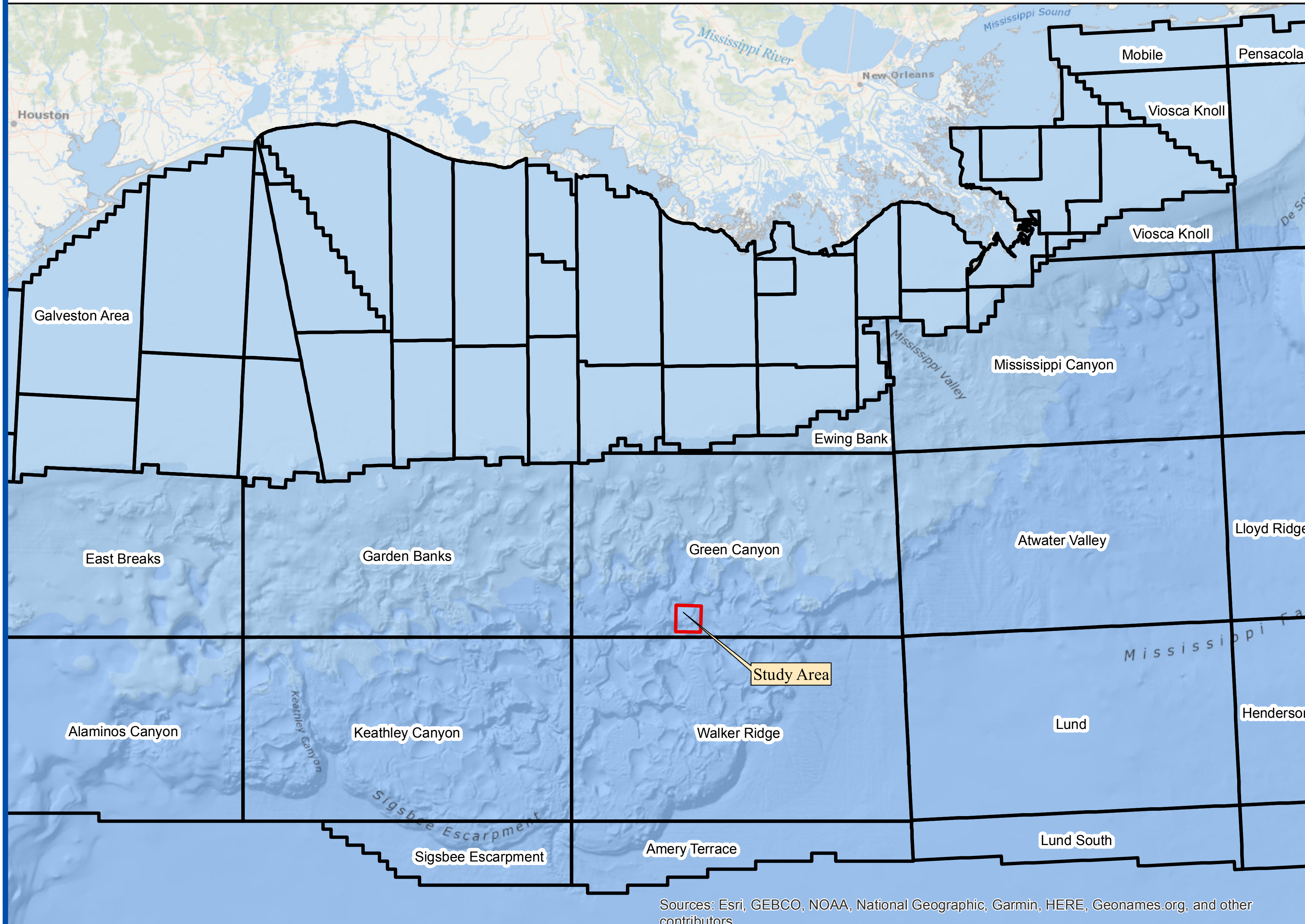


TABLE OF CONTENTS

LIST OF FIGURES

WELL CLEARANCE LETTER – PROPOSED GC895-D WELL LOCATION

PUBLIC COPY

March 02, 2020
Bureau of Ocean Energy Management (MS 5230)
Gulf of Mexico OCS Region
1201 Elmwood Park Blvd.
New Orleans, LA 70123-2394

RE: **BOE Exploration & Production LLC**
Proposed GC895-D
Block 895, Green Canyon
Offshore Gulf of Mexico
OCS-G-35879

Echo Offshore, LLC was contracted by BOE Exploration & Production LLC, to prepare a Well Clearance Letter for the proposed GC895-D well in Block 895, Green Canyon Area (OCS-G-35879). This letter addresses seafloor and shallow geologic conditions that may impact exploratory drilling operations within 2,000ft of the proposed well site. The depth limit of this site clearance assessment is at -11,274ft below sea surface (5,832ft below seafloor). BOE Exploration & Production LLC plans to operate from a dynamically positioned drilling module; therefore, an anchoring assessment is not required. Relevant letter-size chart extracts, data examples are presented with this Well Clearance Letter, plus annotated data examples of the two nearest intersecting inlines and crosslines, the nearest sub-bottom profiler transect line, and the side-scan sonar mosaic. This site clearance assessment is primarily based on the interpretation of and AUV data set for seafloor and shallow soils and a 3D seismic data set for deeper geology. This assessment is based on the area specific hazard assessment that has been produced under separate cover (Houston Energy – Gardline Surveys Inc. Report No. 11115).

AUV Archaeological Investigation. The proposed activities occur within an area of the outer continental shelf defined by BOEM as having a high archaeological resource potential (see NTL No. 2011-JOINT-G01). An archaeological investigation was performed across the wellsite area by Echo Offshore on Nov. 21-27, 2017 using AUV geophysical data.

3D Geophysical Survey. The 3D seismic dataset is of good quality and suitable for shallow hazard assessment. Inlines are oriented northeast to southwest, have a numerical increment of one, and exhibit a line spacing of 98.42ft. Crosslines are oriented northwest to southeast, have a numerical increment of four and exhibit a line spacing of 82.02ft. Sample rate of the data was 4ft, and record length is 60,000ft.

The data presents an acceptable frequency response across the upper one second below seafloor, with an equivalent effective frequency range at 50% power of 55-85Hz (Figure 11). The data exhibits a dominant frequency in the upper one second of approximately 70Hz plus significant higher usable frequencies, resulting in a mean vertical resolvability of typically 20ft and a layer detectability of 5ft.

Several data types were provided, within two surveys: E Wave and E Octopus. The E Octopus survey was used primarily, and is characterized by the following collection and processing parameters and history, based on the survey collection and processing phases:

- Modern WAZ data
- Spec. data widely licensed by many companies for exploration
- Using highest frequency product available "High-resolution sediment flood", after 3 iterations of multiazimuth sediment tomography
- E-Octopus VII:
  - Shot 2010, Processed 2011
- E-Octopus II
  - Shot 2008, Processed 2008
- E-Octopus III
  - Shot 2009, Processed 2009
- Note that E-Oct II and III were merged together by WesternGeco

E-Octopus VII

<u>Acquisition Parameters</u>

Recording System: Q-Marine*

Energy Source: Single Source; 8,475 in.^{3}

Line Orientation: NE/SW

Source Depth: 12m

Streamer Configuration: Multi-streamer: 10 X 7,000m cables

Streamer Depth: 12m

Maximum Offset: 8,600m

Sample Rate: 2ms

Record Length: 14s

DGF Receiver Interval: 12.5m

Recording Bin Dimensions: 6.25 X60m

Acquisition Completed: April 2010

<u>Processing Flow</u>

Q* point-receiver seismic acquisition and processing methodology

Digital group forming (DGF): output 12.5m

Navigation merge

Calibrated marine source designature

Anomalous amplitude attenuation

Water velocity correction

3D GSMP demultiple

3 iterations of multiazimuth sediment tomography

High-resolution sediment flow (pick top of salt 1)

Salt flood 1(pick bottom salt 1)

Salt body 1 (pick top of salt 2)

Salt flood 1(pick bottom salt 2)

Salt body 2

Subsalt tomography (using ample gathers)

Full salt velocity models

RTM (Reverse Time Migration) and Kirchhoff migration

Processing completed: December 2011

E-Octopus I & II

Acquisition Parameters

Recording System: Q-Marine*

Energy Source: Single Source; 8,475 in.^{3}

Line Orientation: NE/SW

Source Depth: 10m

Streamer Configuration: Multi-streamer: 10 X 7,000m cables

Streamer Depth: 12m

Maximum Offset: 9,600m

Sample Rate: 2ms

Record Length: 14s

DGF Receiver Interval: 12.5m

Recording Bin Dimensions: 6.25 X60m

Acquisition Completed: Phase I December 2006; Phase II: December 2008

Processing Flow

Q* point-receiver seismic acquisition and processing methodology

Digital group forming (DGF): output 12.5m

Navigation merge

Calibrated marine source designature

Anomalous amplitude attenuation

Water velocity correction

Inverse Q: phase only

WEM demultiple

3 iterations of multiazimuth sediment tomography (incorporating anistrophy)

High-resolution sediment flow (pick top of salt 1)

Salt flood 1(pick bottom salt 1)

Salt body 1 (pick top of salt 2)

Salt flood 1(pick bottom salt 2)

Salt body 2

Subsalt tomography (using ample gathers)

Full salt velocity models

Final WEM (Wave Equation Migration) 25Hz

Processing completed: Phase I: April 2008; Phase II: December 2008

E-Octopus III

Acquisition Parameters

Recording System: Q-Marine*
Energy Source: Single Source; 8,475 $in.^3$
Line Orientation: NE/SW
Source Depth: 10m
Streamer Configuration: Multi-streamer: 10 X 7,000m cables
Streamer Depth: 12m
Maximum Offset: 8,600m
Sample Rate: 2ms
Record Length: 14s
DGF Receiver Interval: 12.5m
Recording Bin Dimensions: 6.25 X60m
Acquisition Completed: Phase I December 2008

Processing Flow

Q* point-receiver seismic acquisition and processing methodology
Digital group forming (DGF): output 12.5m
Navigation merge
Calibrated marine source designature
Anomalous amplitude attenuation
Water velocity correction
Inverse Q: phase only
WEM demultiple
3 iterations of multiazimuth sediment tomography (incorporating anistrophy)
High-resolution sediment flow (pick top of salt 1)
Salt flood 1(pick bottom salt 1)
Salt body 1 (pick top of salt 2)
Salt flood 1(pick bottom salt 2)
Salt body 2
Subsalt tomography (using ample gathers)
Full salt velocity models
Final WEM (Wave Equation Migration) 25Hz
Processing completed: May 2009

Spectral whitening was applied to the data set as a post-processing technique to optimize interpretability.

In summary, and with reference to NTL No. 2008-G04 and 2008-G05, the following statements are applicable to the seismic data:

In summary and with reference to NTL No. 2008-G04:

a) The data provides imaging of sufficient resolution of the shallow section allowing a clear analysis of the shallow conditions.
b) The data can be loaded to a workstation at 16-bit resolution or greater and is unscaled.
c) There is no trace or sample decimation.
d) The sample interval and bin size are maintained throughout the assessment area.

e) The data possess a frequency content of 50Hz or higher at 50% power in the first second below seafloor.

f) Seafloor reflection is free of gaps and is defined by a wavelet of stable shape and phase, allowing auto-tracking of the seafloor event with minimum user intervention and guidance.

g) There are no significant acquisition artifacts throughout the dataset.

h) Merge points in the data are marked by no time shifts and very minimal amplitude changes and are not a detriment to interpretation.

i) Processed bin sizes are 98.42ft x 82.02ft.

j) The sample rate of the data is 4ft.

k) There is no significant multiple energy.

1. LOCATION COORDINATES

1.1 Proposed GC895-D Well Location (OCS-G-35879).

Proposed GC895-D Well Location							
Location Coordinates							
NAD 27 Datum - Clarke 1866 Ellipsoid					UTM Zone 15 - CM 93° West		
Latitude	27°	05’	08.628”	North	Easting	2,228,530	US ft E
Longitude	91°	11’	31.505	West	Northing	9,832,825	US ft N
FEL Green Canyon 895	4,910ft	US ft	Inline	5176			
FNL Green Canyon 895	3,815ft	US ft	Crossline	39433			
Water Depth: -5,442 ft.	Slope: 2.1° NW						
Nearest Shoreline	118 Nautical Miles @ 06.47°						
Nearest Manned Platform	A-Constitution TLP in GC680	18.83 Nautical Miles @ 23.5°					

2. VELOCITY DATA

2.1 Seafloor Depth

Seafloor depth around the proposed well was derived from multibeam echosounder data acquired as part of an AUV geophysical investigation over approximately 15.3 square miles of blocks GC895 & GC939.

2.2 Sub-seafloor Depth

3D seismic data was provided as a depth volume; therefore, no depth conversion was required.

3. SEAFLOOR CONDITIONS

3.1 Seafloor Depth

Water depth at the Proposed GC895-D well location is -5,442ft below sea surface (Figure 1). The seafloor slopes to the northwest at 2.1°.

3.2 Seafloor Morphology and Man-Made Features

The proposed GC895-D well location is in the east-central part of block GC895.

Side-scan sonar data indicates the proposed well is located on an area of smooth seafloor interpreted as clays and silts. The scarp of a surficial failure is located 1,470ft to the west of the proposed well. No other major seabed features were identified within 2,000ft of the proposed well (Figures 4 & 6).

In accordance with NTL stipulations for archaeological resources, an archeological survey was performed in the study area in November 2017. Several targets were identified within the study area. No side scan targets occur within 2,000ft of the proposed well. **No features of archaeological resources were identified within 2,000ft of the proposed well location.** All targets are interpreted as modern anthropogenic debris.

A cable is located 1,765ft to the southeast of the proposed well.

There are no anomalous seafloor amplitudes indicative of hydrocarbon macroseep observed within a 2,000ft radius of the proposed location (Figure 3). **No features or areas that could support high-density sensitive sessile benthic communities are located within 2,000ft of any mud or cuttings discharge location.** The nearest area with the potential for benthic communities **occurs** approximately 3,479ft to the southeast.

4. SUB-SEAFLOOR CONDITIONS

4.1 Geology and Lithology

The sub-seafloor geology has been divided into seven Units, A, B, C, D, E, F, and G, separated by Horizons, H10, H20, H30, H40, H50, H60, and Top of salt (Figures 8 through 10). Top of Salt is the depth limit of investigation.

4.2 Unit A

The lithology within Unit A from seafloor to -5,820ft below sea surface (378ft below seafloor) is characterized by well-layered, low and slightly moderate-amplitude reflectors interpreted as clays and silts with the possibility of minor sandy interbeds.

Sub-bottom profiler data shows the upper part of Unit A consists of predominantly clays and silts (Figure 7).

No risk of gas or shallow water flow is interpreted within Unit A at the location or within 2,000ft of the proposed well.

Unit A appears conducive to conductor jetting, though the possibility of minor sandy interbeds could cause some slight variability.

Horizon H10 marks the base of Unit A occurring at -5,820ft below sea surface (378ft below seafloor).

4.3 Unit B

Unit B, from -5,820ft to -6,518ft below sea surface (378ft to 1,076ft below seafloor), is characterized by well-layered and slightly chaotic, low and occasional moderate-amplitude reflectors interpreted as clays, silts, and occasional sands.

No risk of gas is predicted within Unit B at the proposed well location or within 2,000ft of the proposed well.

The well-path will not traverse any faults at the proposed well.

Horizon H20 marks the base of Unit B occurring at -6,518ft below sea surface (1,076ft below seafloor).

4.4 Unit C

The lithology within Unit C from 6,518ft below sea surface (1,076ft below seabed) to 7,316ft below sea surface (1,874ft below seabed) is characterized by low to moderate amplitude discontinuous to semi-continuous reflectors interpreted as a higher-energy mass-transport comprising channelized deposits interpreted as clays, silts, and several sands. Due to the possibility of rapid deposition with inadequate dewatering time a **Slight Shallow Water Flow Risk** is assigned to this interval. Due to the increased possibility of encountering poorly consolidated granular sediments minor drilling fluid circulation and wellbore stability problems may also occur within this interval.

No risk of gas is predicted within Unit C at the proposed well location. Nearest risk of gas occurs 865ft to WSW with no connectivity to the proposed well.

The well-path will not traverse any faults within Unit C.

Horizon H30 marks the base of Unit C occurring at -7,316ft below sea surface (1,874ft below seabed).

4.5 Unit D

Unit D from -7,316ft to -9,065ft below sea surface (1,874ft to 3,623ft below seafloor) is interpreted as a higher energy mass-transport deposit, characterized by semi-continuous and discontinuous variable amplitude reflectors interpreted as clays, silts, and several sands. Sand interbeds within this interval may have been rapidly deposited with inadequate dewatering time. The proposed well is located within a regional sand fairway that occupies most of the study rea (Figure 5). Several wells in the Green Canyon protraction area experienced shallow water flow risk but these are at least 15miles to the northeast of the proposed well. However, at the proposed well location seismic data indicates a lesser sand content in the upper part of Unit D and a **Slight Shallow Water Flow Risk** is still assigned throughout this unit. Due to the increased potential for encountering poorly consolidated granular material in Unit D, minor drilling fluid circulation and wellbore stability problems may also occur.

A vertical borehole will not penetrate any faults within Unit D.

No risk of gas is predicted.

Horizon H40 marks the base of Unit D at -9,065ft below sea surface (3,623ft below seafloor).

4.6 Unit E

The well-path will not traverse Unit E.

4.7 Unit F

Unit F, from -9,065ft to -9,669ft below sea surface (3,623ft to 4,227ft below seafloor), is characterized by slightly chaotic, low-amplitude reflectors interpreted as clays and silts with occasional sands.

No risk of gas is predicted within Unit F at the proposed well. Nearest risk of gas anomaly is located 1,551ft to the west and is not connected to the proposed well.

The well-path will not traverse any faults within Unit F.

Horizon H60 marks the base of this unit and the base of this interpretation at -9,669ft below sea surface (4,227ft below seafloor).

4.8 Unit G

Unit G, from -9,669ft to -11,274ft below sea surface (4,227ft to 5,832ft below seafloor), is characterized by slightly chaotic, low and occasional moderate-amplitude reflectors interpreted as clays and silts with occasional sands.

No risk of gas is predicted within Unit G at the proposed well. The nearest risk of gas anomaly occurs approximately 1,387ft to the northeast with no connectivity to the proposed location.

The well-path will not traverse any faults within Unit G.

Top of Salt marks the base of this unit and the base of this interpretation at -11,274ft below sea surface (5,382ft below seafloor).

4.9 Shallow Gas Assessment

No risk of gas is interpreted at the proposed well location.

4.10 Shallow Water Flow Assessment

Throughout Unit C, a **Slight Shallow Water Flow Risk** is interpreted from -6,518ft to -7,316ft below sea surface (1,076ft to 1,874ft below seafloor).

Throughout Unit D, a **Slight Shallow Water Flow Risk** is interpreted from -7,316ft to -9,065ft below sea surface (1,874ft to 3,623ft below seafloor).

5. CONCLUSIONS AND RECOMMENDATIONS

- Seafloor

  No major drilling hazards or problems are predicted at seafloor.

  No features of potential biological or archaeological significance were identified within 2,000ft of the proposed well location.

  No side-scan targets were identified within 2,000ft of the proposed well.

- Unit A

  No drilling hazards or problems are interpreted.

- Unit B

  No drilling hazards or problems are interpreted.

- Unit C

  Throughout Unit C, a **Slight Shallow Water Flow Risk** is interpreted from -6,518ft to -7,316ft below sea surface (1,076ft to 1,874ft below seafloor). Appropriate drilling methodology should be applied to contain a short-lived, non-persistent water flow event. Additionally, minor drilling and wellbore stability problems are possible within this unit.

- Unit D

  Throughout Unit D, a **Slight Shallow Water Flow Risk** is interpreted from -7,316ft to -9,065ft below sea surface (1,874ft to 3,623ft below seafloor). Appropriate drilling methodology should be applied to contain a short-lived, non-persistent water flow event. Additionally, minor drilling and wellbore stability problems are possible within this unit.

- Unit E

  The well-path will not traverse Unit E.

- Unit F

  No drilling hazards or problems are interpreted.

- Unit G

  No drilling hazards or problems are interpreted.

We appreciate the opportunity to work with you on this project and look forward to continuing as your geohazards consultants. Please contact us if you have any questions or if we can be of further assistance.

Sincerely,
Echo Offshore, LLC

Andrew Haigh	Matt Keith
Geophysical Manager	Quality Assurance
Ocean Geo Solutions, Inc	Echo Offshore, LLC

Copies Submitted: One digital copy (PDF) to Eva Gravouilla at BOE Exploration & Production LLC.

Attachments:

Proposed GC895-D Well Location

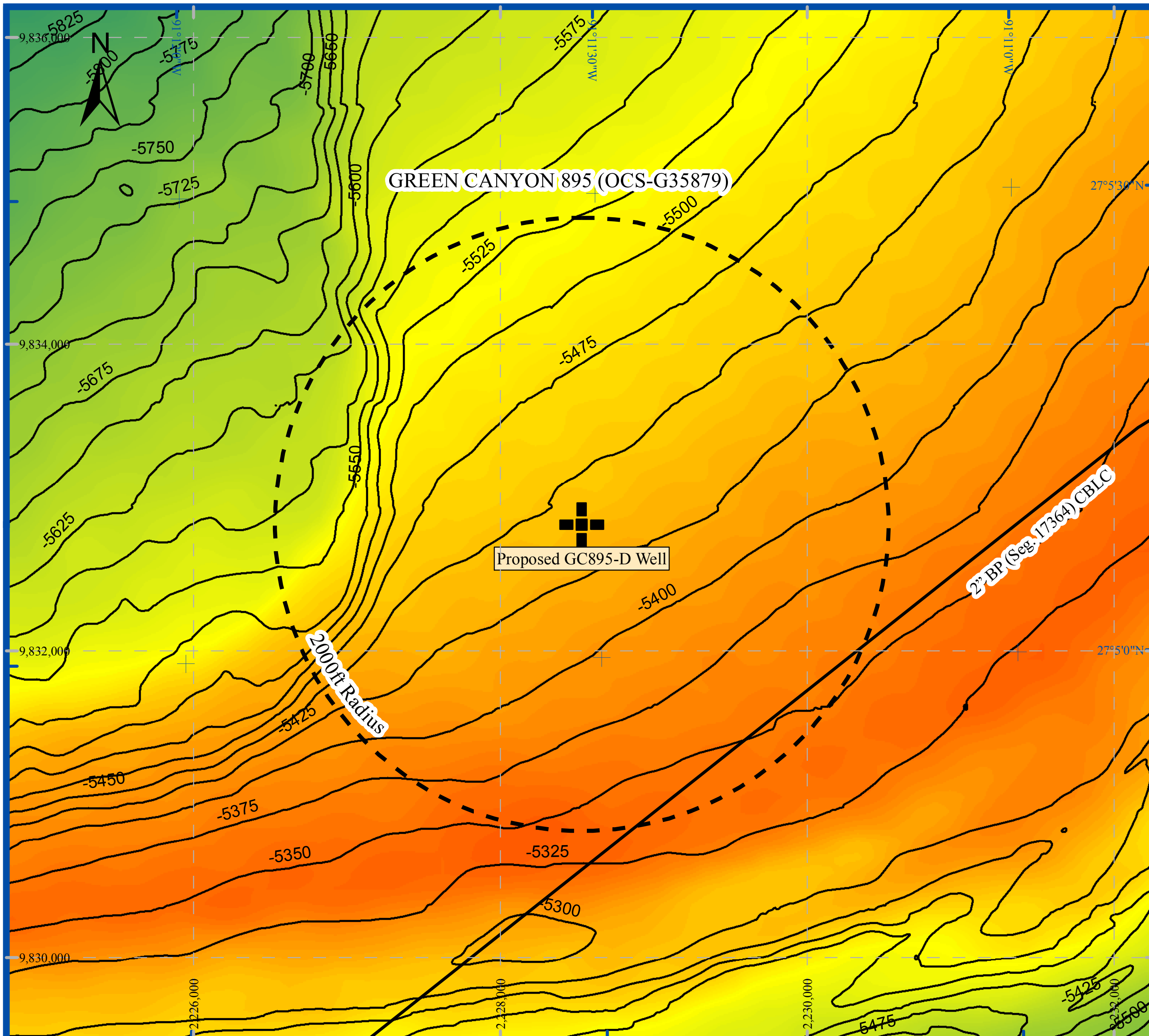
Seafloor Depth Extract

Seafloor Morphology Extract

Seafloor Amplitude Extract

Geohazard Summary Extract

Sand Lithology Extract-Unit D

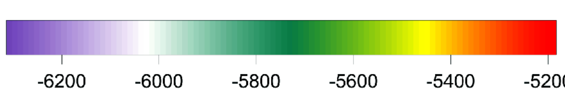


Seabed Depth Extract

Proposed GC895-D Well Location
(2,228,530ft E / 9,832,825ft N)

-5400 Depth in feet below sea surface to seabed contoured at 25ft intervals

Existing infastructure



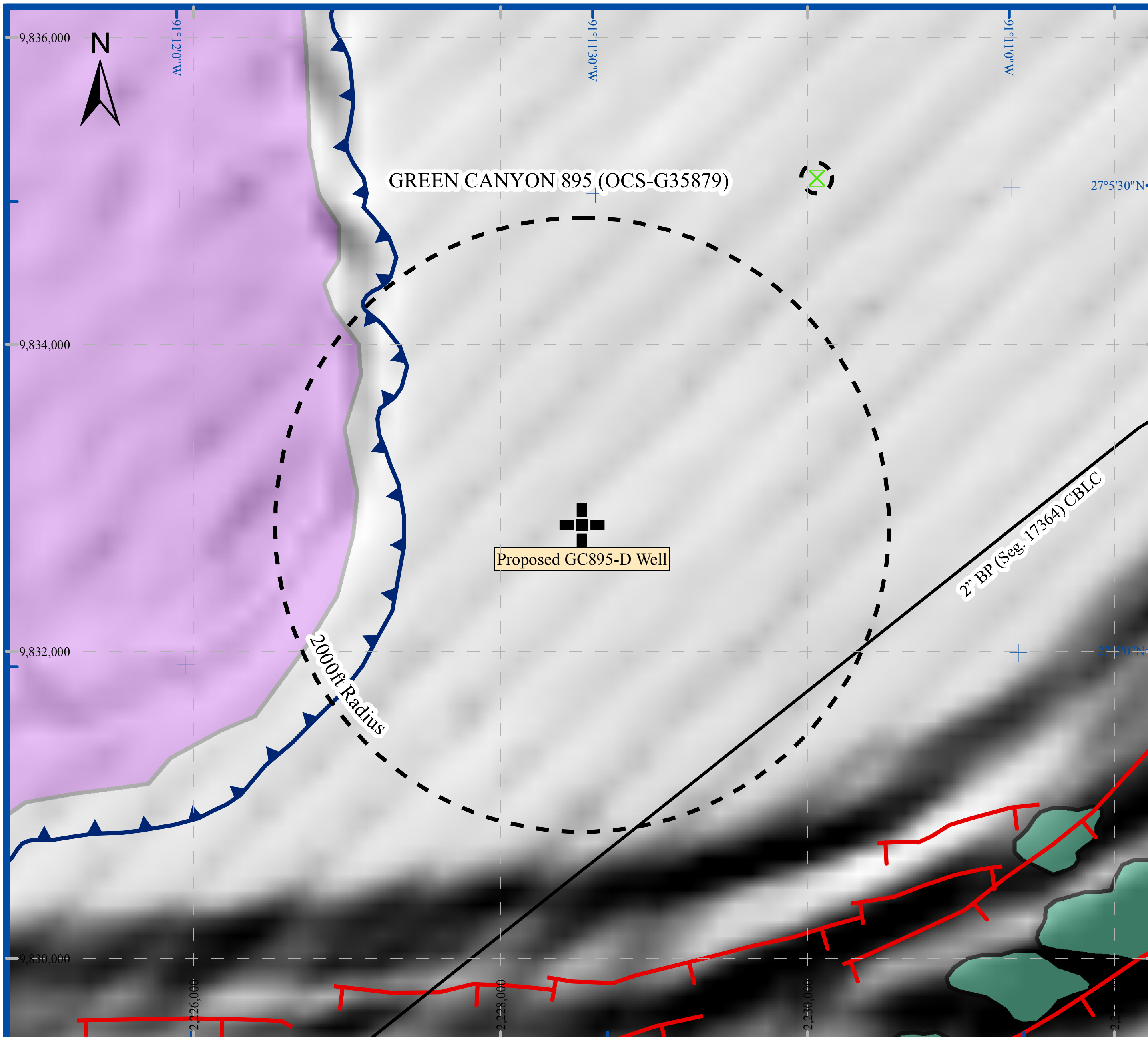
Seabed Depth (Feet)

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 1
(GC895-D)



Seabed Morphology Extract

Proposed GC895-D Well Location (2,228,530ft E / 9,832,825ft N)

Existing infastructure

Seabed failure scarps. Tick shows failed side

Seabed fault identified in AUV multibeam bathymetry data. Tick shows downthrown side

Area of mass transport deposits at or near the seabed

Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.

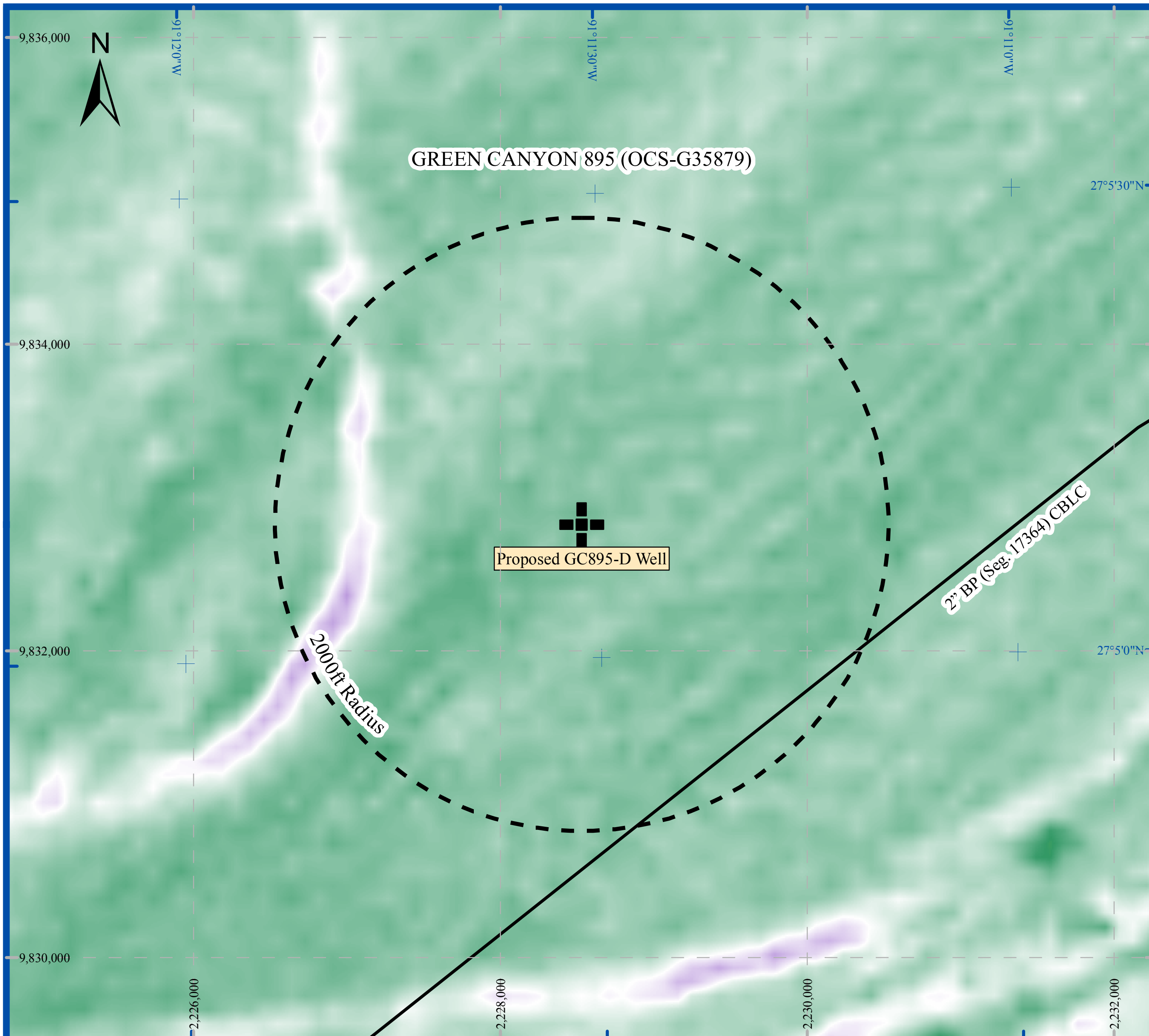
Side-scan sonar contact with 100ft exclusion zone

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

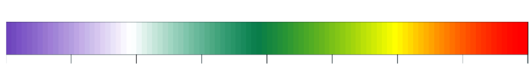
Figure 2
(GC895-D)



Seabed Amplitude Extract

Proposed GC895-D Well Location
(2,228,530ft E / 9,832,825ft N)

Existing infastructure



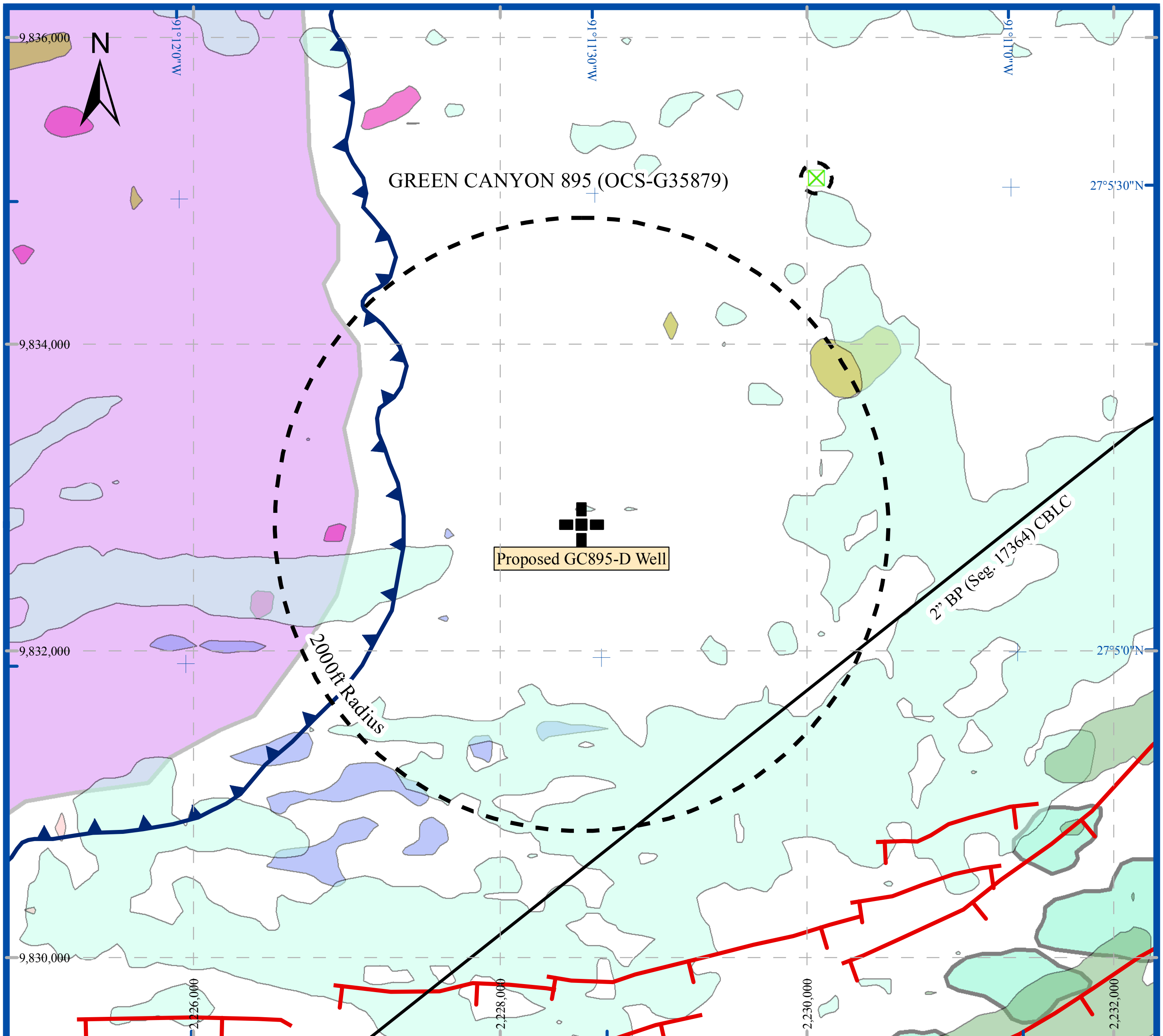
Relative Seabed Amplitude

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 3
(GC895-D)



Geohazard Summary Extract

Proposed GC895-D Well Location (2,228,530ft E / 9,832,825ft N)

Existing infastructure

Seabed failure scarps. Tick shows failed side

Seabed fault identified in AUV multibeam bathymetry data. Tick shows downthrown side

Area of mass transport deposits at or near the seabed

Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.

Side-scan sonar contact with 100ft exclusion zone

Slight and Moderate Risk of Gas within Unit A

Slight, Moderate, and High Risk of Gas within Unit B

Slight, Moderate, and High Risk of Gas within Unit C

Slight, Moderate, and High Risk of Gas within Unit D

Slight Risk of Gas within Unit F

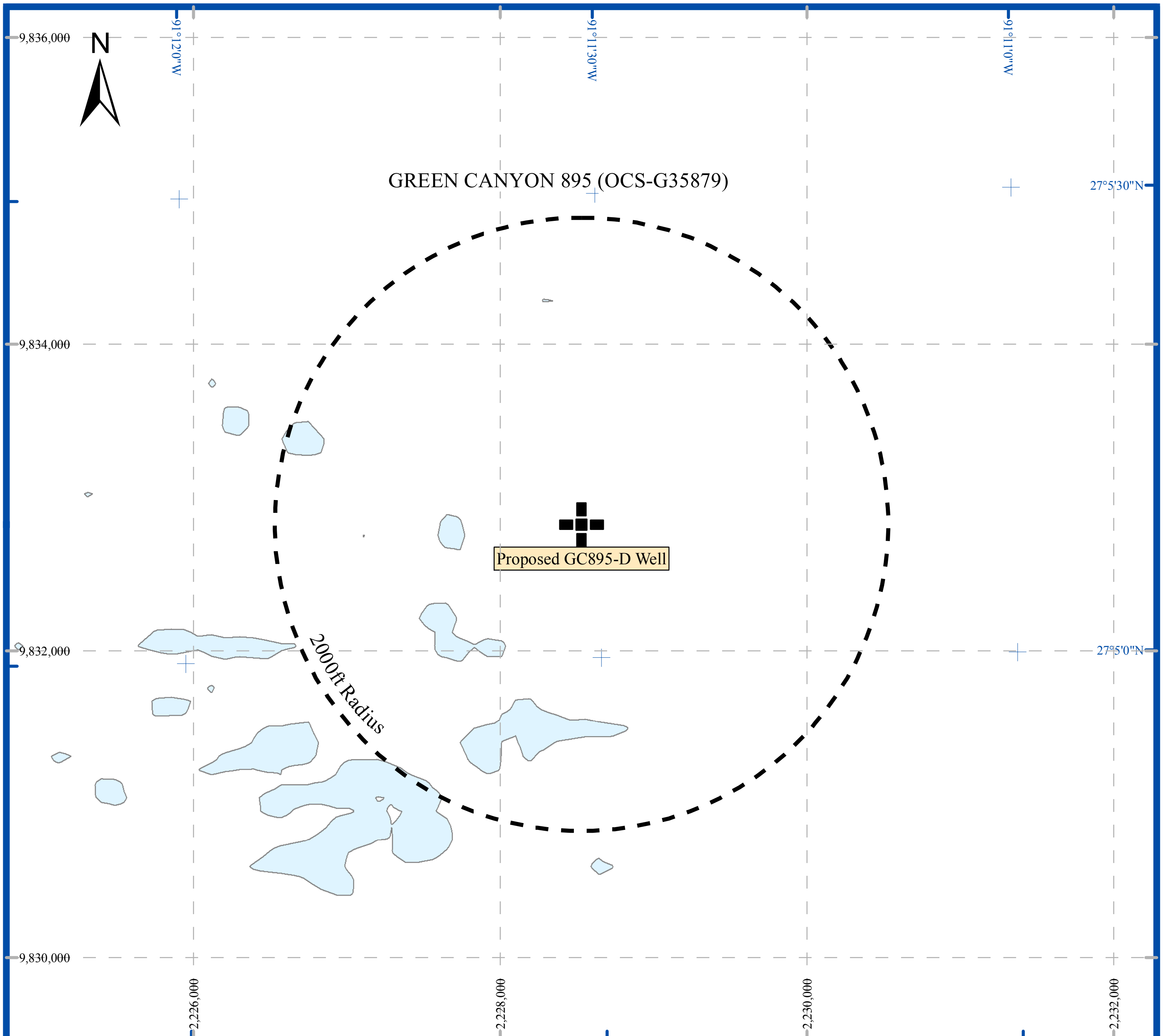
Slight and Moderate Risk of Gas within Unit G

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 4
(GC895-D)



Sand-Prone Lithology Extract (Unit D)

Proposed GC895-D Well Location
(2,228,530ft E / 9,832,825ft N)

Predicted sands within Unit D

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 5
(GC895-D)

APPENDIX D
HYDROGEN SULFIDE INFORMATION

A) CONCENTRATION
In accordance with NTL 2008-G04, this information is not applicable as BOE Exploration & Production does not anticipate encountering any H2S while conducting the activities proposed in this plan.

B) CLASSIFICATION
In accordance with 30 CFR 250.490(c), BOE Exploration & Production is requesting the subject area and block, and lease(s), respectively be classified as an area where H2S is absent. This is based upon information from the well(s) listed in the table below.

PROPRIETARY INFORMATION

C) H2S CONTINGENCY PLAN
In accordance with NTL 2008-G04, this information is not applicable as BOE Exploration & Production does not anticipate encountering H2S while conducting the activities proposed in this plan.

D) MODELING REPORT
In accordance with NTL 2008-G04, a modeling report is not included in the attachments for this appendix as BOE Exploration & Production does not anticipate encountering H2S in concentrations greater than 500 ppm.

APPENDIX E
MINERAL RESOURCE CONSERVATION INFORMATION

A) TECHNOLOGY & RESERVOIR ENGINEERING PRACTICES & PROCEDURES
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as this is an Exploration Plan.

B) TECHNOLOGY & RECOVERY PRACTICES & PROCEDURES
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as this is an Exploration Plan.

C) RESERVOIR DEVELOPMENT
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as this is an Exploration Plan.

APPENDIX F
BIOLOGICAL, PHYSICAL, & SOCIOECONOMIC INFORMATION

A) HIGH-DENSITY DEEPWATER BENTHIC COMMUNITIES INFORMATION
The activities proposed in this plan could disturb seafloor areas in water depths or 984 feet or greater.

Echo Offshore prepared a Wellsite Clearance Letter for the proposed locations indicated in this plan addressing site-specific seafloor and subsurface geologic conditions.

A summary statement addressing seafloor and subsurface geologic conditions for the proposed locations indicated in this plan is included below.

Green Canyon 895 Well Location A
No features or areas that could support high-density sensitive sessile benthic communities are located within 2,000ft of any mud or cuttings discharge location.

Green Canyon 895 Well Location B
No features or areas that could support high-density sensitive sessile benthic communities are located within 2,000ft of any mud or cuttings discharge location.

Green Canyon 895 Well Location C
No features or areas that could support high-density sensitive sessile benthic communities are located within 2,000ft of any mud or cuttings discharge location.

Green Canyon 895 Well Location D
No features or areas that could support high-density sensitive sessile benthic communities are located within 2,000ft of any mud or cuttings discharge location.

Maps depicting wellsite-specific seafloor features are included in the attachment to this appendix.

B) TOPOGRAPHIC FEATURES MAP
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as no rig, barge or anchors, etc. will be placed within 1,000 feet of the "No Activity Zone" of an identified topographic feature.

C) TOPOGRAPHIC FEATURES STATEMENT (SHUNTING)
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as BOE Exploration & Production is not proposing to drill more than two wells from the same surface location.

D) LIVE BOTTOM (PINNACLE TREND) MAP
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as the Live Bottom (Pinnacle Trend) lease stipulation is not attached to the subject lease(s).

E) LIVE BOTTOM (LOW RELIEF) MAP
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as the Live Bottom (Low Relief) lease stipulation is not attached to the subject lease(s).

F) POTENTIALLY SENSITIVE BIOLOGICAL FEATURES
In accordance with NTL 2009-G39. this information is not applicable to the activities proposed in this plan as the bottom-disturbing activities are not within 100 feet of potentially sensitive biological features.

G) THREATENED & ENDANGERED SPECIES, CRITICAL HABITAT, & MARINE MAMMAL INFORMATION
The subject area(s) and block(s) is not designated as a critical habitat for any federally listed threated or endangered species. BOE Exploration & Production does not anticipate that any threatened or endangered species will be adversely affected as a result of the activities proposed in this plan. However, in the unlikely event of an accident, adverse impacts to endangered marine mammal species are possible.

In monitoring the effect of the proposed activities on marine life, BOE Exploration & Production will adhere to the information and guidelines set forth by NTL 2015-G03 "Marine Trash and Debris Awareness and Elimination" and NTL BOEM 2016-G01 "Vessel Strike Avoidance and Injured/Dead Protected Species Reporting" and will follow guidance resulting from the Programmatic Biological Opinion on Federally Regulated Oil and Gas Program Activities in the Gulf of Mexico.

A list of endangered and threatened species and critical habitats found in the Gulf of Mexico is included in the attachments to this appendix.

For reference, Appendices to the Programmatic Biological Opinion on the Gulf of Mexico Oil and Gas Program is included in the attachments to this appendix.

H) ARCHAEOLOGICAL REPORT
Echo Offshore prepared a Wellsite Clearance Letter for the proposed locations indicated in this plan addressing archaeological resources. A summary of the archaeological assessment for the proposed well locations indicated in this plan is included below.

Green Canyon 895 Well Location A
No features of archaeological resources were identified within 2,000ft of the proposed well location.

Green Canyon 895 Well Location B
No features of archaeological resources were identified within 2,000ft of the proposed well location.

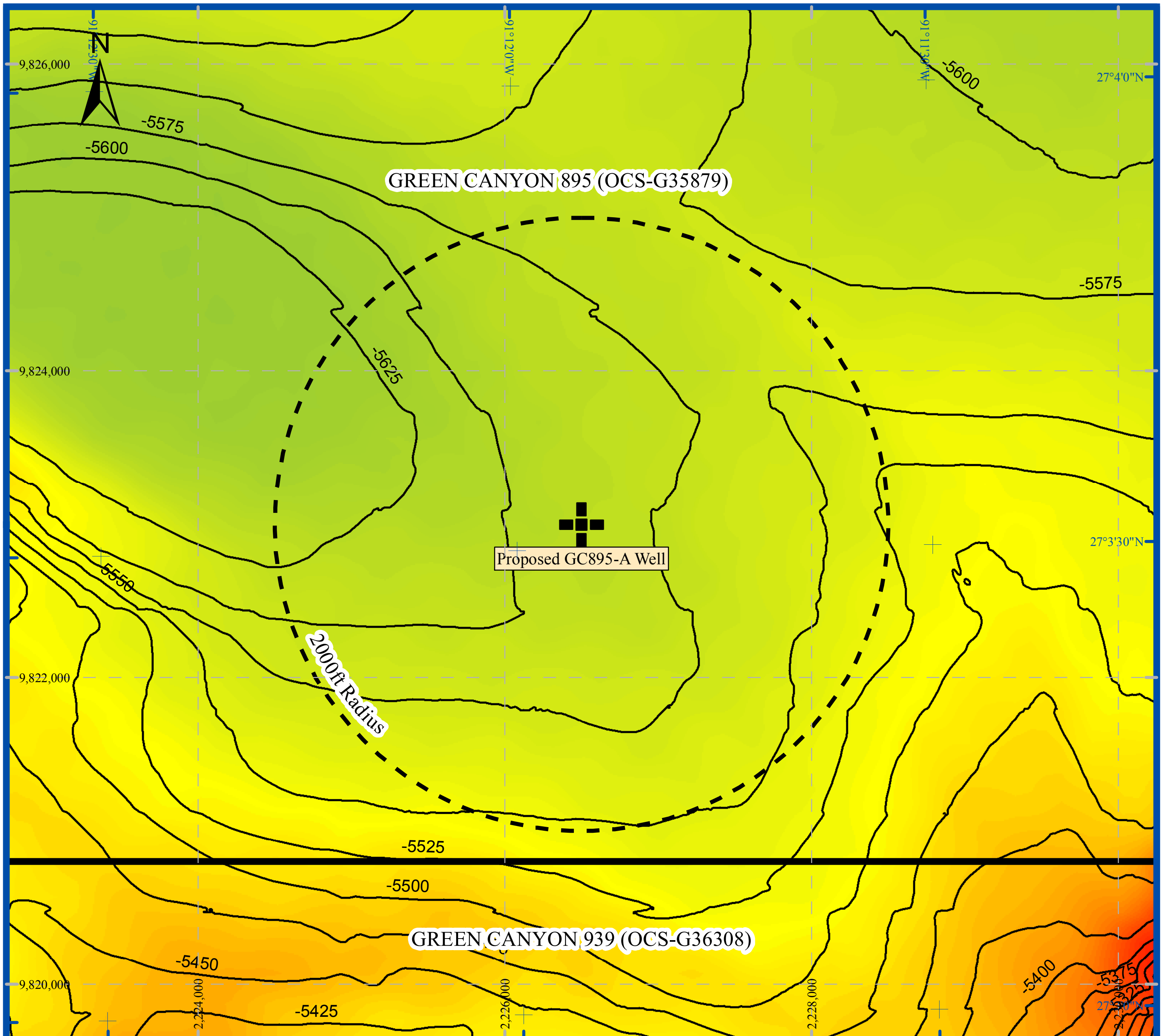
Green Canyon 895 Well Location C
No features of archaeological resources were identified within 2,000ft of the proposed well location.

Green Canyon 895 Well Location D
No features of archaeological resources were identified within 2,000ft of the proposed well location.

I) AIR & WATER QUALITY INFORMATION
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as the State of Florida is not an affected State.

J) SOCIOECONOMIC INFORMATION
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as the State of Florida is not an affected State.

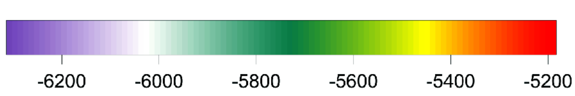
WELLSITE-SPECIFIC SEAFLOOR FEATURES MAPS



Seabed Depth Extract

Proposed GC895-A Well Location
(2,226,500ft E / 9,823,000ft N)

-5575 Depth in feet below sea surface to seabed contoured at 25ft intervals



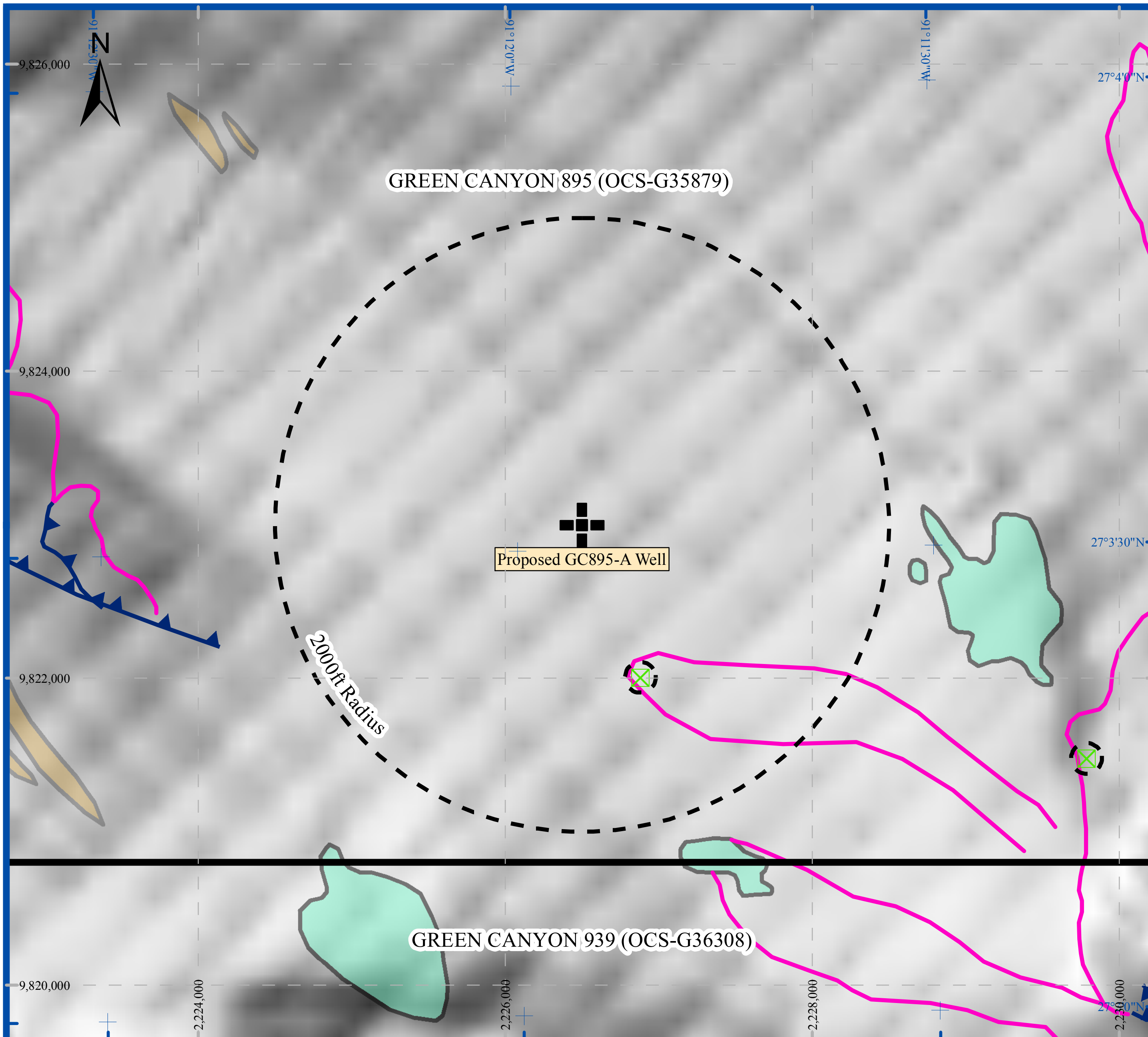
Seabed Depth (Feet)

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 1
(GC895-A)



Seabed Morphology Extract

Proposed GC895-A Well Location
(2,226,500ft E / 9,823,000ft N)

Seabed failure scarps

Area of mass transport deposits

Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.

Seabed furrow area

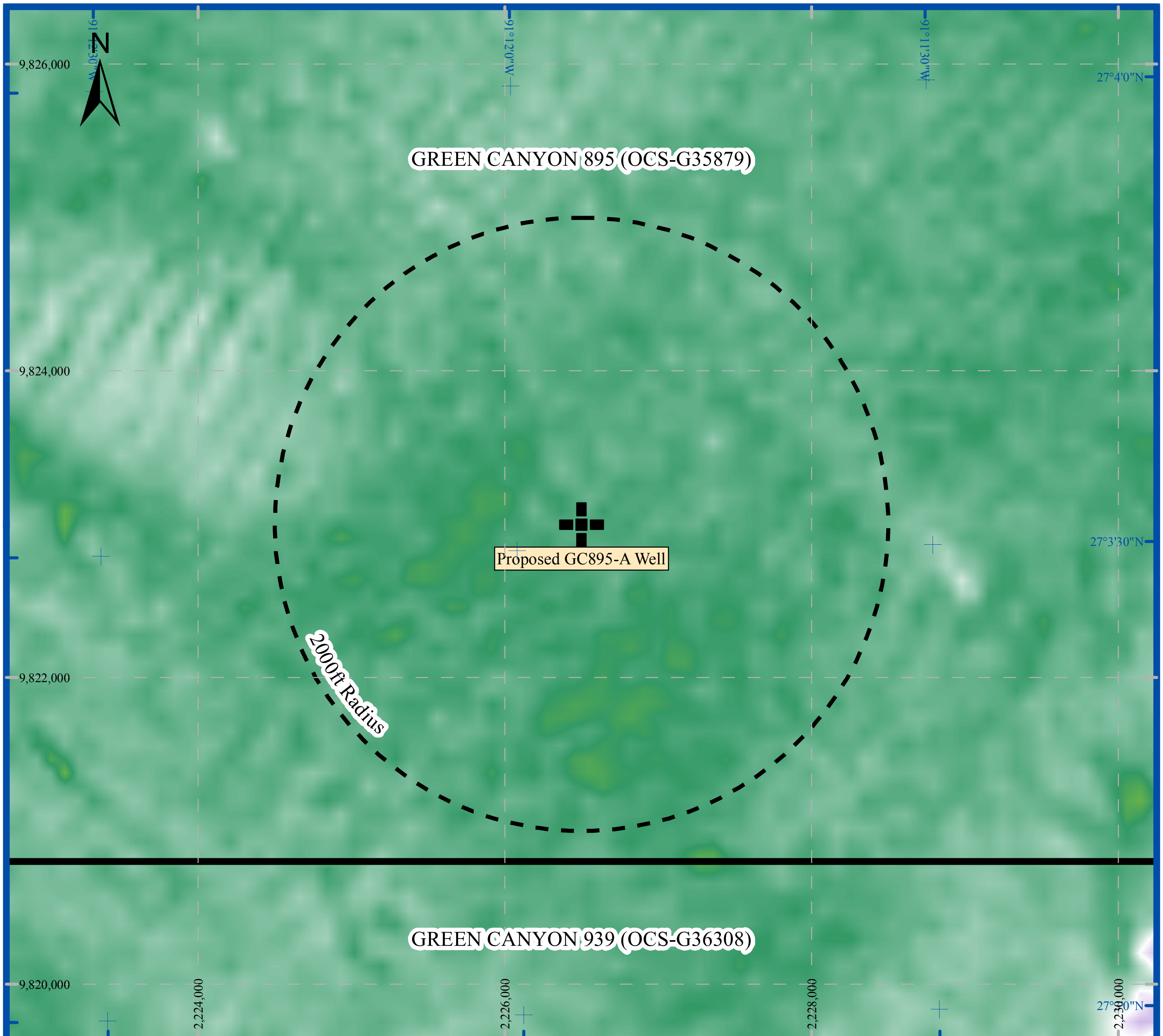
Side-scan sonar contact with 100ft exclusion zone

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 2
(GC895-A)



Seabed Amplitude Extract

Proposed GC895-A Well Location
(2,226,500ft E / 9,823,000ft N)

9000 12000 15000 18000 21000 24000 27000 30000 33000

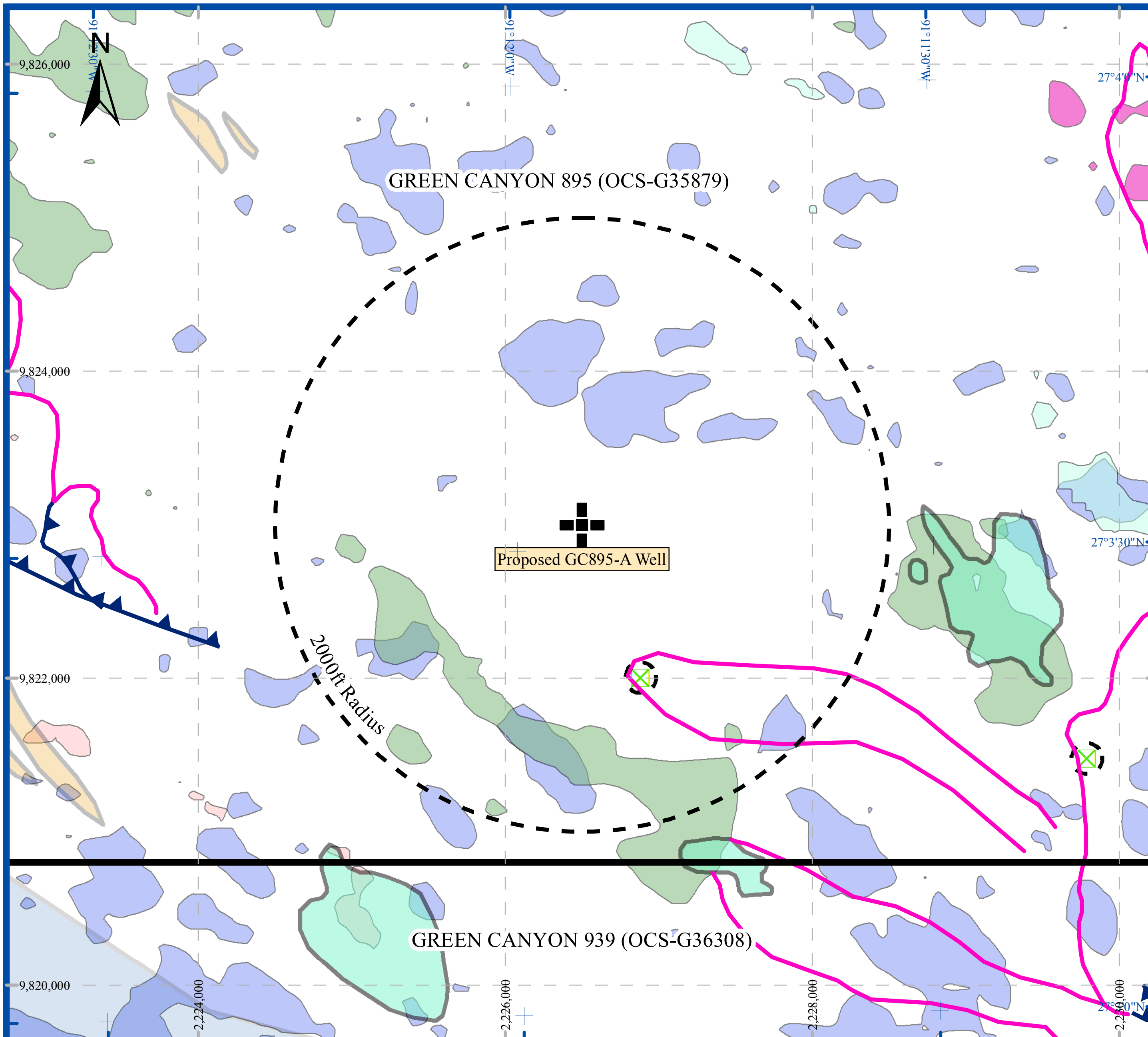
Relative Seabed Amplitude

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 3
(GC895-A)



Geohazard Summary Extract

Proposed GC895-A Well Location (2,226,500ft E / 9,823,000ft N)

Seabed failure scarps

Area of mass transport deposits

Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.

Seabed furrow area

Side-scan sonar contact with 100ft exclusion zone

Slight and Moderate Risk of Gas within Unit A

Slight, Moderate, and High Risk of Gas within Unit B

Slight, Moderate, and High Risk of Gas within Unit C

Moderate and High Risk of Gas within Unit D

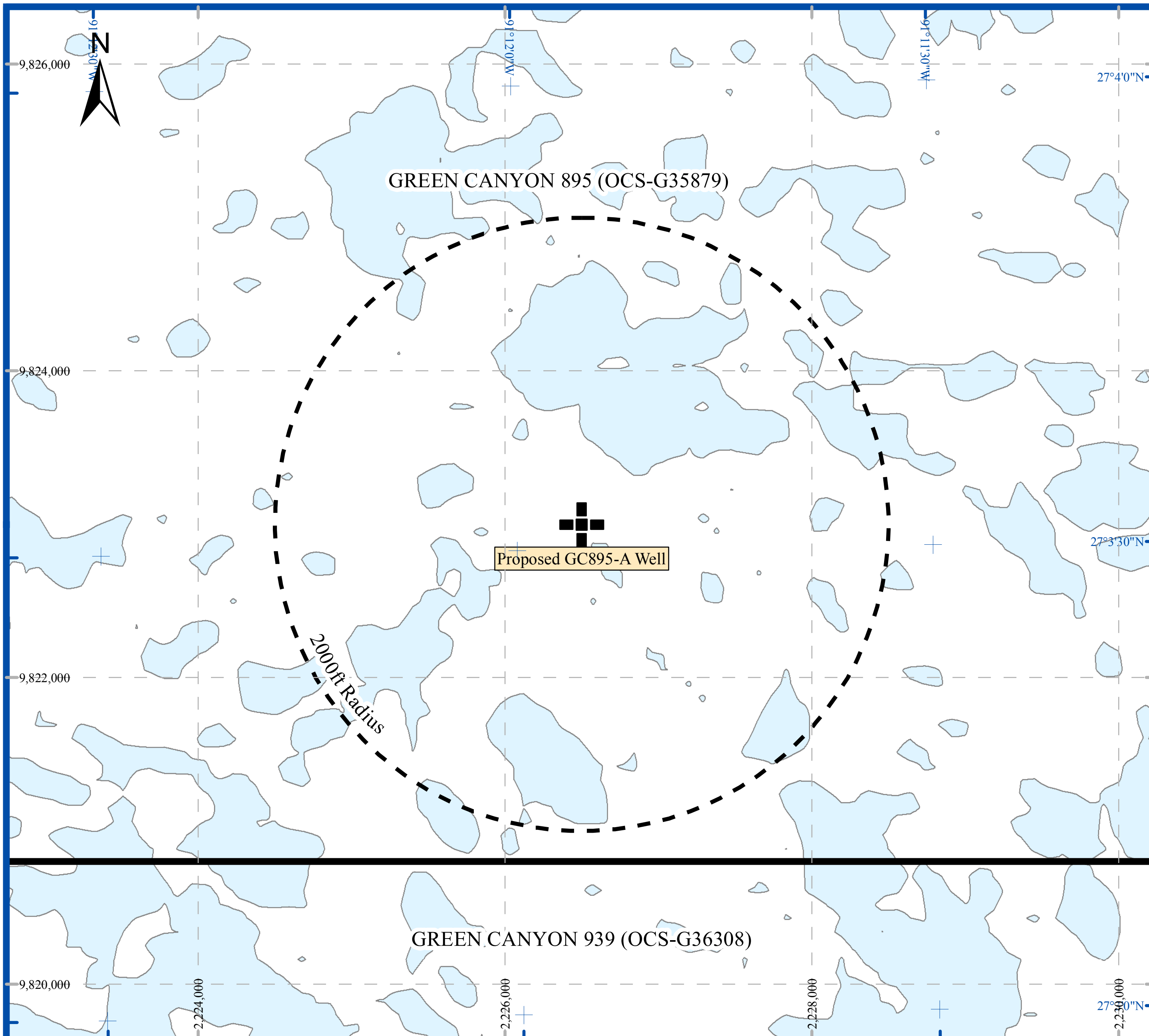
Slight Risk of Gas within Unit F

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 4
(GC895-A)



Sand-Prone Lithology Extract (Unit D)

Proposed GC895-A Well Location
(2,226,500ft E / 9,823,000ft N)

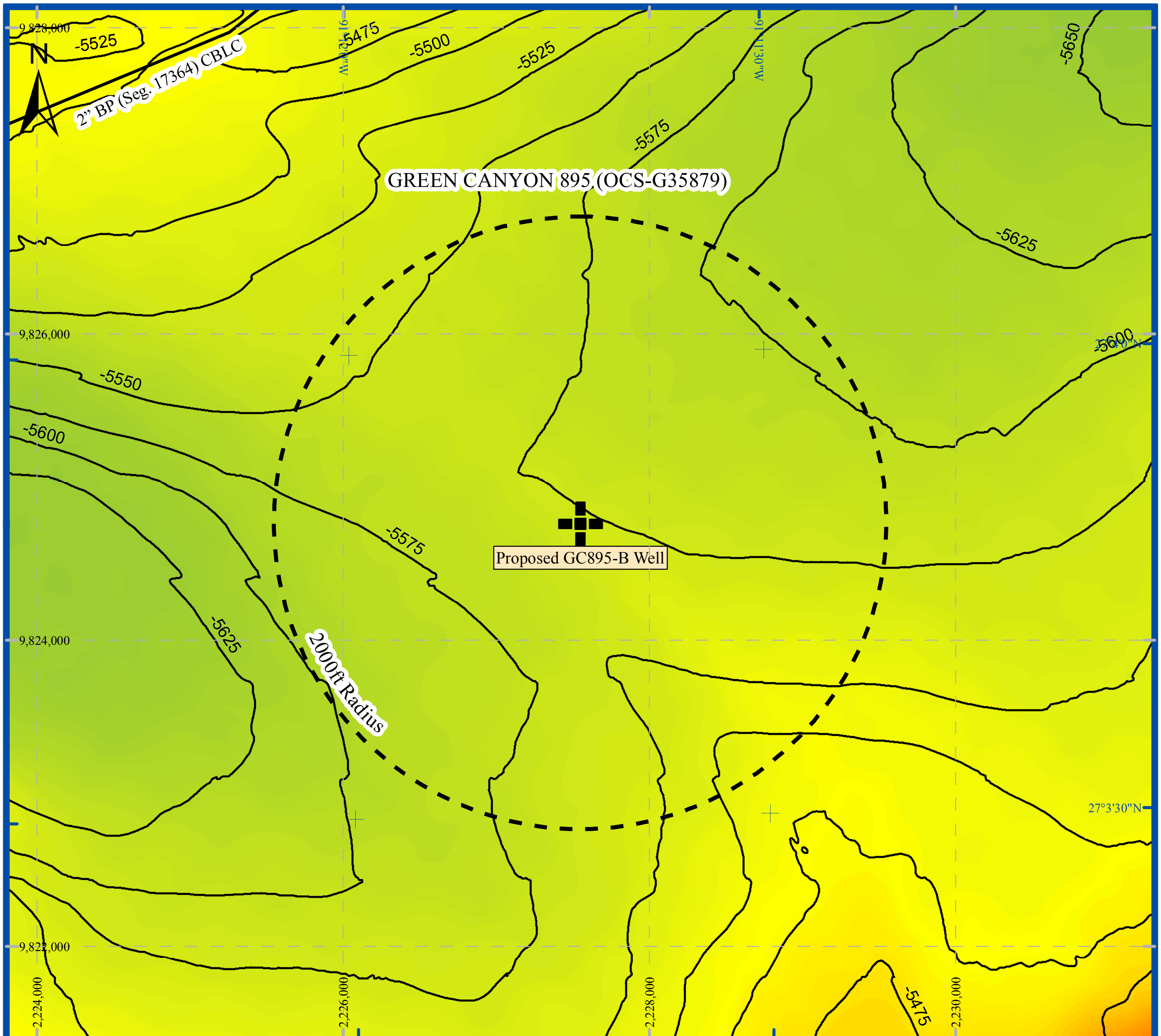
Predicted sands within Unit D

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 5
(GC895-A)



Seabed Depth Extract

Proposed GC895-B Well Location (2,227,550ft E / 9,824,760ft N)

Existing infastructure

-5575 Depth in feet below sea surface to seabed contoured at 25ft intervals

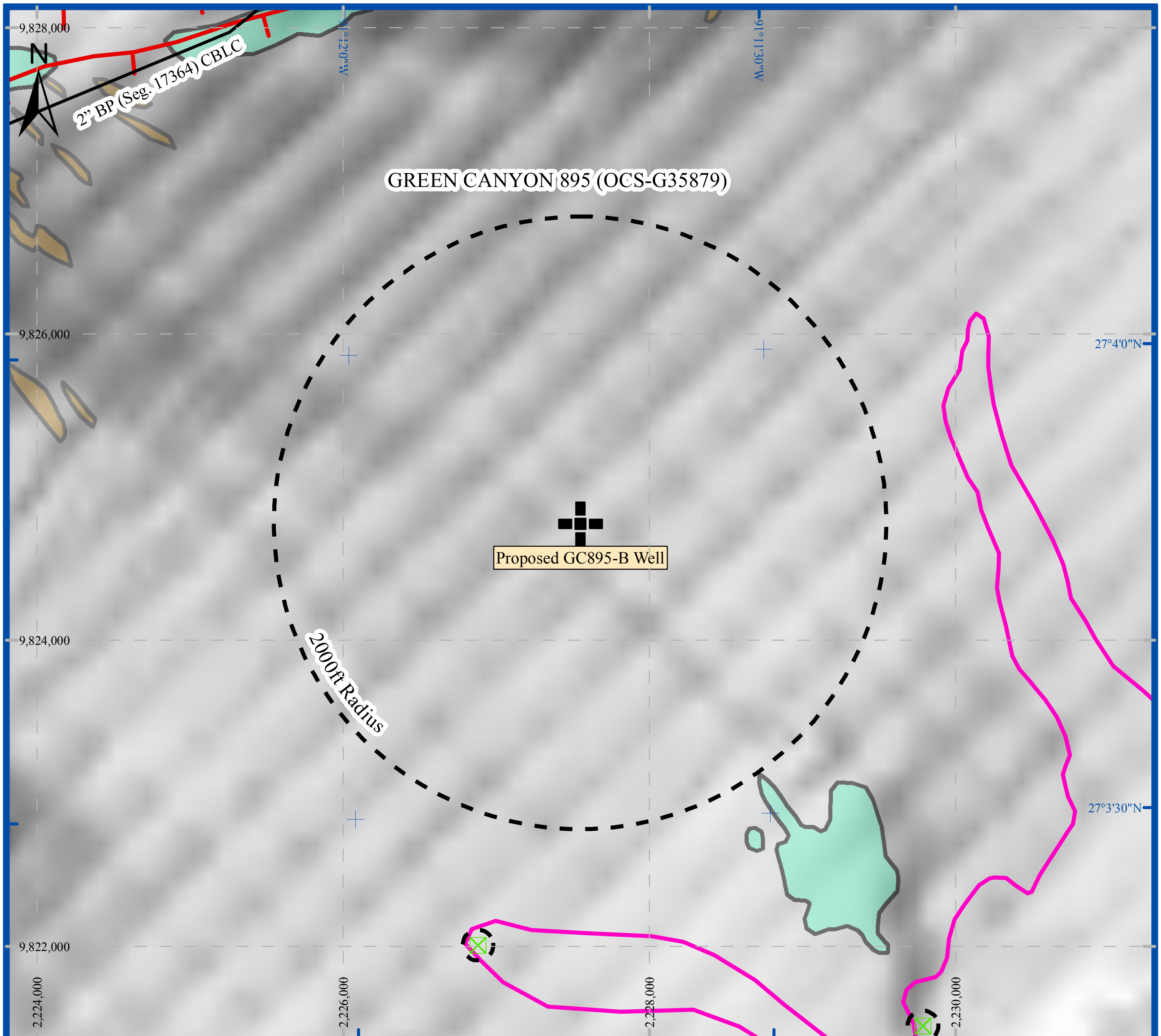
Seabed Depth (Feet)

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 1
(GC895-B)



Seabed Morphology Extract

Proposed GC895-B Well Location (2,227,550ft E / 9,824,760ft N)

Existing infastructure

Area of mass transport deposits

Seabed fault identified in AUV multibeam bathymetry data. Tick shows downthrown side

Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.

Seabed furrow area

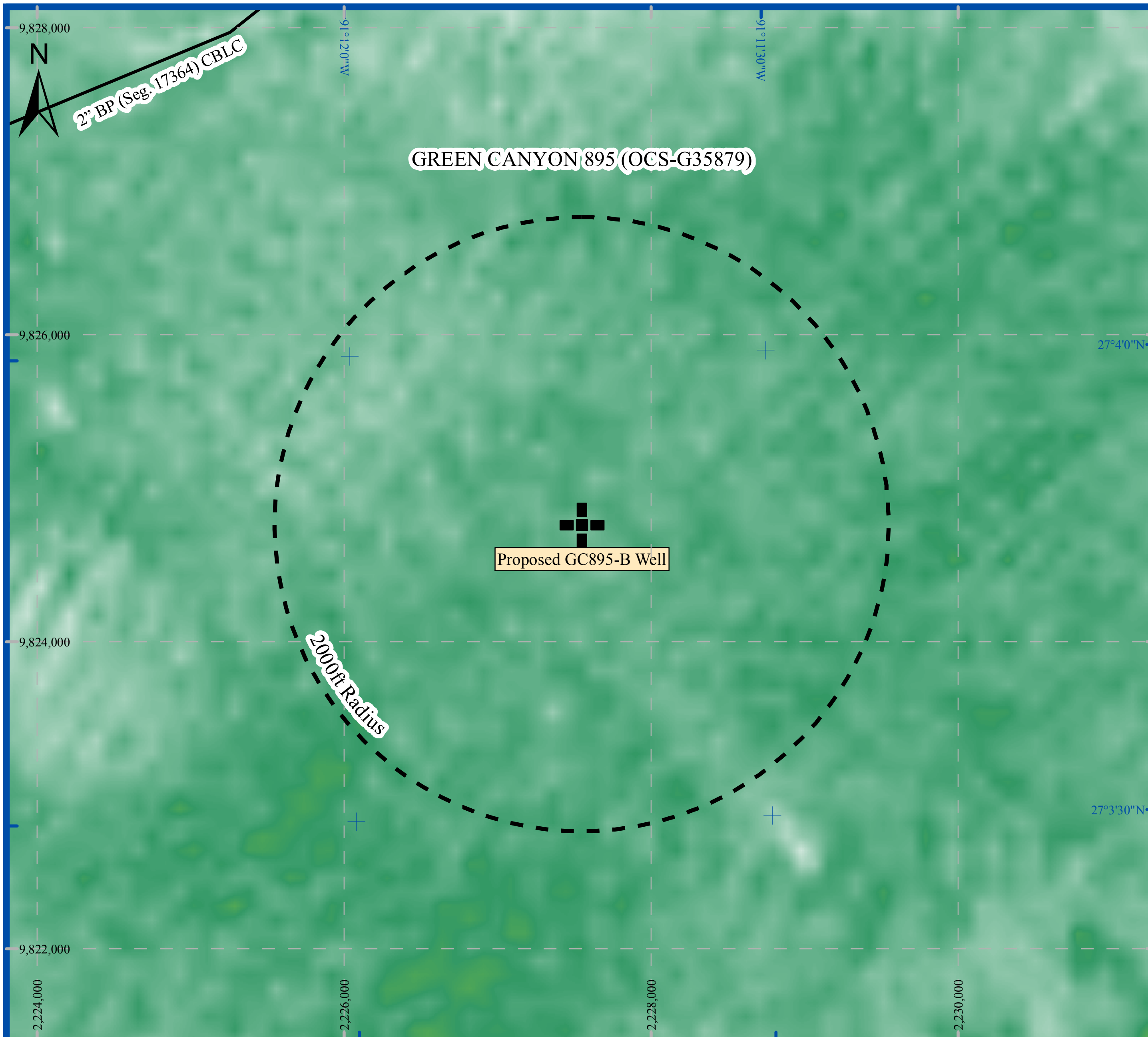
Side-scan sonar contact with 100ft exclusion zone

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 2 (GC895-B)



Seabed Amplitude Extract

Proposed GC895-B Well Location
(2,227,550ft E / 9,824,760ft N)

Existing infastructure

9000 12000 15000 18000 21000 24000 27000 30000 33000

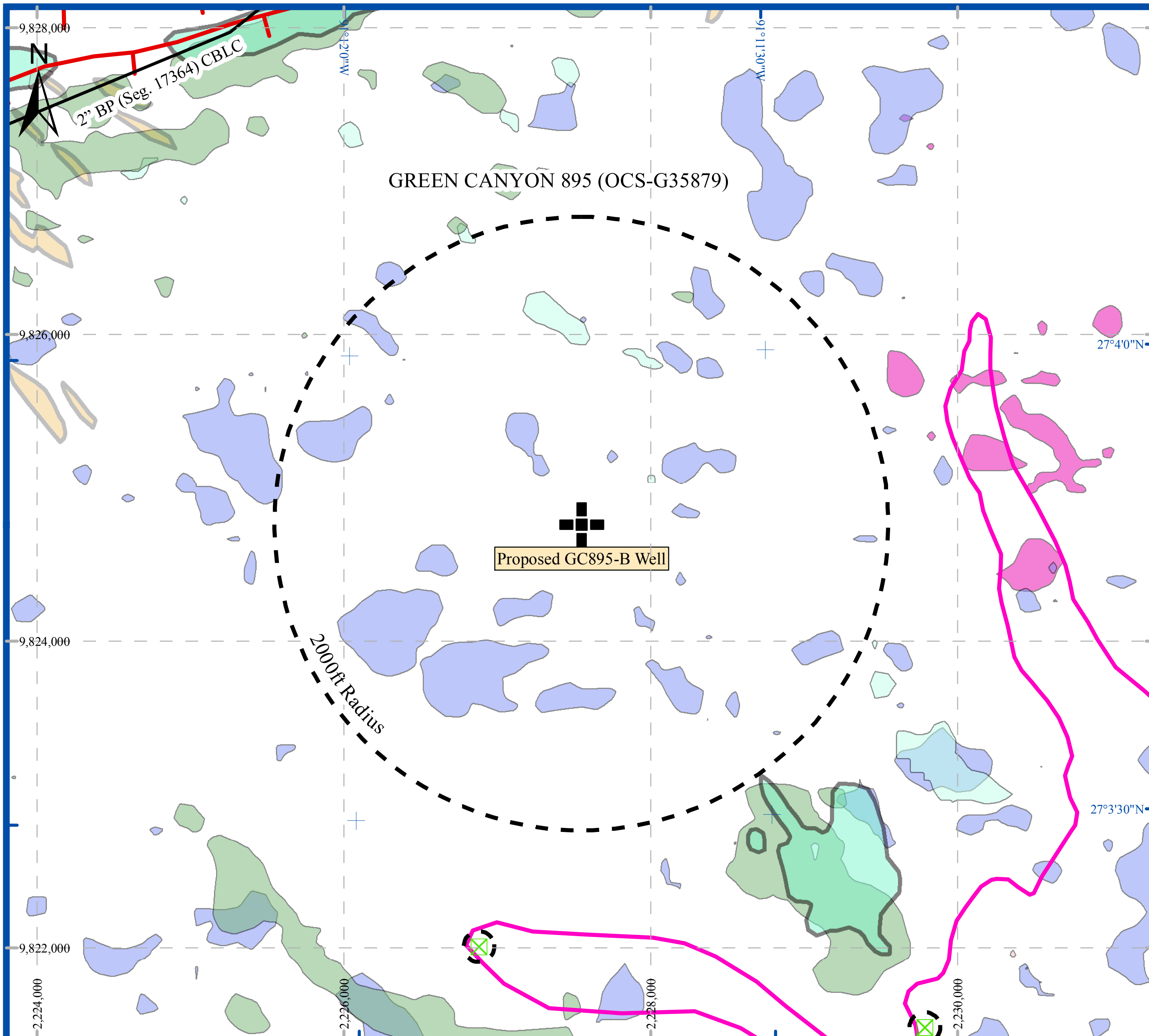
Relative Seabed Amplitude

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 3
(GC895-B)



Geohazard Summary Extract

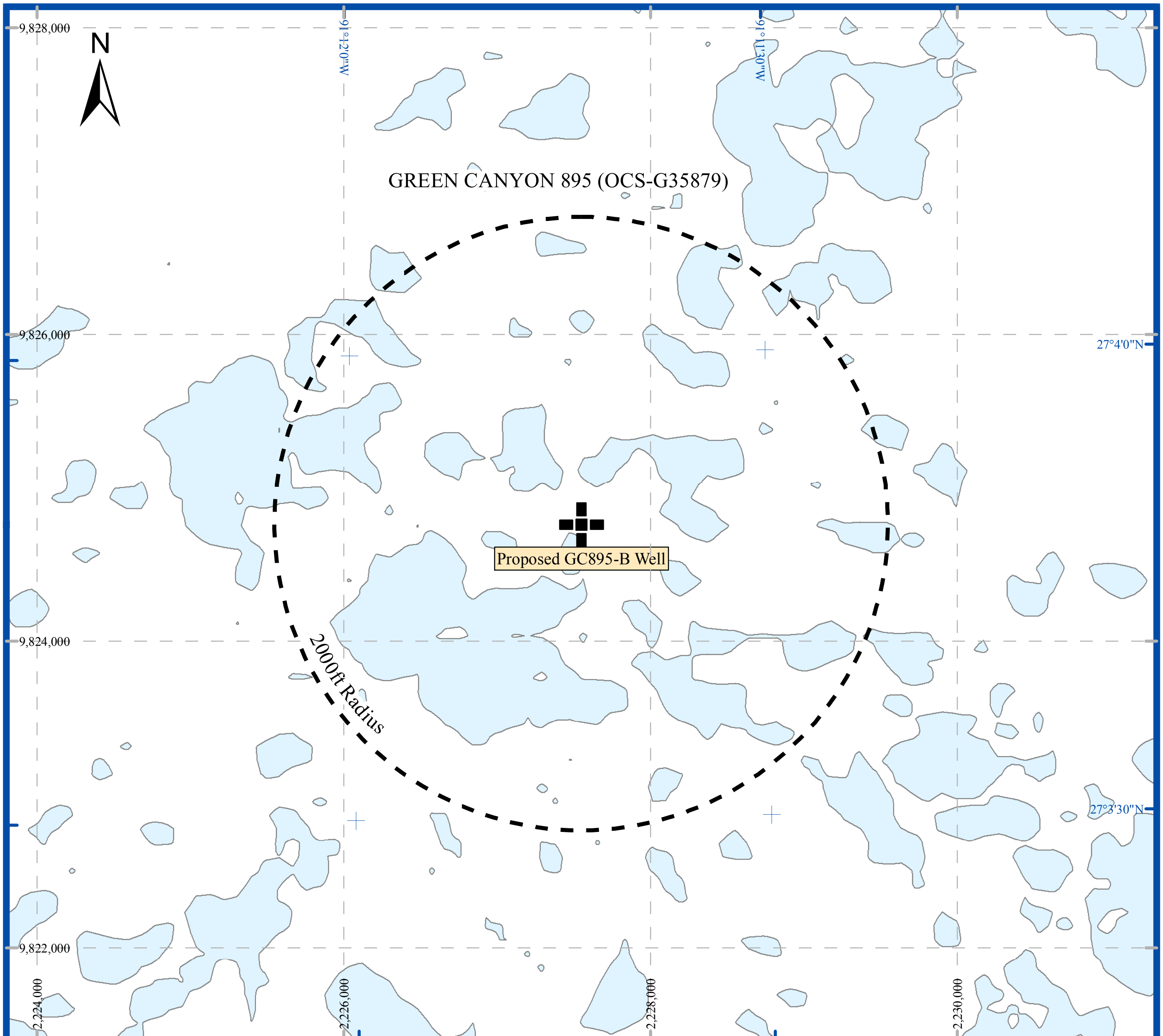
- Proposed GC895-B Well Location (2,227,550ft E / 9,824,760ft N)
- Existing infastructure
- Area of mass transport deposits
- Seabed fault identified in AUV multibeam bathymetry data. Tick shows downthrown side
- Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.
- Seabed furrow area
- Side-scan sonar contact with 100ft exclusion zone
- Slight and Moderate Risk of Gas within Unit A
- Slight, Moderate, and High Risk of Gas within Unit B
- Slight, Moderate, and High Risk of Gas within Unit C
- Slight, Moderate, and High Risk of Gas within Unit D
- Slight Risk of Gas within Unit F

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 4
(GC895-B)



Sand-Prone Lithology Extract (Unit D)

Proposed GC895-B Well Location
(2,227,550ft E / 9,824,760ft N)

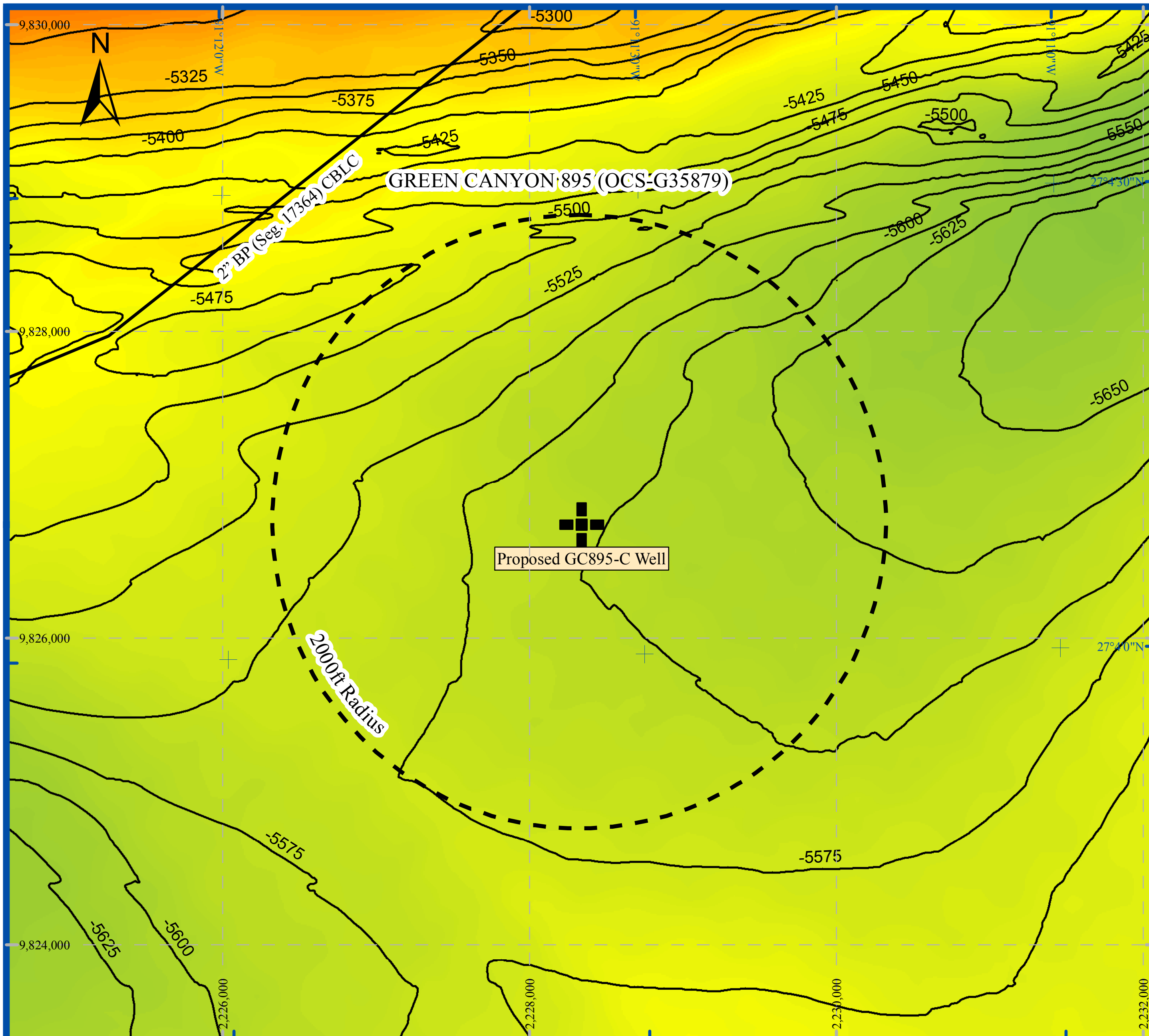
Predicted sands within Unit D

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 5
(GC895-B)



Seabed Depth Extract

Proposed GC895-C Well Location
(2,228,339ft E / 9,826,742ft N)

Existing infastructure

-5600 Depth in feet below sea surface to seabed contoured at 25ft intervals

-6200 -6000 -5800 -5600 -5400 -5200

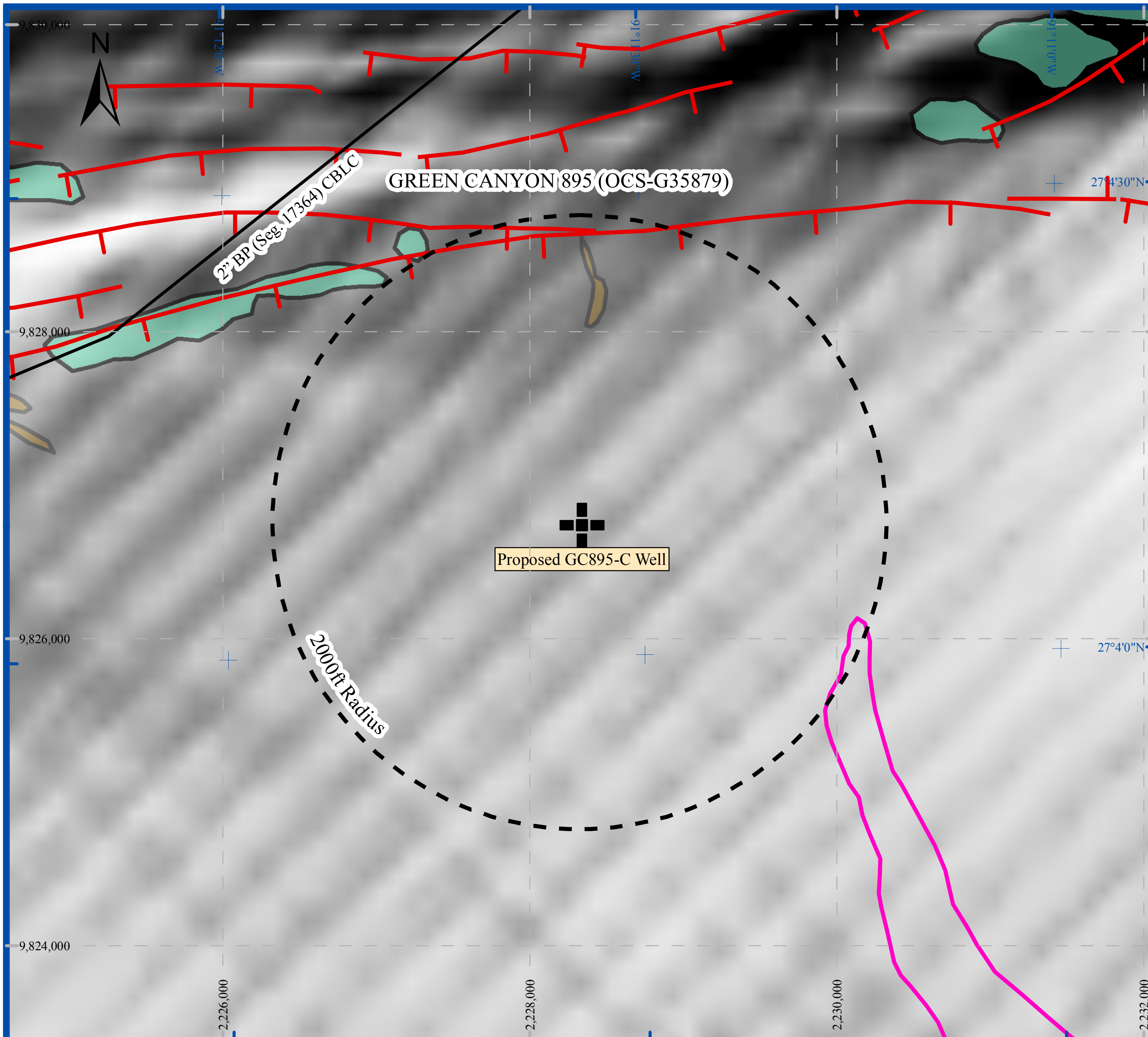
Seabed Depth (Feet)

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 1
(GC895-C)



Seabed Morphology Extract

Proposed GC895-C Well Location
(2,228,339ft E / 9,826,742ft N)

Existing infastructure

Area of mass transport deposits

Seabed fault identified in AUV multibeam bathymetry data. Tick shows downthrown side

Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.

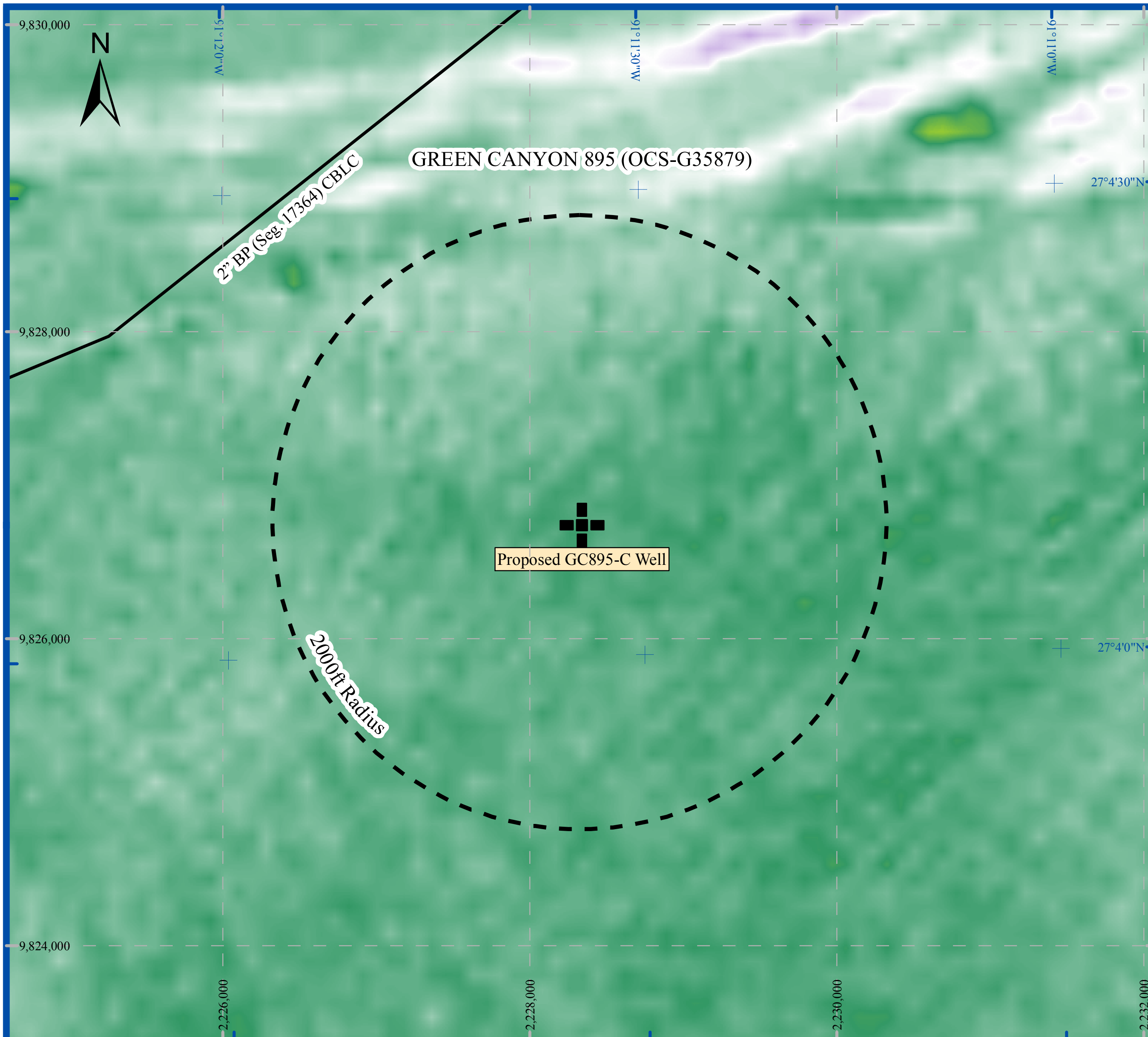
Seabed furrow area

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 2
(GC895-C)



Seabed Amplitude Extract

Proposed GC895-C Well Location
(2,228,339ft E / 9,826,742ft N)

Existing infastructure

9000 12000 15000 18000 21000 24000 27000 30000 33000

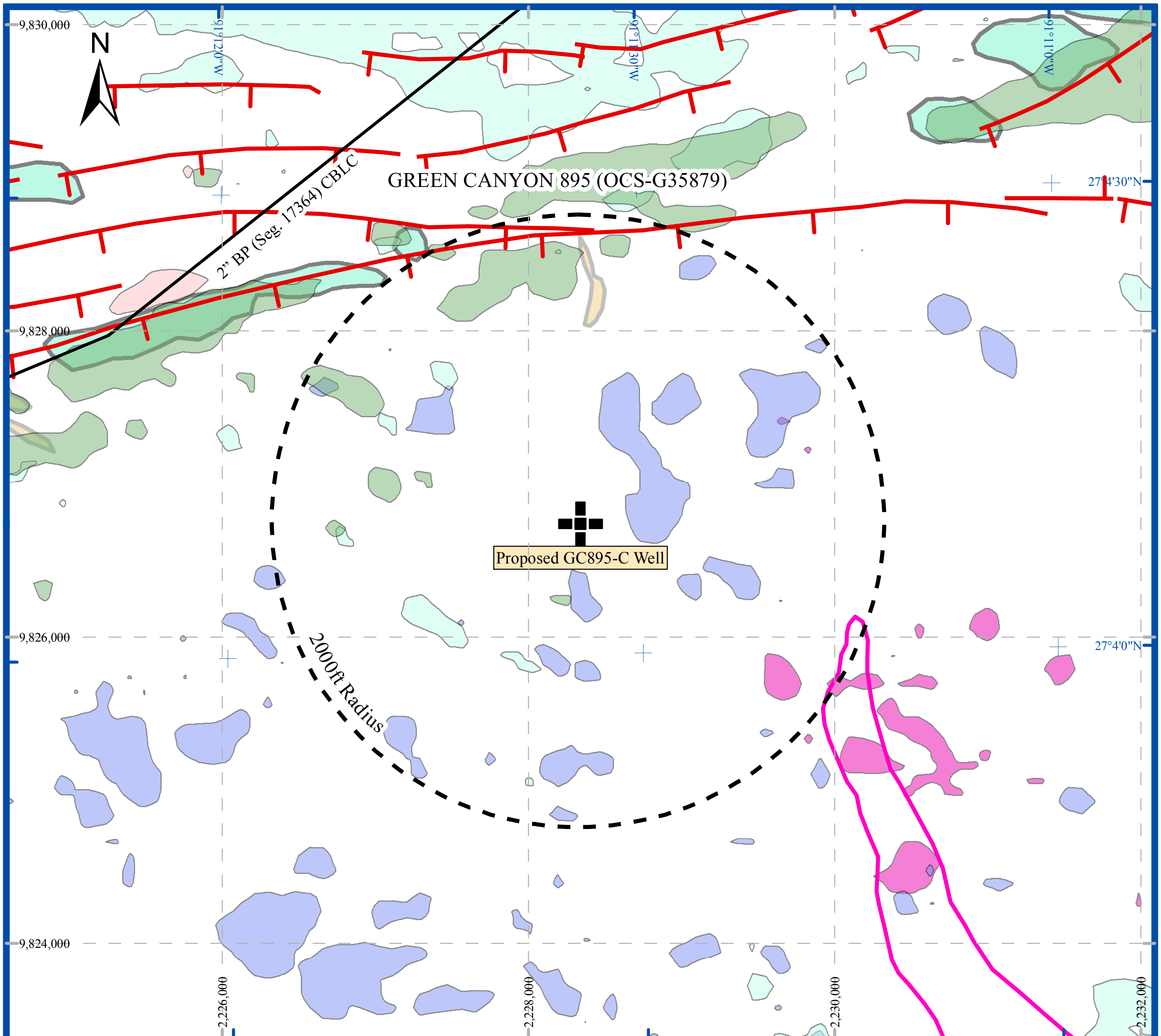
Relative Seabed Amplitude

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 3
(GC895-C)



Geohazard Summary Extract

Proposed GC895-C Well Location (2,228,339ft E / 9,826,742ft N)

Existing infastructure

Area of mass transport deposits

Seabed fault identified in AUV multibeam bathymetry data. Tick shows downthrown side

Seabed furrow area

Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.

Slight and High Risk of Gas within Unit A

Slight, Moderate, and High Risk of Gas within Unit B

Slight, Moderate, and High Risk of Gas within Unit C

Slight, Moderate, and High Risk of Gas within Unit D

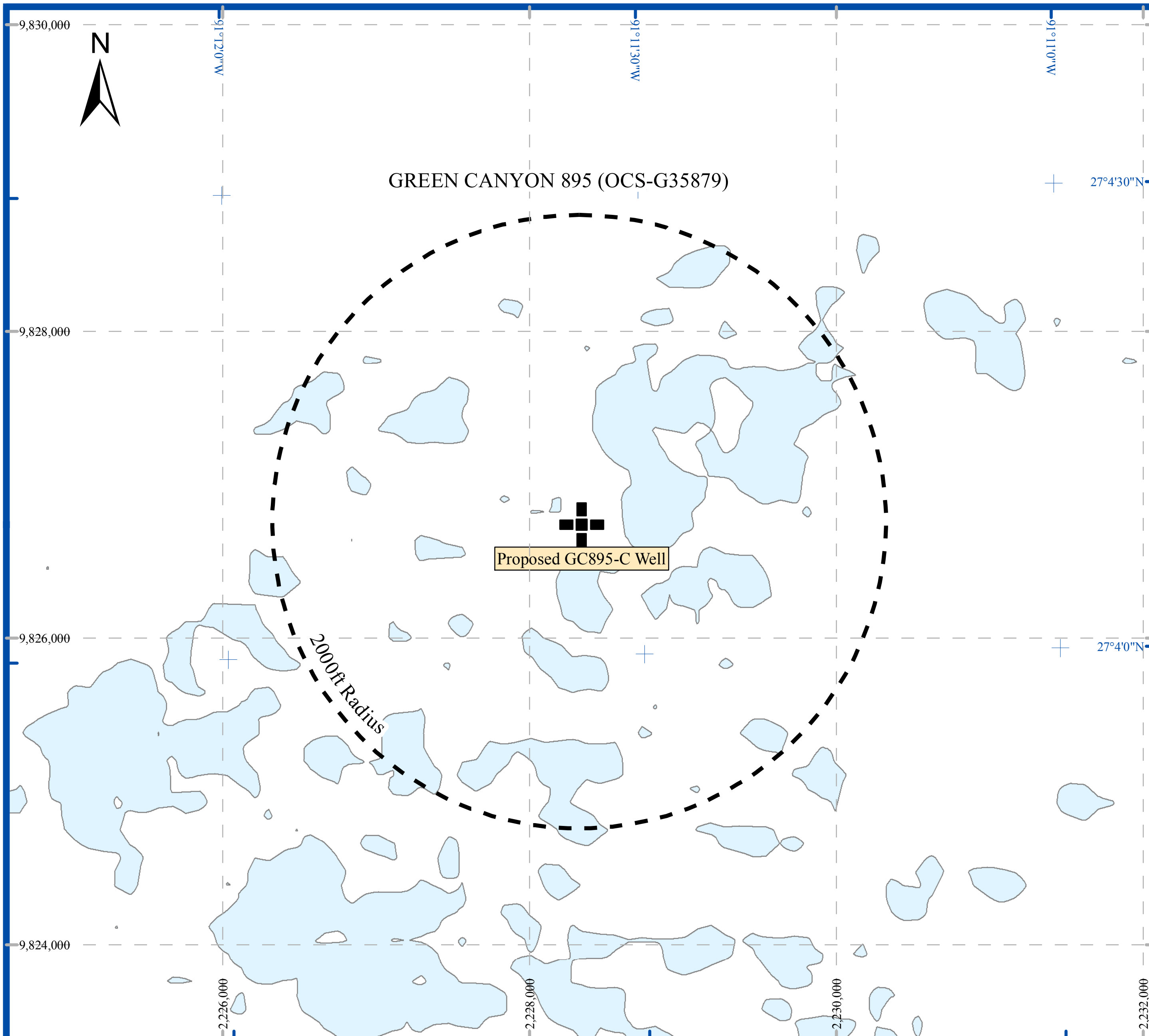
Slight Risk of Gas within Unit F

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 4
(GC895-C)



Sand-Prone Lithology Extract (Unit D)

Proposed GC895-C Well Location
(2,228,339ft E / 9,826,742ft N)

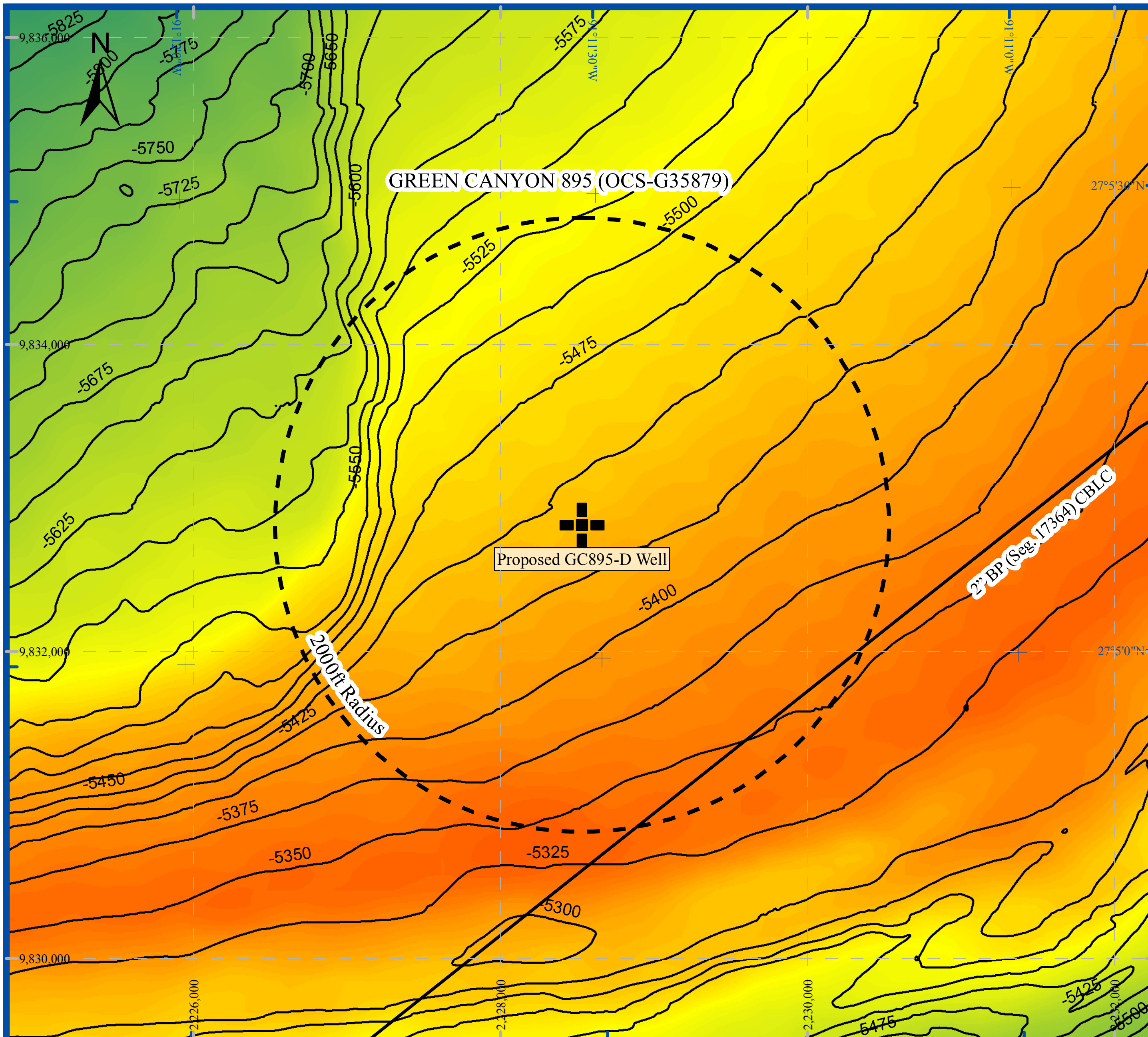
Predicted sands within Unit D

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 5
(GC895-C)

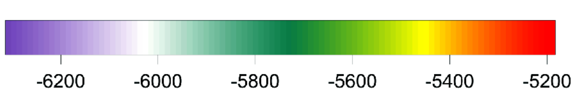


Seabed Depth Extract

Proposed GC895-D Well Location
(2,228,530ft E / 9,832,825ft N)

Existing infastructure

-5400 Depth in feet below sea surface to seabed contoured at 25ft intervals



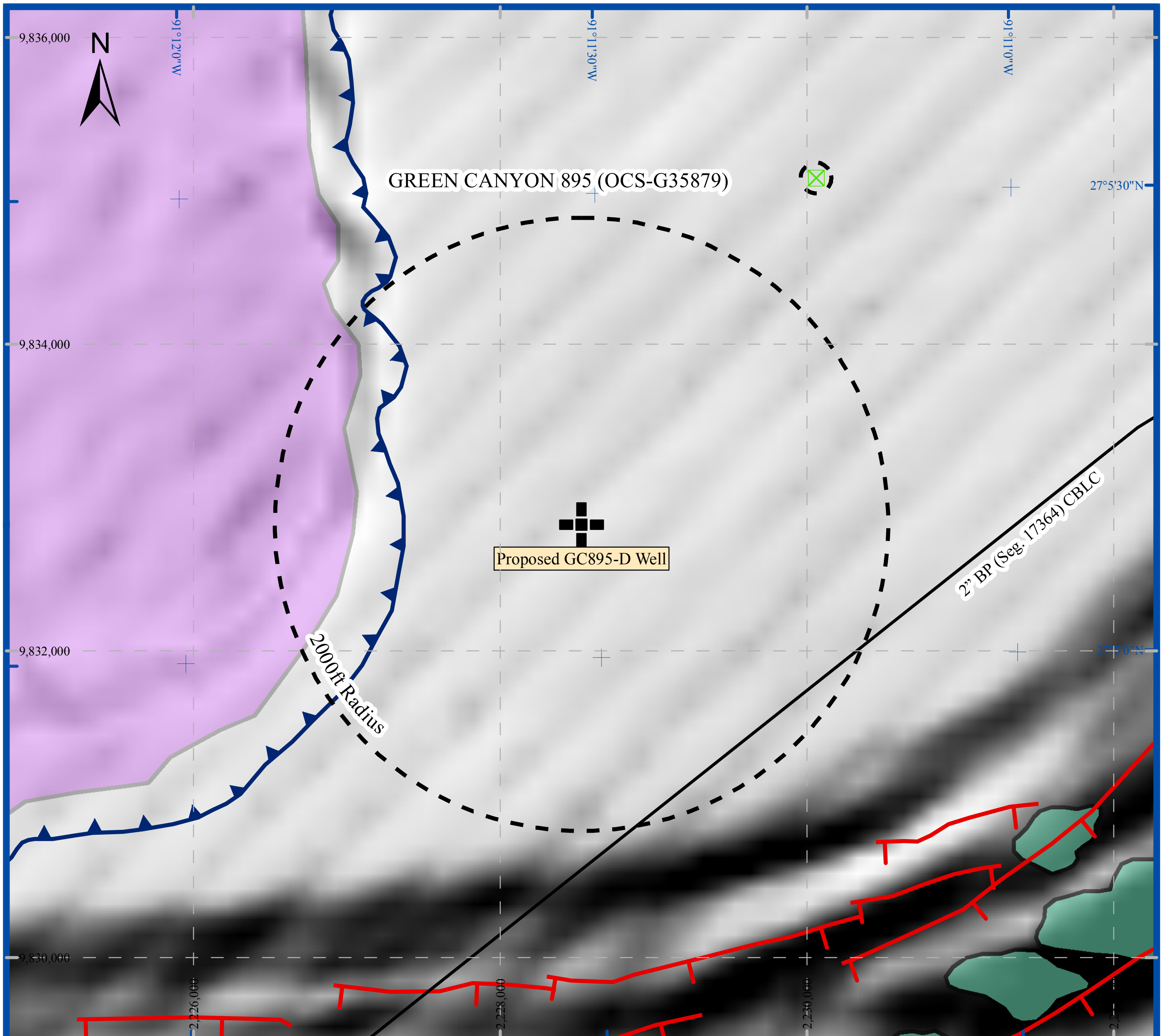
Seabed Depth (Feet)

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 1
(GC895-D)



Seabed Morphology Extract

Proposed GC895-D Well Location (2,228,530ft E / 9,832,825ft N)

Existing infastructure

Seabed failure scarps. Tick shows failed side

Seabed fault identified in AUV multibeam bathymetry data. Tick shows downthrown side

Area of mass transport deposits at or near the seabed

Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.

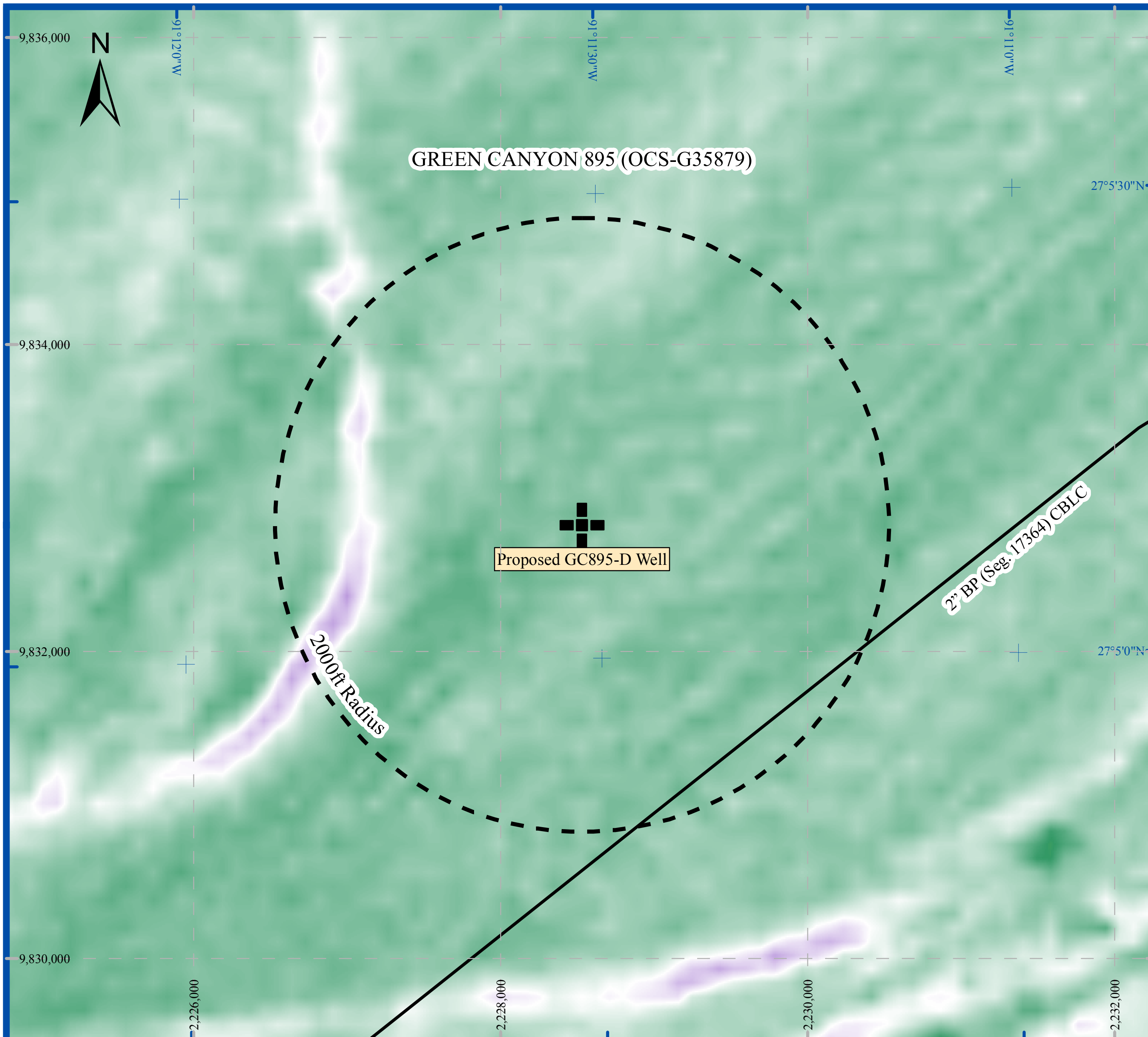
Side-scan sonar contact with 100ft exclusion zone

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 2
(GC895-D)



Seabed Amplitude Extract

Proposed GC895-D Well Location
(2,228,530ft E / 9,832,825ft N)

Existing infastructure

9000 12000 15000 18000 21000 24000 27000 30000 33000

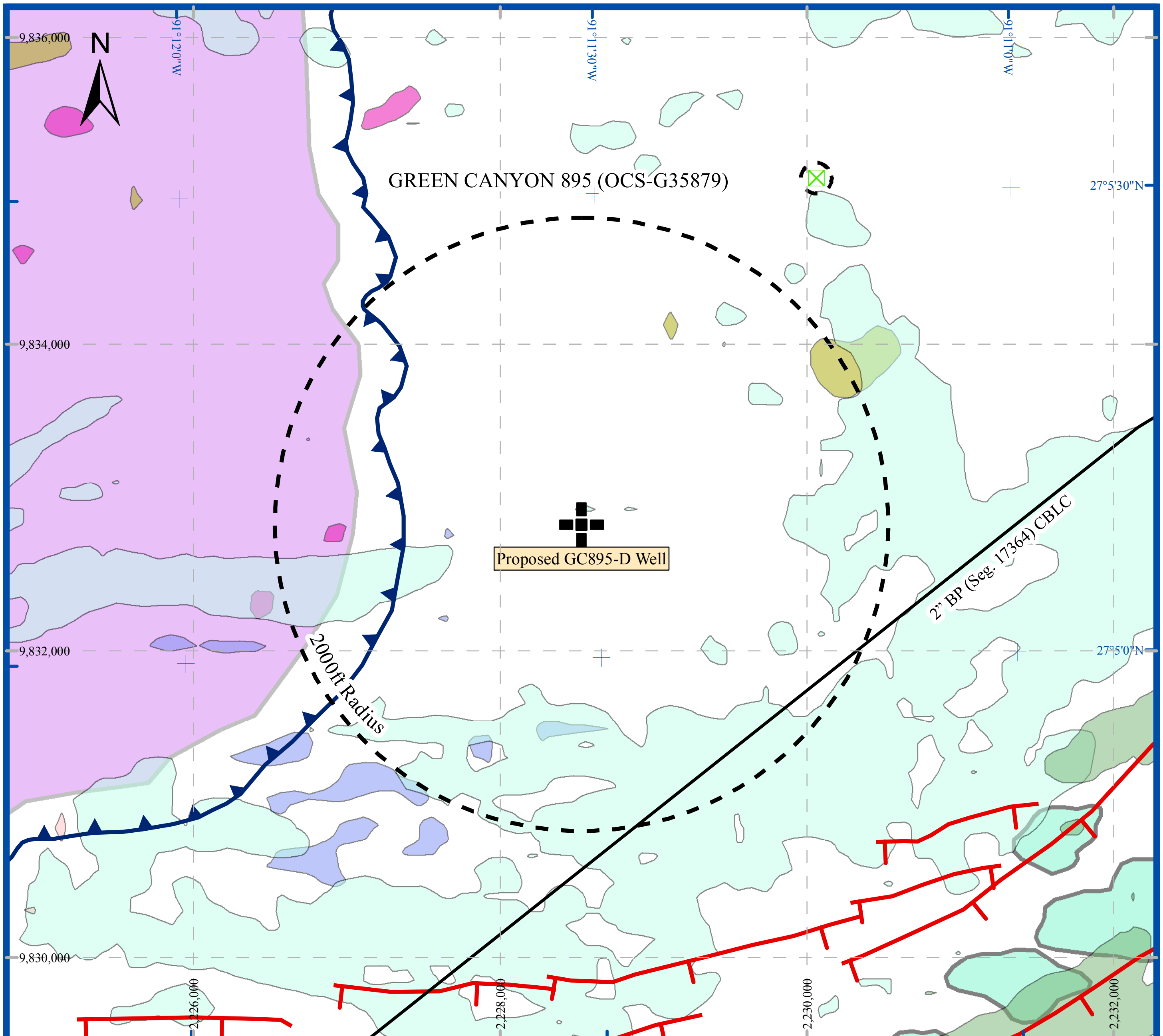
Relative Seabed Amplitude

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 3
(GC895-D)



Geohazard Summary Extract

Proposed GC895-D Well Location (2,228,530ft E / 9,832,825ft N)

Existing infastructure

Seabed failure scarps. Tick shows failed side

Seabed fault identified in AUV multibeam bathymetry data. Tick shows downthrown side

Area of mass transport deposits at or near the seabed

Seabed mounds or areas of disturbed seabed related to shallow subsurface hydrocarbons and/or possible fluid expulsion sites. Sensitive sessile benthic communities are possible.

Side-scan sonar contact with 100ft exclusion zone

Slight and Moderate Risk of Gas within Unit A

Slight, Moderate, and High Risk of Gas within Unit B

Slight, Moderate, and High Risk of Gas within Unit C

Slight, Moderate, and High Risk of Gas within Unit D

Slight Risk of Gas within Unit F

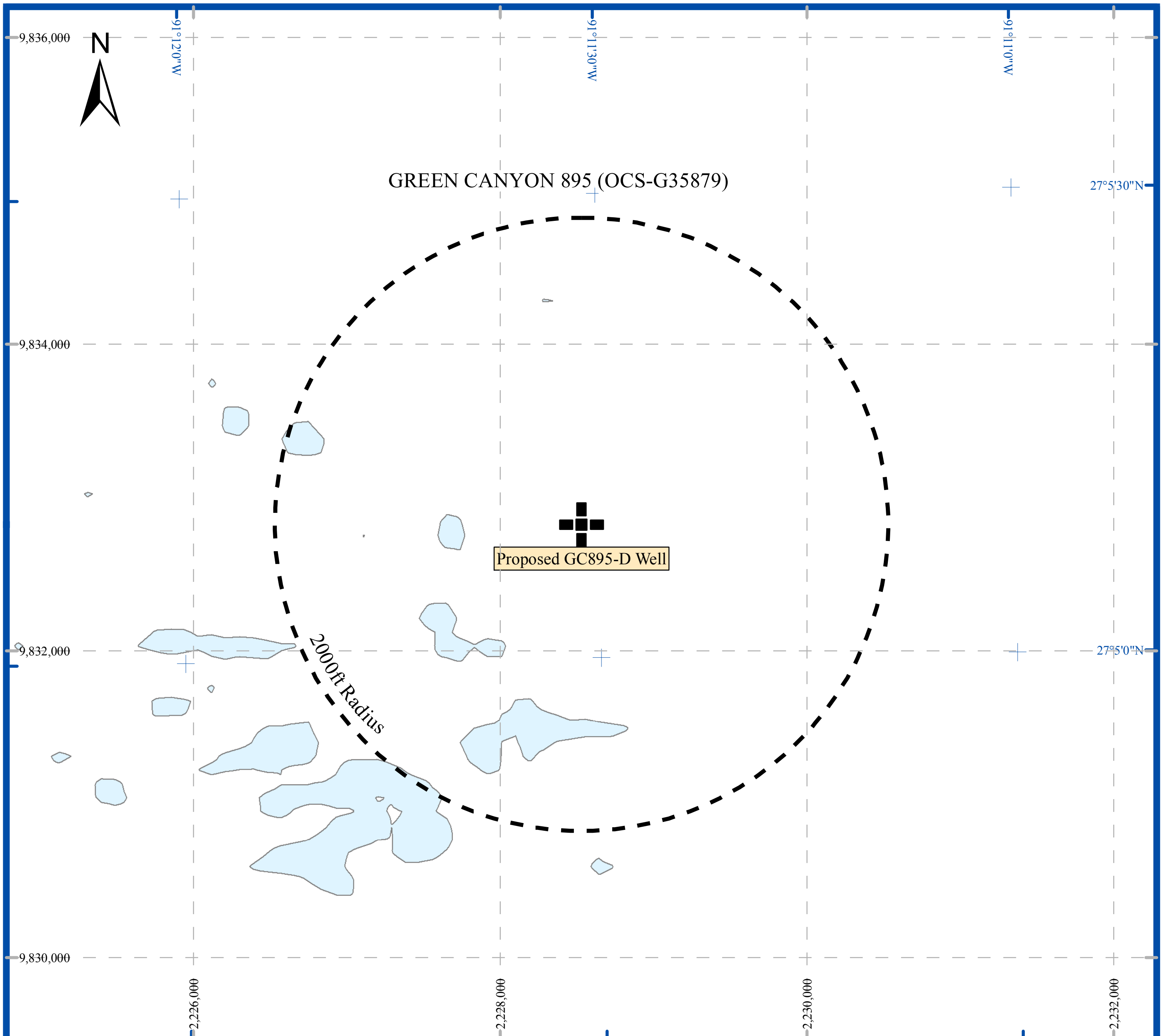
Slight and Moderate Risk of Gas within Unit G

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 4
(GC895-D)



Sand-Prone Lithology Extract (Unit D)

Proposed GC895-D Well Location
(2,228,530ft E / 9,832,825ft N)

Predicted sands within Unit D

Chart Scale 1" = 1,000'

0 950 1,900 Feet

0 150 300 600 Meters

Figure 5
(GC895-D)

ENDANGERED AND THREATENED SPECIES IN THE GULF OF MEXICO

Gulf of Mexico

Threatened and Endangered Species and Critical Habitats Under NOAA Fisheries Jurisdiction

Species	Listing Status	Recovery Plan	Critical Habitat
Green sea turtle	Threatened - North and South Atlantic Distinct Population Segment (81 FR 20057; April 6, 2016)	October 1991	63 FR 46693; September 2, 1998
Kemp's ridley sea turtle	Endangered (35 FR 18319; December 2, 1970)	September 2011	None
Leatherback sea turtle	Endangered (35 FR 8491; June 2, 1970)	April 1992	44 FR 17710; March 23, 1979
Loggerhead sea turtle	Threatened - Northwest Atlantic Ocean Distinct Population Segment (76 FR 58868; September 22, 2011)	December 2008	79 FR 39856; July 10, 2014
Hawksbill sea turtle	Endangered (35 FR 8491; June 2, 1970)	December 1993	63 FR 46693; September 2, 1998
Smalltooth sawfish	U.S. Distinct Population Segment Endangered (68 FR 15674; April 1, 2003)	January 2009	72 FR 45353; October 2, 2009
Gulf sturgeon	Threatened (56 FR 49653; September 30, 1991)	September 1995	68 FR 13370; March 19, 2003
Nassau grouper	Threatened (81 FR 42268; June 29, 2016)	2018 Recovery Outline	None

Species	Listing Status	Recovery Plan	Critical Habitat
Oceanic whitetip shark	Threatened (83 FR 4153; January 30, 2018)	2018 Recovery Outline	None
Giant manta ray	Threatened (83 FR 2916; January 22, 2018)	December 2019	None
Elkhorn coral	Threatened (71 FR 26852; May 9, 2006)	March 2015	73 FR 72210; November 26, 2008
Staghorn coral	Threatened (71 FR 26852; May 9, 2006)	March 2015	73 FR 72210; November 26, 2008
Boulder star coral	Threatened (79 FR 53851; September 10, 2014)	None	None
Mountainous star coral	Threatened (79 FR 53851; September 10, 2014)	None	None
Lobed star coral	Threatened (79 FR 53851; September 10, 2014)	None	None
Rough cactus coral	Threatened (79 FR 53851; September 10, 2014)	None	None
Pillar coral	Threatened (79 FR 53851; September 10, 2014)	None	None
Fin whale	Endangered (35 FR 18319/ December 2, 1970)	August 2010	None
Sperm whale	Endangered (35 FR 18319; December 2, 1970)	December 2010	None
Sei whale	Endangered (35 FR 12222/ December 2, 1970)	December 2011	None
Gulf of Mexico Bryde's whale	Endangered (81 FR 88639; December 8, 2016)	None	None

Last updated by Southeast Regional Office on February 05, 2020

Appendices to the Programmatic Biological Opinion on the Gulf of Mexico Oil and Gas Program

Appendix A: Seismic Survey Mitigation and Protected Species Observer Protocols

These protocols will be implemented by the Bureau of Ocean Energy Management (BOEM), the Bureau of Safety and Environmental Enforcement (BSEE), and provide guidelines to operators in complying with the Endangered Species Act (ESA; 16 U.S.C. §§ 1531-1544) and Marine Mammal Protection Act (MMPA; 16 U.S.C. §§1361- 1423h). The measures contained herein apply to all seismic surveys approved by BOEM and associated with the federally regulated oil and gas program in the Gulf of Mexico.

Background

Geophysical surveys, including the use of airguns and airgun arrays,may have an impact on marine wildlife. Many marine species are protected under the Endangered Species Act (ESA) and all marine mammals (including manatees) are protected under the Marine Mammal Protection Act (MMPA). The following Gulf of Mexico species are listed under the ESA:

ESA-listed Species common to the Gulf of Mexico
Gulf of Mexico Bryde's Whale (*Balaenoptera edeni*)
Sperm Whale (*Physeter macrocephalus*)
Green Turtle (*Chelonia mydas*) – North Atlantic DPS and South Atlantic DPS
Hawksbill Turtle (*Eretmochelys imbricata)*
Kemp's Ridley Turtle (*Lepidochelys kempii*)
Leatherback Turtle (*Dermochelys coriacea*) - Northwest Atlantic DPS
Loggerhead Turtle (*Caretta caretta*) – Northwest Atlantic Ocean DPS
Gulf Sturgeon (*Acipenser oxyrinchus desotoi*)
Oceanic Whitetip Shark (*Carcharhinus longimanus*)
Giant Manta Ray (*Manta birostris*)
West Indian Manatee (*Trichechus manatus*)*

**Managed by the US Fish and Wildlife Service*

Note that this list can change as other species are listed/delisted, and this protocol shall be applied to any ESA protected species (and all marine mammals) that occur in the Gulf of Mexico, including rare and extralimital species.

BSEE and BOEM consult jointly with the National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service (FWS) under Section 7 of the ESA to ensure that BOEM- or BSEE-authorized activities do not jeopardize the continued existence of ESA-listed species nor result in destruction or adverse modification of designated critical habitat. Incidental take of ESA-listed species is prohibited except as authorized pursuant to an Incidental Take Statement in the attached Biological Opinion. Incidental take of ESA-listed marine mammals cannot be exempted under the ESA unless also authorized under the MMPA. In this case, NMFS is developing an incidental take regulation (ITR) to facilitate subsequent issuance of MMPA authorization (as applicable) to operators to authorize take incidental to seismic surveys. The proposed regulations would establish a framework for authorization of incidental take by Level A and Level B harassment through MMPA authorization (as applicable). Once an ITR and subsequent LOA is complete, the Biological Opinion and associated Incidental Take Statement may be amended to exempt take for Gulf of Mexico Bryde's whale and sperm whale, which are listed under the ESA. Following development of the ITRs, implementation could occur via issuance of MMPA authorization (as applicable and as Letters of Authorization [LOAs]) upon request from individual industry applicants planning specific seismic survey activities.

These protocols are the result of coordination between BOEM, BSEE, and NMFS and are based on: past and present mitigation measures; terms and conditions and reasonable and prudent measures identified in the attached Biological Opinion issued to the Bureaus; conditions, mitigation, monitoring, and reporting requirements identified in the MMPA ITR; and NMFS' technical memorandum on standards for a protected species observer and data management program (Baker et al. 2013). BSEE is tasked as the lead agency for compiling lessee or operator reporting data required under current Biological Opinions applicable to both Bureaus. Therefore, while BOEM is issuing these protocols, all observer reports described herein must be submitted to BSEE as well as to NMFS where specified.

In order to protect ESA-listed species and marine mammals during seismic operations, seismic operators will be required to use protected species observers (PSOs) and follow specific seismic survey protocols when operating. These measures contained herein apply to all on-lease ancillary activity surveys conducted under 30 CFR Part 550 and all off-lease surveys conducted under 30 CFR Part 551, regardless of water depth. Operators must demonstrate your compliance with these requirements by submitting to BSEE and NMFS certain reports as detailed below.

Definitions

Terms used in these protocols have the following meanings:

1. Protected species means any species listed under the ESA and/or protected by the MMPA. The requirements discussed herein focus on marine mammals and sea turtles since these species are the most likely to be observed during seismic surveys. However, other ESA-listed species (e.g., giant manta rays) are also protected and observations of them should be reported as detailed below.
2. Airgun means a device that releases compressed air into the water column, creating an acoustical energy pulse with the purpose of penetrating the seafloor.
3. Deep penetration surveys are those using a large airgun array as the acoustic source. These surveys may in some cases collect return signals using sensors incorporated into ocean-bottom cables (OBC) or autonomous ocean-bottom nodes (OBN) placed

on the seafloor. These surveys are also referred to as high energy surveys.

4. Shallow penetration surveys are those using a small airgun array or single airgun, or could include certain non-airgun acoustic sources (e.g., “boomer,” a type of sub-bottom profiler) as the acoustic source. These surveys are also referred to as low energy surveys.
5. Ramp-up (sometimes referred to as "soft start") means the gradual and systematic increase of emitted sound levels from an airgun array. Ramp-up begins by first activating a single airgun of the smallest volume, followed by doubling the number of active elements in stages until the full complement of an array's airguns are active. Each stage should be approximately the same duration, and the total duration should not be less than approximately 20 minutes for deep penetration surveys.
6. Shutdown of an airgun array means the immediate de-activation of all individual airgun elements of the array.
7. Exclusion zone means the area to be monitored for possible shutdown in order to reduce or eliminate the potential for injury of protected species. Two exclusion zones are defined, depending on the species and context. For beaked whales, *Kogia* spp., sperm whales, and baleen whales, the exclusion zone encompasses the area at and below the sea surface out to a radius of 1.5 kilometers from the edges of the airgun array (0–1,500 meters). For all other protected species, the exclusion zone encompasses the area at and below the sea surface out to a radius of 500 meters from the edges of the airgun array (0–500 meters).
8. Buffer zone means an area beyond the exclusion zone to be monitored for the presence of protected species that may enter the exclusion zone. During pre-clearance monitoring (i.e., before ramp-up begins), the buffer zone also acts as an extension of the exclusion zone in that observations of marine mammals and sea turtles within the buffer zone would also prevent airgun operations from beginning (i.e. ramp-up). The buffer zone is not applicable for contexts that require an exclusion zone beyond 500 meters. The buffer zone encompasses the area at and below the sea surface from the edge of the 0– 500 meter exclusion zone, out to a radius of 1000 meters from the edges of the airgun array (500–1,000 meters).
9. Visual monitoring means the use of trained protected species observers (herein referred to as visual PSOs) to scan the ocean surface visually for the presence of protected species. These observers must have successfully completed a visual observer training program as described below. The area to be scanned visually includes primarily the exclusion zone, but also the buffer zone. Visual monitoring of the exclusion zones and adjacent waters is intended to establish and, when visual conditions allow, maintain zones around the sound source that are clear of marine mammals and sea turtles, thereby reducing or eliminating the potential for injury. Visual monitoring of the buffer zone is intended to (1) provide additional protection to marine mammals and sea turtles and awareness and potential protection of other visual protected species that may be in

the area during pre-clearance, and (2) during airgun use, aid in establishing and maintaining the exclusion zone by alerting the visual observer and crew of marine mammals and sea turtles that are outside of, but may approach and enter, the exclusion zone.

10. Acoustic monitoring means the use of trained personnel (sometimes referred to as passive acoustic monitoring [PAM] operators, herein referred to as acoustic PSOs) to operate PAM equipment to acoustically detect the presence of marine mammals. These observers must have successfully completed a passive acoustic observer training program as described below. Acoustic monitoring is intended to further support visual monitoring in maintaining an exclusion zone around the sound source that is clear of marine mammals, in part for the purpose of reducing or eliminating the potential for injury. In cases where visual monitoring is not effective (e.g., due to weather, nighttime), acoustic monitoring may be used to allow certain activities to occur, as further detailed below.

General Requirements

1. A copy of a MMPA incidental take authorization (as applicable) and BOEM-approved Permit/Plan must be in the possession of the vessel operator, other relevant personnel, the lead PSO (see description below), and any other relevant designees operating under the authority of the MMPA authorization (as applicable) and BOEM Permit/Plan.
2. The MMPA authorization (as applicable) and BOEM-approved Permit/Plan holder shall instruct relevant vessel personnel with regard to the authority of the protected species monitoring team, and shall ensure that relevant vessel personnel and the protected species monitoring team participate in a joint onboard briefing (hereafter PSO briefing) led by the vessel operator and lead PSO to ensure that responsibilities, communication procedures, protected species monitoring protocols, operational procedures, and MMPA authorization (as applicable) and BOEM Permit/Plan requirements are clearly understood. This PSO briefing must be repeated when relevant new personnel join the survey operations before work commences.
3. The acoustic source must be deactivated when not acquiring data or preparing to acquire data, except as necessary for testing. Unnecessary use of the acoustic source shall be avoided. Notified operational capacity (not including redundant backup airguns) must not be exceeded during the survey, except where unavoidable for source testing and calibration purposes. All occasions where activated source volume exceeds notified operational capacity must be communicated to the PSO(s) on duty and fully documented. The lead PSO must be granted access to relevant instrumentation documenting acoustic source power and/or operational volume.

Protected Species Observers (PSOs, Visual and Acoustic)

Qualifications

1. The MMPA authorization (as applicable) and BOEM-approved Permit/Plan holder must use independent, dedicated, trained visual and acoustic PSOs, meaning that the PSOs must be employed by a third-party observer provider, may have no tasks other than to conduct observational effort (visual or acoustic), collect data, and communicate with and instruct relevant vessel crew with regard to the presence of protected species and mitigation requirements (including brief alerts regarding maritime hazards), and must have successfully completed an approved PSO training course appropriate for their designated task (visual or acoustic). Acoustic PSOs are required to complete specialized training for operating PAM systems and are encouraged to have familiarity with the vessel with which they will be working. PSOs can act as acoustic or visual observers (but not at the same time) as long as they demonstrate to NMFS (nmfs.psoreview@noaa.gov) that their training and experience are sufficient to perform necessary tasks. NMFS must review and approve PSO resumes accompanied by a relevant training course information packet that includes the name and qualifications (i.e., experience, training completed, or educational background) of the instructor(s), the course outline or syllabus, and course reference material as well as a document stating successful completion of the course. NMFS shall have one week to approve PSOs from the time that the necessary information is submitted by the BOEM-approved Permit/Plan holder, after which PSOs meeting the minimum requirements shall automatically be considered approved.
2. NMFS approves PSOs as conditional or unconditional. A conditionally-approved PSO may be one who is trained but has not yet attained the relevant experience, or who has attained the necessary level of experience but not in the particular region. An unconditionally-approved PSO is one who has attained the necessary experience within the relevant region. At least one of the visual and two of the acoustic PSOs aboard the vessel must have a minimum of 90 days at-sea experience working in those roles, respectively, during a deep penetration seismic survey, with no more than 18 months elapsed since the conclusion of the at-sea experience. One visual PSO with such experience shall be designated as the lead for the entire protected species observation team. The lead shall coordinate duty schedules and roles for the PSO team and serve as primary point of contact for the vessel operator. To the maximum extent practicable, the lead PSO shall devise the duty schedule such that experienced PSOs are on duty with those PSOs with appropriate training but who have not yet gained relevant experience.
    a. PSOs must successfully complete relevant training, including completion of all required coursework and passing (80 percent or greater) a written and/or oral examination developed for the training program. PSOs must have successfully attained a bachelor's degree from an accredited college or university with a major in one of the natural sciences, a minimum of 30 semester hours or

equivalent in the biological sciences, and at least one undergraduate course in math or statistics. The educational requirements may be waived if the PSO has acquired the relevant skills through alternate experience. Requests for such a waiver shall be submitted by the BOEM-approved Permit/Plan holder to NMFS (nmfs.psoreview@noaa.gov) and must include written justification. Requests shall be granted or denied (with justification) by NMFS within one week of receipt of submitted information. Alternate experience that may be considered includes, but is not limited to: (1) secondary education and/or experience comparable to PSO duties; (2) previous work experience conducting academic, commercial, or government-sponsored protected species surveys; or (3) previous work experience as a PSO; the PSO should demonstrate good standing and consistently good performance of PSO duties.

Equipment

The MMPA incidental take authorization (as applicable) and BOEM-approved Permit/Plan holder is required to:

1. Provide PSOs with bigeye binoculars (e.g., 25 x 150; 2.7 view angle; individual ocular focus; height control) of appropriate quality solely for PSO use. These shall be pedestal-mounted on the deck at the most appropriate vantage point that provides for optimal sea surface observation, PSO safety, and safe operation of the vessel.
2. Work with the selected third-party observer provider to ensure PSOs have all equipment (including backup equipment) needed to adequately perform necessary tasks, including accurate determination of distance and bearing to observed protected species. Such equipment, at a minimum, shall include:
    a. Each vessel requiring PAM will include a passive acoustic monitoring system that has been verified and tested by an experienced acoustic PSO that will be using it during the trip for which monitoring is required.
    b. Reticle binoculars (e.g., 7 x 50) of appropriate quality (at least one per PSO, plus backups)
    c. Global Positioning Units (GPS) (plus backup)
    d. Digital camera with a telephoto lens (the camera or lens should also have an image stabilization system) that is at least 300 mm or equivalent on a full-frame single lens reflex (SLR) (plus backup)Radios for communication among vessel crew and PSOs (at least one per PSO, plus backups)
    e. Any other tools necessary to adequately perform necessary PSO tasks.

Equipment specified in (a) through (g) above may be provided by an individual PSO, the third-party observer provider, or the MMPA authorization (as applicable) and BOEM-approved Permit/Plan holder but the latter is responsible for ensuring PSOs have the proper equipment required to perform the duties specified within these protocols.

Visual Monitoring

1. During survey operations (e.g., any day on which use of the acoustic source is planned to occur, and whenever the acoustic source is in the water, whether activated or not), a minimum of two visual PSOs must be on duty and conducting visual observations at all times during daylight hours (i.e., from 30 minutes prior to sunrise through 30 minutes following sunset).
2. Visual monitoring of the exclusion and buffer zones must begin no less than 30 minutes prior to ramp-up and must continue until one hour after use of the acoustic source ceases or until 30 minutes past sunset.
3. Visual PSOs shall coordinate to ensure 360° visual coverage around the vessel from the most appropriate observation posts, and shall conduct visual observations using binoculars and the naked eye while free from distractions and in a consistent, systematic, and diligent manner.
4. PSOs shall establish and monitor applicable exclusion and buffer zones. These zones shall be based upon the radial distance from the edges of the airgun array (rather than being based on the center of the array or around the vessel itself). During use of the acoustic source (i.e., anytime the acoustic source is active, including ramp-up), occurrences of protected species within the buffer zone (but outside the exclusion zone) should be communicated to the operator to prepare for the potential shutdown for marine mammals (or voluntary pause for other non-marine mammal protected species [e.g., sea turtles] if being employed) of the acoustic source.
5. Visual PSOs shall immediately communicate all observations to the on duty acoustic PSO(s), including any determination by the PSO regarding species identification, distance, and bearing and the degree of confidence in the determination.
6. Any observations of protected species by crew members aboard any vessel associated with the survey shall be relayed to the PSO team.
7. During good conditions (e.g., daylight hours; Beaufort sea state (BSS) 3 or less), visual PSOs shall conduct observations when the acoustic source is not operating for comparison of sighting rates and behavior with and without use of the acoustic source and between acquisition periods, to the maximum extent practicable.
8. Visual PSOs may be on watch for a maximum of two consecutive hours followed by a break of at least one hour between watches and may conduct a maximum of 12 hours of observation per 24-hour period. Combined observational duties (visual and acoustic but not at same time) may not exceed 12 hours per 24-hour period for any individual PSO.

Acoustic Monitoring

1. Applicants must provide a PAM plan to NMFS according to the MMPA authorization

including description of the hardware and software proposed for use prior to proceeding with any survey where PAM is required. The source vessel must use a towed PAM system at all times when operating in waters deeper than 100 m, which must be monitored by at a minimum one on duty acoustic PSO beginning at least 30 minutes prior to ramp-up and at all times during use of the acoustic source. “PAM system” refers to calibrated hydrophone arrays with full system redundancy to detect, identify, and estimate distance and bearing to vocalizing cetaceans. The PAM system must have at least one calibrated hydrophone (per each deployed hydrophone type and/or set) sufficient for determining whether background noise levels on the towed PAM system are sufficiently low to meet performance expectations, and must incorporate appropriate hydrophone elements (1 Hz to 180 kHz range) and sound data acquisition card technology for sampling relevant frequencies (*i.e.*, to 360 kHz). Applicants must provide a PAM plan including description of the hardware and software proposed for use prior to proceeding with any survey where PAM is required.

2. Acoustic PSOs shall immediately communicate all detections to visual PSOs, when visual PSOs are on duty, including any determination by the PSO regarding species identification, distance, and bearing and the degree of confidence in the determination.
3. Acoustic PSOs may be on watch for a maximum of four consecutive hours followed by a break of at least two hours between watches and may conduct a maximum of 12 hours of observation per 24-hour period. Combined observational duties (acoustic and visual but not at same time) may not exceed 12 hours per 24-hour period for any individual PSO.
4. Survey activity may continue for 30 minutes when the PAM system malfunctions or is damaged, while the PAM operator diagnoses the issue. If the diagnosis indicates that the PAM system must be repaired to solve the problem, operations may continue for an additional two hours without acoustic monitoring during daylight hours only under the following conditions:
    a. Sea state is less than or equal to BSS 4;
    b. No marine mammals (excluding delphinids) detected solely by PAM in the applicable exclusion zone in the previous two hours;
    c. NMFS and BSEE are notified via email (nmfs.psoreview@noaa.gov and protectedspecies@bsee.gov, respectively) as soon as practicable with the time and location in which operations began occurring without an active PAM system; and
    d. Operations with an active acoustic source, but without an operating PAM system, do not exceed a cumulative total of four hours in any 24-hour period.

Data Collection

PSOs must use a standardized data collection form, whether hard copy or electronic. PSOs shall record detailed information about any implementation of mitigation requirements, including the distance of animals to the acoustic source and description of specific actions that ensued, the behavior of the animal(s), any observed changes in behavior before and after implementation of mitigation, and if shutdown was implemented, the length of time before any subsequent ramp-up of the acoustic source. If required mitigation was not implemented, PSOs should record a description of the circumstances. At a minimum, the following information must be recorded within the interim reports:

1. BOEM Permit/Plan number;
2. Vessel names (source vessel and other vessels associated with survey), vessel size and type, maximum speed capability of vessel, port of origin, and call signs;
3. PSO names and affiliations;
4. Dates of departures and returns to port with port name;
5. Date and participants of PSO briefings (as discussed in General Requirements. 2.);
6. Dates and times (Greenwich Mean Time) of survey effort and times corresponding with PSO effort;
7. Vessel location (latitude/longitude) when survey effort began and ended and vessel location at beginning and end of visual PSO duty shifts;
8. Vessel heading and speed at beginning and end of visual PSO duty shifts and upon any line change;
9. Environmental conditions while on visual survey (at beginning and end of PSO shift and whenever conditions changed significantly), including BSS and any other relevant weather conditions including cloud cover, fog, sun glare, and overall visibility to the horizon;
10. Factors that may have contributed to impaired observations during each PSO shift change or as needed as environmental conditions changed (e.g., vessel traffic, equipment malfunctions);
11. Survey activity information, such as acoustic source power output while in operation, number and volume of airguns operating in the array, tow depth of the array, and any other notes of significance (i.e., pre-clearance, ramp-up, shutdown, testing, shooting, ramp-up completion, end of operations, streamers, etc.); and
12. Upon visual observation of any protected species, the following information:
    a. Watch status (sighting made by PSO on/off effort, opportunistic, crew, alternate vessel/platform);
    b. PSO who sighted the animal;
    c. Time of sighting;
    d. Vessel location at time of sighting;
    e. Water depth;
    f. Direction of vessel's travel (compass direction);
    g. Direction of animal's travel relative to the vessel;
    h. Pace of the animal;
    i. Estimated distance to the animal and its heading relative to vessel at

initial sighting;

j. Identification of the animal (e.g., genus/species, lowest possible taxonomic level, or unidentified) and the composition of the group if there is a mix of species;
k. Estimated number of animals (high/low/best);
l. Estimated number of animals by cohort (adults, juveniles,, group composition, etc.);
m. Description (as many distinguishing features as possible of each individual seen, including length, shape, color, pattern, scars or markings, shape and size of dorsal fin, shape of head, and blow characteristics);
n. Detailed behavior observations (e.g., number of blows/breaths, number of surfaces, breaching, spyhopping, diving, feeding, traveling; as explicit and detailed as possible; note any observed changes in behavior), including an assessment of behavioral responses to survey activity;
o. Animal's closest point of approach (CPA) and/or closest distance from any element of the acoustic source;
p. Platform activity at time of sighting (e.g., deploying, recovering, testing, shooting, data acquisition, other); and
q. Description of any actions implemented in response to the sighting (e.g., delays, shutdown, ramp-up) and time and location of the action.

13. If a marine mammal is detected while using the PAM system, the following information should be recorded:
    a. An acoustic encounter identification number, and whether the detection was linked with a visual sighting;
    b. Date and time when first and last heard;
    c. Types and nature of sounds heard (e.g., clicks, whistles, creaks, burst pulses, continuous, sporadic, strength of signal);
    d. Any additional information recorded such as water depth of the hydrophone array, bearing of the animal to the vessel (if determinable), species or taxonomic group (if determinable), spectrogram screenshot, and any other notable information.

Seismic Survey Protocols[1]

Pre-clearance and Ramp-up

The intent of pre-clearance observation (30 minutes) is to ensure no protected species are observed within the exclusion zones, and buffer zone if applicable (i.e., only when the exclusion zone is equal to 500 meters, see Definitions section for details on when the buffer

[1] This includes borehole or vertical seismic profile surveys.

zone is not applicable), prior to the beginning of ramp-up. During pre-clearance is the only time observations of protected species in the buffer zone would prevent operations (i.e., the beginning of ramp-up). The intent of ramp-up is to warn protected species of pending seismic operations and to allow sufficient time for those animals to leave the immediate vicinity. A ramp-up procedure, involving a step-wise increase in the number of airguns firing and total array volume until all operational airguns are activated and the full volume is achieved, is required at all times as part of the activation of the acoustic source. All operators must adhere to the following pre-clearance and ramp-up requirements, which are applicable to both marine mammals and sea turtles:

1. The operator must notify a designated PSO of the planned start of ramp-up as agreed upon with the lead PSO; the notification time should not be less than 60 minutes prior to the planned ramp-up in order to allow the PSOs time to monitor the exclusion and buffer zones for 30 minutes prior to the initiation of ramp-up (pre-clearance).
2. Ramp-ups shall be scheduled so as to minimize the time spent with the source activated prior to reaching the designated run-in.
3. One of the PSOs conducting pre-clearance observations must be notified again immediately prior to initiating ramp-up procedures and the operator must receive confirmation from the PSO to proceed.
4. Ramp-up may not be initiated if any marine mammal or sea turtle is within the applicable exclusion or buffer zone. If a marine mammal or sea turtle is observed within the applicable exclusion zone or the buffer zone during the 30 minute pre-clearance period, ramp-up may not begin until the animal(s) has been observed exiting the zones or until an additional time period has elapsed with no further sightings (15 minutes for small odontocetes and 30 minutes for all other species including sea turtles).
5. Ramp-up shall begin by activating a single airgun of the smallest volume in the array and shall continue in stages by doubling the number of active elements at the commencement of each stage, with each stage of approximately the same duration. Duration shall not be less than 20 minutes. The operator must provide information to the PSO documenting that appropriate procedures were followed.
6. PSOs must monitor the exclusion and buffer zones during ramp-up, and ramp-up must cease and the source must be shut down upon observation of a marine mammal or sea turtle within the applicable exclusion zone. Once ramp-up has begun, observations of marine mammals and sea turtles within the buffer zone do not require shutdown, or voluntarily pause for other non-marine mammal protected species (e.g., sea turtles) if being employed, but such observation shall be communicated to the operator to prepare for the potential shutdown, or voluntarily pause if being employed.
7. Ramp-up may occur at times of poor visibility, including nighttime, if appropriate acoustic monitoring has occurred with no detections in the 30 minutes prior to beginning ramp-up. Acoustic source activation may only occur at times of poor

visibility where operational planning cannot reasonably avoid such circumstances.

8. If the acoustic source is shut down for brief periods (i.e., less than 30 minutes) for reasons other than that described below in *Shutdown* (e.g., mechanical difficulty), it may be activated again without ramp-up if PSOs have maintained constant visual and/or acoustic observation and no visual detections of marine mammals or sea turtles have occurred within the applicable exclusion zone and no acoustic detections of marine mammals have occurred. For any longer shutdown, pre-clearance observation and ramp-up are required. For any shutdown at night or in periods of poor visibility (e.g., BSS 4 or greater), ramp-up is required, but if the shutdown period was brief and constant observation was maintained, pre-clearance watch of 30 min is not required.
9. Testing of the acoustic source involving all elements requires ramp-up. Testing limited to individual source elements or strings does not require ramp-up but does require pre-clearance of 30 min.

Shutdown

For non-marine mammal protected species (e.g., sea turtles), shutdowns are not required. However, the BOEM Permit or authorized Plan and MMPA authorization (as applicable) holder may employ a voluntary pause during which the visual PSO would request that the operator voluntarily pause the airgun array for six shots if a non-marine mammal protected species is observed within the exclusion zone (within 500 meters) during active airgun use, to let the animal float past the array while it is inactive. For marine mammals, all operators must adhere to the following shutdown requirements:

1. Any PSO on duty has the authority to delay the start of survey operations or to call for shutdown of the acoustic source if a marine mammal is detected within the applicable exclusion zone.
2. The operator must establish and maintain clear lines of communication directly between PSOs on duty and crew controlling the acoustic source to ensure that shutdown, and voluntary pause commands (optional for other protected species) are conveyed swiftly while allowing PSOs to maintain watch.
3. When both visual and acoustic PSOs are on duty, all detections must be immediately communicated to the remainder of the on-duty PSO team for potential verification of visual observations by the acoustic PSO or of acoustic detections by visual PSOs.
4. When the airgun array is active (i.e., anytime one or more airguns is active, including during ramp-up) and (1) a marine mammal appears within or enters the applicable exclusion zone and/or (2) a marine mammal (excluding delphinids) is detected acoustically and localized within the applicable exclusion zone, the acoustic source must be shut down. When shutdown is called for by a PSO, the acoustic source must be immediately deactivated and any dispute resolved only following deactivation.
5. The shutdown requirement is waived for dolphins of the following genera: *Steno*, *Tursiops*, *Stenella*, and *Lagenodelphis*.

   a. If a small delphinid (individual of the Family Delphinidae, which includes the aforementioned dolphin genera), is acoustically detected and localized within the exclusion zone, no shutdown is required unless the acoustic PSO or a visual PSO confirms the individual to be of a genera other than those listed above, in which case a shutdown is required.
6. If there is uncertainty regarding identification (i.e., whether the observed marine mammal(s) belongs to one of the delphinid genera for which shutdown is waived or one of the species with a larger exclusion zone), visual PSOs may use best professional judgment in making the decision to call for a shutdown.
7. Upon implementation of shutdown, the source may be reactivated after the marine mammal(s) has been observed exiting the applicable exclusion zone (i.e., animal is not required to fully exit the buffer zone where applicable) or following a 30-minute clearance period with no further observation of the marine mammal(s).

Shallow penetration protocols

1. Shallow penetration surveys are defined as surveys using airgun arrays with total volume equal to or less than 400 in^3, single airguns, boomers, or equivalent sources.
2. LOA-holders shall follow the requirements defined for deep penetration surveys at § 217.184(b), with the following exceptions:
   a. PAM is not required for shallow penetration surveys.
   b. Ramp-up for small airgun arrays must follow the procedure described above for large airgun arrays, but may occur over an abbreviated period of time. Ramp-up is not required for surveys using only a single airgun. For sub-bottom profilers, power should be increased as feasible to effect a ramp-up.
   c. Two exclusion zones are defined, depending on the species and context. A standard exclusion zone encompassing the area at and below the sea surface out to a radius of 100 meters from the edges of the airgun array (if used) or from the acoustic source (0-100 m) is defined. For special circumstances (§ 217.184(b)(6)(v)), the exclusion zone encompasses an extended distance of 500 meters (0-500 m).
   d. The buffer zone encompasses the area at and below the sea surface from the edge of the 0-100 meter exclusion zone out to a radius of 200 meters from the edges of the airgun array (if used) or from the acoustic source (100-200 meters). The buffer zone is not applicable when the exclusion zone is greater than 100 meters.

Non-Airgun High-Resolution Geophysical (HRG) Protocol

Non-airgun HRG surveys are conducted in leases and along pipeline routes to evaluate the potential for geohazards, archaeological resources, and certain types of benthic communities. Non-airgun HRG sources include but are not limited to side-scan sonars, boomers, sparkers (in limited situations) and compressed high-intensity radiated pulse (CHIRP) subbottom profilers (in limited situations), and single-beam or multibeam depth sounders.

Non-Airgun HRG Surveys with Frequencies ≥180 kHz

Acoustic sources do not require detailed analyses because the frequency is outside the general hearing range of marine mammals.

Non-Airgun HRG Surveys with Frequencies <180 kHz

For all non-airgun HRG surveys in which one or more active acoustic sound sources are operating at these frequencies, the following will be required for the indicated water depths. PAM is not required for any HRG survey. No shutdowns would be required for HRG surveys. Pre-clearance watch is required for a period of 30 minutes and over a 200-m radius from the acoustic source.

Shallow-water (< 100 m)

1. Employ a minimum of one visual PSO, which may be a crew member. PSOs employed during shallow-water HRG surveys are only required during a pre-clearance period.

Deep-water (> 100 m)

1. Employ a minimum of one independent visual PSO during all daylight operations, in the same manner as was described for deep and shallow airgun penetration surveys.
2. PSOs are not required during survey operations in which the active acoustic source(s) are deployed on an autonomous underwater vehicle.

Entanglement and Entrainment Risk Reduction

All lines (rope, chain, cable, etc.) associated with geophysical surveys must be stiff, taut, and non-looping. Flexible lines such as nylon or polypropylene that could loop or tangle protected species must be enclosed in a sleeve to add rigidity and prevent looping or tangling. No excess underwater line is allowed. All equipment, especially towed apparatuses (e.g., tail buoys), shall be designed in a way as to prevent entrainment of sea turtles or other protected species.

Nodal Survey Requirements

To avoid the risk of entanglement, lessees and operators conducting surveys using ocean-bottom nodes or similar gear must:

1. Use negatively buoyant coated wire-core tether cable;
2. Ensure any cables/lines are designed to be rigid ;
3. Retrieve all lines immediately following completion of the survey; and
4. Attach acoustic pingers directly to the coated tether cable; acoustic releases should not be used.

Reporting

1. The BOEM Permit/Plan holder shall submit interim reports (see Data Collection section for details) on the 1st of each month to BSEE (protectedspecies@bsee.gov) detailing all protected species observations with closest approach distance.
2. The MMPA authorization (as applicable) and BOEM Permit/Plan holder shall submit a draft comprehensive report to BOEM/BSEE (protectedspecies@boem.gov and protectedspecies@bsee.gov) and NMFS (nmfs.psoreview@noaa.gov) on all activities and monitoring results within 90 days of the completion of the survey or expiration of the MMPA authorization (as applicable) or BOEM Permit/Plan, whichever comes sooner, or if an issued MMPA authorization is valid for greater than one year, the summary report must be submitted on an annual basis,. The report must describe all activities conducted and sightings of protected species near the activities, must provide full documentation of methods, results, and interpretation pertaining to all monitoring, and must summarize the dates and locations of survey operations and all protected species sightings (dates, times, locations, activities, associated survey activities, and information regarding locations where the acoustic source was used). The draft report shall also include geo-referenced time-stamped vessel tracklines for all time periods during which airguns were operating. Tracklines should include points recording any change in airgun status (e.g., when the airguns began operating, when they were turned off, or when they changed from full array to single gun or vice versa). GIS files shall be provided in ESRI shapefile format and include the UTC date and time, latitude in decimal degrees, and longitude in decimal degrees. All coordinates shall be referenced to the WGS84 geographic coordinate system. In addition to the report, all raw observational data shall be made available to BOEM/BSEE and NMFS. The report must summarize the information submitted in interim monthly reports as well as additional data collected as described above in *Data Collection* and the MMPA authorization (as applicable). The draft report must be accompanied by a certification from the lead PSO as to the accuracy of the report, and the lead PSO may submit directly to BOEM/BSEE and NMFS a statement concerning implementation and effectiveness of the required mitigation and monitoring. A final report must be submitted within 30 days following resolution of any comments on the draft report.

3. Reporting injured or dead protected species:
   The MMPA authorization (as applicable) and BOEM Permit/Plan holder must report sightings of any injured or dead aquatic protected species immediately, regardless of the cause of injury or death.

   For injured or dead non-marine mammal aquatic protected species, report incidents to the hotlines listed at https://www.fisheries.noaa.gov/report (phone numbers vary by state). For reporting dead or injured marine mammals, refer to the reporting requirements specified in the MMPA authorization (as applicable), associated with the activity being conducted. The report must include the following information:

   1. Time, date, water depth and location (latitude/longitude) of the first discovery (and updated location information if known and applicable);
   2. Relevant weather conditions (e.g., cloud cover, fog, sun glare, etc.);
   3. Name, type, call sign, and speed of the vessel during and leading up to the first sighting;
   4. Species identification (if known) or description of the animal(s) involved;
   5. Condition of the animal(s) (including carcass condition if the animal is dead);
   6. Observed behaviors of the animal(s), if alive;
   7. If available, photographs or video footage of the animal(s); and
   8. General circumstances under which the animal was discovered.

References

Baker, K., D. Epperson, G. Gitschlag, H. Goldstein, J. Lewandowski, K. Skrupky, B. Smith, and T. Turk. 2013. National standards for a protected species observer and data management program: A model using geological and geophysical surveys. Technical Memorandum NMFS-OPR-49, Office of Protected Resources, National Marine Fisheries Service, National Oceanic and Atmospheric Administration; Bureau of Ocean Energy Management, U.S. Department of the Interior; Bureau of Safety and Environmental Enforcement, U.S. Department of the Interior, Silver Spring, Maryland.

Appendix B. Gulf of Mexico Marine Trash and Debris Awareness and Elimination Survey Protocols

These protocols will be implemented by the Bureau of Ocean Energy Management (BOEM), the Bureau of Safety and Environmental Enforcement (BSEE), and operators in complying with the Endangered Species Act (ESA; 16 U.S.C. §§ 1531-1544) and Marine Mammal Protection Act (MMPA; 16 U.S.C. §§1361- 1423h).

Background

Marine trash and debris pose a threat to fish, marine mammals, sea turtles, and potentially other marine animals; cause costly delays and repairs for commercial and recreational boating interests; detract from the aesthetic quality of recreational shore fronts; and increase the cost of beach and park maintenance. As Outer Continental Shelf (OCS) oil- and gas-related activities expand into deeper waters, the number of species of protected marine animals exposed to marine debris could increase. Many marine species are protected under the Endangered Species Act (ESA) and all marine mammals (including manatees) are protected under the Marine Mammal Protection Act (MMPA). The discharge of garbage and debris has been the subject of strict laws, such as MARPOL-Annex V and the Marine Debris Act, 33 U.S.C. 1951 *et seq.*, and regulations imposed by various agencies including the United States Coast Guard and the Environmental Protection Agency.

Since OCS oil and gas operations in the Gulf of Mexico may contribute to this problem, 30 CFR 250.300(a) and (b)(6) prohibit discharging containers and other materials into the marine environment, and 30 CFR 250.300(c) and (d) require durable identification markings on skid-mounted equipment, portable containers, spools or reels, and drums, and to record and report such items when lost overboard to the District Manager through facility daily operations reports. Therefore, in accordance with 30 CFR 250.300(a) and (b)(6), exercise special caution when handling and transporting small items and packaging materials, particularly those made of non-biodegradable, environmentally persistent materials such as plastic or glass that can be lost in the marine environment and washed ashore. Increasing awareness of the problem and emphasizing offshore worker's responsibilities will help minimize the litter issue and control the unintended loss of items such as empty buckets, hard hats, shrink wrap, strip lumber and pipe thread protectors.

BSEE and BOEM consult jointly with the National Marine Fisheries Service (NMFS) and the U.S. Fish and Wildlife Service (FWS) under Section 7 of the ESA to ensure that BOEM or BSEE authorized activities do not jeopardize the continued existence of ESA-listed species nor result in adverse modification of designated critical habitat. Incidental take of ESA-listed species is prohibited except as authorized pursuant to an Incidental Take Statement in a Biological Opinion. Incidental take of ESA listed marine mammals cannot be authorized under the ESA unless also authorized under the MMPA.

Marine Trash and Debris Placards

Permit holders must continue to post placards that include each of the information text boxes in Attachment 1 of this Appendix in prominent places on all fixed and floating production facilities that have sleeping or food preparation capabilities and on mobile drilling units engaged in oil and gas operations in the Gulf of Mexico OCS. Each of the placards depicted, with the language specified, must be displayed on a 5x8 inch format or larger. These signs must be displayed at line-of-sight height at or near boat landings and heliports; in mess areas; and in the recreation, training or orientation areas. One or more areas may be omitted if there is insufficient space. These notices must be referenced, and their contents explained, during any initial orientation given on the facility for visitors or occupants. Placards must be sturdy enough to withstand the local environment and must be replaced when damage or wear compromises readability.

Marine Trash and Debris Awareness Training

All OCS offshore employees and those contractors actively engaged in OCS offshore operations (e.g., wireline operators, contract lease operators, and maintenance or construction crews) should complete marine trash and debris awareness training annually.

The training for employees and contractors consists of two parts: (1) viewing a marine trash and debris training video or slide show (described below); and (2) receiving an explanation from management personnel of the lessee or designated lease operator that emphasizes their commitment to the requirements.

You may obtain the marine trash and debris training video, training slide packs, and other marine debris related educational material produced by the Offshore Operators Committee (OOC), through the OOC website at https://www.ooctraining.org/ or https://www.bsee.gov/debris. The video and slides are offered in English and Spanish versions and the video is available as a DVD or VHS tape. The video, slides, and related material may also be downloaded directly from the website.

Marine Trash and Debris Awareness Training and Certification Process

Permit holders and offshore operators must continue to develop and use a marine trash and debris awareness training and certification process that reasonably assures that the employees and contractors specified above are in fact trained. Your training process must include the following elements:

1) viewing of either the video or the slide show by the personnel specified above using one of the following methods:
   a) attendance at periodic meetings held for this purpose;
   b) as part of several scheduled training components;
   c) web-based training with email notification; or
   d) training by a third-party contractor;
2) an explanation from the management that conveys the commitment of the company to achieve the objectives of the trash and debris containment requirement;
3) attendance measures (initial and annual); and
4) recordkeeping and availability of records for inspection by BSEE.

By January 31st of each year, you must provide BSEE and NMFS with an annual report (1-2 pages) signed by a company official that describes your marine trash and debris awareness training process and certifies that the training process has been followed for the previous calendar year. You should send the report by email to marinedebris@bsee.gov[1].

In lieu of emailing the report, you may send a printed copy to:

Bureau of Safety and Environmental Enforcement
Gulf of Mexico OCS Region
Office of Environmental Compliance (MS GE466)
1201 Elmwood Park Blvd.
New Orleans, Louisiana 70123

Contact

Please submit any questions by e-mail to: marinedebris@bsee.gov.

[1] BSEE will forward these reports to NMFS per the requirements under this biological opinion.

Attachment 1

Marine Debris Placards

WHAT IS MARINE DEBRIS?

Marine debris is any object or fragment of wood, metal, glass, rubber, plastic, cloth, paper or any other man-made item or material that is lost or discarded in the marine environment. Marine debris may be intentionally dumped, accidentally dropped, or indirectly deposited. Whatever the source, marine debris is a direct result of human activities on land and at sea. Depending upon its composition, marine debris may sink to the seafloor, drift in the water column, or float on the surface of the sea. Certain debris, such as plastics, can persist for hundreds of years in the marine environment without decomposing.

WARNING!

YOUR ACTIONS MAY SUBJECT YOU TO SEVERE LEGAL CONSEQUENCES!

The disposal and/or discharge of any solid waste anywhere in the marine environment (other than ground-up food particles) is strictly prohibited by U.S. Coast Guard and Environmental Protection Agency regulations. THIS INCLUDES MATERIALS OR DEBRIS ACCIDENTALLY LOST OVERBOARD.

The disposal of equipment, cables, chains, containers or other materials into offshore waters is prohibited by the Bureau of Safety and Environmental Enforcement (30 CFR 250.300(b)(6)). THIS INCLUDES MATERIALS OR DEBRIS ACCIDENTALLY LOST OVERBOARD.

ATTENTION!

MARINE DEBRIS MAY CAUSE SEVERE ECOLOGICAL DAMAGE!

Marine debris discarded or lost from offshore and coastal sources may injure or kill fish, marine mammals, sea turtles, seabirds and other wildlife.

Thousands of marine animals, including marine mammals, sea turtles and seabirds, die every year from entanglement in fishing line, strapping bands, discarded ropes and nets and plastic six-pack rings. Additionally, unknown numbers of marine animals die each year from internal injury, intestinal blockage and starvation as a result of ingesting marine debris.

Marine debris fouls boat propellers and clogs water intake ports on engines thereby endangering the safety of fishermen and boaters and resulting in heavy loss of time and money.

Marine debris detracts from the aesthetic quality of recreational beaches and shorelines and increases the cost of park and beach maintenance.

ATTENTION!

SECURE ALL LOOSE ARTICLES!

NOAA Fisheries now expects petroleum industry personnel to pick up and recover any articles lost overboard from boats and offshore structures as safety conditions permit. Additionally, 30 CFR 250.300 (d) requires recording and reporting items lost overboard to the District Manager through facility daily operations reports.

Protect marine animals, as well as your valuable time and money, by doing the following to prevent accidental loss of these items:

Properly securing all materials, equipment, and personal belongings. Articles such as hardhats, life vests, sunglasses, cigarette lighters, parts bags, buckets, shrink wrap, strip lumber, and pipe thread protectors become marine debris when lost overboard.

Making sure that all trash receptacles have tight fitting lids and that the lids are used.

Providing and using secure cigarette butt containers. Cigarette butts are one of the most common forms of marine debris. Many cigarette butts contain some form of plastic and do not decompose in the ocean. Cigarette butts pose a major threat to marine wildlife as they resemble food and cause gut blockages and starvation when ingested.

Do your part to eliminate marine debris. Encourage others to be responsible about marine debris by making suggestions to secure potential marine debris on your boat or structure or by participating in a beach cleanup.

Appendix C. Gulf of Mexico Vessel Strike Avoidance and Injured/Dead Aquatic Protected Species Reporting Protocols

These protocols will be implemented by the Bureau of Ocean Energy Management (BOEM), the Bureau of Safety and Environmental Enforcement (BSEE), and provide guidelines to operators in complying with the Endangered Species Act (ESA; 16 U.S.C. §§ 1531-1544) and Marine Mammal Protection Act (MMPA; 16 U.S.C. §§1361- 1423h). The measures contained herein apply to all vessels associated with the federally regulated oil and gas program in the Gulf of Mexico.

Aquatic Protected Species Identification

Crew and supply vessel personnel should use a Gulf of Mexico reference guide that includes identifying information on marine mammals, sea turtles, and other marine protected species (i.e., Endangered Species Act listed species such as Gulf sturgeon, giant manta ray, or oceanic whitetip shark; hereafter collectively termed “other aquatic protected species”) that may be encountered in the Gulf of Mexico Outer Continental Shelf (OCS). Vessel operators must comply with the below measures except under extraordinary circumstances when the **safety of the vessel or crew is in doubt or the safety of life at sea is in question**.

Vessel Strike Avoidance

1. Vessel operators and crews must maintain a vigilant watch for all aquatic protected species and slow down, stop their vessel, or alter course, as appropriate and regardless of vessel size, to avoid striking any protected species. A single aquatic protected species at the surface may indicate the presence of submerged animals in the vicinity of the vessel; therefore, precautionary measures should always be exercised. A visual observer aboard the vessel must monitor a vessel strike avoidance zone (species-specific distances detailed below) around the vessel according to the parameters stated below, to ensure the potential for strike is minimized. Visual observers monitoring the vessel strike avoidance zone can be either third-party observers or crew members (e.g., captain), but crew members responsible for these duties must be provided sufficient training to distinguish aquatic protected species to broad taxonomic groups, as well as those specific species detailed further below.
2. Vessel speeds must also be reduced to 10 knots or less when mother/calf pairs, pods, or large assemblages (greater than three) of any marine mammal are observed near a vessel.
3. All vessels must maintain a minimum separation distance of 100 meters (m) from

sperm whales, and 500 m from any baleen whale to specifically protect the Gulf of Mexico Bryde's. If a large whale species is unidentifiable, then the vessel/observer/crew should act upon their actions per these mitigations as if it is a baleen whale.

4. All vessels must, to the maximum extent practicable, attempt to maintain a minimum separation distance of 50 meters from all "other aquatic protected species" including sea turtles, with an exception made for those animals that approach the vessel.
5. When aquatic protected species are sighted while a vessel is underway, the vessel should take action as necessary to avoid violating the relevant separation distance (e.g., attempt to remain parallel to the animal's course, avoid excessive speed or abrupt changes in direction until the animal has left the area). If aquatic protected species are sighted within the relevant separation distance, the vessel should reduce speed and shift the engine to neutral, not engaging the engines until animals are clear of the area. This does not apply to any vessel towing gear (e.g., source towed array and site clearance trawling).
6. If a manatee is sighted, vessels associated with the project should operate at "no wake/idle" speeds within that area. Vessels should follow routes of deep water whenever possible and attempt to maintain a distance of 50 m if practicable. This does not apply to any vessel towing gear (e.g., source towed array and site clearance trawling).
7. Any BOEM/BSEE-authorized or -permitted activity occurring within the Eastern Planning Area will be subject to a step-down review with NMFS under the attached 2020 biological opinion on BOEM Oil and Gas Program Activities in the Gulf of Mexico.

The above requirements do not apply in any case where compliance would create an imminent and serious threat to a person or vessel or to the extent that a vessel is restricted in its ability to maneuver and, because of that restriction, is unable to comply.

Injured/Dead Protected Species Reporting

Vessel operators must report sightings of any injured or dead aquatic protected species immediately, regardless of whether the injury or death is caused by your vessel. If the injury or death was caused by a collision with the operator's vessel, an entrapment within the operator's equipment or vessel (e.g. moon pool), or an entanglement within the operator's equipment, the operator must further notify BOEM and BSEE within 24 hours of the strike or entrapment/entanglement by email to protectedspecies@boem.gov and protectedspecies@bsee.gov[1].

[1] BOEM/BSEE will forward these reports to NMFS ESA section 7 biologist per reporting requirements under the attached biological opinion terms and conditions.

For injured or dead non-marine mammal aquatic protected species, report incidents to the hotlines listed at https://www.fisheries.noaa.gov/report (phone numbers vary by state). For reporting dead or injured marine mammals, refer to the reporting requirements specified in the MMPA authorization (as applicable), associated with the activity being conducted. The report must include the following information:

1. Time, date, water depth and location (latitude/longitude) of the first discovery (and updated location information if known and applicable);
2. Relevant weather conditions (e.g., cloud cover, fog, sun glare, etc.);
3. Name, type, call sign, and speed of the vessel during and leading up to the first sighting;
4. Species identification (if known) or description of the animal(s) involved;
5. Condition of the animal(s) (including carcass condition if the animal is dead);
6. Observed behaviors of the animal(s), if alive;
7. If available, photographs or video footage of the animal(s); and
8. General circumstances under which the animal was discovered.

Appendix D. Fisheries Take of Turtles

Table A- 1. Summary of Anticipated 3-year Take and Mortality Estimates for the Coastal Migratory Pelagic Resources in the Atlantic and Gulf of Mexico (NMFS 2015).

Species	Take	Total
Green sea turtle North Atlantic DPS	Total	31
	Lethal	9
Loggerhead sea turtle NWA DPS	Total	27
	Lethal	7
Kemp's ridley sea turtle	Total	8
	Lethal	2
Hawksbill sea turtle	Total	1
	Lethal	1
Leatherback sea turtle	Total	1
	Lethal	1
Smalltooth sawfish	Total	1
	Lethal	0
Atlantic sturgeon GM DPS	Total	2 (12)
	Lethal	0
Atlantic sturgeon NYB DPS	Total	4 (12)
	Lethal	0
Atlantic sturgeon CB DPS	Total	3 (12)
	Lethal	0
Atlantic sturgeon Carolina DPS	Total	4 (12)
	Lethal	0
Atlantic sturgeon SA DPS	Total	10 (12)
	Lethal	0

Table A- 2. Anticipated takes over 3-years for the Highly Migratory Species Atlantic Shark and Smoothhound Fisheries (NMFS 2012).

Sea Turtles	Non-Lethal Take	Lethal Take	Total Estimated Take
Loggerhead	48	78	126
Green	24	33	57
Leatherback	9	9	18
Kemp's ridley	15	21	36
Hawksbill	9	9	18
Marine Fish	**Non-Lethal Take**	**Lethal Take**	**Total Estimated Take**
Smalltooth sawfish	25	7	32
Atlantic sturgeon	GOM DPS = 27	GOM DPS = 9	GOM DPS = 36
	NYB DPS = 129	NYB DPS = 30	NYB DPS = 159
	CB DPS = 36	CB DPS = 9	CB DPS = 45
	SA DPS = 51	SA DPS = 12	SA DPS = 63
	Carolina DPS = 12	Carolina DPS = 6	Carolina DPS = 18
	All DPSs = 255	All DPSs = 66	All DPSs = 321
GOM = Gulf of Maine, NYB = New York Bight, CB = Chesapeake Bay, and SA = South Atlantic.			

Table A- 3. Anticipated takes over 3-years for the Southeast U.S. Shrimp Fisheries in Federal Waters (NMFS 2014).

Species	Otter Trawl Interactions, Captures, and Mortalities	Try Net Interactions**, Captures, and Mortalities	Otter Trawl and Try Net Combined Interactions, Captures, and Mortalities
Atlantic Sturgeon [31]	1710 total interactions, including 222 captures of which 27 are expected to be lethal every three years*, with DPS limits as follows: • Gulf of Maine DPS ≤ 156 interactions, including 21 captures, of which 3 are expected to be lethal • New York Bight DPS ≤ 447 interactions, including 60 captures, of which 9 are expected to be lethal • Chesapeake Bay DPS ≤ 309 interactions, including 42 captures, of which 6 are expected to be lethal • Carolina DPS ≤ 498 interactions, including 66 captures, of which 9 are expected to be lethal • South Atlantic DPS ≤ 1353 interactions, including 177 captures, of which 21 are expected to be lethal	63total interactions, all resulting in capture and of which none are expected to be lethal every three years*, with DPS limits as follows: • Gulf of Maine DPS ≤ 6 interactions all resulting in captures, of which none are expected to be lethal • New York Bight DPS ≤ 18 capture, of which none are expected to be lethal • Chesapeake Bay DPS ≤ 12 interactions, all resulting in capture, of which none are expected to be lethal • Carolina DPS ≤ 21 interactions all resulting in capture, of which none are expected to be lethal • South Atlantic DPS ≤ 51 interactions all which resulting in capture, of which none are expected to be lethal	1773 total interactions, including 285 captures of which 27 are expected to be lethal every three years*, with DPS limits as follows: • Gulf of Maine DPS ≤ 162 interactions, including 27 captures, of which 3 are expected to be lethal • New York Bight DPS ≤ 465 interactions, including 66 captures, of which 9 are expected to be lethal • Chesapeake Bay DPS ≤ 312 interactions, including 54 captures, of which 6 are expected to be lethal • Carolina DPS ≤ 519 interactions, including 87 captures, of which 9 are expected to be lethal • South Atlantic DPS ≤ 1404 interactions, including 228 captures, of which 21 are expected to be lethal
Smalltooth Sawfish	288 (105) every three years	--	288 (105) every three years

*Incidental take will be monitored based on the 3-year running totals (e.g., 2012-2014, 2013-2015)

**All try net interactions result in captures

Table A- 4. Anticipated take over three years starting in 2010 under the Gulf Of Mexico Reef Fish Fishery Management Plan (NMFS 2011).

Species	Commercial Bottom Longline Takes (Mortalities)	Commercial Vertical Line Takes (Mortalities)	Recreational Vertical Line Takes (Mortalities)	Vessel Strike Takes- All Lethal	Entire Fishery Takes (Mortalities)
Loggerhead	644 (397)[A] 623 (384)[B]	77 (23)	254 (75)	90(90)	1065 (585)[A] 1044 (572)[B]
Kemp's ridley	3 (3)	22 (7)	74 (22)	9 (9)	108 (41)
Green	3 (3)	14 (4)	45 (14)	54 (54)	116 (75)
Leatherback	3 (3)	1 (1)	1 (1)	6 (6)	11 (11)
Hawksbill	3 (3)	1 (1)	2 (1)	3 (3)	9 (8)
Smalltooth sawfish	2 (0)	2 (0)	4 (0)	0 (0)	8 (0)

[A]=anticipated in 2010-2012; [B]=anticipated for all subsequent three-year running totals (i.e., 2011-2013, 2012-2014, 2013-2015, etc.).

Appendix E. Summary of Oil Industry Discharges to the OCS Authorized by USEPA General NPDES Permits

Section 402 of the Clean Water Act authorizes the EPA to issue NPDES permits to regulate discharges into the nation's waters. EPA will issue a permit if they determine that the proposed discharges will not result in unreasonable degradation. Factors for determining unreasonable degradation can be found at 40 CFR 125.122. The EPA's review of information provided for the issuance of general permits GMG290000 and GEG460000 has not resulted in a determination of degradation of the impacted waters. These permits considered the following discharges, restrictions, and monitoring requirements:

1. **Drilling fluids/muds –** Fluids that are pumped down the drill pipe to counteract formation pressure, remove drill cuttings, cool the drill bit, and support the bore hole. They are often referred to as drilling muds due to the addition of fine-grained solids, inorganic salts, and organic additives. There are two main types of drilling fluids: water-based fluids (WBF) and Non-aqueous based fluids (NABF) which include oil based fluids (OBF) and synthetic-based fluids (SBF). Drilling fluids often contain barite which is a source of cadmium and mercury, which have been shown to bio-accumulate in marine organisms.

   Restrictions: (1) The discharge of non-aqueous based drilling fluid is prohibited, except that which adheres to cuttings and small volume discharges. Non-aqueous base fluids may be used as a carrier fluid (transporter fluid), lubricity additive or pill in water based drilling fluids and discharged with those drilling fluids provided the discharge continues to meet the "No free oil" and 96-hour LC50 toxicity limits (see below for description), and a pill is removed prior to discharge. (2) The discharge of oil-based drilling fluids and oil-based inverse emulsion drilling fluids are prohibited. (3) Drilling fluids to which any diesel oil has been added as a lubricant may not be discharged. (4) There shall be no discharge of drilling fluids to which barite has been added, if such barite contains mercury in excess of 1.0 mg/kg (dry weight) or cadmium in excess of 3.0 mg/kg (dry weight). (5) No free oil shall be discharged as measured using the static sheen test method. (6) All facilities are subject to a maximum discharge rate of 1,000 barrels per hour.

   Toxicity testing: Operators wanting to discharge drilling fluids must conduct testing to insure the effluent is not toxic to marine organisms. Discharges must meet both a daily minimum and a monthly average minimum 96-hour lethal concentration test (LC50) in which 50% of the test organisms, *Mysidopsis bahia*, must survive the effluent medium. The effluent medium must be at least 30,000 ppm in a 9:1 seawater to drilling fluid suspended particulate phase (SPP) volumetric ratio. Monitoring shall be performed at least once per month for both a daily minimum and the monthly average. In addition, an end-of-well sample is required for a daily minimum when drilling is conducted using aqueous-based drilling fluid. The type of sample required is a grab sample, taken from beneath the shale shaker, or if there are no returns across the shale shaker, the sample must be taken from a location that is characteristic of the overall mud system to be discharged. Permittees shall report the results on the DMR using either the full toxicity test or the partial toxicity test as specified at 58 FR 12512, March 4, 1993; however, if the partial toxicity test shows a failure, all testing of future samples from that well shall be conducted using the full toxicity test method to determine the 96-hour LC50.

Monitoring: Toxicity monitoring shall be performed at least once per month for both a daily minimum and the monthly average. Monitoring for sheen shall be performed using the static sheen method once per week when discharging. The permittee shall also maintain a precise chemical inventory of all constituents and their total volume or mass added down-hole for each well.

2. **Drill cuttings –** particles of crushed rock produced by the grinding action of the drill bit as it penetrates the earth (Neff 2005). Drill cuttings are suspended in drilling fluids and conveyed up the annulus to the surface where they are removed from the fluid and disposed.

   Restrictions: No free oil as measured using the static sheen test method. Cuttings from oil contaminated drilling fluids are prohibited, including those containing diesel oil or mineral oil. Drill cuttings generated using drilling fluids to which barite has been added shall not be discharged if the barite contains mercury in excess of 1.0 milligram per kilogram (mg/kg) dry weight or cadmium in excess of 3.0 mg/kg dry weight.

   Toxicity: Drill cuttings generated using drilling fluids that do not pass the 96-hour LC50 test described above shall not be discharged.

   Sheen Monitoring: Monitoring shall be performed using the static sheen test method once per week when discharging. Monitoring of base fluids retained on cuttings shall be performed at least once per day when generating new cuttings, unless meeting the conditions of a best management practice as described in the permits.

3. **Produced water –** The water (brine) brought up from the hydrocarbon-bearing strata during the extraction of oil or gas. This can include formation water, injection water, and any chemicals added down-hole or during the oil/water separation. Since the oil/water separation process does not completely separate the oil, some hydrocarbons remain with the produced water and often the water is treated to prevent the formation of sheen. The composition of the discharge can vary greatly in the amounts of organic and inorganic compounds and may include: aluminum, arsenic, barium, benzene, cadmium, chromium, copper, cyanide, lead, mercury, nickel, selenium, silver, and zinc among others. The EPA general permits allow the discharge of produced waters provided they meet discharge criteria. Discharge volumes are variable and may range from 500-2,500 barrels per day.

Restrictions: Discharged oil and grease cannot exceed 42 milligrams per liter (mg/l) daily maximum or 29 mg/l monthly average (technology-based limits). The discharge must also be tested for toxicity on a monthly basis.

Toxicity testing: Platforms wishing to discharge produced waters will be required to test the effluent for toxicity. Test results are good for a period of 6 months.

7-day chronic toxicity testing – Tests the survival and growth of mysid shrimp *(Mysidopsis bahia)* and larval inland silversides *(Menidia beryllina)* in a series of effluent dilutions (different dilutions based on a critical dilution as determined by flow rates and the depth of discharge for each platform) in comparison to a control group. The purpose of the test is to determine the greatest effluent dilution at which no significant effect is observed between the test and the control (no observable effects concentration - NOEC). The 7-day average minimum and monthly average minimum NOEC must be equal to or greater than the critical dilution concentration. Test is to be completed at least every 6 months.

Sheen Monitoring: Monitoring shall be performed using the static sheen test method once per day when discharging when a facility is manned. Grab sampling for oil and grease analysis will be conducted once per month. Flow rates shall also be monitored once per month.

4. **Well treatment, completion fluids, and workover fluids**
   a. Well treatment fluids are any fluids used to restore or improve productivity by chemically or physically altering hydrocarbon-bearing strata after a well has been drilled. These fluids are typically added down-hole and mostly remain within the wellbore; any fractions that may escape are subject to the limitations described in the following restrictions.
   b. Completion fluids are salt solutions, weighted brines, polymers, and various additives used to prevent damage to the well bore during operations which prepare the drilled well for hydrocarbon production.
   c. Workover fluids are salt solutions, weighted brines, polymers, or other specialty additives used in a producing well to allow for maintenance, repair, or abandonment procedures. This includes packer fluids.

   Restrictions: No free oil as measured using the static sheen test method and no priority pollutants except in trace amounts (as established in the 2005 issued permit) may be discharged. Fluids must also meet both a daily maximum of 42 mg/l and a monthly average of 29 mg/l limitation for oil and grease.

   Sheen Monitoring: Sampling for the static sheen test will be done daily when a discharge occurs. Grab sampling for oil and grease analysis will be conducted once per month and should not exceed technology-based limits.

5. **Deck drainage –** Any waste resulting from deck washings, spillage, rainwater, and runoff from gutters and drains including drip pans and work areas within facilities subject to this permit. Deck drainage of the largest concern include oil and detergents, drilling fluids, and acids used during workover operations.

Restrictions: No free oil shall be discharged as determined by the presence of a film or sheen upon the surface of the receiving water. Typically these platforms are equipped with pans to collect deck drainage. The drainage is separated by gravity into waste material and liquid effluent. Waste materials are sent to a sump tank for treatment followed by disposal, recycling back to the drilling mud system, or transport to shore. Liquid effluent is discharged to the sea.

Monitoring: Visual sheen test method to be completed once per day when discharging.

6. **Sanitary waste –** human body waste discharged from toilets and urinals located within facilities subject to this permit. The volume and concentrations of these wastes vary widely with time, occupancy, platform characteristics, and operational situation. Past monthly average sanitary waste flows from Gulf Coast platforms was approximately 35 gallons per day (EPA 1993).

   Restrictions: No floating solids and residual chlorine to be maintained as close to 1 mg/l as possible for facilities continuously manned by 10 or more persons. No floating solids for facilities continuously manned by 9 or fewer persons. Any facility that properly operates and maintains a marine sanitation device (MSD) that complies with pollution control standards and regulations under Section 312 of the Clean Water Act shall be deemed to be in compliance with permit limitations for sanitary waste.

   Monitoring: Observation for floating solids shall be conducted once daily during discharge while sampling for residual chlorine shall be done once per month. If a MSD is being used, yearly testing to insure proper operation is required.

7. **Domestic waste –** Material discharged from galleys, sinks, showers, safety showers, eye wash stations, hand washing stations, fish cleaning stations, and laundries. The volume of domestic waste discharged is estimated to be 50-100 gallons per person per day.

   Restrictions: No floating solids or foam and require compliance with the requirements of 33 CFR 151. *Region 4 only*: Any soaps and detergents must be phosphate free (contain less than 0.5% phosphate).

   Monitoring: Observation for floating solids shall be conducted daily during daylight hours by visual observation of the receiving waters in the vicinity of the outfall. Observations shall be made following either the morning or midday meals at a time of maximum estimated discharge.

8. **Miscellaneous discharges –** Various discharges of relatively small, though highly variable quantities.
   a. Hydrate control fluids – used to dehydrate natural gas in deep water operations to prevent pipeline blockages. It is unlikely that these fluids will be necessary in the relatively shallow water wells of the territorial seas of Texas. If used, however, they will typically be discharged in the produced water stream and would be limited by the same restrictions.
   b. Blowout preventer control fluid – fluid used to actuate the hydraulic equipment on the blow-out preventer or subsea production wellhead assembly. These may be

discharged periodically in small quantities (67-314 barrels per day, EPA 1993) at the sea floor.

c. Boiler blowdown – discharges from boilers necessary to minimize solids build-up in the boilers, including vents from boilers and other heating systems. Based on past operations, these may be discharged at a volume of 0-5 barrels per day (EPA 1993).
d. Diatomaceous earth filter media – filter media used to filter seawater or other authorized completion fluids and subsequently washed from the filter.
e. Excess cement slurry – the excess mixed cement, including additives and wastes from equipment wash-down, after a cementing operation.
f. Mud, cuttings, and cement at the sea floor – discharges that occur at the sea floor prior to installation of the marine riser and during marine riser disconnect, well abandonment, and plugging operations.
g. Source water and sand – water from non-hydrocarbon bearing formations for the purpose of pressure maintenance or secondary recovery.
h. Uncontaminated or treated ballast/bilge water – seawater added or removed to maintain proper draft or water from a variety of sources that accumulates in the lowest part of the vessel/facility. Volumes may be expected to range from 70-620 barrels per day (EPA 1993).
i. Uncontaminated freshwater or seawater – waters discharged without contact with or addition of chemicals, oil, or other wastes.

Restrictions: No free oil, floating solids, or foam shall be discharged.
Monitoring: Observations shall be made once per week.

9. **Chemically-treated seawater and freshwater** – waters to which corrosion inhibitors, scale inhibitors, biocides, and/or other chemicals have been added and include the following discharges:

   a. Excess seawater which allows the continuous operation of fire control and utility lift pumps
   b. Excess seawater from pressure maintenance and secondary recovery projects
   c. Water released during training and testing of personnel in fire protection
   d. Seawater used to pressure test piping and pipelines
   e. Ballast water or bilge water
   f. Non-contact cooling water
   g. Desalinization unit discharge – the residual high-concentration brine discharged offshore from distillation or reverse osmosis units used for producing potable water. Past operations have discharged this at a volume of up to 238 barrels per day (EPA 1993).

   Restrictions: No free oil and the most stringent of the 3 following conditions:

      i. The maximum concentrations and any other condition specified in the EPA product registration labeling if the chemical additive is an EPA-registered product

ii. The maximum manufacturer's recommended concentration when one exists
iii. 500mg/l

Toxicity testing: 48-hr acute toxicity test will determine if an appropriately dilute effluent sample adversely affects the survival of mysid shrimp and inland silversides. The 48-hr minimum and monthly average minimum NOEC must be equal to or greater than the critical dilution concentration (determined by the discharge rate and the pipe diameter at each facility).

Monitoring: Visual sheen test shall be conducted once per week when discharging. Monitoring for toxicity will be required at least once per 6 months when discharging.

Requirements pertaining to cooling water intake structure regulations per 40 CFR Part 125 Subpart N (Requirements Applicable to Cooling Water Intake Structures for New Offshore Oil and Gas Extraction Facilities under Section 316(b) of the Clean Water Act). These requirements will limit intake velocity, minimize impingement and entrainment, and set monitoring and record keeping requirements (40 CFR 125.134 (b)(2-8)).

In addition, the new permit will also include the following improvement:
Increased ambient water monitoring requirements are replaced with well treatment fluids study.

Appendix F. BOEM Oil and Gas Program AIS vessel types

id	Level 5 type	Level 5 description
1	Aggregates Carrier	A single deck cargo vessel for the carriage of aggregates in bulk. Also known as a Sand Carrier. May be self discharging
2	Waste Disposal Vessel	A vessel equipped for the transportation, treatment and/or (now illegal) discharge at sea of waste material
3	Crane Vessel	A vessel equipped with a large crane for lifting operations
5	Mooring Vessel	A vessel equipped to assist with the mooring and/or anchoring of larger vessels. Typically it will have a frame to prevent the ropes and chains fouling on the superstructure
10	Crude/Oil Products Tanker	A tanker for the bulk carriage of crude oil but also for carriage of refined oil products
11	Shuttle Tanker	A tanker for the bulk carriage of crude oil specifically for operation between offshore terminals and refineries. Is typically fitted with bow loading facilities
12	Pipe Burying Vessel	A vessel equipped to carry small stones and aggregates and to deliver them via a flexible fall pipe system to bury pipes and cables on the sea bed
15	Trailing Suction Hopper Dredger	A vessel equipped to obtain material from the sea bed by use of a trailing suction pipe. The material may be carried on board and discharged elsewhere through the bottom of the vessel, either by bottom doors or a split hull, or delivered to other vessels
16	Supply Platform, semi submersible	A semi submersible offshore supply platform
17	Water Tank Barge, non propelled	A non propelled tank barge for the carriage of water
19	Asphalt/Bitumen Tanker	A tanker for the bulk carriage of asphalt/bitumen at temperatures between 150 and 200 deg C
24	Cable Repair Ship	A vessel equipped for the retrieval and repair of underwater cables
25	Pipe Layer Crane Vessel	A pipe layer also equipped with a large crane or derrick

26	Bulk Cement Barge, non propelled	A non propelled barge for the carriage of bulk cement
33	FSO, Oil	A tanker purpose built or converted to store oil produced from a field prior to its transfer to another vessel for transportation. May be self or non propelled. This type does not include vessels which are temporarily being used for storage of oil
34	Jacket Launching Pontoon, semi submersible	A semi submersible pontoon designed for positioning and launching jackets for offshore use
37	Drilling Rig, jack up	A jack up offshore drilling rig
44	Combination Gas Tanker (LNG/LPG)	A tanker for the bulk carriage of Liquefied Natural Gas (primarily methane) and/or Liquefied Petroleum Gas in independent insulated tanks
52	Research Survey Vessel	A vessel equipped for research and/or survey (e.g. geophysical, hydrographic)
53	LNG Tanker	A tanker for the bulk carriage of Liquefied Natural Gas (primarily methane) in independent insulated tanks. Liquefaction is achieved at temperatures down to -163 deg C
54	Effluent carrier	A vessel equipped for the transportation of effluents. Discharge at sea is now illegal
55	Utility Vessel	A small multi functional response vessel not dedicated to a particular function
57	Anchor Handling Tug Supply	An offshore tug/supply ship equipped with a high bollard pull and a stern roller for anchor handling
58	Accommodation Platform, semi submersible	A semi submersible offshore accommodation platform
71	Cement Storage Barge, non propelled	A barge with pumping facilities for loading & discharging cement.
82	Support Platform, jack up	A non-propelled jack up vessel for offshore support
83	Pollution Control Vessel	A vessel equipped for the primary function of pollution control. Typical types include oil spill recovery vessel and a pollution and debris collector
86	Pusher Tug	A vessel equipped to push cargo-carrying barges and pontoons.
88	Bulk/Oil Carrier (OBO)	A bulk carrier arranged for the alternative (but not simultaneous) carriage of crude oil
91	Crane Platform, jack up	A jack up offshore crane platform
94	Crane Vessel, non propelled	A non self propelled vessel equipped with a large crane for lifting operations

96	Bulk Aggregates Barge, non propelled	A non propelled barge for the carriage of bulk aggregates
99	Jacket Launching Pontoon	A pontoon designed for positioning and launching jackets for offshore use
100	Crew Boat	A vessel equipped for the transportation of crew to ships and/or installations
102	Crude Oil Tanker	A tanker for the bulk carriage of crude oil
107	Hopper/Dredger (unspecified)	A vessel equipped to obtain material from the sea bed by an unspecified means. The material may be carried on board and discharged elsewhere through the bottom of the vessel, either by bottom doors or a split hull, or delivered to other vessels, pumped a
110	FSO, Gas	A tanker purpose built or converted to store gas produced from a field prior to its transfer to another vessel for transportation. May be self or non propelled. This type does not include vessels which are temporarily being used for storage of gas
112	Barge Carrier	A cargo vessel arranged for the carriage of purpose built barges (lighters) loaded with cargo. Typically loading is by way of a gantry crane. Also known as Lighter Aboard SHip vessels (LASH)
113	Grab Dredger	A vessel equipped to obtain material from the sea bed by use of a grab. The material may be carried on board, transferred to other vessels, pumped ashore or deposited elsewhere using a spray
118	Pipe Carrier	A platform supply ship equipped with increased scantlings & longer deck space for the transportation of pipes
123	Pipe layer Platform, semi submersible	A semi submersible offshore pipe layer platform
131	LPG Tanker	A tanker for the bulk carriage of Liquefied Petroleum Gas in insulated tanks, which may be independent or integral. The cargo is pressurised (smaller vessels), refrigerated (larger vessels) or both ('semi-pressurised') to achieve liquefaction.
132	Well Stimulation Vessel	A vessel primarily equipped to maximize oil production from a well
136	Grab Hopper Dredger	A vessel equipped to obtain material from the sea bed by use of a grab or backhoe. The material may be carried on board and discharged elsewhere through the bottom of the vessel, either by bottom doors or a split hull, or delivered to other vessels, pump

147	Ore/Oil Carrier	An ore carrier arranged for the alternative (but not simultaneous) carriage of crude oil
152	Maintenance Platform, semi Submersible	A semi submersible offshore maintenance platform
153	Tug	A vessel equipped with a towing winch to tow other vessels (either in harbour or in open sea) and with manoeuvring capabilities to assist vessels to berth/unberth in ports. May also be able to push barges and other vessels
155	Pipe Layer	A vessel primarily equipped to lay solid or flexible pipes on the sea bed
156	Pile Driving Vessel	A vessel equipped for pile driving operations
158	FPSO, Oil	A vessel with the capability to control production rates from an oilfield and to store oil produced prior to its transfer to another vessel for transportation. May be self or non propelled
162	Production Platform, jack up	A jack up offshore production platform
165	Offshore Tug/Supply Ship	A vessel for the transportation of stores and goods to offshore platforms on an open stern deck and equipped with a towing facility
166	CNG Tanker	A tanker for the bulk carriage of Compressed Natural Gas. Cargo remains in gaseous state but is highly compressed
167	Offshore Support Vessel	A single or multi functional offshore support vessel
168	Accommodation Platform, jack up	A jack up offshore accommodation platform
175	Water Tanker	A tanker for the bulk carriage of water
176	Trenching Support Vessel	A vessel primarily equipped to operate submersibles for digging trenches on the sea bed for pipes and cables
177	Crude Oil Tank Barge, non propelled	A non propelled tank barge for the carriage of crude oil
180	Cable Layer	A vessel equipped to lay and repair underwater cables
182	Sheerlegs Pontoon	A pontoon with sheerlegs for lifting
184	Production Platform, semi submersible	A semi submersible offshore production Platform
186	Drilling Ship	A vessel primarily equipped for offshore drilling operations. May also be able to obtain cores for research purposes
187	Anchor Handling Vessel	A vessel equipped to assist with the handling of anchors

188	Barge Carrier, semi submersible	A barge carrier which is semi submersible for the float on loading/unloading of the barges
194	Heavy Load Carrier, semi submersible	A heavy load carrier which is semi submersible for the float on loading/unloading of the cargoes
195	LPG/Chemical Tanker	An LPG tanker additionally capable of the carriage of chemical products as defined in the International Bulk Chemical Code
210	Drilling Rig, semi submersible	A semi submersible offshore drilling rig
214	Suction Dredger Pontoon	A non propelled dredger pontoon fitted with suction equipment
218	Passenger Ship	A vessel certificated to carry more than 12 passengers, some of whom may be accommodated in cabins
222	Crew/Supply Vessel	A typically high speed vessel primarily for the transportation of crew to offshore facilities; may also have limited stores carriage capability on an open deck
228	Work/Repair Vessel	A multi functional vessel for general work and repair operations
236	Floating Dock	A submersible unit constructed and fitted out to dry dock ships whilst afloat.
237	Cement Carrier	A single deck cargo vessel fitted with pumping arrangements for the carriage of cement in bulk. There are no weather deck hatches. May be self discharging
238	Salvage Ship	A vessel equipped for salvage operations
239	Diving Support Platform, semi submersible	A semi submersible diving support platform
243	Crane Platform, semi submersible	A semi submersible offshore crane platform
244	Deck Cargo Pontoon, semi submersible	A non propelled semi submersible pontoon for the carriage of general deck cargoes
248	LPG Tank Barge, non propelled	A non propelled tank barge for the carriage of LPG
251	Suction Hopper Dredger	A vessel equipped to obtain material from the sea bed by use of a suction pipe. The material may be carried on board and discharged elsewhere through the bottom of the vessel, either by bottom doors or a split hull, or delivered to other vessels
256	Supply Platform, jack up	A supply platform, jack up
258	Accommodation Ship	A vessel providing accommodation for those working on other vessels and installations

263	Standby Safety Vessel	A vessel primarily equipped to perform safety standby duties. Will be fitted with accommodation and facilities for the rescue, reception and initial care of survivors from offshore installations accidents
271	Pipe layer Platform, jack up	A jack up offshore pipe layer platform
277	Diving Support Vessel	A vessel primarily equipped with decompression chambers for air dive operation. Does not include vessels which can only operate submersibles
281	Platform Supply Ship	A vessel for the transportation of stores and goods to offshore platforms on an open deck, typically at the stern. May also be fitted with specialist under deck tanks for water, cement and/or drilling mud
286	Cutter Suction Dredger	A vessel equipped to obtain material from the sea bed by use of a cutter wheel, which loosens the material, and a suction pipe. The material may be carried on board, transferred to other vessels, pumped ashore or deposited elsewhere using a spray
297	Production Testing Vessel	A vessel primarily equipped for testing the quality and amount of oil produced by a well
298	Mechanical Lift Dock	A lifting dock facility using winches to lower and raise platform
301	Offshore Construction Vessel, jack up	A propelled vessel with a self-elevating facility to facilitate offshore maintenance, construction and/or installation
305	Grab Dredger Pontoon	A non propelled dredger pontoon fitted with a system of grabs
318	Suction Dredger	A vessel equipped to obtain material from the sea bed by use of a suction pipe. The material may be carried on board, transferred to other vessels, pumped ashore or deposited elsewhere using a spray

Appendix G. Extremely large spill assessment

Before we conducted our hazard assessment and exposure analysis for oil spills associated with the proposed action, we first assessed the available information used to determine the potential largest spill size volumes (refer to Table 114 in the Opinion), which one of these estimates of representative very large spill sizes was provided by BOEM (100,000 bbl per Ji et al. 2014).

Determination of the Upper Range of Spill Sizes

BOEM has defined very large spills as any spill volume greater than or equal to 10,000 bbl, and provided NMFS with information projecting that two oil spills greater than or equal to 10,000 bbl may occur over the duration of the proposed action. However, BOEM has not defined an upper volume for such a spill size. BOEM stated that it "does not consider an extremely large event as reasonably certain to occur" over the time frame of this opinion, although BOEM does acknowledge that impacts from the DWH blowout and resulting spill warrant inclusion in Gulf of Mexico consultation as part of the environmental baseline. For informational purposes for decision-makers, BOEM used current reservoir sizes to demonstrate the size and duration of extremely large releases in shallow water and deepwater areas. BOEM characterized an extremely large spill in shallow water as being uncontrolled flow for one to three months, resulting in an estimated range of 900,000-3,000,000 bbl released[1]. For deep water, BOEM provided information that if an extremely large event occurred and remained uncontrolled up to four months, potentially 2.7-7.2 million bbl could be released. Following our analysis of spill data and statistical assessments of the occurrence of very large spills that is explained in more detail below, we estimated the volume of the largest spill size based on the duration of a spill that could possibly occur over the timeframe of the opinion.

A fundamental challenge is to accurately describe this risk, especially since there have been relatively few large to very large oil spills that can serve as benchmarks. Prior to the DWH event, the three largest blowout spills on the U.S. OCS were 80,000 bbl, 65,000 bbl, and 53,000 bbl, and all occurred before 1971 (Anderson et al. 2012). At the present time, there is a not an ideal, standardized approach to characterizing the risk of spill occurrence and consequence. Historically, BOEM has characterized oil-spill risk using the Oil Spill Risk Analysis (OSRA) model to identify the risk of oil released from numerous locations on the OCS occurring and contacting environmental, social and economic resources. BOEM performs OSRA modeling in the evaluation of individual lease sales and certain exploration/development plans. BOEM or BSEE also consider risk during the review of an operator's Exploration Plan, Development and Production Plan (or Development Operations Coordination Document), and/or Application for Permit to Drill.

BOEM's probabilistic spill estimates use an oil spill risk method based on historical spill rates per volume of oil produced. The number of spills has been estimated for different spill sizes based on the anticipated volume of oil produced over this consultation period. One data point,

---

[1] BOEM 2014 Qualitative Review of Safety Measures to Minimize Frequency of Blowouts and Spills and Maximize Containment Capabilities

the DWH event, represents both the greater than or equal to 10,000 bbl and extremely large spill categories in BOEM's analyses. The lack of data for very large spills results in a high degree of statistical uncertainty. It is worth noting that BOEM's methodology would not have predicted that the DWH event would have occurred. Because of this high uncertainty to produce probabilistic estimates of the frequency of large oil spills resulting from protracted loss of well control, BOEM provided NMFS additional information to support their conclusions. BOEM provided NMFS a summary of recent peer reviewed literature regarding oil spills, information on new safety requirements, spill response preparedness, and new spill response and containment technology. Given the additional information we decided to defer to BOEM as the experts on the probability of occurrence of an extremely large spill.

To estimate a reasonable maximum possible spill size, we considered the following main factors:

- The pre-DWH spill risk considered in the 2007 biological opinion.
- The causes of blowout, loss of well control and other potential risks that cause spills.
- Information from our review of extremely large spill risk assessments provided by BOEM, federal reports, and independent studies on determining the risk and frequency of very large spills found in the peer-reviewed literature.
- Regulatory reforms and improvements in offshore drilling safety since DWH. Assuming some risk of a blowout and other risk factors, we will consider the likelihood of those risk factors that could actually result in a loss of well control and uncontrolled release of oil into the ocean.
- The volume of oil that could be spilled in the future using BOEM's estimated flow rates.
- The anticipated flow duration of an uncontrolled blowout based on our assessment of the ability of industry to rapidly respond to a blowout and bring a well under permanent control.
- The adequateness of OSRPs to prepare for extremely large spill responses, limit the duration of the spill, clean up the oil, and respond to ESA-listed species and critical habitat that may be affected.

Pre-Deepwater Horizon Risk

In the 2007 biological opinion, although BOEM did not predict a major, uncontrolled oil spill, we predicted that a single extremely large spill would occur approximately every 40 years. That estimate proved reasonably accurate, with the DWH spill's occurrence 31 years after Ixtoc I and is reflected in the 26-34 year pre-DWH extremely large spill frequency estimate found in the economic analysis prepared for BOEM's drilling safety rule (https://www.bsee.gov/sites/bsee.gov/files/research-guidance-manuals-or-best-practices/regulations-and-guidance/aa02-final-rule-8-10-12.pdf). Our 2007 opinion significantly underestimated the severity of a major uncontrolled release, as evidenced by the DWH event. The flow rate of oil from the well and the amount of time it took to bring the well under control were the primary reasons we underestimated the size of and impacts associated with the largest spill we predicted would occur. Our underestimate of impacts to listed species was the primary reason reinitiation of consultation was requested in 2010. During consultation, we emphasized the necessity of additional information on the risk of future extremely large spills to complete this opinion.

Causes of Very Large Oil Spills and Risks

Blowouts and subsequent losses of well control are the primary concern for a very large release of oil in the Gulf of Mexico. Blowouts are generally associated with equipment failures, human error, hurricane-related failures, or a combination of these events. The DWH event has been the only disastrous blowout and loss of well control on the U.S. OCS in the Gulf of Mexico; therefore, in this section, we will review the past occurrences of blowouts, as well as some recent causes of other large, but non-disasterous oil spills.

There have been 21 blowouts associated with seven individual events that have resulted in loss of well control in the Gulf of Mexico (Table 1). Four of the spills were the result of hurricane-related failures, another four were the result of blowouts during drilling, and the remaining spills resulted from a single event where a platform shifted position and blew out all the wells connected to it. Four of these blowout-related spills, including DWH, were greater than 10,000 bbl. Until the occurrence of the DWH event, all blowout-related spills occurred between 1965 and 1970 (Table 1).

Table 1. Blowouts on the Federal OCS that have Resulted in Loss of Well Control and Oil Spills Greater than 1,000 bbl.

Year of Spill Event	Number of Blowouts	Duration (days)	Water Depth (ft)	Volume Spilled (bbl)	Details
1964	3	several days	48	5,180	Hurricane Hilda destroyed 3 platforms in Eugene Island, Block 208
1964	1	17	33	5,100	Hurricane Hilda destroyed a platform in Ship Shoal, Block 149
1965	1	8	190	1,688	Drilling Blowout in Ship Shoal, Block 29
1969	1	10	190	80,000	Drilling blowout in Santa Barbara Channel in lease area 6B 5165
1970	13	49	39	65,000	Rig shift and fire resulting in 13 blowouts in Main Pass, Block 41

Year of Spill Event	Number of Blowouts	Duration (days)	Water Depth (ft)	Volume Spilled (bbl)	Details
1970	1	138	60	53,000	Drilling blowout and fire in South Timbalier, Block 26
2010	1	86	4,992	4.9 million est.	Blowout and fire in Mississippi Canyon, Block 252

Source: BOEM BA supplemental information

Several other non-blowout-related spills were caused by Hurricane Rita in 2005 (six structures lost or damaged), Hurricane Jeanne in 1980 (one damaged structure), a sinking storage barge (one event), vessels colliding with platform (two events), and leaking storage structures (three events) (Table 2). However, all but one of these non-blowout-related spills were less than 10,000 bbl.

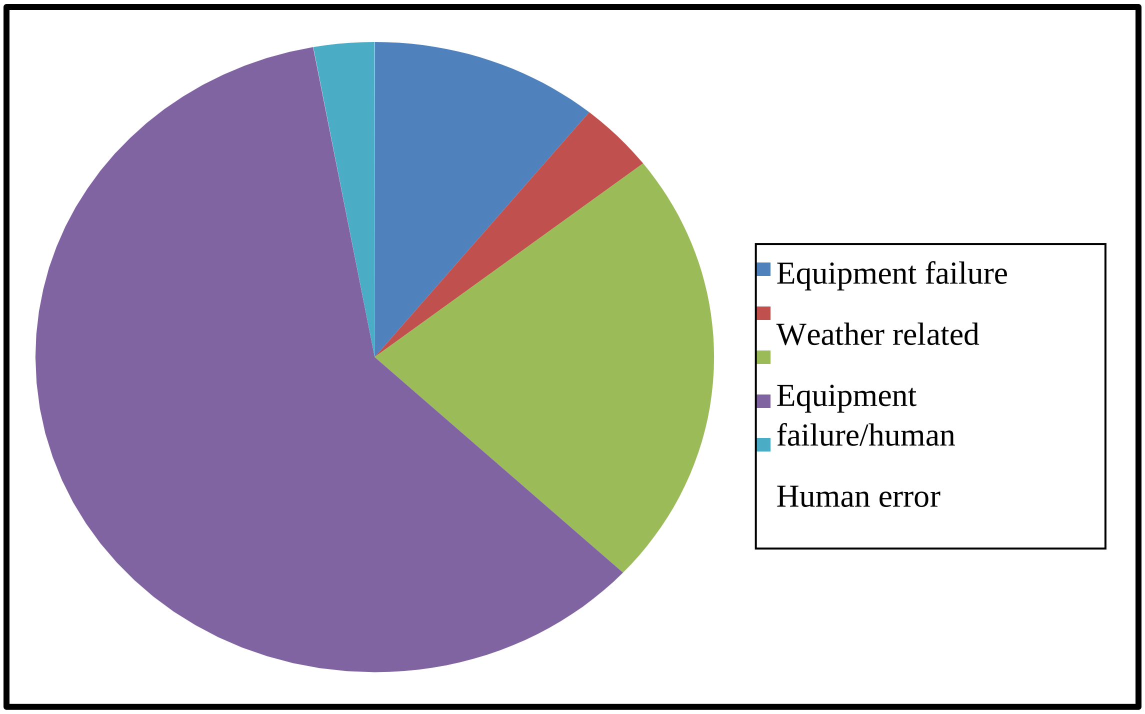
Table 2. Non-blowout Spills on the Outer Continental Shelf that Have Resulted in Spills Greater than 1,000 bbl.

Year of Spill Event	Number of Structures	Water Depth (ft)	Volume Spilled (bbl)	Details
1964	1	94	2,559	Freighter struck platform in Eugene Island, block 208.
1964	1	102	1,589	Storage tank lost during Hurricane Hilda in Ship Shoal, Block 149
1969	1	30	2,500	Supply vessel collided with a semisubmersible drilling rig in Ship Shoal, Block 72
1973	1	110	9,935	Storage tank failure in West Delta, Block 79
1973	1	61	7,000	Storage barge sank
1979	1	61	1,500	Workboat collided with a drilling rig putting a hole in a diesel tank, Main Pass, Block 151

Year of Spill Event	Number of Structures	Water Depth (ft)	Volume Spilled (bbl)	Details
1980	1	60	1,456	A storage tank overflowed during evacuation of platform during hurricane Jeanne, High Island, Block 206
2004	1		>1,000	Hurricane Ivan and underwater landslide toppled platforms and severed numerous wellheads. Low discharge, chronic oil seepage is still ongoing.
2005	3	182-238	5,066	Hurricane Rita destroyed 1 platform and 2 drilling rigs.
2013	1		1,531	Drilling rig lost station; lower marine riser emergency disconnect activated.
2015	1		2,200	Lower marine riser installation error.
2016	1		2,100	Subsea flowline.
2017	1		16,152	Subsea jumper (pipeline segment) damage.

Source: BOEM BA supplemental information

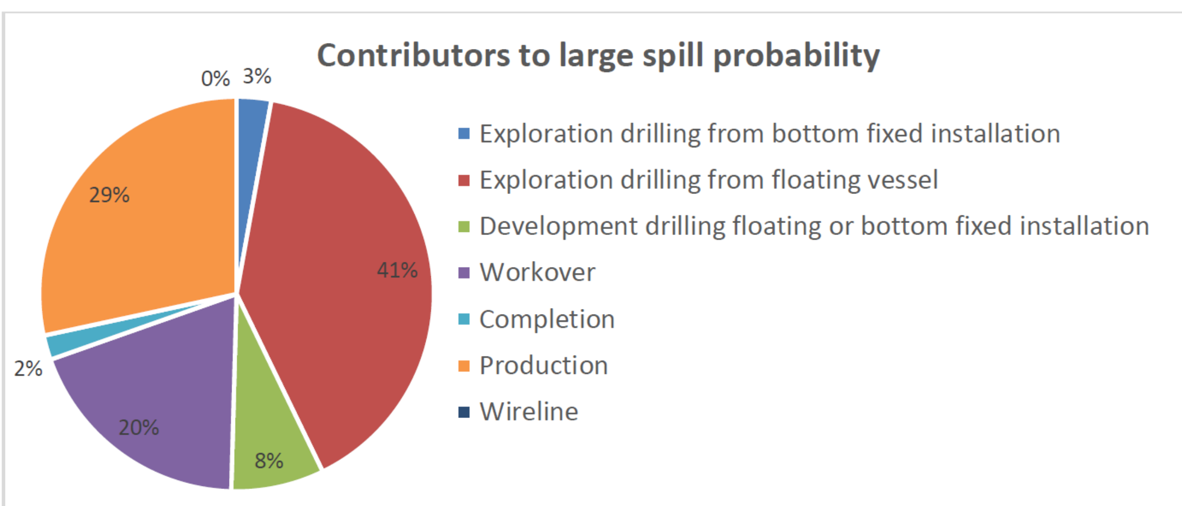
After the DWH incident, from 2011-2013 BSEE investigated 139 total accidents including 18 spill releases. One hundred and fifteen accidents (82.7 percent) were caused, at least in part, by human error and 73 (52.5 percent) were determined to have been entirely caused by human error (Figure 1). Eighteen of the accidents (12.9 percent) resulted in some type of pollution being released and those included spills of less than one gallon of gas/oil (only enough to produce a sheen), minor chemical or diesel spills associated with facility maintenance, drilling fluid releases and releases of synthetic oil based mud. Spills were mainly small volumes of oil caused by human error (misuse of equipment or failure to notice an over-pressurized vessel), sometimes leading to a series of events, and ultimately causing an unplanned release.



Source: BOEM BA supplemental information

Figure 1. Causes of oil and gas accidents reported on the Gulf of Mexico OCS from 2011-2013 as reported to BSEE.

BSEE (2017) examined loss of well control events and categorized contributors to the probability as shown in Figure 2, and Figure 3 displays BSEE's risk analysis for oil spills caused by loss of well control events. The highest risk events are the blowout (surface flow) accidents, which have potential for the more severe overall impacts (BSEE 2017). According to BSEE (2017), risk may be reduced by reducing the drilling kick frequency.



Source: BOEM BA supplemental information

Figure 2. Pie chart from BSEE (2017) displaying the categories of contributors to large spill probability.

Probability	LOWC consequence (Spill size)					
	No or insignificant spill	Minor spill (10 - 50 bbls)	Medium spill (50 -500 bbls)	Large spill (500 – 5,000 bbls)	Very large spill (5,000 - 50,000 bbls)	Gigantic spill (>50,000 bbls)
More frequent than once a year	X					
1 - 5 times in 5 year		X				
1 - 4 times in 20 year						
1- 4 times in 80 year			X			
1 - 2 times in 160 year				X	X	X
less than once in 160 year						

Source: BOEM BA supplemental information

Figure 3. Risk matrix from BSEE (2017) for oil spills caused by loss of well control events, with the X indicating BSEE's predicted loss of well control risk level. Red indicates high risk, yellow indicates moderate risk, green indicates low risk.

Based on our review of the historical spill data above, the cause of spills occurring in volumes greater than 10,000 bbl could likely be the result of a loss of well control resulting from a drilling-related blowout. Three of the four very large drilling-related blowouts that have occurred in the greater than or equal to 10,000 bbl category average a spill size of 66,000 bbl (53,000, 65,000 and 80,000 bbl) and one spill (DWH) has been extremely large (≥ three million bbl). BOEM has indicated that two spills greater than 10,000 bbl may result from the proposed action. Based on the historical data above and the estimate of the number of spills provided by BOEM, two very large (greater than 10,000 bbl) drilling-related releases of oil can be expected to occur during the next 50 years, for the reasons discussed in further detail below. The information above leads us to conclude that one of these spills can be expected as the result of a blowout resulting in a release of 100,000 bbl (per Ji et al. 2014; and Table 114, section 8.8 of the biological opinion). Since we have only a single extremely large release of oil (the DWH event) from which to estimate future impacts, we will next consider in more detail the frequency and likely largest size of such extremely large releases occurring on the OCS.

Best Available Information on the Largest Potential Spill

This section first provides a summary of some relevant peer-reviewed literature regarding statistical methods to predict the risk of extremely large spills occurring from significant uncontrolled blowouts. As discussed above, loss of well control and associated extremely large release of oil is more likely to occur in deep water due to the increased risks associated with higher well pressures and the technological challenges of drilling in deep water than are present in shallow water. Many regulatory changes have been made since the DWH event. NMFS agrees with BOEM that new regulatory and technological advances reduce the risk of another DWH-sized event. However, the effectiveness of the changes cannot be quantitatively measured. By their very nature, oil spill risk analyses rely on data from past accidents to project future spill occurrences. Consequently, analyses published since the DWH event do not consider the effectiveness of post-DWH risk-reducing measures that decrease the likelihood or magnitude of spills which occur in the future. NMFS requested that BOEM provide a quantitative estimate of risk reduction from their new regulations, but this was not provided. Thus, we consider qualitative information on risk reducing measures that BOEM provided and we will take into account that oil and gas drilling is occurring in increasingly deeper waters thereby increasing risk. An ultra-deep lease at 2200 m can yield a predicted 374.9 thousand barrels per month-18 times a lease at 200m deep (Murawski et al. 2020). Murawski et al. (2020) also states: “The inherent risks of catastrophic well blowouts at extreme depths will increase as the productivity of oil facilities increases exponentially with water depth.” The following summarizes some of the relevant oil spill risk literature since DWH.

Muehlenbachs et al. 2013 provides an empirical analysis of company-reported incidents (e.g. blowouts, injuries, spills) on oil and gas production platforms in the Gulf of Mexico between 1996 and 2010. This same time period was marked by a dramatic increase in the depths at which offshore oil and gas extraction occurred. Compared with platforms at water depths less than 1,000 ft, the average number of incidents increases more than threefold for depths greater than 1,000 ft. One of the key findings is that company-reported incidents (such as blowouts, fires, injuries, and pollution) increase with water depth. Controlling for platform characteristics such as age, quantity of oil and gas produced, and number of producing wells, for an average platform, each 100 ft of added depth increases the probability of a company-reported incident by 8.5 percent. The paper does not demonstrate that there is a causal link between water depth and incident or violations, but it demonstrates there are statistically significant relationships between the variables.

Rathnayaka et al. (2013) developed an accident modeling and risk assessment framework based on “early warning” accident precursors using system hazard identification, prediction and prevention methodology to model the event. The risk assessment methodology was demonstrated using the DWH event and modeled over a given time period a disasterous event occurrence probability of 1.52×10^{-5}. Results generated from this method of assessment can provide a comprehensive understanding of safety barrier performance, occurrence probabilities, risk values of severity levels, and safety performance of the deepwater drilling rig.

Xue et al. (2013) proposed a new barrier-based accident model for drilling-related blowouts based on the three-level well-control theory: primary and secondary well-control barriers and an extra well-monitoring barrier established between the reservoir and the blowout event. The DWH event was used as a case study to show how the model can be used to understand the development of events leading to an accident and can also be used as an aid to prevent future blowouts or to stop the escalation of events. In addition to primary and secondary barriers, well monitoring is included as an independent and special barrier between the other barriers. Well monitoring is considered crucial to remedy an incomplete primary well barrier or activate the secondary barrier in a timely manner. The authors state that “the simplest and safest way to prevent blowout accidents is certainly keeping all the safety barriers intact” and further noted that “these failures, especially the ones based on statistical data or accident reports, are still conceptual because the records or reports are not always sufficiently detailed.”

In Eckle et al. (2012) accidental global oil spills in the energy sector larger than 200 tons between 1974 and 2010 were extracted from the global Energy-Related Severe Accident Database, resulting in a total of 1,213 accidents. This independent analysis with global data of marine exploration and production oil spills, including the DWH event, calculated an approximate return frequency (i.e., occurrence) of an event the size of DWH as of once every 17 years with an uncertainty of between eight and 91 years (five and 95 percent confidence). The high uncertainty is a direct result of the structure of the risk with few but very severe events. Importantly, given that this analysis relied on a global dataset, the calculated return period represents the occurance on a global scale.

Ji et al. (2014), an analysis conducted by BSEE oil spill experts, used new methods to predict rare events and apply extreme value methods to predict the return period specific to the OCS for extremely large spills. These methods have been used with good results for other events that are rare when considered individually for a smaller area or shorter time period, but become predictable or foreseeable when larger areas and longer times periods are considered. The authors used Federal OCS oil spill data from 1964-2012, which mainly consists of data from the Gulf of Mexico. This study predicted the return period for a worst-case spill (defined as a spill over 1 Mbbl) as 165 years with a 95 percent confidence interval between 41-500 years (Ji et al. 2014).

The peer-reviewed literature discussed above highlights some key points that are relevant for determining the largest spill size that is possible within the time frame covered in the scope of this opinion. The large range of predicted frequency, or return periods, of disasterous spills from a minimum of 17 years globally to more than 500 years in the Gulf of Mexico specifically demonstrates that different statistical methods and different data sets can yield very different results. Human error and hurricanes play a large role in the occurrence of large spill events and occurrence of blowouts resulting in loss of well control in the Gulf of Mexico. There is some evidence suggesting that there may be a relationship between increased accidents as the depth of oil and gas development increases (Muehlenbachs et al. 2013). Increased accident rates could lead to an increased risk of an oil spill occurring.

BOEM estimates that in an average year operators will drill 160 deepwater wells and 186 shallow wells on the federal OCS. In shallow water, well pressures are generally lower due to the fact that many reserves have been produced, resulting in lower well pressures and the general trend of no new large discoveries in shallow water. Although small to medium volumes of oil are sometimes released from blowouts, the blowout is most often controlled with safety equipment such as BOPs, and any release of oil is minimized.

BOEM believes that a blowout leading to a loss of well control and release of oil is most likely in water deeper than 3,000 ft, where the spill size and consequences from a blowout are estimated to be greater (BSEE 2012). Figure 2 displays the annual number of blowouts resulting in a loss of well control from 2007 through 2016. Although blowouts may still occur in shallow water, there is a high likelihood that well control will be maintained due to lower reservoir pressure, the greater prevalence of gas rather than oil, and the presence of more accessible surface BOPs with diverters (BSEE 2012). If a release were to occur, it most likely would not be a large volume of oil. From 1990-2010, BSEE recorded six Gulf of Mexico shallow water well-control incidents resulting in a spill of hydrocarbons. The total volume spilled is estimated to be 132 bbl of condensate over these last two decades. Our review of the information for shallow water and deep water wells leads us to agree with BOEM’s finding of a low risk of an extremely large release of oil in shallow water. However, based on the historical data we analyzed above, including Ji et al. (2014), we believe the very large release of 100,000 bbl of oil could occur either in shallow water or deep water.

Regulatory Reform and Drilling Safety Improvements

BOEM and BSEE have carried out many regulatory reforms in response to reviews of the DWH event to improve offshore safety and oversight. These reforms are expected to reduce the volume of oil spilled during accidental events by reducing risks and improving control and response measures. BOEM provided NMFS a qualitative analysis of oil spill literature, regulatory changes, and improvements in response since DWH. The key points of the 2014 *Qualitative Review of Safety Measures to Minimize Frequency of Blowouts and Spills and Maximize Containment Capabilities* appear in the proposed action section of this opinion. Pertinent to this section of the analysis, we looked at the improvements in the well-containment system and responses that are specifically designed to cap a well after a blowout in order to assess how long a drilling-related extremely large release might last. While the blowout preventer is designed to manage drilling operations and prevent a blowout, a capping stack is designed to be deployed after a subsea blowout has already occurred. At the time of the DWH, there were few capping stacks in existence, and capabilities to support subsea well containment were limited. Subsequent improvements have increased industry’s capacity to respond to a subsea well blowout in the Gulf of Mexico. The new well-containment response capability includes multiple vessels for assessment of the well, clearance of debris from the well, and launch and installation of the capping stack. BSEE conducted field testing with installation and testing of capping stacks for Shell and the Marine Well Containment Corporation in July 2012 and Noble Energy and Helix Well Containment Group in April 2013 to assess compliance with their regulations for oil-spill-response/containment systems. In both of these actual field tests, the capping stacks were installed and tested in less than seven days. The total process would take about 21 days under ideal sea conditions. BOEM has indicated that a new capping system has the capacity to contain about 55,000 bbl for transfer to storage vessels and includes a 15,000 psi single or dual ram capping stack. New regulatory measures and improvements in the capping stack technology are effective to bringing a spill under control in shorter time periods than occurred for DWH.

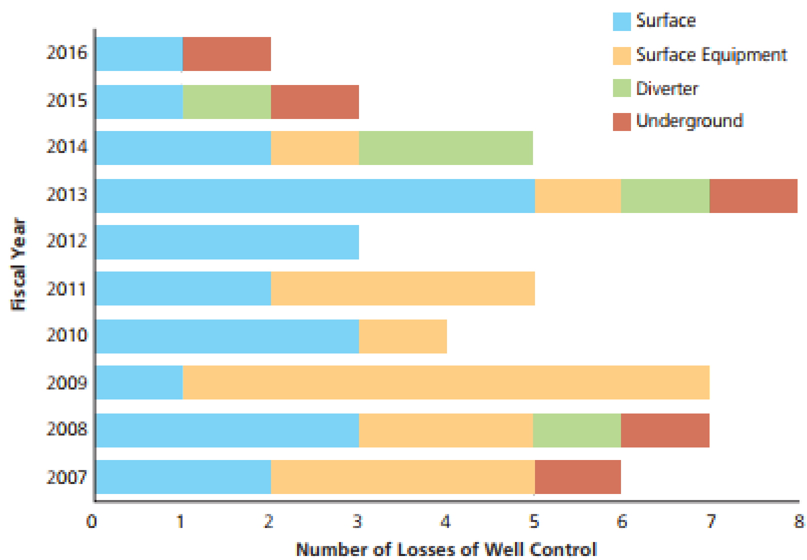


Figure 4. Annual losses of well control from 2007 to 2016 (BSEE 2016).

There were 4,123 deepwater wells drilled between 1973 and 2010. Active leases and associated oil and gas activities have been moving into increasingly deeper waters over the last two decades and are continuing to move into ultra deepwater. As drilling occurs at deeper depths, there can be an increased risk of loss of well control (Murawski et al. 2020). Pressures and temperatures in deeper waters provide extreme conditions where equipment, including safety-critical systems, could be more likely to fail and that are more difficult to reach quickly. Capping deepwater wells is not a regularly-occurring activity, so lack of experience also plays into the risk. Vessels are having to travel much farther to get out to those deeper sites, which could increase spill response times or have fewer available response vessels. Murawski et al. (2020) states, "…the next deep oil blowout and ensuing spill, wherever it may happen, will likely occur under fundamentally different conditions than have the two previous sub-surface mega-blowouts (DWH and Ixtoc)… While the previous 80+ years of oil exploration and production from the Gulf of Mexico have included responses to literally hundreds of oil spills (Ramseur 2010), a 3000 m blowout will be unlike any previous."

Muehlenbachs et al. (2013) reported that the probability of offshore oil and gas accidents increase by 8.5 percent for every 100 feet of increasing depth. BOEM indicated there have been 20 deepwater blowouts. In their 2016 annual report, BSEE calculated an average of five losses of well control per year over the last ten years. According to BSEE's loss of well control data (available at BSEE's website; www.bsee.gov), from 2006 to 2014 and including DWH, there have been eleven blowouts resulting in loss of well control in greater than 2,000 feet of water, eight of which were greater than 3,000 feet of water, and two of which resulted in spills. Since 1990, the frequency of deepwater blowouts is about one blowout for about every 275 deepwater wells. BOEM forecasts that an average of 160 wells will be drilled each year in deep water, or up to 8,000 wells over the scope of this opinion. Using these estimates, we predict up to 29 blowouts [(1/275)*8000] will occur in deepwater over the next 50 years. Using BSEE loss of well control data to estimate for two spills for every eight loss of well control incidents, we would expect about eight (rounding up) of those blowouts occurring in depths at the greatest risk (i.e., depth greater than 3,000 ft) of an oil spill resulting from loss of well control (Table 3). Eight blowouts in deepwater over 50 years is equivalent to about one deepwater blowout every six years for the proposed action. Based on historical data provided by BOEM, most of these blowouts will result in non-disasterous loss of well control.

Table 3. Deepwater Wells Drilled Greater Than 3,000 ft and Blowout Risk as a Result of the Proposed Action.

Total Wells			
Annual Average Number of Deepwater Wells Drilled	Total Number of Deepwater Wells Drilled under the Proposed Action	Number of Deepwater Blowouts and Subsequent Oil Spill Predicted*	Number of Deepwater Disasterous Blowouts resulting in uncontrolled release of oil
160	8,000	8	1

*Number of drilled deepwater wells resulting in blowout over 38 years.

BOEM has concluded that an extremely large blowout and uncontrolled release of oil should not be considered an effect of the action because the probability is so low that it is not reasonably certain to occur within the time period covered by this opinion and so is not an anticipated result of the proposed action. The more recent analysis by Ji et al. (2014) used more applicable statistical methods to evaluate the risk of extremely large spill events on the U.S. OCS. As noted earlier, this study predicted the return period for a worst-case spill (defined as a spill over 1 Mbbl) as 165 years with a 95 percent confidence interval between 41-500 years. This still results in a wide range of years over which a disasterous uncontrolled blowout might occur. This wide range of years is due, in part, to the high uncertainty involved in predicting rare events. The lower end of this range (the year 2051 is 41 years after DWH) places us at the higher end of the scope of this consultation (2068). According to this statistical prediction, a disasterous blowout, subsequent protracted loss of well control and resulting oil spill would still be a statistically rare event, but it could possibly occur within the timeframe analyzed in this opinion. The majority of spills are less than one barrel, however the majority of volume spilled comes from larger spill events. DWH was 8.5 times the cumulative 570,000 bbl that were spilled in the previous 46 years in the U.S. (Ji et al. 2014). Figure 3, from Ji et al. (2014) shows the time series of annual largest oil spills derived from OCS data for 49 years from 1964 to 2012. The return level (or return frequency or value) of a random variable is the quantile value which is exceeded, on average, once in a period of time (called the return period). For example, the return period (such as 100-year flood) based on extreme precipitation (i.e., certain return value) is commonly used to assess the capacity of drainage systems (Ji et al. 2014).

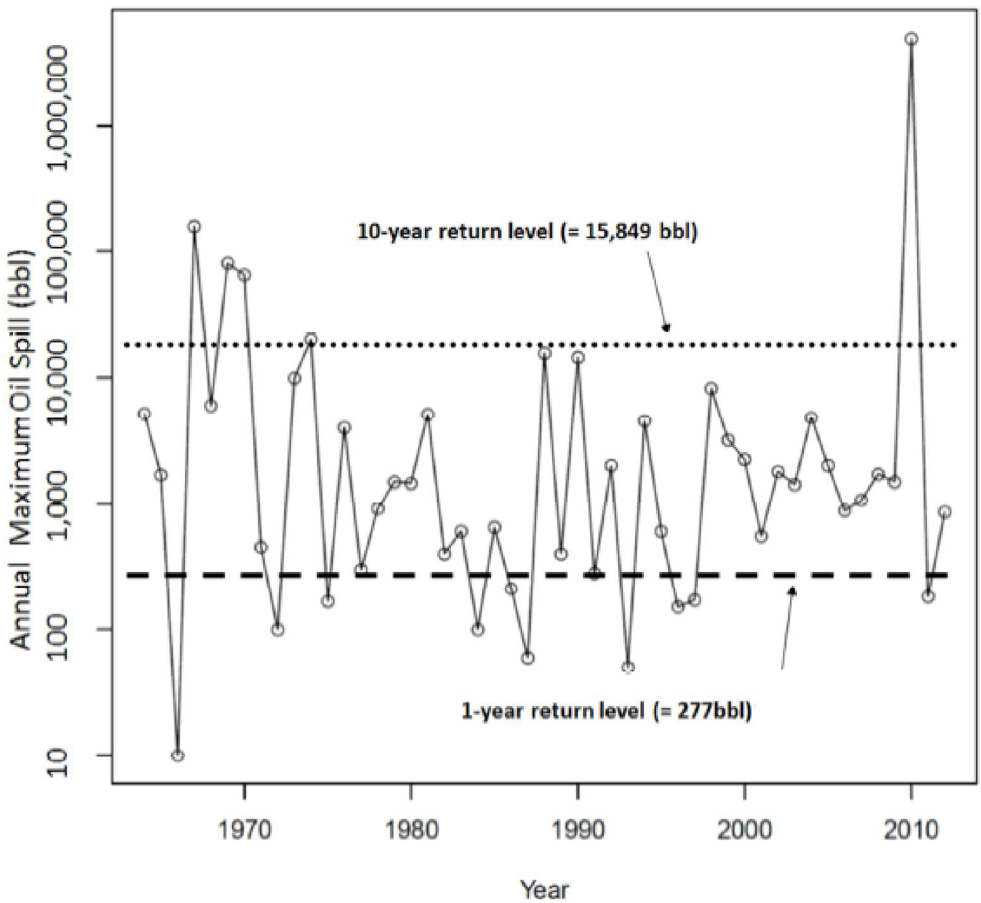


Figure 5. Annual largest oil spills derived from OCS data from 1964 to 2012. The dotted line is the 10-year return level and the dashed line is the 1-year return level. Figure from Ji et al. (2014).

The ranges in return frequencies of oil spills from protracted loss of well control provided in several studies and their strengths/limitations are provided in Table 4. The lower spill return value of 41 years from Ji et al. (2014) is within range of other estimates of possible spill frequencies[2], and is still consistent with the predicted frequency of one extremely large spill every 40 years used in the 2007 biological opinion. Considering all the information above, while an extremely large spill is hypothetically possible, NMFS agrees with BOEM that new regulatory and technological advances reduce the risk of another DWH-sized event.

Table 4. Comparison from Different Studies of Recurrence Values for Very Large Spill Risk.

Study	Recurrence frequency (years)	95 percent confidence interval (years)	Limitations	Strengths
Rathnayaka et al. 2013	probability 1.52×10^{-5}	NA	Narrow focus on DWH and risk assessment methodology is reliant on available and precise precursory data	Used publicly available data to create a framework accident model and risk assessment algorithm based on DWH series of events
Eckle et al. 2012	17	8-91	Global data takes into account risk factors potentially not relevant to Gulf of Mexico	More data points on extreme spill events; 1213 accidents total. Data from 1974-2010. Bayesian model fitting.
Ji et al. 2014	165	41-500	Using all available data, which is mostly shallow water spill data, to analyze for ultra deepwater drilling risk	Uses multiple approaches and 49 years of spill data (rather than only one or a few data points). Data from 1964-2012. Maximum likelihood model fitting.

In summary, BOEM provided NMFS with information that two oil spills greater than or equal to 10,000 bbl may occur over the duration of the proposed action. Based on the historical

[2] Note also that, as shown in Table 4, Eckle et al 2012 estimated a 17 year recurrence frequency based on a larger number of large events with a confidence interval range from 8-91 years.

information on oil spills and advances in offshore drilling safety, we anticipate that one of these spills will be on the order of approximately 100,000 bbl (Ji et al. 2014). We define the largest spill size possible as a median spill volume of 1.1 million bbl (Mbbl) in the Gulf of Mexico (between 900,000-1.3 Mbbl). We determined this volume of oil by assessing how long a spill might last and how much oil could flow over that time. We also determined that a median volume would be a reasonable estimate of the largest spill size possible because of the safety measures that were implemented with the 2012 drilling rule and subsequent safety measures.

The volume of oil spilled during an uncontrolled blowout is highly dependent on the flow rate per day and the duration of the flow. BOEM estimates an uncontrolled flow rate of 30,000-60,000 bbl per day is possible if an uncontrolled blowout occurs. These flow rates are based on BOEM data from well tests, the maximum flow rate from the 1979 Ixtoc blowout in shallow water, and the maximum flow rate estimated for the 2010 DWH oil spill in deep water. Considering the time to deploy a capping stack and accounting for poor weather or other logistical delays that could arise, we conservatively consider the possibility of BOEM's position that an uncontrolled blowout release could last up to 30 days before containment, which we estimated could result in a release of up to 1.1 Mbbl of oil. BOEM and BSEE, predicted the return period for an extremely large event due to a well-control incident in the Gulf of Mexico (Ji et al. 2014) within the next 165 years with a 95 percent confidence interval between 41-500 years. NMFS will defer to the BOEM and BSEE analysis for this conclusion based on their expertise in this subject, and accordingly will not carry an extremely large event into our analysis of the effects of the action for the hypothetical occurrence of this low-probability extremely large (greater than 1 Mbbl) event.

BSEE. 2012. Final Regulatory Impact Analysis for the Final Rule on Increased Safety Measures for Energy Development on the Outer Continental Shelf. Department of Commerce Bureau of Safety and Environmental Enforcement, RIN 1014-AA02.

BSEE. 2016. Bureau of Safety and Environmental Enforcement 2016 Annual Report.

BSEE. 2017. Loss of well control occurrence and size estimators. USDOI Bureau of Safety and Environmental Enforcement.

Eckle, P., P. Burgherr, and E. Michaux. 2012. Risk of Large Oil Spills: A Statistical Analysis in the Aftermath of Deepwater Horizon. Environmental Science & Technology 46(23):13002-13008.

Ji, Z.-G., W. R. Johnson, and G. L. Wikel. 2014. Statistics of Extremes in Oil Spill Risk Analysis. Environmental Science & Technology 48(17):10505-10510.

Muehlenbachs, L., M. A. Cohen, and T. Gerarden. 2013. The impact of water depth on safety and environmental performance in offshore oil and gas production. Energy Policy 55:699-705.

Murawski, S. A., D. J. Hollander, S. Gilbert, and A. Gracia. 2020. Deepwater Oil and Gas Production in the Gulf of Mexico and Related Global Trends. Pages 16-32 *in* S. A. Murawski, and coeditors, editors. Scenarios and Responses to Future Deep Oil Spills: Fighting the Next War. Springer International Publishing, Cham.

Ramseur, J. L. 2010. Deepwater Horizon Oil Spill: The Fate of the Oil. Congressional Research Service, Washington D.C.

Rathnayaka, S., F. Khan, and P. Amayotte. 2013. Accident modeling and risk assessment framework for safety critical decision-making: application to deepwater drilling operation. Proceedings of the Institution of Mechanical Engineers Part O: J Risk and Reliability 227(1):86-105.

Xue, L., J. Fan, M. Rausand, and L. Zhang. 2013. A safety barrier-based accident model for offshore drilling blowouts. Journal of Loss Prevention in the Process Industries 26(1):164-171.

Appendix H. Cetacean and Sea Turtle Wildlife Response Guidance for the Gulf of Mexico

I. Introduction

The protection of wildlife during the course of an oil release event is an essential element in every oil spill response operation. A Wildlife Response Plan (WRP) as part of an OSRP provides for coordinated, immediate, and effective protection, rescue or recovery, and rehabilitation of wildlife resources present in the oceanic, coastal, and inland waters of the Gulf of Mexico. WRPs typically focus on bird species and coastal terrestrial animals. This document provides a framework for Cetacean *and Sea Turtle Response Plans*, which should be included in the larger WRP covering all potential impacted wildlife based on the geographic area covered[1].

Under incident command, NOAA's National Marine Fisheries Service (NMFS) will lead marine mammal and sea turtle response efforts for spills that may impact any sea turtle species, cetaceans, and/or pinnipeds. Therefore, the Wildlife Response Plan for these species must ensure that NMFS is notified immediately if any sea turtle or cetacean species are suspected to be impacted, using the contact information provided in this document. If response is determined to be necessary, NMFS will lead the response and follow existing protocols found in approved agency Oil Spill Response Guidelines documents. The WRP and OSRP must ensure that NMFS is engaged and included in the response efforts, and that the responsible party is prepared to provide appropriate and reasonable resources for response efforts.

II. Marine Mammal and Sea Turtle Response Plans and Guidance Documents

Oil spill response planning and strategies should follow standard protocols, techniques, and best management practices for particular taxa, species and habitats, as available. NMFS developed Oil Spill Response Guideline documents for use during oil spills, and recommends that these Guidelines be incorporated by reference to WRPs, to avoid duplication and variability between

---

[1] Wildlife Response Plan considerations for birds are not included in this document, although that information is available in other documents and formats. Additionally, this document does not address response strategies to other ESA-listed species under NMFS jurisdiction, such as corals, smalltooth sawfish, and sturgeon. If an oil spill involves these species, please consult with NMFS representatives on response needs. Emergency consultation for responses which may affect ESA-listed species in the Gulf of Mexico can be accomplished by emailing nmfs.ser.emergency.consult@noaa.gov.

protocols. This will allow for consistent and coordinated response efforts regardless of the responsible party. NMFS recommends that all WRPs include the following information related to marine mammal and sea turtle species that are present in the specific geographic area covered: 1) the notification/contact information listed in Section III below, 2) reference to the following two documents, and 3) overview of response roles and anticipated response strategies including pre-planned facility and equipment availability during a spill. For response to marine mammals and sea turtles during a spill, response strategies will likely include initial reconnaissance efforts at a minimum. Based on initial reconnaissance, response strategies may also require continued reconnaissance/surveillance throughout the response, recovery of stranded and oiled animals, triage, and rehabilitation care. Further details on these activities including descriptions of procedures and safety considerations can be found in the following guidance documents.

Title: *Pinniped and Cetacean Oil Spill Response Guidelines*
Citation: Ziccard, M., Wilkin, S., Rowles, T.K. and S. Johnson. 2015. NOAA Technical Memorandum.
URL: https://www.fisheries.noaa.gov/resource/document/pinniped-and-cetacean-oil-spill-response-guidelines
These Guidelines provide a foundation for coordination and communication between local, state and federal oil spill response agencies and the marine mammal conservation, research and welfare communities (including marine mammal stranding networks and research scientists). More specifically, these Guidelines provide key information to, and standardize activities of, marine mammal responders to build and maintain oiled wildlife readiness at a national level.

Title: *Guidelines for Oil Spill Response and Natural Resource Damage Assessments: Sea Turtles* (in review): Stacy, B.A., B.P. Wallace, T. Brosnan, S.M. Wissmann, B.A. Schroeder, A.M. Lauritsen, R.F. Hardy, J.L. Keene, S.A. Hargrove. 2018. Guidelines for Oil Spill Response and Natural Resource Damage Assessment: Sea Turtles. U.S. Department of Commerce, National Marine Fisheries Service and National Ocean Service, NOAA Technical Memorandum [Designated number], Washington, D.C.
URL: https://www.fisheries.noaa.gov/resource/document/guidelines-oil-spill-response-and-natural-resource-damage-assessment-sea-turtles
These guidelines provide a foundation for coordination and communication between local, state and federal oil spill response agencies for sea turtle response efforts. These guidelines specifically cover actions that may be undertaken during emergency response to oil spills or subsequent Natural Resource Damage Assessment (NRDA), and provide standardized protocols for responders. Since the circumstances of each oil spill vary significantly, the information in this document is not meant to be prescriptive, it is intended to supplement existing regulations, policy, and guidance.

III. Notification of Spills

NMFS Office of Protected Resources coordinates agency assessment of the need for response and leads response efforts for spills that may impact sea turtles, and cetaceans. If a spill may impact cetaceans, or sea turtles, NMFS Protected Resources Contacts should be notified and they will initiate notification of other relevant parties.

NMFS Protected Resources Contacts for the Gulf of Mexico:

- Marine mammals- Southeast emergency stranding hotline 1-877-433-8299
- Sea turtles- Dr. Brian Stacy at brian.stacy@noaa.gov and 352-283-3370(cell); or Stacy Hargrove at stacy.hargrove@noaa.gov and 305-781-7453(cell)
- Other ESA-listed species- ESA section 7 consulting biologist: nmfs.ser.emergency.consult@noaa.gov

Appendix I. Explosive Removal of Structures Measures

I. *Sargassum* habitat monitoring

"*Sargassum* habitat" is defined as the presence of *Sargassum* in sufficient amounts that serve as developmental habitat in which small juvenile sea turtles are likely to be found. Small juvenile turtles are extremely difficult to detect and *Sargassum* habitat will be used as the primary indicator of their presence in an impact zone. Typically, the occasional presence of a few, small *Sargassum* "clumps" are not considered developmental habitat. *Sargassum* habitat for sea turtles is visually described as mats, continuous lines, broken windrows (short lines or non-linear clumps), or scattered patches (Table 135). NMFS PSOs will be required to monitor local conditions to determine if *Sargassum* habitat is present based on the hourly conditions at a decommissioning site and implement the appropriate measures.

Table I- 1. Description of Sea Turtle Sargassum Habitat Types {Witherington, 2012 #648}.

***Sargassum* Habitat Type**	**Description**
Mat	One or more consolidated areas of *Sargassum* forming a mat large enough to provide shelter and/or food for a small sea turtle.
Continuous Line	One or more contiguous meandering lines or scattered patches along a linear path. Lines may be narrow or wide. These lines are often associated with convergence zones.
Broken Windrows	Many parallel, short lines or clumps that may or may not be distributed linearly
Scattered patches	Numerous patches scattered over an area

II. Requirements for Establishing Impact Zones

A. Impact zones in both shallow and deep water are determined by the net explosive weights used during a decommissioning event. The impact distance(s) shall be based on the largest charge size proposed to be used during a removal event when multiple charges are used. The measures herein apply to any charge size up to 500 lb. The charge weight establishes the specific mitigation scenario that must be adhered to as a permit condition.

B. Impact zones for each scenario shall be calculated using the most recent version of the Underwater Calculator (UWC) that has been reviewed and approved by NMFS. The current required impact zones (Table 136) are based on UWC version 1.5.3 that is the latest approved version at the time of this opinion. Review and approval of UWC revisions will be completed according to the second tier consultation procedures detailed in section 4 of this opinion.

Table I- 2. Impact zones for net explosive weights based on underwater calculator version 1.5.3.

Net Explosive Weight (lb)	Impact Zone Distance	
	BLM	AML
1-10	261 m (856 ft)	293 m (961 ft)
>10-20	373 m (1,224 ft)	522 m (1,714 ft)
>20-80	631 m (2,069 ft)	829 m (2,721 ft)
>80-200	941 m (3,086 ft)	1,126 m (3,693 ft)
>200-500	1,500 m (4,916 ft)	1,528 m (5,012 ft)

C. NMFS understands all decisions on explosive composition, configuration, and usage need to be made by the qualified explosive contractors in accordance with the applicable explosive-related laws and regulations. BSEE or their permitee shall provide a written blasting plan to the PROP Program Manager prior to the anticipated blasting date. The blasting plan shall include the number of and type of structures, number of decommissioning events, type of explosives, and weight of explosives. Any changes to the net explosive weights detailed in the blasting plan shall be submitted in writing to the PROP program manager or lead PSO on site. The PROP Program Manager or lead PSO will determine the appropriate scenario measure (described below) and impact zone required based on the final net explosive weights used for the removal.

D. PSOs may use binoculars and the naked eye to monitor the exclusion zones. The sighting distance of all listed species and *Sargassum* habitat that result in delays must be recorded.

E. Buoys or some visible markers will be necessary for visual reference of the impact zone when only surface monitoring is required. The perimeter of impact zones should be demarcated (e.g., brightly colored buoys, vessels, or other markers) for visual reference.

F. If any ESA-listed species, or *Sargassum* habitat indicative of small juvenile sea turtles are present in the impact zone, a detonation must not proceed. Steps for tracking animals, inspecting *Sargassum* habitat, delay periods, and additional monitoring are detailed below.

III. Requirements for differing scenario mitigations

A. Permittees must fully comply with the relevant measures according to impact zones in Table 136 and the mitigation scenarios in Table 137. Table 136 provides the impact zone distances required based on the net explosive weight used. Table 137 summarizes the required mitigation and monitoring surveys, and duration of monitoring required. Sea turtles can remain submerged on a single dive for well over 30 minutes, hence the reason for increasing the pre-detonation aerial survey to 45 minutes (Byles, 1989; Renaud, 1995; Gitschlag, 1996).

Table I- 3. Mitigation overview for net explosive weights used in any configuration in shallow water (SW; less than 200 m) and deep water (DW; greater than 200 m).

Mitigation scenario Number	Net explosive weight (lb)	Pre-Det Surface Survey (min)	Pre-Det Aerial Survey (min)	Pre-Det PAM (min)	Animal Sightings Waiting Period (min)	*Sargassum* Habitat Waiting Period	Post-Det Surface Survey (min)	Post-Det Aerial Survey (min)	Post-Post-Det Aerial Survey within one Week
SHALLOW WATER									
SW-1	1-10	60	N/A	N/A	30	Until visually inspected <u>or</u> *Sargassum* floats out of Impact Zone	30	N/A	No
SW-2	>10-20	90	45	N/A	30		N/A	45	No
SW-3	>20-80	90	45	N/A	30		N/A	45	No
SW-4	>80-200	120	60	N/A	30		N/A	45	No
SW-5	>200-500	150	90	N/A	45		N/A	45	No
DEEPWATER									
DW-1	1-10	90	N/A	N/A	45	Until visually inspected <u>or</u> *Sargassum* floats out of Impact Zone	30	N/A	No
DW-2	>10-20	90	45	N/A	45		N/A	45	No
DW-3	>20-80	90	60	150	45		N/A	45	Yes
DW-4	>80-200	150	60	180	45		N/A	45	Yes
DW-5	>200-500	180	90	270	45		N/A	45	Yes

B. Permittees must stagger the detonation of multiple charges in a series by an interval of at least 0.9 sec (900 msec) between blasts. Otherwise, the combined charge sizes (or net explosive weight) will be used to determine the impact zone.

C. Detonations must only occur during daylight and during a time that would allow for post- detonation surveys. Monitoring will cease if the lead PSO determines that weather or marine conditions are not adequate for visual observations.

D. Scare charges shall not be used to clear impact zones of sea turtles or ESA-listed whales (i.e., sperm whale).

E. Images/pictures taken during any surveys are the property of the U.S. Government and should not be sold, duplicated or used in any way other than for which the project it was intended.

F. Unusual Circumstances: Occasionally, sea turtle(s) remain within the impact zone or are present in high numbers. On rare occasions, very small turtles may be seen in absence of *Sargassum* habitat near vessels from which monitoring is occurring. During these unusual circumstances, the on-site NMFS PSO shall exercise discretion in the implementation of measures or modification of the mitigation procedures that serve to avoid or minimize impacts to sea turtle(s). Typically, modifications of mitigations include increasing the duration of monitoring periods, increasing the number of PSOs, delaying blasting, or a combination of measures. The lead PSO will coordinate with the PROP Manager, appropriate BSEE personnel, and NMFS ESA section 7 consulting biologist when circumstances necessitate additional monitoring.

IV. Requirements for Surface Monitoring Surveys

A. A surface monitoring survey is required for all blasting scenarios and must be conducted for the length of time indicated for the net explosive weights in Table 136 and Table 137.

B. Surface monitoring is generally conducted by at least two PSOs. Surface monitoring surveys are to be conducted from the highest vantage point(s) and/or other location(s) that provide the best, clear view of the entire impact zone. These vantage points may be on the structure being removed or proximal surface vessels such as crew boats and derrick barges. Additional PSOs will be positioned around the decommissioning site, as determined by the PROP manager/coordinator in consultation with the lead PSO for additional structures, large net explosive weights, or other circumstances as needed.

C. Surface monitoring must be conducted in adequate light during daylight hours (sunrise to sunset) and with an adequate line of sight including meteorological conditions free of rain or fog, and free of other visual obstructions such as other work vessels.

D. For mitigation scenarios requiring only surface monitoring and no aerial monitoring, surface monitoring must be conducted under good environmental conditions that are conducive for monitoring for sea turtles and marine mammals. Surface-only monitoring shall be delayed if: 1.) Sea conditions exceed Beaufort Wind Force Scale 4.5 (see Table 138), or 2.) inadequate line of sight including poor light conditions, meteorological conditions (e.g., rain or fog) and other visual obstructions such as other work vessels.

Table I- 4. Beaufort Sea State Scale.

Beaufort State	Wind mph	Wind Knots	Wave Height (ft)	Description
0 (calm)	0-1	0-1	0	Sea surface like a mirror
1 (light air)	1-3	1-3	0.33-0.65	Ripples with the appearance of scales, but no foam crests
2 (light breeze)	4-7	4-6	0.66-1.9	Small wavelets, more pronounced. Crests have glassy appearance, but do not break.
3 (gentle breeze)	8-12	7-10	2-3.2	Large wavelets. Crests begin to break. Foam of glassy appearance. Perhaps scattered white horses.

Beaufort State	Wind mph	Wind Knots	Wave Height (ft)	Description
4 (moderate breeze)	13-18	11-16	3.3-6.5	Small waves, becoming larger; fairly frequent white horses.
4.5 (moderate-fresh breeze)	≤15.5	≤13.5	≤4.9	Small waves, crests break, scattered but regular white horses
5 (fresh breeze)	19-24	17-21	6.6-9.8	Moderate waves, more pronounced long form, many white horses, some spray possible

E. For charge sizes between 0-10 lb, the detonation may proceed if ESA-listed species or *Sargassum* habitat is not sighted.

F. If a listed species is sighted, or sighted heading inbound toward the impact zone, a waiting period is required (see Waiting Periods in “F” below), or

G. If *Sargassum* habitat is sighted in the impact zone, , a waiting period is required until the *Sargassum* habitat drifts out of the impact zone (see Waiting Periods in “F” below). Alternatively, a vessel-based PSO could inspect the *Sargassum* for juvenile sea turtles. This must be done from a small vessel or inflatable boat so that an observer will be close to the water surface and can see small turtles. If no sea turtles are sighted, the waiting period ends and the survey can continue for the remaining period required under the mitigation. If a sea turtle(s) is sighted, the waiting period must continue until the *Sargassum* drifts out of the impact zone.

V. Requirements for Pre-Det Aerial Surveys

A. Aerial monitoring surveys are to be conducted from helicopters running standard low-altitude search patterns over the extent of the decommissioning area, including the impact zone that corresponds to the appropriate mitigation scenario.

B. Aerial surveys will be restricted to daylight hours only and cannot begin until the requisite surface monitoring survey has been completed.

C. Aerial surveys will cease if the lead PSO determines that weather or marine conditions are not adequate for visual observations, or when the pilot/removal supervisor determines that helicopter operations must be suspended.

D. When two or more PSOs are on site, NMFS may decide two PSOs conduct the aerial survey or have one or more PSOs continue surface monitoring while the other observer flies the survey. The helicopter will traverse the impact zone at low speed/altitude in the specified survey pattern.

E. Flight patterns during pre-detonation and post-detonation surveys shall follow the procedures listed in Table 139. At any time during the survey period, the flight path may be altered to investigate sightings and confirm their location in reference to the impact zone.

Table I- 5. Flight patterns during pre-detonation surveys. All surveys should begin at the center of the impact zone. At any time during the entire survey period it may be necessary to alter the flight path to investigate sightings and confirm their location in reference to the impact zone.

Flight Path	30-minute	45-minute	60-minute	90-minute
Follow a spiraling or corkscrewing flight path out from the center of the impact zone to the perimeter of the impact zone. This should be followed by a gradually contracting spiral flight path until the aircraft returns to the center of the impact zone. Repeat the pattern for the specified time period.	10 minutes	20 minutes	25 minutes	40 minutes
Unless higher priority targets (ex. turtles, dolphins, *Sargassum*) are present, the aircraft should survey outside of the impact zone to a distance approximately equal to the radius of the impact zone to determine if any protected species (sea turtles or marine mammals) might be moving into the area. Expanding and contracting spirals should again be used for the	5 minutes	5 minutes	5 minutes	5 minutes
The aircraft should survey inside the impact zone and follow the same procedures as during the first part of the survey. However, near the end of the survey period the flight path should usually be concentrated near the center of the impact zone since this is where animals will have the highest risk of severe impact.	15 minutes	20 minutes	30 minutes	45 minutes

F. For charge sizes greater than 10-500 lb, the detonation may proceed if listed species are not sighted.

G. If listed species are sighted, or sighted heading inbound toward the impact zone, a waiting period is required (see Waiting Periods below).

H. If *Sargassum* habitat is sighted, a waiting period is required until either a) a vessel-based PSO inspects the *Sargassum* from a small vessel or inflatable boat for juvenile sea turtles to determine if a *Sargassum* waiting period is required, or b) no vessel-based inspection occurs and a waiting period is triggered until the *Sargassum* has drifted out of the impact zone. If no sea turtles are sighted during a PSO inspection, the surface monitoring can continue for the remainder of the required monitoring period.

VI. Requirements for Passive Acoustic Monitoring (PAM)

A. BOEM and BSEE must require operators to provide for review a plan for the use of passive acoustic monitoring for marine mammal detection in the relevant deepwater mitigation scenarios (DW-3, DW-4, and DW-5). The plan must include on-site monitoring protocols, description of the passive acoustic system, software used, recording and storage of data, and other aspects of acoustic monitoring.

B. Persons conducting acoustic surveys will be required to comply with NMFS-approved passive acoustic monitoring protocols and use approved devices and technicians.

C. Acoustic surveys will be run concurrent with requisite pre-detonation surveys, beginning with the surface observations and concluding at the finish of the aerial surveys when the detonation(s) is allowed to proceed. Operators must also report on an assessment of the usefulness, effectiveness, and problems encountered with the use of the method. PAM operators shall notify NMFS PSOs immediately when any acoustic targets are detected.

D. For mitigation Scenarios DW-3, DW-4, and DW-5, the detonation may proceed if ESA-listed whales (i.e., sperm whale) are not detected with PAM and the other pre-det surveys do not detect listed species or Sargassum habitat. If ESA-listed whales are detected with PAM (or listed species or Sargassum habitat are otherwise sighted), a waiting period is required (see Waiting Periods below).

VII. Requirements for Waiting Periods for Surface, Aerial, and PAM Surveys

A. For pre-det surveys. If sea turtle, Sargassum habitat or ESA-listed whales (i.e., sperm whale) are observed within (or about to enter, heading inbound) the impact zone of any pre-detonation survey, detonations must be delayed until no protected species are inside the impact zone or the *Sargassum* has drifted out of the impact zone. The waiting period must be completed before the monitoring protocol for the requisite mitigation, and following measures can continue. The purpose of a waiting period is to allow any inbound animal(s) within the impact zone to exit the impact zone under their own volition. For small juvenile sea turtles, the purpose of the waiting period is to allow floating *Sargassum* habitat to drift out of the area or to confirm no turtles are present in the *Sargassum*.

B. For surface, aerial, PAM surveys. When listed species are inside the impact zone or inbound toward the impact zone during a surface, aerial or PAM survey:

i. Halt the detonation countdown and implement the waiting period,

ii. Continue opportunistic monitoring during the required waiting period after the last sighting.

iii. If additional sightings occur inside the impact zone or animals sighted heading inbound during the waiting period, then continue surface surveys and start a new waiting period after the occurrence of the last sighting.

iv. Except for waiting periods triggered by Sargassum habitat, anytime a waiting period for an aerial survey or for a surface survey for blast scenarios with surface only surveys (when no aerial survey is required) is triggered by a sea turtle or marine mammal sighting, the interrupted survey must be completed over in its entirety. For blast scenarios that include both survey types, only the aerial survey would need to be repeated.

v. Anytime a surface survey waiting period is due only for *Sargassum* habitat, a waiting period is required until either a) a vessel-based PSO inspects the *Sargassum* and determines no turtles are present, or b) no vessel-based inspection occurs and a waiting period is triggered until the *Sargassu*m has drifted out of the impact zone. If no sea turtles are sighted during a PSO inspection of Sargassum habitat, the surface monitoring can continue for the remainder of the required monitoring period.

vi. Anytime an aerial survey waiting period is triggered only due to Sargassum habitat (no marine mammals or large juvenile or adult sea turtles sighted), only the aerial survey needs to be repeated.

vii. Other than in the case of waiting periods described above, any interrupted surface or aerial surveys must be repeated in their entirety. Also, the post-detonation aerial survey must begin immediately following completion of the pre-detonation surface survey.

VIII. Requirements for Post-Detonation and Post-Post Detonation Monitoring Surveys

The primary purpose of post-det and post-post-det surveys is to detect any listed species that may have been impacted (stunned, injured or killed) by the detonation and monitor the effectiveness of the pre-det mitigation requirements. Post-det and post-post-det surveys must follow the following measures.

A. A 45-minute post-detonation aerial survey must be conducted by the PSO(s) for all explosive use greater than 10 lb. The aerial survey must be conducted immediately upon conclusion of the detonation.

B. For deepwater, mitigation scenarios DW-3, DW-4 and DW-5, post-post-detonation aerial monitoring surveys must be conducted within 2-7 days after detonation activities conclude, by either helicopter or fixed-wing aircraft. Any distressed, stunned, injured, or dead marine mammals will be noted in the survey report, and if possible, tracked and collected after notifying the National Marine Fisheries Service.

C. Detonations shall not occur if the post-detonation survey cannot be concluded prior to sunset.

D. For post-detonation surveys, follow a spiraling or corkscrewing flight path out from the center of the impact zone to the perimeter of the impact zone. This should be followed by gradually contracting spiral flight path until the aircraft returns to the center of the impact zone. If strong currents are present, the down current area should be surveyed outside the impact zone to an appropriate distance. Repeat the pattern for the specified time period.

E. For post-post-detonation surveys, survey a 7x7 nmi grid centered over the removal site. This grid includes eight, parallel transect lines each measuring 7 nmi long and spaced approximately 1 nmi apart. If strong currents are determined to be present, the the grid may be shifted in the down current direction to an appropriate distance. Any injured or dead sea turtle or marine mammal must be recorded in the survey report and reported to the appropriate stranding network. The stranding network may request that the carcass be tracked and collected if possible.

IX. Requirements for the Recovery of Sea Turtles

A. BOEM and BSEE shall allow an option for trained diver(s) to attempt capture of sea turtles known to be present around a structure slated for removal by explosive severance. NMFS SERO shall be notified prior to any capture attempts and the capture, handling, holding, and release of sea turtles shall be under the guidance and supervision of NMFS PSOs

B. Sea turtles that are observed to be stunned, injured, or killed during post-det surveys or follow-up aerial surveys must be recovered by PSOs when it is possible to do so. The company and offshore service contractors on site must make assets available, such as vessels, divers, so PSOs can capture or recover stunned, injured, or dead turtles and transport them to shore.

C. Impacted sea turtles that are recovered alive or dead must be immediately transported to shore in coordination with NMFS. Turtles must be transported to an authorized rehabilitation facility for veterinary treatment, or properly stored for necropsy to document the injuries and cause of death.

D. If a sperm whale is unintentionally exposed to a blast, the incident must immediately be reported to the Marine Mammal Stranding Network at 1-877-WHALE-HELP (1-877-942-5343).

X. PSO Requirements

A. NMFS PSOs are required to perform surface and aerial surveys. These PSOs are qualified NMFS employees or contractors delegated under the Platform Removal Observer Program (PROP) of NMFS' Galveston Laboratory. Explosive-severance contractors or operators enter into agreements with the NMFS Galveston Laboratory to provide PSO monitoring. Under the agreements, NMFS achieves full cost recovery for the goods and services provided. Generally, at least 2 or 3 NMFS PSOs are required to conduct surveys for the mitigation scenarios. When simultaneous surface, aerial, or PAM surveys are required, teams of PSOs may be required. The PROP Manager will determine the required number of teams and PSOs depending on the complexity of severance activities, structure configurations, adequacy of structures and vessels to conduct effective monitoring, and other environmental monitoring conditions.

B. PSOs must brief affected crew and severance contractors of the monitoring efforts and notify topsides personnel to report any sighted animals or Sargassum habitat to the lead PSO immediately;

C. PSOs must establish an active line of communication (such as 2-way radio) with company and blasting personnel;

D. PSOs must devote the entire, uninterrupted survey time to listed species monitoring.

E. For aerial surveys, a PSO should sit in one of the seats in the front of the cockpit. This is typically on the port side of the aircraft next to the pilot. Whenever possible, a second PSO should sit on the opposite side of the aircraft so that both sides of the aircraft are surveyed. If additional PSOs are available, seating should be adjacent to a window. Communications equipment should be provided which allows the pilot and PSOs to talk to each other and which provides clear communications.

XI. Requirements for Reporting

A. Any take of listed species should be reported to NMFS at takereport.nmfsser@noaa.gov and nmfs.psoreview@noaa.gov. If the taking involves a whale, the lead PSO shall also report it immediately to the Marine Mammal Stranding Network at 1-877-WHALE-HELP (1-877-942-5343).

B. Final monitoring reports (also referred to as the trip report) will be prepared for each removal. The monitoring report responsibilities will be assumed by NMFS's lead PSO and completed following completion of the severance activities.

C. In addition to basic operational data (e.g., area and block, water depth, company/platform information), the trip reports must contain all of the applicable information:

i. Target: Type/Composition (pile, caisson, concrete piling, nylon mooring, etc.) and Diameter and Thickness

ii. Charge: Type (bulk, configured-bulk, linear-shaped, etc.), Charge weight/material (RDX, C4, HMX, etc.), Configuration (internal/external, cut depth [below mud line], water depth [above mud line], etc.), Deployment method (diver, ROV, from surface, etc.)

iii. Monitoring: Survey Type: (pre-det and post-det; surface, aerial, etc.), Time(s) initiated/terminated, Marine Conditions

iv. Observed/Detected summary: Type/number (basic description or species identification, if possible, during all survey types- i.e., surface, aerial, and acoustic and both during pre- and post-detonation periods), Location/orientation – inside/outside impact zone, inbound/outbound, etc., Any "halted-detonation" details – i.e., waiting periods, re-surveys, etc., Any "Take-Event" details – actual MPS injury/mortality

D. BOEM shall provide an annual report to the NMFS consulting biologist describing the total annual structures removed, sea turtle and sperm whale sightings during pre-detonation surveys, sea turtle and sperm whale sightings during post- detonation surveys, visibility during the surveys, details of sea turtles (including loggerhead, green, Kemp's ridley, hawksbill and leatherback sea turtles) and ESA-listed whales (i.e., sperm whale) that were observed injured, killed or otherwise affected and the measures taken for each sea turtle and sperm whale. These annual reports should be combined with any MMPA reporting requirements, as appropriate.

E. The annual reports shall be sent electronically by email to nmfs.psoreview@noaa.gov with "Decommissioning Protected Species Annual Report" in the subject header.

References:

Byles, R.A., 1989. Satellite telemetry of Kemp's ridley sea turtle, Lepidochelys kempi, in the Gulf of Mexico. In, Proceedings of the Ninth Annual Workshop on Sea Turtle Conservation and Biology, compiled by S.A. Eckert, K. L. Eckert and T. H. Richardson, NOAA Tech. Memo. NMFS-SEFC-232, pp. 25-26.

Renaud, M. L., 1995. Movements and submergence patterns of Kemp's ridley turtles (Lepidochelys kempii). J. Herpetology, Vol. 29, pp. 370-374.

Gitschlag, G. R. 1996. Migration and diving behavior of Kemp's ridley (Garman) sea turtles along the U.S. southeastern Atlantic coast. J. Experimental Marine Biology and Ecology, Vol. 205, pp. 115-135.

Appendix J. Sea Turtle Handling and Resuscitation Guidelines

Any sea turtles taken incidentally during the course of fishing or scientific research activities must be handled with due care to prevent injury to live specimens, observed for activity, and returned to the water according to the following procedures:

I. Sea turtles that are actively moving or determined to be dead (as described in paragraph (B)(4) below) must be released over the stern of the boat. In addition, they must be released only when fishing or scientific collection gear is not in use, when the engine gears are in neutral position, and in areas where they are unlikely to be recaptured or injured by vessels.

II. Resuscitation must be attempted on sea turtles that are comatose or inactive by:

   i. Placing the turtle on its bottom shell (plastron) so that the turtle is right side up and elevating its hindquarters at least 6 inches (15.2 cm) for a period of 4 to 24 hours. The amount of elevation depends on the size of the turtle; greater elevations are needed for larger turtles. Periodically, rock the turtle gently left to right and right to left by holding the outer edge of the shell (carapace) and lifting one side about 3 inches (7.6 cm) then alternate to the other side. Gently touch the eye and pinch the tail (reflex test) periodically to see if there is a response.
   ii. Sea turtles being resuscitated must be shaded and kept damp or moist but under no circumstance be placed into a container holding water. A water-soaked towel placed over the head, carapace, and flippers is the most effective method in keeping a turtle moist.
   iii. Sea turtles that revive and become active must be released over the stern of the boat only when fishing or scientific collection gear is not in use, when the engine gears are in neutral position, and in areas where they are unlikely to be recaptured or injured by vessels. Sea turtles that fail to respond to the reflex test or fail to move within 4 hours (up to 24, if possible) must be returned to the water in the same manner as that for actively moving turtles.
   iv. A turtle is determined to be dead if the muscles are stiff (rigor mortis) and/or the flesh has begun to rot; otherwise, the turtle is determined to be comatose or inactive and resuscitation attempts are necessary.

Any sea turtle so taken must not be consumed, sold, landed, offloaded, transshipped, or kept below deck.

These requirements are excerpted from 50 CFR 223.206(d)(1). Failure to follow these procedures is therefore a punishable offense under the Endangered Species Act.

APPENDIX G
WASTES AND DISCHARGES INFORMATION

A) PROJECTED GENERATED WASTES
A table entitled "Wastes you will transport and/or dispose of onshore" is included in the attachments to this appendix.

B) PROJECTED OCEAN DISCHARGES
A table entitled "Wastes you will generate, treat and/or downhole dispose or discharge to the GOM" is included in the attachments to this appendix.

C) MODELING REPORT
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as the subject activities do not require an individual NPDES permit. Therefore, a modeling report is not required.

D) NPDES PERMITS
The subject rig and/or facility will be covered under BOE Exploration & Production's General Permit upon commencement of the activities proposed in this plan.

E) COOLING WATER INTAKES
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as the associated leases are within the Gulf of Mexico Region.

WATER QUALITY SPREADSHEETS

TABLE 1. WASTES YOU WILL GENERATE, TREAT AND DOWNHOLE DISPOSE OR

please specify if the amount reported is a total or per well amount

GC895 #1

Projected generated waste			Projected ocean discharges		Downhole Disposal
Type of Waste	Composition	Projected Amount	Discharge rate	Discharge Method	Answer yes or no
Will drilling occur ? If yes, fill in the muds and cuttings.					
EXAMPLE: Cuttings wetted with synthetic based fluid	*Cuttings generated while using synthetic based drilling fluid.*	*X bbl/well*	*X bbl/day/well*	*discharge overboard*	*No*
Water-based drilling fluid	Water based mud additives, barite and gel used for WBM	101,194 bbls/well	7,354 bbls/day/well	Discharge overboard	No
Cuttings wetted with water-based fluid	Cuttings generated while using water based drilling fluid.	5,613 bbls/well	408 bbls/day/well	Discharge overboard	No
Cuttings wetted with synthetic-based fluid	Cuttings generated while using synthetic based drilling fluid.	6,165 bbls/well	171 bbls/day/well	Discharge overboard	No
Will humans be there? If yes, expect conventional waste					
EXAMPLE: Sanitary waste water	Sanitary waste from living quarters	X bbl/well	X bbl/hr/well	chlorinate and discharge overboard	No
Domestic waste	Misc waste for living quarters	9,411 bbls/well	4.6 bbls/hr/well	Discharge overboard (no free oil)	No
Sanitary waste	Processed sanitary waste from living quarters	6,274 bbls/well	3.1 bbls/hr/well	Chlorinate and discharge overboard	No
Is there a deck? If yes, there will be Deck Drainage					
Deck Drainage	Accumulated drainage due to rainfall	0 to 47,261 bbls/well	0 to 167 bbls/hr/well	Test for oil and grease and discharge overboard	No
Will you conduct well treatment, completion, or workover?					
Well treatment fluids	NPDES approved treatment fluid used for well operations	100 bbls/well	20 bbls/hr/well	Test for oil and grease and discharge overboard.	No
Well completion fluids	Clear brines used for completion operations	500 bbls/well	100 bbls/hr/well	Test for oil and grease and discharge overboard. This excludes clear brines containing Zinc	No
Workover fluids	NA	NA	NA	NA	NA
Miscellaneous discharges. If yes, only fill in those associated with your activity.					
Desalinization unit discharge	Uncontaminated spent seawater used for potable water generation unit	0 to 100,000 bbls/well	60 bbls/hr/well	Discharge overboard	No
Blowout prevent fluid	Treated freshwater used control of subsea blowout preventers	0 to 100 bbls/well	5 bbls/hr/well	Discharge at seafloor	No
Ballast water	Uncontaminated seawater used for ballast control	0 to 100,000 bbls/well	16,350 bbls/hr/well	Discharge overboard	No
Bilge water	NA	NA	NA	NA	NA
Excess cement at seafloor	Excess cement slurry and mixwater used for cementing operation - NPDES allowed	300 bbls/well	360 bbls/hr/well	Discharge at mudline	No
Fire water	Uncontaminated seawater used for fire control system	0 to 10,000 bbls/well	16,350 bbls/hr/well	Discharge overboard	No
Cooling water	Uncontaminated seawater used for heat exchanger operations used to cool machinery	0 to 400,000 bbls/well	120 bbls/hr/well	Discharge overboard	No
Will you produce hydrocarbons? If yes fill in for produced water.					
Produced water	NA	NA	NA	NA	NA
Will you be covered by an individual or general NPDES permit ?		General NPDES	GMG 290000		
			Comply with the requirements of the NPDES permit.		

NOTE: If you will not have a type of waste, enter NA in the row.

TABLE 2. WASTES YOU WILL TRANSPORT AND /OR DISPOSE OF ONSHORE

Please specify whatever the amount reported is a total or per well

GC 895 #1	Projected generated waste	Solid and Liquid Wastses Transportation	Waste Disposal		
Type of Waste	**Composition**	**Transport Method**	**Name/Location of Facility**	**Amount**	**Disposal Method**
			Newport Environmental Services Inc., Ingleside, TX	*X bbl/well*	*Recycled*
Oil-based drilling fluid or mud	NA	NA	NA	NA	NA
Synthetic-based drilling fluid or mud	Internal olifin, ester nbased mud	Barged in 25 bbls cutting boxes and / or liquid mud tanks for supply vessels	Ecoserv, Fourchon, LA / R360, Fourcon, LA	6750 bbls / well	Recycled
Cuttings wetted with Water-based fluid	NA	NA	NA	NA	NA
Cuttings wetted with Synthetic-based fluid	NA	NA	NA	NA	NA
Cuttings wetted with oil-based fluids	NA	NA	NA	NA	NA
Will you produce hydrocarbons? If yes fill in for produced sand.					
Produced sand	NA	NA	NA	NA	NA
Will you have additional wastes that are not permitted for discharge? If					
EXAMPLE: trash and debris (recylables)	*Plastic, paper, aluminum*	*barged in a storage bin*	*ARC, New Iberia, LA*	*X lb/well*	*Recycled*
Trash and debris	Plastic, paper, aluminum	Barged in a storage bin	Blanchard Landfill, Golden Meadows, LA	4000 lbs / well	Recycled
Used oil	Spent oil from machinery	Barged in USCG approved transfer tote tanks.	L&L Services, Fourchon, LA	200 bbls / well	Recycled
Wash water	Wash water w/ SBM residue and surfactants	Barged in 25 bbls cutting boxes and / or liquid mud tanks for supply vessels	Ecoserv, Fourchon, LA / R360, Fourcon, LA	2000 bbls / well	Approved disposal well injection or land farm
Chemical product wastes	Spent treatment and / or damaged chemicals used in operations	Barged in 25 bbls cutting boxes and / or cutting boxes	L&L Services, Fourchon, LA	10 bbls / well	Recycled

NOTE: If you will not have a type of waste, enter NA in the row.

APPENDIX H
AIR EMISSIONS INFORMATION

A specific drilling unit has not been determined to conduct activities proposed in this plan.

In accordance with BOEM guidance, only one form for the type of drilling unit that has the highest potential emissions is included in the attachments to this appendix.

Multiple rig types proposed to conduct activities proposed in this plan are clarified on the title page of the attached.

AIR EMISSION SPREADHSEETS

EXPLORATION PLAN (EP)
AIR QUALITY SCREENING CHECKLIST

COMPANY	BOE Exploration & Productoin
AREA	GC
BLOCK	895
LEASE	OCS-G 35879
PLATFORM	N/A
WELL	A / B / C / D
COMPANY CONTACT	Brandon Hebert
TELEPHONE NO.	985.666.0143
REMARKS	Proposed Rig Types: Drillship / DP Semisubmerisble

EMISSIONS FACTORS

Fuel Usage Conversion Factors	Natural Gas Turbines		Natural Gas Engines		Diesel Recip. Engine		REF.	DATE
	SCF/hp-hr	9.524	SCF/hp-hr	7.143	GAL/hp-hr	0.0483	AP42 3.2-1	4/76 & 8/84

Equipment/Emission Factors	units	PM	SOx	NOx	VOC	CO	REF.	DATE
NG Turbines	gms/hp-hr		0.00247	1.3	0.01	0.83	AP42 3.2-1& 3.1-1	10/96
NG 2-cycle lean	gms/hp-hr		0.00185	10.9	0.43	1.5	AP42 3.2-1	10/96
NG 4-cycle lean	gms/hp-hr		0.00185	11.8	0.72	1.6	AP42 3.2-1	10/96
NG 4-cycle rich	gms/hp-hr		0.00185	10	0.14	8.6	AP42 3.2-1	10/96
Diesel Recip. < 600 hp.	gms/hp-hr	1	0.1835	14	1.12	3.03	AP42 3.3-1	10/96
Diesel Recip. > 600 hp.	gms/hp-hr	0.32	0.1835	11	0.33	2.4	AP42 3.4-1	10/96
Diesel Boiler	lbs/bbl	0.084	0.3025	0.84	0.008	0.21	AP42 1.3-12,14	9/98
NG Heaters/Boilers/Burners	lbs/mmscf	7.6	0.593	100	5.5	84	P42 1.4-1, 14-2, & 14	7/98
NG Flares	lbs/mmscf		0.593	71.4	60.3	388.5	AP42 11.5-1	9/91
Liquid Flaring	lbs/bbl	0.42	6.83	2	0.01	0.21	AP42 1.3-1 & 1.3-3	9/98
Tank Vapors	lbs/bbl				0.03		E&P Forum	1/93
Fugitives	lbs/hr/comp.				0.0005		API Study	12/93
Glycol Dehydrator Vent	lbs/mmscf				6.6		La. DEQ	1991
Gas Venting	lbs/scf				0.0034			

Sulphur Content Source	**Value**	**Units**
Fuel Gas	3.33	ppm
Diesel Fuel	0.05	% weight
Produced Gas(Flares)	3.33	ppm
Produced Oil (Liquid Flaring)	1	% weight

EMISSIONS CALCULATIONS 3RD YEAR

COMPANY	AREA	BLOCK	LEASE	PLATFORM	WELL		CONTACT	PHONE	REMARKS
BOE Exploration & Produ	GC	895	OCS-G 35879	N/A	A / B / C / D		Brandon Hebert	985.666.0143	Drillship

OPERATIONS	EQUIPMENT	RATING	MAX. FUEL	ACT. FUEL	RUN TIME		MAXIMUM POUNDS PER HOUR					ESTIMATED TONS				
	Diesel Engines	**HP**	**GAL/HR**	**GAL/D**												
	Nat. Gas Engines	**HP**	**SCF/HR**	**SCF/D**												
	Burners	**MMBTU/HR**	**SCF/HR**	**SCF/D**	**HR/D**	**D/YR**	**PM**	**SOx**	**NOx**	**VOC**	**CO**	**PM**	**SOx**	**NOx**	**VOC**	**CO**
DRILLING	PRIME MOVER>600hp diesel	61800	2984.94	71638.56	24	150	43.56	24.98	1497.36	44.92	326.70	78.41	44.96	2695.24	80.86	588.05
	PRIME MOVER>600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	PRIME MOVER>600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	PRIME MOVER>600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	BURNER diesel	0			0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	AUXILIARY EQUIP<600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	VESSELS>600hp diesel(crew)	7200	347.76	8346.24	6	86	5.07	2.91	174.45	5.23	38.06	1.31	0.75	45.01	1.35	9.82
	VESSELS>600hp diesel(supply)	7200	347.76	8346.24	10	128	5.07	2.91	174.45	5.23	38.06	3.25	1.86	111.65	3.35	24.36
	VESSELS>600hp diesel(tugs)	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FACILITY	DERRICK BARGE diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INSTALLATION	MATERIAL TUG diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	VESSELS>600hp diesel(crew)	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	VESSELS>600hp diesel(supply)	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MISC.	**BPD**	**SCF/HR**	**COUNT**												
	TANK-	0			0	0				0.00					0.00	
DRILLING	OIL BURN	0			0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WELL TEST	GAS FLARE		0		0	0		0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00
2020	**YEAR TOTAL**						**53.71**	**30.80**	**1846.26**	**55.39**	**402.82**	**82.96**	**47.57**	**2851.90**	**85.56**	**622.23**

EXEMPTION CALCULATION	DISTANCE FROM LAND IN MILES	PM	SOx	NOx	VOC	CO
	136.0	**4528.80**	**4528.80**	**4528.80**	**4528.80**	**89916.25**

EMISSIONS CALCULATIONS 4TH YEAR

COMPANY	AREA	BLOCK	LEASE	PLATFORM	WELL		CONTACT	PHONE	REMARKS
BOE Exploration & Produ	GC	895	OCS-G 35879	N/A	A / B / C / D		Brandon Hebert	985.666.0143	Drillship

OPERATIONS	EQUIPMENT	RATING	MAX. FUEL	ACT. FUEL	RUN TIME		MAXIMUM POUNDS PER HOUR					ESTIMATED TONS				
	Diesel Engines	HP	GAL/HR	GAL/D												
	Nat. Gas Engines	HP	SCF/HR	SCF/D												
	Burners	MMBTU/HR	SCF/HR	SCF/D	HR/D	D/YR	PM	SOx	NOx	VOC	CO	PM	SOx	NOx	VOC	CO
DRILLING	PRIME MOVER>600hp diesel	61800	2984.94	71638.56	24	150	43.56	24.98	1497.36	44.92	326.70	78.41	44.96	2695.24	80.86	588.05
	PRIME MOVER>600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	PRIME MOVER>600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	PRIME MOVER>600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	BURNER diesel	0			0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	AUXILIARY EQUIP<600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	VESSELS>600hp diesel(crew)	7200	347.76	8346.24	6	86	5.07	2.91	174.45	5.23	38.06	1.31	0.75	45.01	1.35	9.82
	VESSELS>600hp diesel(supply)	7200	347.76	8346.24	10	128	5.07	2.91	174.45	5.23	38.06	3.25	1.86	111.65	3.35	24.36
	VESSELS>600hp diesel(tugs)	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FACILITY	DERRICK BARGE diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INSTALLATION	MATERIAL TUG diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	VESSELS>600hp diesel(crew)	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	VESSELS>600hp diesel(supply)	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MISC.	**BPD**	**SCF/HR**	**COUNT**												
	TANK-	0			0	0				0.00					0.00	
DRILLING	OIL BURN	0			0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WELL TEST	GAS FLARE		0		0	0		0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00
2021	**YEAR TOTAL**						**53.71**	**30.80**	**1846.26**	**55.39**	**402.82**	**82.96**	**47.57**	**2851.90**	**85.56**	**622.23**
EXEMPTION CALCULATION	**DISTANCE FROM LAND IN MILES**											**4528.80**	**4528.80**	**4528.80**	**4528.80**	**89916.25**
	136.0															

EMISSIONS CALCULATIONS 5TH YEAR

COMPANY	AREA	BLOCK	LEASE	PLATFORM	WELL		CONTACT	PHONE	REMARKS
BOE Exploration & Produ	GC	895	OCS-G 35879	N/A	A / B / C / D		Brandon Hebert	985.666.0143	Drillship

OPERATIONS	EQUIPMENT	RATING	MAX. FUEL	ACT. FUEL	RUN TIME		MAXIMUM POUNDS PER HOUR					ESTIMATED TONS				
	Diesel Engines	**HP**	**GAL/HR**	**GAL/D**												
	Nat. Gas Engines	**HP**	**SCF/HR**	**SCF/D**												
	Burners	**MMBTU/HR**	**SCF/HR**	**SCF/D**	**HR/D**	**D/YR**	**PM**	**SOx**	**NOx**	**VOC**	**CO**	**PM**	**SOx**	**NOx**	**VOC**	**CO**
DRILLING	PRIME MOVER>600hp diesel	61800	2984.94	71638.56	24	150	43.56	24.98	1497.36	44.92	326.70	78.41	44.96	2695.24	80.86	588.05
	PRIME MOVER>600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	PRIME MOVER>600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	PRIME MOVER>600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	BURNER diesel	0			0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	AUXILIARY EQUIP<600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	VESSELS>600hp diesel(crew)	7200	347.76	8346.24	6	86	5.07	2.91	174.45	5.23	38.06	1.31	0.75	45.01	1.35	9.82
	VESSELS>600hp diesel(supply)	7200	347.76	8346.24	10	128	5.07	2.91	174.45	5.23	38.06	3.25	1.86	111.65	3.35	24.36
	VESSELS>600hp diesel(tugs)	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FACILITY	DERRICK BARGE diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INSTALLATION	MATERIAL TUG diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	VESSELS>600hp diesel(crew)	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	VESSELS>600hp diesel(supply)	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MISC.	**BPD**	**SCF/HR**	**COUNT**												
	TANK-	0			0	0				0.00					0.00	
DRILLING	OIL BURN	0			0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WELL TEST	GAS FLARE		0		0	0		0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00
2022	**YEAR TOTAL**						**53.71**	**30.80**	**1846.26**	**55.39**	**402.82**	**82.96**	**47.57**	**2851.90**	**85.56**	**622.23**
EXEMPTION CALCULATION	**DISTANCE FROM LAND IN MILES**											**4528.80**	**4528.80**	**4528.80**	**4528.80**	**89916.25**
	136.0															

EMISSIONS CALCULATIONS 6TH YEAR

COMPANY	AREA	BLOCK	LEASE	PLATFORM	WELL		CONTACT	PHONE	REMARKS
BOE Exploration & Produ	GC	895	OCS-G 35879	N/A	A / B / C / D		Brandon Hebert	985.666.0143	Drillship

OPERATIONS	EQUIPMENT	RATING	MAX. FUEL	ACT. FUEL	RUN TIME		MAXIMUM POUNDS PER HOUR					ESTIMATED TONS				
	Diesel Engines	HP	GAL/HR	GAL/D												
	Nat. Gas Engines	HP	SCF/HR	SCF/D												
	Burners	MMBTU/HR	SCF/HR	SCF/D	HR/D	D/YR	PM	SOx	NOx	VOC	CO	PM	SOx	NOx	VOC	CO
DRILLING	PRIME MOVER>600hp diesel	61800	2984.94	71638.56	24	150	43.56	24.98	1497.36	44.92	326.70	78.41	44.96	2695.24	80.86	588.05
	PRIME MOVER>600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	PRIME MOVER>600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	PRIME MOVER>600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	BURNER diesel	0			0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	AUXILIARY EQUIP<600hp diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	VESSELS>600hp diesel(crew)	7200	347.76	8346.24	6	86	5.07	2.91	174.45	5.23	38.06	1.31	0.75	45.01	1.35	9.82
	VESSELS>600hp diesel(supply)	7200	347.76	8346.24	10	128	5.07	2.91	174.45	5.23	38.06	3.25	1.86	111.65	3.35	24.36
	VESSELS>600hp diesel(tugs)	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FACILITY	DERRICK BARGE diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INSTALLATION	MATERIAL TUG diesel	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	VESSELS>600hp diesel(crew)	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	VESSELS>600hp diesel(supply)	0	0	0.00	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	MISC.	**BPD**	**SCF/HR**	**COUNT**												
	TANK-	0			0	0				0.00					0.00	
DRILLING	OIL BURN	0			0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WELL TEST	GAS FLARE		0		0	0		0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00
2023	**YEAR TOTAL**						**53.71**	**30.80**	**1846.26**	**55.39**	**402.82**	**82.96**	**47.57**	**2851.90**	**85.56**	**622.23**
EXEMPTION CALCULATION	**DISTANCE FROM LAND IN MILES**											**4528.80**	**4528.80**	**4528.80**	**4528.80**	**89916.25**
	136.0															

COMPANY	AREA	BLOCK	LEASE	PLATFORM	WELL
BOE Exploration	GC	895	OCS-G 35879	N/A	A / B / C / D

Year	Emitted Substance				
	PM	SOx	NOx	VOC	CO
2020	82.96	47.57	2851.90	85.56	622.23
2021	82.96	47.57	2851.90	85.56	622.23
2022	82.96	47.57	2851.90	85.56	622.23
2023	82.96	47.57	2851.90	85.56	622.23
Allowable	4528.80	4528.80	4528.80	4528.80	89916.25

APPENDIX I
OIL SPILLS INFORMATION

A) OIL SPILL RESPONSE PLANNING
Pursuant to 30 CFR 550.219 and NTL BOEM 2015-N01, this appendix provides information regarding any potential oil spill(s), the assumptions and calculations used to determine the worst-case discharge (WCD) measures scenario.

Below is a reference to and status of BOE Exploration & Production's Regional OSRP. A site specific OSRP nor a sub-regional OSRP is not required with this plan, as the State of Florida is not an affected State for the activities proposed in this plan.

1) REGIONAL OR SUBREGIONAL OSRP INFORMATION
Activities proposed in this plan will be covered by oil spill response plan number O-1039, approved via letter dated September 17, 2019.

The below operators are covered under oil spill response plan number O-1039:
- BOE Exploration & Production LLC (03572)
- Beacon Growthco Operating Company, L.L.C. (03567)

2) SPILL RESPONSE SITES
The table below provides information on the location of the primary spill response equipment and the location of the planned staging area(s) that would be used should an oil spill occur resulting from the activities proposed in this plan.

Primary Response Equipment Location	Pre-Planned Staging Location
Houma, LA	Venice, LA

3) OIL SPILL REMOVAL ORGANIZATION (OSRO) INFORMATION
The O'Brien Group will provide trained personnel capable of providing supervisory oil spill response management in addition to contacting and deploying cleanup personnel and equipment.

BOE Exploration & Production's primary equipment provider is Clean Gulf Associates (CGA). CGA is supported by the Marine Spill Response Corporation (MSRC), which is responsible for storing, inspecting, maintaining and dispatching CGA equipment. The MSRC STARs network provides for the closest available personnel as well as an MSRC supervisor to operate the equipment.

4) WORST CASE SCENARIO COMPARISON
The table below provides a comparison of the worst-case discharge scenario from the above referenced Regional OSRP with the worst-case scenario from the activities proposed in this plan. Please note the Regional OSRP distance to shore scenarios are approximate and will be updated as required with modifications to the OSRP. The distance to shore for the proposed activities is accurate and based on survey data.

Worst Case Discharge Comparison Chart

Category	Regional OSRP WCD	Plan WCD
Type of Activity	Drilling	Plan WCD
Facility (Area/Block)	Mississippi Canyon 257	Green Canyon 895
Facility Designation	Well 002	Location A
Distance to Shore (miles)	61	136
	Volume	
Flowlines (on facility)	0	0
Lease Term Pipelines	0	0
Storage	0	0
Uncontrolled Blowout	337,164 BOPD	313,100 BOPD
Total Volume	**337,164 BOPD**	**313,100 BOPD**
Type of Oil	Crude	Crude
API Gravity	35°	31.6°

BOE Exploration & Production has the capability to respond to the worst-case spill scenario included in its regional OSRP, approved via letter dated September 17, 2019, and since the worst-case scenario determined for the subject EP does not replace the worst-case scenario in its regional OSRP, BOE Exploration & Production hereby certifies that it has the capability to respond, to the maximum extent practicable, to a worst-case discharge, or a substantial threat of such a discharge, resulting from the activities proposed in the subject EP.

5) WORST CASE DISCHARGE ASSUMPTIONS AND CALCULATIONS

In accordance with NTL No. 2015-N01, "Information Requirements for Exploration Plans, Development and Production Plans, and Development Operations Coordination Documents on the OCS," worst case discharge assumptions and calculations are included in the attachments of the proprietary information copy of this plan.

6) OIL SPILL RESPONSE DISCUSSION

An oil spill response discussion is included in the attachments to this appendix.

OIL SPILL RESPONSE DISCUSSION

SPILL RESPONSE DISCUSSION

BOE Exploration & Production LLC will make every effort to respond to the Worst Case Discharge as effectively as practicable. A description of the response equipment under contract to contain and recover the Worst Case Discharge is shown in **Figure 2.**

Figure 2 outlines equipment, personnel, materials and support vessels as well as temporary storage equipment available to respond to the worst case discharge. The volume accounts for the amount remaining after evaporation/dispersion at 24 hours. The list estimates individual times needed for procurement, load out, travel time to the site and deployment. **Figure 2** also indicates how operations will be supported.

BOE Exploration & Production LLC's Oil Spill Response Plan includes alternative response technologies such as dispersants and in-situ burn. Strategies will be decided by Unified Command based on an operations safety analysis, the size of the spill, weather and potential impacts. If aerial dispersants are utilized, 8 sorties (9,600 gallons) from two of the DC-3 aircrafts and 4 sorties (8,000 gallons) from the Basler aircraft would provide a daily dispersant capability of 7,540 barrels. If the conditions are favorable for in-situ burning, the proper approvals have been obtained and the proper planning is in place, in-situ burning of oil may be attempted. Slick containment boom would be immediately called out and on-scene as soon as possible. Offshore response strategies may include attempting to skim utilizing CGA and MSRC spill response equipment, with a total derated skimming capacity of 616,318 barrels. Temporary storage associated with skimming equipment equals 120,896 barrels. If additional storage is needed, various tank barges with a total of 505,000+ barrels of storage capacity may be mobilized and centrally located to provide temporary storage and minimize off-loading time. **Safety is first priority. Air monitoring will be accomplished and operations deemed safe prior to any containment/skimming attempts.**

If the spill went unabated, shoreline impact would depend upon existing environmental conditions. Shoreline protection would include the use of CGA's near shore and shallow water skimmers with a totaled derated skimming capacity of 235,300 barrels. Temporary storage associated with skimming equipment equals 2,841 barrels. If additional storage is needed, various tank barges with a total of 235,000+ barrels of storage capacity may be mobilized and centrally located to provide temporary storage and minimize off-loading time. Onshore response may include the deployment of shoreline boom on beach areas, or protection and sorbent boom on vegetated areas. Master Service Agreements with AMPOL and OMI Environmental will ensure access to 131,350 feet of 18" shoreline protection boom. **Figure 2** outlines individual times needed for procurement, load out, travel time to the site and deployment. Strategies would be based upon surveillance and real time trajectories that depict areas of potential impact given actual sea and weather conditions. Applicable Area Contingency Plans (ACPs), Geographic Response Plans (GRPs), and Unified Command (UC) will be consulted to ensure that environmental and special economic resources are correctly identified and prioritized to ensure optimal protection. Shoreline protection strategies depict the protection response modes applicable for oil spill clean-up operations. As a secondary resource, the State of Louisiana Initial Oil Spill Response Plan will be consulted as appropriate to provide detailed shoreline protection strategies and describe necessary action to keep the oil spill from entering Louisiana's coastal wetlands. The UC should take into consideration all appropriate items detailed in Tactics discussion of this Appendix. The UC and their personnel have the option to modify the deployment and operation of equipment to allow for a more effective response to site-specific circumstances. BOE Exploration & Production LLC's contract Incident Management Team has access to the applicable ACP(s) and GRP(s).

Initial Response Considerations
Actual actions taken during an oil spill response will be based on many factors to include but not be limited to:

- Safety
- Weather
- Equipment and materials availability
- Ocean currents and tides
- Location of the spill
- Product spilled
- Amount spilled
- Environmental risk assessments
- Trajectory and product analysis
- Well status, i.e., shut in or continual release

BOE Exploration & Production LLC will take action to provide a safe, aggressive response to contain and recover as much of the spilled oil as quickly as it is safe to do so. In an effort to protect the environment, response actions will be designed to provide an "in-depth" protection strategy meant to recover as much oil as possible as far from environmentally sensitive areas as possible. Safety will take precedence over all other considerations during these operations.

Coordination of response assets will be supervised by the designation of a SIMOPS group as necessary for close quarter vessel response activities. Most often, this group will be used during source control events that require a significant number of large vessels operating independently to complete a common objective, in close coordination and support of each other. This group must also monitor the subsurface activities of each vessel (ROV, dispersant application, well control support, etc.). The SIMOPS group leader reports to the Source Control Section Chief.

In addition, these activities will be monitored by the Incident Management Team (IMT) and Unified Command via a structured Common Operating Picture (COP) established to track resource and slick movement in real time.

Upon notification of a spill, the following actions will be taken:

- Information will be confirmed
- An assessment will be made and initial objectives set
- OSROs and appropriate agencies will be notified
- ICS 201, Initial Report Form completed
- Initial Safety plan will be written and published
- Unified Command will be established
    - Overall safety plan developed to reflect the operational situation and coordinated objectives
    - Areas of responsibility established for Source Control and each surface operational site
    - On-site command and control established

Offshore Response Actions

Equipment Deployment

Surveillance

- Surveillance Aircraft: within two hours of QI notification, or at first light
- Provide trained observer to provide on site status reports
- Provide command and control platform at the site if needed
- Continual surveillance of oil movement by remote sensing systems, aerial photography and visual confirmation
- Continual monitoring of vessel assets using vessel monitoring systems

Dispersant application assets

- Put ASI on standby
- With the FOSC, conduct analysis to determine appropriateness of dispersant application (refer to Section 18)
- Gain FOSC approval for use of dispersants on the surface
- Deploy aircraft in accordance with a plan developed for the actual situation
- Coordinate movement of dispersants, aircraft, and support equipment and personnel
- Confirm dispersant availability for current and long range operations
- Start ordering dispersant stocks required for expected operations

Containment boom

- Call out early and expedite deployment to be on scene ASAP
- Ensure boom handling and mooring equipment is deployed with boom
- Provide continuing reports to vessels to expedite their arrival at sites that will provide for their most effective containment
- Use Vessels of Opportunity (VOO) to deploy and maintain boom

Oceangoing Boom Barge

- Containment at the source
- Increased/enhanced skimmer encounter rate
- Protection booming

In-situ Burn assets

- Determine appropriateness of in-situ burn operation in coordination with the FOSC and affected SOSC
- Determine availability of fire boom and selected ignition systems
- Start ordering fire boom stocks required for expected operations
- Contact boom manufacturer to provide training & tech support for operations, if required
- Determine assets to perform on water operation
- Build operations into safety plan
- Conduct operations in accordance with an approved plan
- Initial test burn to ensure effectiveness

Dedicated off-shore skimming systems
General

- Deployed to the highest concentration of oil
- Assets deployed at safe distance from aerial dispersant and in-situ burn operations

CGA HOSS Barge

- Use in areas with heaviest oil concentrations
- Consider for use in areas of known debris (seaweed, and other floating materials)

CGA 95' Fast Response Vessels (FRVs)

- Designed to be a first vessel on scene
- Capable of maintaining the initial Command and Control function for on water recovery operations
- 24 hour oil spill detection capability
- Highly mobile and efficient skimming capability
- Use as far off-shore as safely possible

CGA FRUs

- To the area of the thickest oil
- Use as far off-shore as allowed
- VOOs 140' – 180' in length
- VOOs with minimum of 18' x 38' or 23' x 50' of optimum deck space
- VOOs in shallow water should have a draft of <10 feet when fully loaded

T&T Koseq Skimming Systems

- To the area of the thickest oil
- Use as far off-shore as allowed
- VOOs with a minimum of 2,000 bbls storage capacity
- VOOs at least 200' in length
- VOOs with deck space of 100' x 40' to provide space for arms, tanks, and crane
- VOOs for shallow water should be deck barges with a draft of <10 feet when fully loaded

Storage Vessels

- Establish availability of CGA contracted assets (See Appendix E)
- Early call out (to allow for tug boat acquisition and deployment speeds)
- Phase mobilization to allow storage vessels to arrive at the same time as skimming systems
- Position as closely as possible to skimming assets to minimize offloading time

Vessels of Opportunity (VOO)

- Use BOE Exploration & Production LLC's contracted resources as applicable
- Industry vessels are ideal for deployment of Vessel of Opportunity Skimming Systems (VOSS)
- Acquire additional resources as needed
- Consider use of local assets, i.e. fishing and pleasure craft for ISB operations or boom tending
- Expect mission specific and safety training to be required
- Plan with the US Coast Guard for vessel inspections
- Place VOOs in Division or Groups as needed
- Use organic on-board storage if appropriate
- Maximize non-organic storage appropriate to vessel limitations
- Decant as appropriate after approval to do so has been granted
- Assign bulk storage barges to each Division/Group
- Position bulk storage barges as close to skimming units as possible
- Utilize large skimming vessel (e.g. barges) storage for smaller vessel offloading
- Maximize skimming area (swath) to the optimum width given sea conditions and available equipment
- Maximize use of oleophilic skimmers in all operations, but especially offshore
- Nearshore, use shallow water barges and shuttle to skimming units to minimize offloading time
- Plan and equip to use all offloading capabilities of the storage vessel to minimize offloading time

Adverse Weather Operations:

In adverse weather, when seas are ≥ 3 feet, the use of larger recovery and storage vessels, oleophilic skimmers, and large offshore boom will be maximized. KOSEQ Arm systems are built for rough conditions, and they should be used until their operational limit (9.8' seas) is met. Safety will be the overriding factor in all operations and will cease at the order of the Unified Command, vessel captain, or in an emergency, "stop work" may be directed by any crew member.

Surface Oil Recovery Considerations and Tactics
(Offshore and Near-shore Operations)

Maximization of skimmer-oil encounter rate

- Place barges in skimming task forces, groups, etc., to reduce recovered oil offloading time
- Place barges alongside skimming systems for immediate offloading of recovered oil when practicable
- Use two vessels, each with heavy sea boom, in an open-ended "V" configuration to funnel surface oil into a trailing skimming unit's organic, V-shaped boom and skimmer (see page 7, *CGA Equipment Guide Book and Tactic Manual* (CGATM)

- Use secondary vessels and heavy sea boom to widen boom swath beyond normal skimming system limits (see page 15, CGATM)
- Consider night-time operations, first considering safety issues
- Utilize all available advanced technology systems (IR, X-Band Radar, etc.) to determine the location of, and move to, recoverable oil
- Confirm the presence of recoverable oil prior to moving to a new location

Maximize skimmer system efficiency

- Place weir skimming systems in areas of calm seas and thick oil
- Maximize the use of oleophilic skimming systems in heavier seas
- Place less mobile, high EDRC skimming systems (e.g. HOSS Barge) in the largest pockets of the heaviest oil
- Maximize onboard recovered oil storage for vessels.
- Obtain authorization for decanting of recovered water as soon as possible
- Use smaller, more agile skimming systems to recover streamers of oil normally found farther from the source. Place recovered oil barges nearby

Recovered Oil Storage

- Smaller barges in larger quantities will increase flexibility for multi-location skimming operations
- Place barges in skimming task forces, groups, etc., to reduce recovered oil offloading time
- Procure and deploy the maximum number of portable tanks to support Vessel of Opportunity Skimming Systems if onboard storage is not available
- Maximize use of the organic recovered oil storage capacity of the skimming vessel

Command, Control, and Communications (C^3)

- Publish, implement, and fully test an appropriate communications plan
- Design an operational scheme, maintaining a manageable span of control
- Designate and mark C^3 vessels for easy aerial identification
- Designate and employ C^3 aircraft for task forces, groups, etc.
- Use reconnaissance air craft and Rapid Response Teams (RAT) to confirm the presence of recoverable oil

On Water Recovery Group
When the first skimming vessel arrives on scene, a complete site assessment will be conducted before recovery operations begin. Once it is confirmed that the air monitoring readings for O2, LEL, H2S, CO, VOC, and Benzene are all within the permissible limits, oil recovery operations may begin.

As skimming vessels arrive, they will be organized to work in areas that allow for the most efficient vessel operation and free vessel movement in the recovery of oil. Vessel groups will vary in structure as determined by the Operations Section of the Unified Command, but will generally consist, at a minimum, of the following dedicated assets:

- 3 to 5 – Offshore skimming vessels (recovery)
- 1 – Tank barge (temporary storage)
- 1 – Air asset (tactical direction)
- 2 – Support vessels (crew/utility for supply)
- 6 to 10 – Boom vessels (enhanced booming)

***Example (Note:** Actual organization of TFs will be dependent on several factors including, asset availability, weather, spilled oil migration, currents, etc.)*

The 95’ FRV Breton Island out of Venice arrives on scene and conducts an initial site assessment. Air monitoring levels are acceptable and no other visual threats have been observed. The area is cleared for safe skimming operations. The Breton Island assumes command and control (CoC) of on-water recovery operations until a dedicated non-skimming vessel arrives to relieve it of those duties.

A second 95’ FRV arrives and begins recovery operations alongside the Breton Island. Several more vessels begin to arrive, including a third 95’ FRV out of Galveston, the HOSS Barge (High Volume Open Sea Skimming System) out of Harvey, a boom barge (CGA 300) with 25,000’ of 42” auto boom out of Leeville, and 9 Fast Response Units (FRUs) from the load-out location at C-Port in Port Fourchon.

As these vessels set up and begin skimming, they are grouped into task forces (TFs) as directed by the Operations Section of the Unified Command located at the command post.

Initial set-up and potential actions:

- A 1,000 meter safety zone has been established around the incident location for vessels involved in Source Control
- The HOSS Barge is positioned facing the incident location just outside of this safety zone or at the point where the freshest oil is reaching the surface
- The HOSS Barge engages its Oil Spill Detection (OSD) system to locate the heaviest oil and maintains that ability for 24-hour operations

- The HOSS Barge deploys 1,320’ of 67” Sea Sentry boom on each side, creating a swath width of 800’
- The Breton Island and H.I. Rich skim nearby, utilizing the same OSD systems as the HOSS Barge to locate and recover oil
- Two FRUs join this group and it becomes TF1
- The remaining 7 FRUs are split into a 2 and 3 vessel task force numbered TF2 and TF3
- A 95’ FRV is placed in each TF
- The boom barge (CGA 300) is positioned nearby and begins deploying auto boom in sections between two utility vessels (1,000’ to 3,000’ of boom, depending on conditions) with chain-link gates in the middle to funnel oil to the skimmers
- The initial boom support vessels position in front of TF2 and TF3
- A 100,000+ barrel offshore tank barge is placed with each task force as necessary to facilitate the immediate offload of skimming vessels

The initial task forces (36 hours in) may be structured as follows:

TF 1

- 1 – 95’ FRV
- 1 – HOSS Barge with 3 tugs
- 2 – FRUs
- 1 – 100,000+ barrel tank barge and associated tug(s)
- 1 – Dedicated air asset for tactical direction
- 8 – 500’ sections of auto boom with gates
- 8 – Boom-towing vessels
- 2 – Support vessels (crew/utility)

TF 2

- 1 – 95’ FRV
- 4 – FRUs
- 1 – 100,000+ barrel tank barge and associated tug(s)
- 1 – Dedicated air asset for tactical direction
- 10 – 500’ sections of auto boom with gates
- 10 – Boom-towing vessels
- 2 – Support vessels (crew/utility)

TF 3

- 1 – 95’ FRV
- 3 – FRUs
- 1 – 100,000+ barrel tank barge and associated tug(s)
- 1 – Dedicated air asset for tactical direction
- 8 – 500’ sections of auto boom with gates
- 8 – Boom-towing vessels
- 2 – Support vessels (crew/utility)

Offshore skimming equipment continues to arrive in accordance with the ETA data listed in figure H.3a; this equipment includes 2 AquaGuard skimmers and 11 sets of Koseq Rigid Skimming Arms. These high volume heavy weather capable systems will be divided into functional groups and assigned to specific areas by the Operations Section of the Unified Command.

At this point of the response, the additional TFs may assume the following configurations:

TF 4
- 2 – Sets of Koseq Rigid Skimming Arms w/ associated 200'+ PIDVs
- 1 – AquaGuard Skimmer
- 1 – 100,000+ barrel tank barge and associated tug(s)
- 1 – Dedicated air asset for tactical direction
- 2 – Support vessels (crew/utility)
- 6 – 500' sections of auto boom with gates
- 6 – Boom-towing vessels

TF 5
- 3 – Sets of Koseq Rigid Skimming Arms w/ associated 200'+ PIDVs
- 1 – AquaGuard Skimmer
- 1 – 100,000+ barrel tank barge and associated tug(s)
- 1 – Dedicated air asset for tactical direction
- 2 – Support vessels (crew/utility)
- 8 – 500' sections of auto boom with gates
- 8 – Boom-towing vessels

TF 6
- 3 – Sets of Koseq Rigid Skimming Arms w/ associated 200'+ PIDVs
- 1 – 100,000+ barrel tank barge and associated tug(s)
- 1 – Dedicated air asset for tactical direction
- 2 – Support vessels (crew/utility)
- 6 – 500' sections of auto boom with gates
- 6 – Boom-towing vessels

TF 7
- 3 – Sets of Koseq Rigid Skimming Arms w/ associated 200'+ PIDVs
- 1 – 100,000+ barrel tank barge and associated tug(s)
- 1 – Dedicated air asset for tactical direction
- 2 – Support vessels (crew/utility)
- 6 – 500' sections of auto boom with gates
- 6 – Boom-towing vessels

CGA Minimum Acceptable Capabilities for Vessels of Opportunity (VOO)

Minimum acceptable capabilities of Petroleum Industry Designed Vessels (PIDV) for conducting Vessel of Opportunity (VOO) skimming operations are shown in the table below. PIDVs are "purpose-built" to provide normal support to offshore oil and gas operators. They include but are not limited to utility boats, offshore supply vessels, etc. They become VOOs when tasked with oil spill response duties.

Capability	FRU	KOSEQ	AquaGuard
Type of Vessel	Utility Boat	Offshore Supply Vessel	Utility Boat
Operating parameters			
Sea State	3-5 ft max	9.8 ft max	3-5 ft max
Skimming speed	≤1 kt	≤3 kts	≤1 kt
Vessel size			
Minimum Length	100 ft	200 ft	100 ft
Deck space for: • Tank(s) • Crane(s) • Boom Reels • Hydraulic Power Units • Equipment Boxes	18x32 ft	100x40 ft	18x32 ft
Communication Assets	Marine Band Radio	Marine Band Radio	Marine Band Radio

Tactical use of Vessels of Opportunity (VOO): BOE Exploration & Production LLC will take all possible measures to maximize the oil-to-skimmer encounter rate of all skimming systems, to include VOOs, as discussed in this section. VOOs will normally be placed within an On-water recovery unit as shown in figures below.

Skimming Operations: PIDVs are the preferred VOO skimming platform. OSROs are more versed in operating on these platforms and the vessels are generally large enough with crews more likely versed in spill response operations. They also have a greater possibility of having on-board storage capacity and the most likely vessels to be under contract, and therefore more readily available to the operator. These vessels would normally be assigned to an on-water recovery group/division (see figure below) and outfitted with a VOSS suited for their size and capabilities. Specific tactics used for skimming operations would be dependent upon many parameters which include, but are not limited to, safety concerns, weather, type VOSS on board, product being recovered, and area of oil coverage. Planners would deploy these assets with the objective of safely maximizing oil- to-skimmer encounter rate by taking actions to minimize non-skimming time and maximizing boom swath. Specific tactical configurations are shown in figures below.

The Fast Response Unit (FRU): A self-contained, skid based, skimming system that is deployed from the right side of a vessel of opportunity (VOO). An outrigger holds a 75' long section of air inflatable boom in place that directs oil to an apex for recovery via a Foilex 250 weir skimmer. The outrigger creates roughly a 40' swath width dependent on the VOO beam. The lip of the collection bowl on the skimmer is placed as close to the oil and water interface as possible to maximize oil recovery and minimize water retention. The skimmer then pumps all fluids recovered to the storage tank where it is allowed to settle, and with the approval of the Coast Guard, the water is decanted from the bottom of the tank back into the water ahead of the containment boom to be recycled through the system. Once the tank is full of as much pure recovered oil as possible it is offloaded to a storage barge for disposal in accordance with an approved disposal plan. A second 100 barrel storage tank can be added if the appropriate amount of deck space is available to use as secondary storage.

Tactical Overview

Mechanical Recovery – The FRU is designed to provide fast response skimming capability in the offshore and nearshore environment in a stationary or advancing mode. It provides a rated daily recovery capacity of 4,100 barrels. An additional boom reel with 440' of offshore boom can be deployed along with the FRU, and a second support vessel for boom towing, to extend the swath width when attached to the end of the fixed boom. The range and sustainability offshore is dependent on the VOO that the unit is placed on, but generally these can stay offshore for extended periods. The FRU works well independently or assigned with other on-water recovery assets in a task force. In either case, it is most effective when a designated aircraft is assigned to provide tactical direction to ensure the best placement in recoverable oil.

Maximum Sea Conditions – Under most circumstances the FRU can maintain standard oil spill recovery operations in 2' to 4' seas. Ultimately, the Coast Guard licensed Captain in charge of the VOO (with input from the CGAS Supervisor assigned) will be responsible to determine when the sea conditions have surpassed the vessel's safe operating capabilities.

Possible Task Force Configuration (Multiple VOOs can be deployed in a task force)

1 – VOO (100' to 165' Utility or Supply Vessel)
1 – Boom reel w/support vessel for towing
1 – Tank barge (offshore) for temporary storage
1 – Utility/Crewboat (supply)
1 – Designated spotter aircraft

The VOSS (yellow) is being deployed and connected to an out-rigged arm. This is suitable for collection in both large pockets of oil and for recovery of streaming oil. The oil-to-skimmer encounter rate is limited by the length of the arm. Skimming pace is ≤ 1 knot.

Through the use of an additional VOO, and using extended sea boom, the swath of the VOSS is increased therefore maximizing the oil-to-skimmer encounter rate. Skimming pace is ≤ 1 knot.

The Koseq Rigid Sweeping Arm: A skimming system deployed on a vessel of opportunity. It requires a large Offshore or Platform Supply Vessel (OSV/PSV), greater than 200' with at least 100' x 50' of free deck space. On each side of the vessel, a 50' long rigid framed Arm is deployed that consists of pontoon chambers to provide buoyancy, a smooth nylon face, and a hydraulically adjustable mounted weir skimmer. The Arm floats independently of the vessel and is attached by a tow bridle and a lead line. The movement of the vessel forward draws the rubber end seal of the arm against the hull to create a collection point for free oil directed to the weir by the Arm face. The collection weir is adjusted to keep the lip as close to the oil water interface as possible to maximize oil recovery while attempting to minimize excess water collection. A transfer pump (combination of positive displacement, screw type and centrifuge suited for highly viscous oils) pump the recovered liquid to portable tanks and/or dedicated fixed storage tanks onboard the vessel. After being allowed to sit and separate, with approval from the Coast Guard, the water can be decanted (pumped off) in front of the collection arm to be reprocessed through the system. Once full with as much pure recovered oil as possible, the oil is transferred to a temporary storage barge where it can be disposed of in accordance with an approved disposal plan.

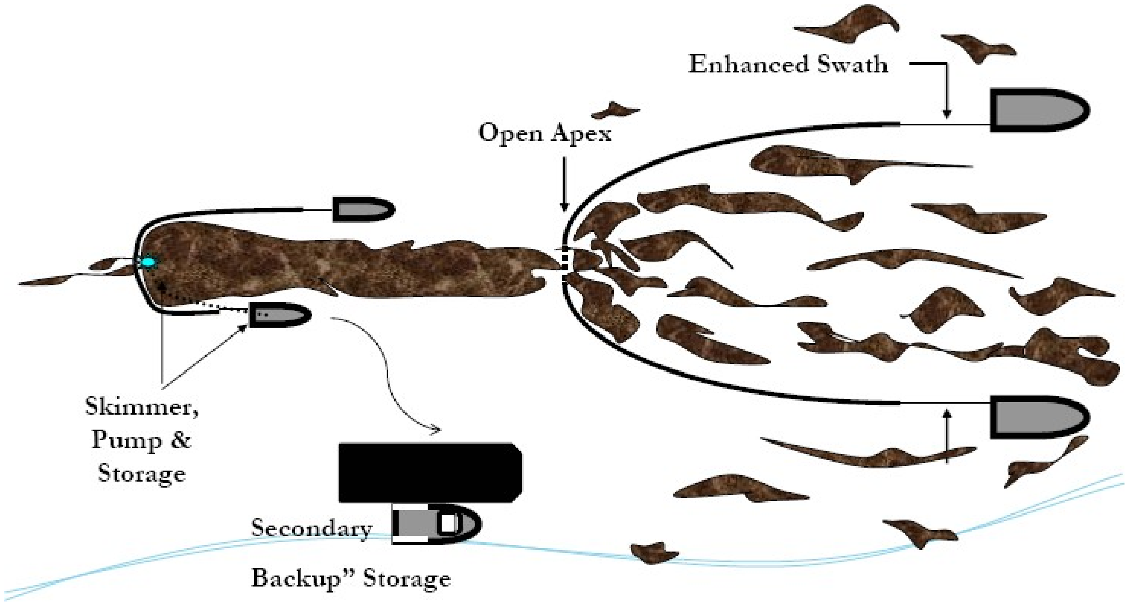
Tactical Overview

Mechanical Recovery – Deployed on large vessels of opportunity (VOO) the Koseq Rigid Sweeping Arms are high volume surge capacity deployed to increase recovery capacity at the source of a large oil spill in the offshore and outer nearshore environment of the Gulf of Mexico. They are highly mobile and sustainable in rougher sea conditions than normal skimming vessels (9.8' seas). The large Offshore Supply Vessels (OSV) required to deploy the Arms are able to remain on scene for extended periods, even when sea conditions pick up. Temporary storage on deck in portable tanks usually provides between 1,000 and 3,000 bbls. In most cases, the OSV will be able to pump 20% of its deadweight into the liquid mud tanks in accordance with the vessels Certificate of Inspection (COI). All storage can be offloaded utilizing the vessels liquid transfer system.

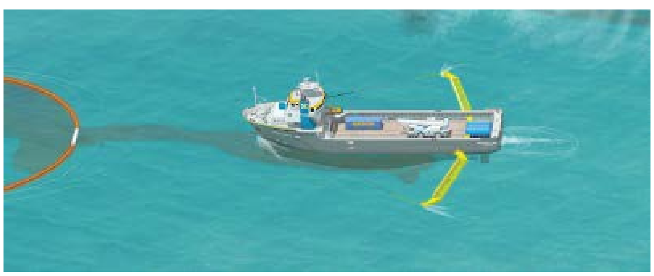
Maximum Sea Conditions - Under most circumstances the larger OSVs are capable of remaining on scene well past the Skimming Arms maximum sea state of 9.8'. Ultimately it will be the decision of the VOO Captain, with input from the T&T Supervisor onboard, to determine when the sea conditions have exceeded the safe operating conditions of the vessel.

Command and Control – The large OSVs in many cases have state of the art communication and electronic systems, as well as the accommodations to support the function of directing all skimming operations offshore and reporting back to the command post.

Possible Task Force Configuration (Multiple Koseq VOOs can be deployed in a task force)
1 – ≥ 200' Offshore Supply Vessels (OSV) with set of Koseq Arms
2 to 4 portable storage tanks (500 bbl)
1 – Modular Crane Pedestal System set (MCPS) or 30 cherry picker (crane) for deployment
1 – Tank barge (offshore) for temporary storage
1 – Utility/Crewboat (supply)
1 – Designated spotter aircraft
4 – Personnel (4 T&T OSRO)



Scattered oil is "caught" by two VOO and collected at the apex of the towed sea boom. The oil moves thought a "gate" at that apex, forming a larger stream of oil which moves into the boom of the skimming vessel. Operations are paced at >1. A recovered oil barge stationed nearby to minimize time taken to offload recovered oil.



This is a depiction of the same operation as above but using KOSEQ Arms. In this configuration, the collecting boom speed dictates the operational pace at ≥ 1 knot to minimize entrainment of the oil.

Clean Gulf Associates (CGA) Procedure for Accessing Member-Contracted and other Vessels of Opportunity (VOOs) for Spill Response

- CGA has procedures in place for CGA member companies to acquire vessels of opportunity (VOOs) from an existing CGA member's contracted fleet or other sources for the deployment of CGA portable skimming equipment including Koseq Arms, Fast Response Units (FRUs) and any other portable skimming system(s) deemed appropriate for the response for a potential or actual oil spill, WCD oil spill or a Spill of National Significance (SONS).

- CGA uses Port Vision, a web-based vessel and terminal interface that empowers CGA to track vessels through Automatic Identification System (AIS) and terminal activities using a Geographic Information System (GIS). It provides live AIS/GIS views of waterways showing current vessel positions, terminals, created vessel fleets, and points-of-interest. Through this system, CGA has the ability to get instant snapshots of the location and status of all vessels contracted to CGA members, day or night, from any web-enabled PC.

Near Shore Response Actions

Timing

- Put near shore assets on standby and deployment in accordance with planning based on the actual situation, actual trajectories and oil budgets
- VOO identification and training in advance of spill nearing shoreline if possible
- Outfitting of VOOs for specific missions
- Deployment of assets based on actual movement of oil

Considerations

- Water depth, vessel draft
- Shoreline gradient
- State of the oil
- Use of VOOs
- Distance of surf zone from shoreline

Surveillance

- Provide trained observer to direct skimming operations
- Continual surveillance of oil movement by remote sensing systems, aerial photography and visual confirmation
- Continual monitoring of vessel assets

Dispersant Use

- Generally will not be approved within 3 miles of shore or with less than 10 meters of water depth
- Approval would be at Regional Response Team level (Region 6)

Dedicated Near Shore skimming systems

- FRVs
- Egmopol and Marco SWS
- Operate with aerial spotter directing systems to observed oil slicks

VOO

- Use BOE Exploration & Production LLC's contracted resources as applicable
- Industry vessel are usually best for deployment of Vessel of Opportunity Skimming Systems (VOSS)
- Acquire additional resources as needed
- Consider use of local assets, i.e. fishing and pleasure craft
- Expect mission specific and safety training to be required
- Plan with the US Coast Guard for vessel inspections
- Operate with aerial spotter directing systems to oil patches

Shoreline Protection Operations

Response Planning Considerations

- Review appropriate Area Contingency Plan(s)
- Locate and review appropriate Geographic Response and Site Specific Plans
- Refer to appropriate Environmentally Sensitive Area Maps
- Capability for continual analysis of trajectories run periodically during the response
- Environmental risk assessments (ERA) to determine priorities for area protection
- Time to acquire personnel and equipment and their availability
- Refer to the State of Louisiana Initial Oil Spill Response Plan, Deep Water Horizon, dated 2 May 2010, as a secondary reference
- Aerial surveillance of oil movement
- Pre-impact beach cleaning and debris removal
- Shoreline Cleanup Assessment Team (SCAT) operations and reporting procedures
- Boom type, size and length requirements and availability
- Possibility of need for In-situ burning in near shore areas
- Current wildlife situation, especially status of migratory birds and endangered species in the area
- Check for Archeological sites and arrange assistance for the appropriate state agency when planning operations the may impact these areas

Placement of boom

- Position boom in accordance with the information gained from references listed above and based on the actual situation
- Determine areas of natural collection and develop booming strategies to move oil into those areas
- Assess timing of boom placement based on the most current trajectory analysis and the availability of each type of boom needed. Determine an overall booming priority and conduct booming operations accordingly. Consider:
    - Trajectories
    - Weather forecast
    - Oil Impact forecast
    - Verified spill movement
    - Boom, manpower and vessel (shallow draft) availability
    - Near shore boom and support material, (stakes, anchors, line)

Beach Preparation - Considerations and Actions

- Use of a 10 mile go/no go line to determine timing of beach cleaning
- SCAT reports and recommendations
- Determination of archeological sites and gaining authority to enter
- Monitoring of tide tables and weather to determine extent of high tides
- Pre cleaning of beaches by moving waste above high tide lines to minimize waste
- Determination of logistical requirements and arranging of waste removal and disposal

- Staging of equipment and housing of response personnel as close to the job site as possible to maximize on-site work time
- Boom tending, repair, replacement and security (use of local assets may be advantageous)
- Constant awareness of weather and oil movement for resource re-deployment as necessary
- Earthen berms and shoreline protection boom may be considered to protect sensitive inland areas
- Requisitioning of earth moving equipment
- Plan for efficient and safe use of personnel, ensuring:
    - A continual supply of the proper Personal Protective Equipment
    - Heating or cooling areas when needed
    - Medical coverage
    - Command and control systems (i.e. communications)
    - Personnel accountability measures
- Remediation requirements, i.e., replacement of sands, rip rap, etc.
- Availability of surface washing agents and associated protocol requirements for their use (see National Contingency Plan Product Schedule for list of possible agents)
- Discussions with all stakeholders, i.e., land owners, refuge/park managers, and others as appropriate, covering the following:
    - Access to areas
    - Possible response measures and impact of property and ongoing operations
    - Determination of any specific safety concerns
    - Any special requirements or prohibitions
    - Area security requirements
    - Handling of waste
    - Remediation expectations
    - Vehicle traffic control
    - Domestic animal safety concerns
    - Wildlife or exotic game concerns/issues

Inland and Coastal Marsh Protection and Response
Considerations and Actions

- All considered response methods will be weighed against the possible damage they may do to the marsh. Methods will be approved by the Unified Command only after discussions with local Stakeholder, as identified above.
    - In-situ burn may be considered when marshes have been impacted
- Passive clean up of marshes should considered and appropriate stocks of sorbent boom and/or sweep obtained.
- Response personnel must be briefed on methods to traverse the marsh, i.e.,
    - use of appropriate vessel
    - use of temporary walkways or road ways
- Discuss and gain approval prior cutting or moving vessels through vegetation
- Discuss use of vessels that may disturb wildlife, i.e, airboats
- Safe movement of vessels through narrow cuts and blind curves

- Consider the possibility that no response in a marsh may be best
- In the deployment of any response asset, actions will be taken to ensure the safest, most efficient operations possible. This includes, but is not limited to:
  - Placement of recovered oil or waste storage as near to vessels or beach cleanup crews as possible.
  - Planning for stockage of high use items for expeditious replacement
  - Housing of personnel as close to the work site as possible to minimize travel time
  - Use of shallow water craft
  - Use of communication systems appropriate ensure command and control of assets
  - Use of appropriate boom in areas that I can offer effective protection
  - Planning of waste collection and removal to maximize cleanup efficiency
- Consideration or on-site remediation of contaminated soils to minimize replacement operations and impact on the area

Decanting Strategy

Recovered oil and water mixtures will typically separate into distinct phases when left in a quiescent state. When separation occurs, the relatively clean water phase can be siphoned or decanted back to the recovery point with minimal, if any, impact. Decanting therefore increases the effective on-site oil storage capacity and equipment operating time. FOSC/SOSC approval will be requested prior to decanting operations. This practice is routinely used for oil spill recovery.

CGA Equipment Limitations

The capability for any spill response equipment, whether a dedicated or portable system, to operate in differing weather conditions will be directly in relation to the capabilities of the vessel the system in placed on. Most importantly, however, the decision to operate will be based on the judgment of the Unified Command and/or the Captain of the vessel, who will ultimately have the final say in terminating operations. Skimming equipment listed below may have operational limits which exceed those safety thresholds. As was seen in the Deepwater Horizon (DWH) oil spill response, vessel skimming operations ceased when seas reached 5-6 feet and vessels were often recalled to port when those conditions were exceeded. Systems below are some of the most up- to-date systems available and were employed during the DWH spill.

Boom	3 foot seas, 20 knot winds
Dispersants	Winds more than 25 knots Visibility less than 3 nautical miles Ceiling less than 1,000 feet.
FRU	8 foot seas
HOSS Barge/OSRB	8 foot seas
Koseq Arms	8 foot seas
OSRV	4 foot seas

Environmental Conditions in the GOM

Louisiana is situated between the easterly and westerly wind belts, and therefore, experiences westerly winds during the winter and easterly winds in the summer. Average wind speed is generally 14-15 mph along the coast. Wave heights average 4 and 5 feet. However, during hurricane season, Louisiana has recorded wave heights ranging from 40 to 50 feet high and winds reaching speeds of 100 mph. Because much of southern Louisiana lies below sea level, flooding is prominent.

Surface water temperature ranges between 70 and 80˚F during the summer months. During the winter, the average temperature will range from 50 and 60˚F.

The Atlantic and Gulf of Mexico hurricane season is officially from 1 June to 30 November. 97% of all tropical activity occurs within this window. The Atlantic basin shows a very peaked season from August through October, with 78% of the tropical storm days, 87% of the minor (Saffir-Simpson Scale categories 1 and 2) hurricane days, and 96% of the major (Saffir-Simpson categories 3, 4 and 5) hurricane days occurring then. Maximum activity is in early to mid September. Once in a few years there may be a hurricane occurring "out of season" - primarily in May or December. Globally, September is the most active month and May is the least active month.

FIGURE 1
TRAJECTORY BY LAND SEGMENT

Trajectory of a spill and the probability of it impacting a land segment have been projected utilizing information in the BOEM Oil Spill Risk Analysis Model (OSRAM) for the Central and Western Gulf of Mexico available on the BOEM website using 30 day impact. The results are tabulated below.

Area/Block	OCS-G	Launch Area	Land Segment and/or Resource	Conditional Probability (%)
GC 895	G35879	C45	Calhoun, TX	1
			Matagorda, TX	1
			Brazoria, TX	1
			Galveston, TX	2
			Jefferson, TX	1
			Cameron, LA	4
			Vermilion, LA	2
			Iberia, LA	1
			Terrebonne, LA	2
			Lafourche, LA	1
			Plaquemines, LA	2

Figure 2 Equipment Response Time

Surveillance Aircraft

Name/Type	Persons Req.	From	Hrs to Procure	Hrs to Loadout	Travel to site	Total Hrs
ASI (available through contract with CGA)						
Aero Commander	2	Houma, LA	2	2	0.9	4.9
T&T Marine (available through contract with CGA)						
CJ3 Citation	2	Houston/Galveston, TX	2	2	1	5

Dispersant Aircraft

Name/Type	Dispersant Capacity (gal)	Persons Req.	From	Hrs to Procure	Hrs to Loadout	Travel to site	Total Hrs
ASI (available through contract with CGA)							
Basler 67T	2000	2	Houma, LA	2	2	0.9	4.9
DC 3	1200	2	Houma, LA	2	2	1.1	5.1
DC 3	1200	2	Houma, LA	2	2	1.1	5.1
MSRC							
C-130 Spray AC	3,250	3	Kiln, MS	4	0	0.4	4.4
King Air BE90 Spray AC	250	2	Kiln, MS	4	0	0.7	4.7

Offshore Response

Offshore Equipment Pre-Determined Staging	EDRC	Storage Capacity	Support Vessel(s)	Persons Required	From	Hrs to Procure	Hrs to Loadout	Hrs to GOM	Travel to Spill Site	Hrs to Deploy	Total Hrs
CGA											
95 FRV	22885	249	NA	6	Galveston	2	0	2	20	1	25
95 FRV	22885	249	NA	6	Leeville	2	0	2	6.5	1	11.5
95 FRV	22885	249	NA	6	Venice	2	0	3	4	1	10
95 FRV	22885	249	NA	6	Vermilion	2	0	3	10	1	16
Boom Barge (CGA-300) 42" Auto Boom (25000')	NA	NA	1 Tug 50 Crew	4 (Barge) 2 (Per Crew)	Leeville, LA	8	0	4	19	2	33
HOSS Barge	76285	4000	3 Tugs	8	Harvey, LA	6	0	12	10	2	30

Offshore Equipment Pre-determined Staging	EDRC	Storage Capacity	VOO	Persons Required	From	Hrs to Procure	Hrs to Loadout	Hrs to GOM	Travel to Spill Site	Hrs to Deploy	Total Hrs
MSRC											
Louisiana Responder 1 Transrec 350 *2,640' 67" Curtain Pressure Boom*	10567	4000	NA	10	Fort Jackson, LA	2	1	4	6.5	1	14.5
MSRC 452 Offshore Barge 1 Crucial Disk 88/30 *2,640' 67" Curtain Pressure Boom*	11122	45000	3 Tugs	9	Fort Jackson, LA	4	1	6	11	1	23
Mississippi Responder 1 Transrec 350 *2,640' 67" Curtain Pressure Boom*	10567	4000	NA	10	Pascagoula, MS	2	1	2	8	1	14
MSRC 402 Offshore Barge 1 Crucial Disk 88/30 *2,640' 67" Curtain Pressure Boom*	11122	40300	3 Tugs	9	Pascagoula, MS	4	1	3	14	1	23
S.T. Benz Responder 1 LFF 100 Brush *2,640' 67" Curtain Pressure Boom*	18086	4000	NA	10	Grand Isle, LA	3	1	1	9	1	15
Gulf Coast Responder 1 Transrec 350 *2,640' 67" Curtain Pressure Boom*	10567	4000	NA	10	Lake Charles, LA	2	1	4	24	1	32
Texas Responder 1 Transrec 350 *2,640' 67" Curtain Pressure Boom*	10567	4000	NA	10	Galveston, TX	2	1	1	29	1	34
MSRC 570 Offshore Barge 1 Crucial Disk 88/30 *2,640' 67" Curtain Pressure Boom*	11122	56900	3 Tugs	9	Galveston, TX	4	1	2	50	1	58
Southern Responder 1 Transrec 350 *2,640' 67" Curtain Pressure Boom*	10567	4000	NA	10	Ingleside, TX	2	1	2	39	1	45
MSRC 403 Offshore Barge 1 Crucial Disk 88/30 *2,640' 67" Curtain Pressure Boom*	11122	40300	3 Tugs	9	Ingleside, TX	4	1	3	69	1	78

Offshore Equipment Pre-determined Staging	EDRC	Storage Capacity	VOO	Persons Required	From	Hrs to Procure	Hrs to Loadout	Hrs to GOM	Travel to Spill Site	Hrs to Deploy	Total Hrs
MSRC											
Florida Responder 1 Transrec 350 *2,640' 67" Curtain Pressure Boom*	10567	4000	NA	10	Miami, FL	2	1	1	47	1	52
MSRC 360 Offshore Barge 1 Crucial Disk 88/30 *1,320' 67" Curtain Pressure Boom*	11122	36000	3 Tugs	9	Tampa, FL	4	1	3	44	1	53

Offshore Recovered Oil Storage Pre-determined Staging	EDRC	Storage Capacity	Support Vessel(s)	Persons Required	From	Hrs to Procure	Hrs to Loadout	Hrs to GOM	Travel to Spill Site	Hrs to Deploy	Total Hrs
Kirby Offshore (available through contract with CGA and/or MSRC)											
RO Barge	NA	80000+	1 Tug	6	Venice, LA	45	0	4	10	1	60
RO Barge	NA	100000+	1 Tug	6	Venice, LA	45	0	4	10	1	60
RO Barge	NA	100000+	1 Tug	6	Venice, LA	45	0	4	10	1	60
RO Barge	NA	100000+	1 Tug	6	Venice, LA	45	0	4	10	1	60
RO Barge	NA	100000+	1 Tug	6	Venice, LA	45	0	4	10	1	60
RO Barge	NA	110000+	1 Tug	6	Venice, LA	45	0	4	10	1	60
RO Barge	NA	130000+	1 Tug	6	Venice, LA	45	0	4	10	1	60
RO Barge	NA	140000+	1 Tug	6	Venice, LA	45	0	4	10	1	60
RO Barge	NA	150000+	1 Tug	6	Venice, LA	45	0	4	10	1	60
RO Barge	NA	160000+	1 Tug	6	Venice, LA	45	0	4	10	1	60

Staging Area: Fourchon

Offshore Equipment Preferred Staging	EDRC	Storage Capacity	Support Vessel(s)	Persons Req.	From	Hrs to Procure	Hrs to Loadout	Travel to Staging	Travel to Site	Hrs to Deploy	Total Hrs
CGA											
FRU (1) + 100 bbl Tank (2)	4251	200	1 Utility	6	Vermilion	2	6	5.5	11	1	25.5
FRU (1) + 100 bbl Tank (2)	4251	200	1 Utility	6	Galveston	2	6	12	11	1	32
FRU (1) + 100 bbl Tank (2)	4251	200	1 Utility	6	Aransas Pass	2	6	16.5	11	1	36.5
FRU (1) + 100 bbl Tank (2)	4251	200	1 Utility	6	Lake Charles	2	6	7	11	1	27
FRU (3) + 100 bbl Tank (6)	12753	600	3 Utility	18	Leeville	2	6	2	11	1	22
FRU (2) + 100 bbl Tank (4)	8502	400	2 Utility	12	Venice	2	6	5	11	1	25
T&T Marine (available through direct contract with CGA)											
Aqua Guard Triton RBS (1)	22323	2000	1 Utility	6	Galveston	4	12	12	11	2	41
Aqua Guard Triton RBS (1)	22323	2000	1 Utility	6	Harvey	4	12	3	11	2	32
Koseq Skimming Arms (10) Lamor Brush	228850	60000	10 OSV	60	Galveston	24	24	12	11	2	73
Koseq Skimming Arms (6) MariFlex 150 HF	108978	36000	6 OSV	36	Galveston	24	24	12	11	2	73
Koseq Skimming Arms (2) Lamor Brush	45770	12000	2 OSV	12	Harvey	24	24	3	11	2	64
Koseq Skimming Arms (4) MariFlex 150 HF	72652	24000	4 OSV	24	Harvey	24	24	3	11	2	64

Offshore Equipment Preferred Staging	EDRC	Storage Capacity	VOO	Persons Req.	From	Hrs to Procure	Hrs to Loadout	Travel to Staging	Travel to Site	Hrs to Deploy	Total Hrs
CGA											
Hydro-Fire Boom	NA	NA	8 Utility	40	Harvey	0	24	3	11	6	44
MSRC											
67" Curtain Pressure Boom (53570')	NA	NA	80*	160	Houston	1	2	11	11	1	37
1000' Fire Resistant Boom	NA	NA	3*	6	Galveston	1	4	12	11	6	45
16000' Fire Resistant Boom	NA	NA	3*	6	Houston	1	4	11	11	6	44
2000' Hydro Fire Boom	NA	NA	8*	8	Lake Charles	1	4	7	11	6	40

** Utility Boats, Crew Boats, Supply Boats, or Fishing Vessels*

Staging Area: Fourchon

Offshore Equipment Preferred Staging	EDRC	Storage Capacity	VOO	Persons Req.	From	Hrs to Procure	Hrs to Loadout	Travel to Staging	Travel to Site	Hrs to Deploy	Total Hrs
MSRC											
Crucial Disk 56/30 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	5671	500	2 Utility	5	Ingleside	1	1	17	11	1	31
GT-185 Skimmer w Adaptor (1) *330‘ 67” Curtain Pressure Boom*	1371	500	2 Utility	5	Ingleside	1	1	17	11	1	31
Foilex 250 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	3977	500	2 Utility	5	Ingleside	1	1	17	11	1	31
Stress I Skimmer (1) *330‘ 67” Curtain Pressure Boom*	15840	500	2 Utility	5	Ingleside	1	1	17	11	1	31
Walosep 4 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	3017	500	2 Utility	5	Ingleside	1	1	17	11	1	31
Crucial Disk 88/30 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	11122	500	2 Utility	5	Galveston	1	1	12	11	1	26
GT-185 Skimmer w Adaptor (2) *660‘ 67” Curtain Pressure Boom*	2742	1000	4 Utility	10	Galveston	1	1	12	11	1	26
Walosep 4 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	3017	500	2 Utility	5	Galveston	1	1	12	11	1	26
Foilex 250 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	3977	500	2 Utility	5	Galveston	1	1	12	11	1	26
Stress I Skimmer (1) *330‘ 67” Curtain Pressure Boom*	15840	500	2 Utility	5	Galveston	1	1	12	11	1	26
GT-185 Skimmer w Adaptor (1) *330‘ 67” Curtain Pressure Boom*	1371	500	2 Utility	5	Port Arthur	1	1	9	11	1	23
Desmi Skimmer (1) *330‘ 67” Curtain Pressure Boom*	3017	500	2 Utility	5	Lake Charles	1	1	7	11	1	21
Foilex 250 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	3977	500	2 Utility	5	Lake Charles	1	1	7	11	1	21
GT-185 Skimmer w Adaptor (1) *330‘ 67” Curtain Pressure Boom*	1371	500	2 Utility	5	Lake Charles	1	1	7	11	1	21

Offshore Equipment Preferred Staging	EDRC	Storage Capacity	VOO	Persons Req.	From	Hrs to Procure	Hrs to Loadout	Travel to Staging	Travel to Site	Hrs to Deploy	Total Hrs
MSRC											
Stress I Skimmer (2) *330‘ 67” Curtain Pressure Boom*	31680	1000	2 Utility	10	Lake Charles	1	1	7	11	1	21
LFF 100 Brush Skimmer (1) *1,320‘ 67” Curtain Pressure Boom*	18086	1000	1 PSV + 1 Support Vessel	9	Lake Charles	1	1	7	11	1	21
LFF 100 Brush Skimmer (1) *1,320‘ 67” Curtain Pressure Boom*	18086	1000	1 PSV + 1 Support Vessel	9	Lake Charles	1	1	7	11	1	21
LFF 100 Brush Skimmer (1) *1,320‘ 67” Curtain Pressure Boom*	18086	1000	1 PSV + 1 Support Vessel	9	Lake Charles	1	1	7	11	1	21
Transrec 350 Skimmer (1) *1,320‘ 67” Curtain Pressure Boom*	10567	1000	1 PSV + 1 Support Vessel	9	Lake Charles	1	1	7	11	1	21
Transrec 350 Skimmer (1) *1,320‘ 67” Curtain Pressure Boom*	10567	1000	1 PSV + 1 Support Vessel	9	Lake Charles	1	1	7	11	1	21
GT-185 Skimmer w Adaptor (1) *330‘ 67” Curtain Pressure Boom*	1371	500	2 Utility	5	Baton Rouge	1	1	4	11	1	18
Stress I Skimmer (1) *330‘ 67” Curtain Pressure Boom*	15840	500	2 Utility	5	Grand Isle	1	1	1	11	1	15
LFF 100 Brush Skimmer (1) *1,320‘ 67” Curtain Pressure Boom*	10567	1000	1 PSV + 1 Support Vessel	9	Houma	1	1	2	11	1	16
GT-185 Skimmer w Adaptor (1) *330‘ 67” Curtain Pressure Boom*	1371	500	2 Utility	5	Belle Chasse	1	1	3	11	1	17
Walosep W4 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	3017	500	2 Utility	5	Belle Chasse	1	1	3	11	1	17
Foilex 250 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	3977	500	2 Utility	5	Belle Chasse	1	1	3	11	1	17
Foilex 200 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	1989	500	2 Utility	5	Belle Chasse	1	1	3	11	1	17
Crucial Disk 56/30 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	5671	500	2 Utility	5	Belle Chasse	1	1	3	11	1	17

Offshore Equipment Preferred Staging	EDRC	Storage Capacity	VOO	Persons Req.	From	Hrs to Procure	Hrs to Loadout	Travel to Staging	Travel to Site	Hrs to Deploy	Total Hrs
MSRC											
Desmi Skimmer (1) *330‘ 67” Curtain Pressure Boom*	3017	500	2 Utility	5	Fort Jackson	1	1	5	11	1	19
Stress I Skimmer (1) *330‘ 67” Curtain Pressure Boom*	15840	500	2 Utility	5	Fort Jackson	1	1	5	11	1	19
Crucial Disk 88/30 Skimmer (1) *1,320‘ 67” Curtain Pressure Boom*	11122	1000	1 PSV + 1 Support Vessel	9	Fort Jackson	1	1	5	11	1	19
Crucial Disk 88/30 Skimmer (1) *1,320‘ 67” Curtain Pressure Boom*	11122	1000	1 PSV + 1 Support Vessel	9	Fort Jackson	1	1	5	11	1	19
GT-185 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	1371	500	2 Utility	5	Pascagoula	1	1	6	11	1	20
Crucial Disk 88/30 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	11122	500	2 Utility	5	Pascagoula	1	1	6	11	1	20
Stress I Skimmer (1) *330‘ 67” Curtain Pressure Boom*	15840	500	2 Utility	5	Pascagoula	1	1	6	11	1	20
Stress II Skimmer (1) *330‘ 67” Curtain Pressure Boom*	3017	500	2 Utility	5	Pascagoula	1	1	6	11	1	20
Stress I Skimmer (1) *330‘ 67” Curtain Pressure Boom*	15840	500	2 Utility	5	Tampa	1	1	22	11	1	36
Crucial Disk 56/30 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	5671	500	2 Utility	5	Tampa	1	1	22	11	1	36
GT-185 Skimmer w Adaptor (1) *330‘ 67” Curtain Pressure Boom*	1371	500	2 Utility	5	Tampa	1	1	22	11	1	36
GT-185 Skimmer w Adaptor (1) *330‘ 67” Curtain Pressure Boom*	1371	500	2 Utility	5	Miami	1	1	28	11	1	42
Walosep W4 Skimmer (1) *330‘ 67” Curtain Pressure Boom*	3017	500	2 Utility	5	Miami	1	1	28	11	1	42
Desmi Skimmer (1) *330‘ 67” Curtain Pressure Boom*	3017	500	2 Utility	5	Miami	1	1	28	11	1	42
Stress I Skimmer (1) *330‘ 67” Curtain Pressure Boom*	15840	500	2 Utility	5	Miami	1	1	28	11	1	42

Nearshore Response

Nearshore Equipment	EDRC	Storage Capacity	Support Vessel(s)	Persons Req.	From	Hrs to Procure	Hrs to Loadout	Hrs to GOM	Travel to Staging	Hrs to Deploy	Total Hrs
CGA											
46 FRV	15257	65	NA	4	Aransas Pass	2	0	2	16	1	21
46 FRV	15257	65	NA	4	Leeville	2	0	2	3	1	8
46 FRV	15257	65	NA	4	Lake Charles	2	0	2	2.5	1	7.5
46 FRV	15257	65	NA	4	Venice	2	0	2	11	1	16
Mid-Ship SWS	22885	249	NA	4	Leeville	2	0	N/A	48	1	51
Mid-Ship SWS	22885	249	NA	4	Venice	2	0	N/A	48	1	51
Mid-Ship SWS	22885	249	NA	4	Galveston	2	0	N/A	48	1	51
Trinity SWS	21500	249	NA	4	Leeville	2	0	N/A	48	1	51
Trinity SWS	21500	249	NA	4	Lake Charles	2	0	N/A	48	1	51
Trinity SWS	21500	249	NA	4	Vermilion	2	0	N/A	48	1	51
Trinity SWS	21500	249	NA	4	Galveston	2	0	N/A	48	1	51
MSRC											
MSRC Lightning 2 LORI Brush Pack	5000	50	NA	3	Tampa. FL	2	0	1	36	1	40
MSRC Quick Strike 2 LORI Brush Pack	5000	50	NA	3	Lake Charles, LA	2	0	1	2	1	6

Nearshore Response, cont'd.

Nearshore Equipment	EDRC	Storage Capacity	Support Vessel(s)	Persons Req.	From	Hrs to Procure	Hrs to Loadout	Hrs to GOM	Travel to Staging	Hrs to Deploy	Total Hrs
Enterprise Marine (available through contract with CGA)											
CTCo 2603	NA	25000	1 Tug	6	Amelia, LA	26	0	6	15	1	48
CTCo 2604	NA	20000	1 Tug	6	Amelia, LA	26	0	6	15	1	48
CTCo 2605	NA	20000	1 Tug	6	Amelia, LA	26	0	6	15	1	48
CTCo 2606	NA	20000	1 Tug	6	Amelia, LA	26	0	6	15	1	48
CTCo 2607	NA	23000	1 Tug	6	Amelia, LA	26	0	6	15	1	48
CTCo 2608	NA	23000	1 Tug	6	Amelia, LA	26	0	6	15	1	48
CTCo 2609	NA	23000	1 Tug	6	Amelia, LA	26	0	6	15	1	48
CTCo 5001	NA	47000	1 Tug	6	Amelia, LA	26	0	6	15	1	48
Kirby Offshore (available through contract with CGA and/or MSRC)											
RO Barge	NA	80000+	1 Tug	6	Venice, LA	24	0	4	31	1	60
RO Barge	NA	80000+	1 Tug	6	Venice, LA	24	0	4	31	1	60

Staging Area: Cameron

Nearshore and Inland Skimmers With Staging	EDRC	Storage Capacity	Support Vessel(s)	Persons Req.	From	Hrs to Procure	Hrs to Load Out	Travel to Staging	Travel to Deployment	Hrs to Deploy	Total Hrs
CGA											
SWS Egmopol	1810	100	NA	3	Galveston	2	2	5	2	1	12
SWS Egmopol	1810	100	NA	3	Leeville	2	2	7	2	1	14
SWS Marco	3588	20	NA	3	Lake Charles	2	2	2	2	1	9
SWS Marco	3588	34	NA	3	Leeville	2	2	7	2	1	14
SWS Marco	3588	34	NA	3	Venice	2	2	9.5	2	1	16.5
Foilex Skim Package (TDS 150)	1131	50	NA	3	Lake Charles	4	12	2	2	2	22
Foilex Skim Package (TDS 150)	1131	50	NA	3	Galveston	4	12	5	2	2	25
Foilex Skim Package (TDS 150)	1131	50	NA	3	Harvey	4	12	7	2	2	27
4 Drum Skimmer (Magnum 100)	680	100	1 Crew	3	Lake Charles	2	2	2	2	1	9
4 Drum Skimmer (Magnum 100)	680	100	1 Crew	3	Harvey	2	2	7	2	1	14
2 Drum Skimmer (TDS 118)	240	100	1 Crew	3	Lake Charles	2	2	2	2	1	9
2 Drum Skimmer (TDS 118)	240	100	1 Crew	3	Harvey	2	2	7	2	1	14
MSRC											
30 ft. Kvichak *Marco I Skimmer (1)*	3588	24	NA	2	Ingleside	1	1	9.5	2	1	14.5
30 ft. Kvichak *Marco I Skimmer (1)*	3588	24	NA	2	Galveston	1	1	5	2	1	10
30 ft. Kvichak *Marco I Skimmer (1)*	3588	24	NA	2	Belle Chasse	1	1	7	2	1	12
30 ft. Kvichak *Marco I Skimmer (1)*	3588	24	NA	2	Pascagoula	1	1	9.5	2	1	14.5
AardVac Skimmer (1)	3840	500	1 Utility	5	Lake Charles	1	1	1	2	1	6
AardVac Skimmer (1)	3840	500	1 Utility	5	Pascagoula	1	1	9.5	2	1	14.5
AardVac Skimmer (2)	7680	1000	2 Utility	10	Miami	1	1	31	2	1	36
Queensboro Skimmer (1)	905	400	1 Push Boat	4	Galveston	1	1	5	2	1	10
Queensboro Skimmer (5)	4525	2000	5 Push Boat	20	Lake Charles	1	1	1	2	1	6
Queensboro Skimmer (1)	905	400	1 Push Boat	4	Belle Chasse	1	1	7	2	1	12
Queensboro Skimmer (1)	905	400	1 Push Boat	4	Pascagoula	1	1	9.5	2	1	14.5

Shoreline Protection

Staging Area: Cameron

Shoreline Protection Boom	VOO	Persons Req.	Storage/Warehouse Location	Hrs to Procure	Hrs to Loadout	Travel to Staging	Travel to Deployment	Hrs to Deploy	Total Hrs
AMPOL (available through Letter of Intent)									
34,050’ 18” Boom	13 Crew	26	New Iberia, LA	2	2	6	2	12	24
12,850’ 18” Boom	7 Crew	14	Chalmette, LA	2	2	2.5	2	6	14.5
900’ 18” Boom	1 Crew	2	Morgan City, LA	2	2	4.5	2	2	12.5
3,200’ 18” Boom	2 Crew	4	Venice, LA	2	2	0	2	2	8
12,750’ 18” Boom	7 Crew	14	Port Arthur, TX	2	2	10	2	6	22
ES&H (available through Letter of Intent)									
13,000’ 18” Boom	6 Crew	12	Golden Meadow, LA	.5	.5	4	2	4	11
14,000’ 18” Boom	6 Crew	12	LaPlace, LA	.5	.5	3	2	4	10
16,000’ 18” Boom	6 Crew	12	Lake Charles, LA	.5	.5	8	2	4	15
500’ 18” Boom	1 Crew	2	Lafayette, LA	.5	.5	6	2	1	10
100’ 18” Boom	1 Crew	2	Morgan City, LA	.5	.5	5	2	1	9
1,000’ 18” Boom	1 Crew	2	Fourchon, LA	.5	.5	5	2	1	9
10,100’ 18” Boom	6 Crew	12	Belle Chasse, LA	.5	.5	2	2	4	7
52,000’ 18” Boom	12 Crew	24	Houma, LA	.5	.5	4	2	4	11
2,100’ 18” Boom	1 Crew	2	Venice, LA	.5	.5	0	2	4	7

Wildlife Response	EDRC	Storage Capacity	VOO	Person s	From	Hrs to Procure	Hrs to Loadout	Travel to Staging	Travel to Deploymen	Hrs to Deploy	Total Hrs
CGA											
Wildlife Support Trailer	NA	NA	NA	2	Harvey	2	2	7	1	2	14
Bird Scare Guns (24)	NA	NA	NA	2	Harvey	2	2	7	1	2	14
Bird Scare Guns (12)	NA	NA	NA	2	Galveston	2	2	5	1	2	12
Bird Scare Guns (12)	NA	NA	NA	2	Aransas Pass	2	2	9.5	1	2	16.5
Bird Scare Guns (48)	NA	NA	NA	2	Lake Charles	2	2	2	1	2	9
Bird Scare Guns (24)	NA	NA	NA	2	Leeville	2	2	7	1	2	14

Response Asset Totals	Total (bbls)
Offshore EDRC	1,189,841
Offshore Recovered Oil Storage	1,585,796+
Nearshore / Shallow Water EDRC	291,303
Nearshore / Shallow Water Recovered Oil Storage	370,737+

APPENDIX J
ENVIRONMENTAL MONITORING INFORMATION

A) MONITORING SYSTEMS
The proposed drilling units are equipped with Acoustic Doppler Current Profile (ADCP) monitoring equipment. Data from these meters are reported to the National Data Buoy Center website.

B) INCIDENTAL TAKES
In accordance with NTL 2008-G04, this information is not applicable as BOE Exploration & Production has no reason to believe that any of the endangered species or marine mammals as listed in the ESA will be "taken" as a result of the operations proposed in this plan.

Additionally, BOE Exploration & Production will follow guidance resulting from the Programmatic Biological Opinion on Federally Regulated Oil and Gas Program Activities in the Gulf of Mexico.

Vessels associated with activity proposed in this plan do not pose an entrapment/entanglement risk to aquatic protected species. In the event of inadvertent entrapment/entanglement of protected aquatic species, vessel operators associated with activity proposed in this plan will report sightings of any injured or dead aquatic protected species immediately, regardless of whether the injury or death is caused by its vessel. If the injury or death was caused by a collision with the operator's vessel, an entrapment within the operator's equipment or vessel (e.g. moon pool), or an entanglement within the operator's equipment, the operator will further notify BOEM and BSEE within 24 hours of the strike or entrapment/entanglement via email to protectedspecies@boem.gov and protectedspecies@bsee.gov.

BOE Exploration & Production and/or its contractor representatives will provide a dedicated crew member to monitor and continually survey the moon pool area for sea turtles and marine mammals during activity requiring moon pool utilization. Further, BOE Exploration & Production and/or its contractor representatives will provide a dedicated crew member to monitor and continually survey the moon pool area for sea turtles and marine mammals after conclusion of operations and prior to hull door(s) closure and vessel transit. Dedicated crew member will continue observations while the door(s) is closing and maintain communication with the door operator(s) and bridge. Once the door(s) is closed and confirmation that no turtle/mammal has been detected, the observer will secure their position for vessel transit.

C) FLOWER GARDEN BANKS NATIONAL MARINE SANCTUARY
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as the subject area and block(s) are not located within the Protective Zones of the Flower Garden Banks and Stetson Bank.

APPENDIX K
LEASE STIPULATIONS INFORMATION

Stipulation 8 - Protected Species
Lease Stipulation No. 8 is designed to reduce the potential taking of federally protected species in conjunction with activity conducted on the Outer Continental Shelf (OCS).

BOE Exploration & Production and its operators, personnel, contractors and subcontractors will operate in accordance with NTL BOEM 2016-G01, "Vessel Strike Avoidance and Injured/Dead Protected Species Reporting," NTL 2015-G03, "Marine Trash and Debris Awareness and Elimination" and NTL BOEM 2016-G02, "Implementation of Seismic Survey Mitigation Measures and Protected Species Observer Program" and any additional measures in conditions of approval for corresponding plans and permits in satisfying this condition of the subject lease relating to its proposed activity.

APPENDIX L
ENVIRONMENTAL MITIGATION MEASURES INFORMATION

A) MEASURES TAKEN TO AVOID, MINIMIZE, AND MITIGATE IMPACTS

In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as the State of Florida is not an affected State.

B) INCIDENTAL TAKES

BOE Exploration & Production will adhere to the requirements as set forth in the following Notices to Lessees, as applicable, to avoid or minimize impacts to any of the species listed in the ESA as a result of the proposed operations:

- NTL BOEM 2016-G01, "Vessel Strike Avoidance and Injured/Dead Protected Species Reporting"
- NTL 2015-G03, "Marine Trash and Debris Awareness and Elimination"
- NTL BOEM 2016-G02, "Implementation of Seismic Survey Mitigation Measures and Protected Species Observer Program"

Additionally, BOE Exploration & Production will follow guidance resulting from the Programmatic Biological Opinion on Federally Regulated Oil and Gas Program Activities in the Gulf of Mexico.

Vessels associated with activity proposed in this plan do not pose an entrapment/entanglement risk to aquatic protected species. In the event of inadvertent entrapment/entanglement of protected aquatic species, vessel operators associated with activity proposed in this plan will report sightings of any injured or dead aquatic protected species immediately, regardless of whether the injury or death is caused by its vessel. If the injury or death was caused by a collision with the operator's vessel, an entrapment within the operator's equipment or vessel (e.g. moon pool), or an entanglement within the operator's equipment, the operator will further notify BOEM and BSEE within 24 hours of the strike or entrapment/entanglement via email to protectedspecies@boem.gov and protectedspecies@bsee.gov.

BOE Exploration & Production and/or its contractor representatives will provide a dedicated crew member to monitor and continually survey the moon pool area for sea turtles and marine mammals during activity requiring moon pool utilization. Further, BOE Exploration & Production and/or its contractor representatives will provide a dedicated crew member to monitor and continually survey the moon pool area for sea turtles and marine mammals after conclusion of operations and prior to hull door(s) closure and vessel transit. Dedicated crew member will continue observations while the door(s) is closing and maintain communication with the door operator(s) and bridge. Once the door(s) is closed and confirmation that no turtle/mammal has been detected, the observer will secure their position for vessel transit.

APPENDIX M
RELATED FACILITIES & OPERATIONS INFORMATION

A) RELATED OCS FACILITIES AND OPERATIONS
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as this is an Exploration Plan.

Operations proposed in this plan will not utilize pile-driving.

Pipelines are not proposed as part of this plan.

B) TRANSPORTATION SYSTEM
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as this is an Exploration Plan.

C) PRODUCED LIQUID HYDROCARBONS TRANSPORTATION VESSELS
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as no new production is being proposed for transport nor is existing production transporting methods being modified.

APPENDIX N
SUPPORT VESSELS AND AIRCRAFT INFORMATION

A) GENERAL
The most practical and direct route from the shorebase as permitted by weather and traffic conditions will be utilized. The table below provides information on vessels and aircraft that will be used to support the proposed activities.

Type	Maximum Fuel Tank Capacity	Maximum Number in Area at Any Time	Trip Frequency or Duration
Supply Boat	1900 bbls	1	6x/week
Crew Boat	1700 bbls	1	4x/week
Aircraft	250 gals	1	As Needed

B) DIESEL OIL SUPPLY VESSELS
The table below provides information on the vessels that will be used to supply diesel oil. It also includes all vessels that will transfer diesel oil that will be used for purposes other than fuel.

Size of Fuel Supply Vessel	Capacity of Fuel Supply Vessel	Frequency of Fuel Transfers	Route Fuel Supply Vessel Will Take
180 feet	1900 bbls	Weekly	Most direct route from shorebase to site

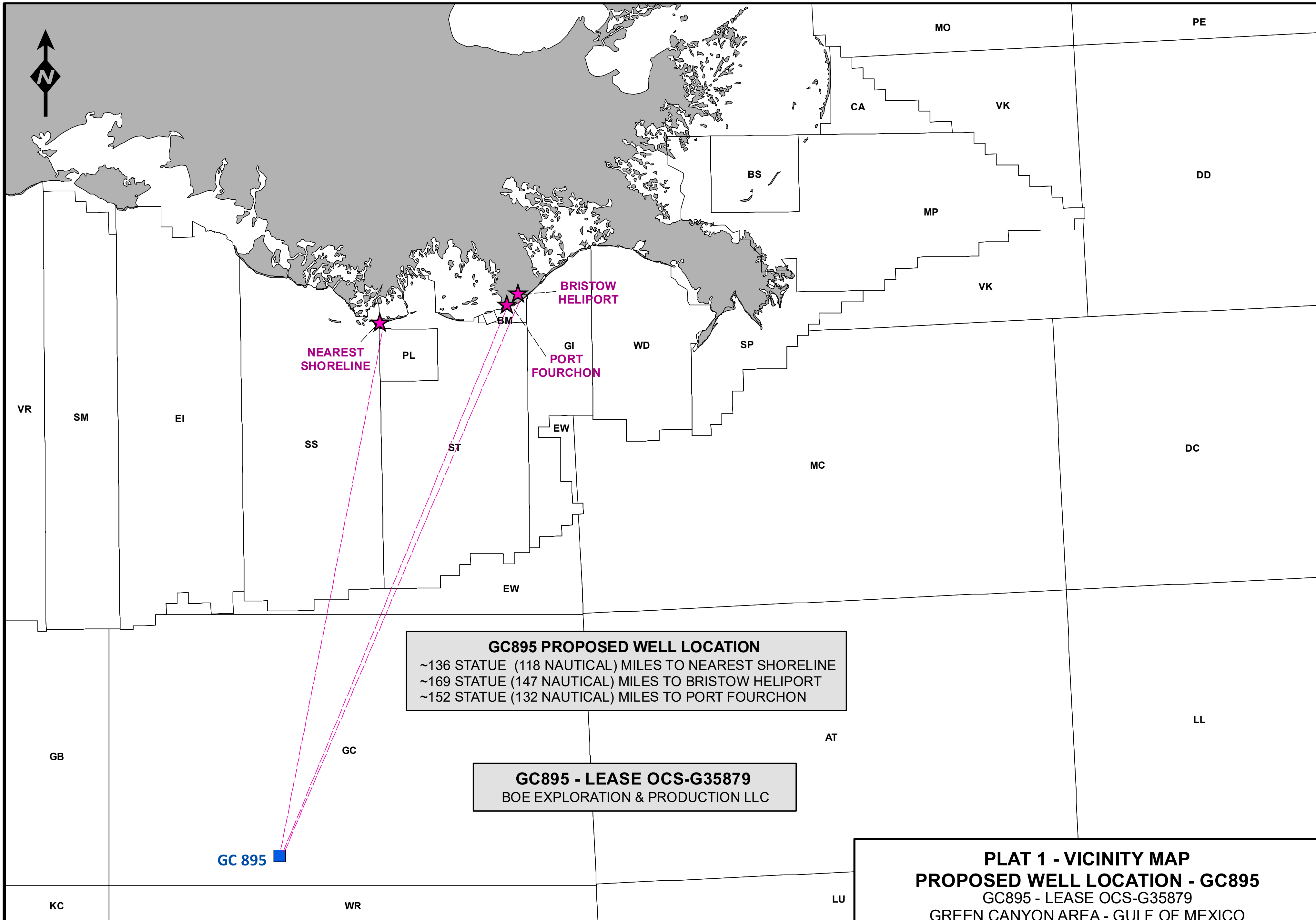
C) DRILLING FLUID TRANSPORTATION
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as the State of Florida is not an affected State.

D) SOLID AND LIQUID WASTE TRANSPORTATION
In accordance with BOEM guidance, the required data regarding the solid and liquid waste which will be transported from the site of the activities proposed in this plan has been incorporated into the Waste & Discharge tables which are included in the attachment(s) to the Waste & Discharge Information appendix.

E) VICINITY MAP
Enclosed as an attachment to this appendix is a vicinity map for the activities proposed in this plan depicting the location of same relative to the shoreline with the distance of the proposed activities from the shoreline and the primary route(s) of the support vessels and aircraft which will be used when traveling between the onshore support facilities and the proposed operations.

Vessels associated with and/or utilized to support activity proposed in this plan will take the most direct route when transiting from onshore support facilities to a well site(s). Vessels associated with and/or utilized to support activity proposed in this plan will not transit the Bryde's whale area.

VICINITY MAP



PLAT 1 - VICINITY MAP
PROPOSED WELL LOCATION - GC895
GC895 - LEASE OCS-G35879
GREEN CANYON AREA - GULF OF MEXICO

GEODETIC DATUM: NAD 27
PROJECTION: BLM 15 (NORTH) UTM 15N
GRID UNITS: US SURVEY FEET

SCALE 0 15 30 60 Miles

BOE Beacon OFFSHORE ENERGY

SHEET: 1 OF 1	MAP BY: ESSJ (BOE) CHECKED BY: DH (BOE)	PROJECT NAME: EP GC895 - HIGHGARDEN	DATE: 04/03/2020

APPENDIX O
ONSHORE SUPPORT FACILITIES INFORMATION

A) GENERAL
The table below is a list of the onshore facilities that will be used to provide supply and service support for the activities proposed in this plan.

Name of Shorebase	Location	Existing/New/Modified
EPS Dock	Fourchon, LA	Existing
Bristow Heliport	Galliano, LA	Existing

B) SUPPORT BASE CONSTRUCTION OR EXPANSION
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as BOE Exploration & Production will use an existing onshore base facility and will not need to expand or modify those facilities to accommodate the operations proposed in this plan.

C) SUPPORT BASE CONSTRUCTION OR EXPANSION TIMETABLE
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as no land is being acquired to construct or expand an onshore support base.

D) WASTE DISPOSAL
In accordance with BOEM guidance, the required data regarding the facilities that will be used to store and dispose of any solid and liquid wastes generated by the activities proposed in this plan has been incorporated into the Waste & Discharge tables which are included in the attachment(s) to the Waste & Discharge Information appendix.

E) AIR EMISSIONS
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as the air emissions information in this section is not required for plans where the activities being proposed are within the boundaries of the Gulf of Mexico Region.

F) UNUSUAL SOLID AND LIQUID WASTES
In accordance with NTL 2008-G04, this information is not applicable to the activities proposed in this plan as the unusual solid and liquid wastes information generated by onshore support facilities is not required for plans that propose activities that fall within the boundaries of the Gulf of Mexico Region.

APPENDIX P
COASTAL ZONE MANAGEMENT (CZMA) INFORMATION

Relevant enforceable policies were considered in certifying consistency for Louisiana.

A certificate of Coastal Zone Management Consistency for each of the states listed above is included in the attachments to this appendix.

COASTAL ZONE MANAGEMENT CONSISTENCY CERTIFICATION

COASTAL ZONE MANAGEMENT CONSISTENCY CERTIFICATION

INITIAL EXPLORATION PLAN

GREEN CANYON 895
OCS-G 35879

The proposed activities described in detail in this OCS Plan comply with Louisiana's approved Coastal Management Program and will be conducted in a manner consistent with such program(s).

BOE Exploration & Production LLC
Lessee or Operator

____
Certifying Official

March 1, 2020

Date

APPENDIX Q
ENVIRONMETAL IMPACT ANALYSIS

An Environmental Impact Analysis is included in the attachments to this appendix.

ENVIRONMETAL IMPACT ANALYSIS

ENVIRONMENTAL IMPACT ANALYSIS WORKSHEET

Identify the IPF's that can cause impacts to the listed environmental resources by placing an "x" in the space under each IPF category associated with your proposed activities that may impact a particular environmental resource. If you determine an IPF would not impact a particular environmental resource, leave the space blank. For those cells that are footnoted, provide a statement as to the applicability to your proposed operations, and, where there may be an effect, provide an analysis of the effect. If you are aware of other environmental resources at or near your activity's site that are not included on the worksheet, address them too.

Environmental Resources	Impact Producing Factors (IPFs) Categories and Examples Refer to a recent GOM OCS Lease Sale EIS for a more complete list of IPFs					
	Emissions (air, noise, light, etc.)	**Effluents (muds, cuttings, other discharges to the water column or seafloor)**	**Physical disturbances to the seafloor (rig or anchor emplacements, etc.)**	**Wastes sent to shore for treatment or disposal**	**Accidents (e.g., oil spills, chemical spills, H_2S releases)**	**Other IPFs you identify**
Site-specific at Offshore Location						
Designated topographic features		(1)	(1)		(1)	
Pinnacle Trend area live bottoms		(2)	(2)		(2)	
Eastern Gulf live bottoms		(3)	(3)		(3)	
Chemosynthetic communities		x	x(4)		x	
Water quality		x	x	x	x	
Fisheries		x	x		x	
Marine mammals	x(8)	x	x		x(8)	
Sea turtles	x(8)	x	x		x(8)	
Air quality	x(9)				x	
Shipwreck sites (known or potential)			x(7)			
Prehistoric archaeological sites			x(7)			
Vicinity of Offshore Location						
Essential fish habitat		x	x		x(6)	
Marine and pelagic birds	x				x	
Public health and safety					(5)	
Coastal and Onshore						
Beaches					x(6)	
Wetlands					x(6)	
Shore birds and coastal nesting birds					x(6)	
Coastal wildlife refuges					x	
Wilderness areas					x	
Other Resources You Identify						

NOTE: The numbers in parentheses refer to the footnotes on page 2 of this form.

Footnotes for Environmental Impact Analysis Matrix

1. Activities that may affect a marine sanctuary or topographic feature. Specifically, if the well or platform site or any anchors will be on the seafloor within the:
   (a) 4-mile zone of the Flower Garden Banks, or the 3-mile zone of Stetson Bank;
   (b) 1000-m, 1-mile or 3-mile zone of any topographic feature (submarine bank) protected by the Topographic Features Stipulation attached to an OCS lease;
   (c) Essential Fish Habitat (EFH) criteria of 500 ft from any no-activity zone; or
   (d) Proximity of any submarine bank (500 ft buffer zone) with relief greater than 2 meters that is not protected by the Topographic Features Stipulation attached to an OCS lease.
2. Activities with any bottom disturbance within an OCS lease block protected through the Live Bottom (Pinnacle Trend) Stipulation attached to an OCS lease.
3. Activities within any Eastern Gulf OCS block where seafloor habitats are protected by the Live Bottom (Low- Relief) Stipulation attached to an OCS lease.
4. Activities on blocks designated by the BOEM as being in water depths 400 meters or greater.
5. Exploration or production activities where H_2S concentrations greater than 500 ppm might be encountered.
6. All activities that could result in an accidental spill of produced liquid hydrocarbons or diesel fuel that you determine would impact these environmental resources. If the proposed action is located a sufficient distance from a resource that no impact would occur, the EIA can note that in a sentence or two.
7. All activities that involve seafloor disturbances, including anchor emplacements, in any OCS block designated by the BOEM as having high-probability for the occurrence of shipwrecks or prehistoric sites, including such blocks that will be affected that are adjacent to the lease block in which your planned activity will occur. If the proposed activities are located a sufficient distance from a shipwreck or prehistoric site that no impact would occur, the EIA can note that in a sentence or two.
8. All activities that you determine might have an adverse effect on endangered or threatened marine mammals or sea turtles or their critical habitats.
9. Production activities that involve transportation of produced fluids to shore using shuttle tankers or barges.

Paperwork Reduction Act of 1995 (PRA) Statement: The PRA (44 U.S.C. 3501et seq.) requires us to inform you that BOEM collects this information as part of an applicant's Exploration Plan (EP) or Development Operations Coordination Document (DOCD) submitted for BOEM approval. We use the information in our review and data entry for OCS plans. Reponses are mandatory (43 U.S.C 1334). We will protect proprietary data according to the Freedom of Information Act and 30 CFR 550.197. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid Office of Management and Budget Control Number. The public reporting burden for this form is included in the burden for preparing EPs and DOCDs. We estimate that burden to average 600 hours per response for EPs and 700 hours per response for DOCDs, including the time for reviewing instructions, gathering and maintaining data, and completing and reviewing the forms associated with subpart B. Direct comments regarding the burden estimate or any other aspect of this form to the Information Collection Clearance Officer, Bureau of Ocean Energy Management, 381 Elden Street, Herndon, VA 20170.

The proposed project includes the drilling of well locations A, B, C and D in Green Canyon Area Block 895 (OCS-G 35879).

SITE-SPECIFIC IMPACTS

- DESIGNATED TOPOGRAPHIC FEATURES

There are no impacts to designated topographic features expected from the proposed project including Impact Producing Factors (IPFs) such as emissions, effluents, physical disturbances to the seafloor, wastes sent to shore for treatment or disposal, accidents, or other factors or resources identified.

The proposed project location is not located in an area characterized by the existence of topographic features and associated no activity zones. The subject lease does not contain a topographic features stipulation. The nearest stipulated topographic features area is located a significant distance from the proposed project location.

- PINNACLE TREND AREA LIVE BOTTOMS

There are no impacts to a pinnacle trend area expected from the proposed project IPFs such as emissions, effluents, physical disturbances to the seafloor, wastes sent to shore for treatment or disposal, accidents, or other factors or resources identified.

The proposed project location is not located in an area characterized by the existence of live bottoms. The subject lease does not contain a live bottom stipulation. The nearest stipulated live bottom pinnacle trend area is located a significant distance from the proposed project location.

- EASTERN GULF LIVE BOTTOMS

There are no impacts to a live bottom low relief area expected from the proposed project including IPFs such as emissions, effluents, physical disturbances to the seafloor, wastes sent to shore for treatment or disposal, accidents, or other factors or resources identified.

The proposed project location is not located in an area characterized by the existence of live bottoms. The subject lease does not contain a live bottom stipulation. The nearest stipulated live bottom low relief area is located a significant distance from the proposed project location.

- CHEMOSYNTHETIC COMMUNITIES

IPFs that have the potential to cause impacts to high density deepwater benthic communities from the proposed project include effluents, physical disturbances to the seafloor, and accidents.

No features or areas that could support high-density sensitive sessile benthic communities are located within 2,000ft of any mud or cuttings discharge location associated with well locations proposed as part of this plan.

Effluents: Discharges from the proposed project will be in compliance with NPDES permit and NTL No. 2009-G40 conditions and are expected to have minimal impact on high density deepwater benthic communities in the area.

Physical Disturbances to the Seafloor: Bottom disturbances to the seafloor from the proposed project could include rig placement, drilling of wells, and installation of pipelines and platforms. Impacts to water column turbidity and distribution of disturbed sediments and associated nutrients could affect high density deepwater benthic communities in the area. The project will adhere to the requirements of NTL No. 2009-G40 to minimize impacts to high density deepwater benthic communities from seafloor disturbances.

Accidents: An accidental spill or well blowout from the proposed project could cause temporary and possibly long term impacts to high density deepwater benthic communities. Accidental spills would be expected to be small in in size, expeditiously recovered from the surface, and droplets in the water table microbiologically degraded, resulting in short term impacts. An accidental blowout of the well could have both short term and long term effects depending on the size and complexity of the event. In the event of a spill or blowout, the facility will immediately implement the Regional Oil Spill Response Plan and active controls and countermeasures to minimize the impact to high density deepwater benthic communities.

There are no other impacts to high density deepwater benthic communities expected from the proposed project including IPFs such as emissions, wastes sent to shore for treatment or disposal, or other factors or resources identified.

- WATER QUALITY

IPFs that have the potential to cause impacts to water quality from the proposed project include effluents, physical disturbances to the seafloor, wastes sent to shore for treatment and disposal, and accidents.

Effluents: Discharges of effluents associated with drilling and production activity from the proposed project include overboard effluents including well cutting, drilling and completion fluids, sanitary and domestic wastewater, deck drainage, excess cement and spacers, rig wash water, and uncontaminated cooling water from the drilling rig which will be in compliance with the Federal Water Pollution Control Act, regulated by the United States Environmental Protection Agency – Region 6, and authorized under the National Pollutant Discharge Elimination System General Permit for New and Existing Sources and New Dischargers in the Offshore Subcategory of the Oil and Gas Extraction Category for the Western Portion of the Outer Continental Shelf of the Gulf of Mexico Permit (NPDES). A comprehensive list of types and quantities of effluent discharges associated with the proposed activities can be found in Appendix G of the governing document to which this report is included. Authorized effluent discharges in compliance with permit conditions are not expected to have significant impact on water quality.

Physical Disturbances to the Seafloor: Bottom disturbances to the seafloor from the proposed project could include rig placement, drilling of wells, and installation of pipelines and platforms. Impacts to water quality include water column turbidity and distribution of disturbed sediments and associated nutrients. Impacts from seafloor disturbances are expected to be minimal and effects temporary.

Wastes Sent to Shore for Treatment or Disposal: Wastes generated by the proposed project could include contaminated well cuttings and fluids, cement cuttings, washwater, oily debris, chemical wastes, used oil and non- contaminated domestic waste. Contaminated material will be manifested, transported, and recycled or disposed of as exempt Exploration and Production Waste to an approved facility in accordance with Louisiana Department of Natural Resources regulations regarding E&P

Wastes. Domestic waste is transported to an approved domestic waste disposal facility. Waste generated which may be hazardous will be manifested, transported, and recycled or disposed of in accordance with the Resource Conservation and Recovery Act (RCRA). A comprehensive list of types, quantities, and methods of disposal can be found in Appendix G of the governing document to which this report is included. Impacts from waste sent to shore for treatment or disposal are not expected.

<u>Accidents:</u> An accidental spill or well blowout from the proposed project could cause temporary and possibly long term impacts to water quality. Accidental spills would be expected to be small in in size, expeditiously recovered from the surface, and droplets in the water table microbiologically degraded, resulting in short term impacts. An accidental blowout of the well could have both short term and long term effects on water quality depending on the size and complexity of the event. In the event of a spill or blowout, the facility will immediately implement the Regional Oil Spill Response Plan and active controls and countermeasures to minimize the impact to water quality.

There are no other IPFs that have the potential to cause impact to water quality from the proposed project including emissions, or other factors or resources identified.

- FISHERIES

IPFs that have the potential to cause impacts to fisheries from the proposed project include effluents, physical disturbances to the seafloor, and accidents. The Magnuson-Stevens Fishery and Conservation and Management Act protects fisheries through implementation of Fishery Management Plans (FMPs). Fisheries located in the Gulf of Mexico managed by the Gulf of Mexico Fishery Management Council plans include Coastal Migratory Pelagics, Red Drum, Reef Fish, Shrimp, Spiny Lobster, and Coral. Fisheries managed by National Oceanic and Atmospheric Administration (NOAA) National Marine Fisheries Service (NMFS) plans include Tuna, Swordfish, Billfish, and Sharks.

<u>Effluents:</u> Discharges from the proposed project will be in compliance with NPDES permit conditions and are expected to have minimal impact on fisheries or fishing activities in the area.

<u>Physical Disturbances to the Seafloor:</u> Bottom disturbances to the seafloor from the proposed project could include rig placement, drilling of wells, and installation of pipelines and platforms. Impacts to water column turbidity and distribution of disturbed sediments and associated nutrients could affect fisheries. Impacts to fisheries from seafloor disturbances are expected to be minimal and effects temporary.

<u>Accidents:</u> An accidental spill or well blowout from the proposed project could cause temporary and possibly long term impacts to fisheries and fishing activity. Accidental spills would be expected to be small in in size, expeditiously recovered from the surface, and droplets in the water table microbiologically degraded, resulting in short term impacts to fisheries. An accidental blowout of the well could have both short term and long term effects on fisheries and fishing activity depending on the size and complexity of the event. Fishing activities could be interrupted or temporarily closed. Effects on fishery populations could include mortality, bioaccumulation, and habitat degradation. In the event of a spill or blowout, the facility will immediately implement the Regional Oil Spill Response Plan and active controls and countermeasures to minimize the impact to fisheries.

There are no other IPFs that have the potential to cause impact to fisheries from the proposed project including emissions, wastes sent to shore for treatment or disposal, or other factors or resources identified.

- MARINE MAMMALS

IPFs that have the potential to cause impacts to marine mammals from the proposed project include emissions, effluents, physical disturbances to the seafloor, and accidents. All marine mammals are protected under the Marine Mammal Protection Act (MMPA). Several species of marine mammals including whales, dolphins, and porpoises occur in the Gulf of Mexico. The Endangered Species Act (ESA) further protects marine mammals designated as endangered or threatened. Species of marine mammals listed as endangered occurring in the Gulf of Mexico include Blue Whale (Balaenoptera musculus), Fin Whale (Balaenoptera physalus), Humpback Whale (Megaptera novaeangliae), Sei Whale (*Balaenoptera borealis*), and Sperm Whale (*Physeter macrocephalus*) and West Indian Manatee (Trichechus manatus).

Emissions: Noise emissions from the proposed project may have an impact on marine mammals. Noise levels from drilling and production activity are generally low in intensity and are not expected to have a significant impact to marine mammals. Operations proposed in this plan will not utilize pile-driving.

Effluents: Discharges from the proposed project will be in compliance with NPDES permit conditions and are expected to have minimal impact on marine mammals in the area.

Physical Disturbances to the Seafloor: Bottom disturbances to the seafloor from the proposed project could include rig placement, drilling of wells, and installation of pipelines and platforms. Impacts to water column turbidity and distribution of disturbed sediments and associated nutrients could affect marine mammals. Impacts to marine mammals from seafloor disturbances are expected to be minimal.

Accidents: An accidental spill or well blowout from the proposed project could cause impacts to marine mammals ranging from sub-lethal to mortal. Accidental spills would be expected to be small in in size, expeditiously recovered from the surface, and droplets in the water table microbiologically degraded, resulting in short term impacts to marine mammals. An accidental blowout of the well could have both short term and long term effects on marine mammals depending on the size and complexity of the event. Effects on marine mammal populations could include mortality, bioaccumulation, and habitat degradation. In the event of a spill or blowout, the facility will immediately implement the Regional Oil Spill Response Plan and active controls and countermeasures to minimize the impact to marine mammals.

Vessel traffic has the potential to impact marine mammals in the event of vessel strikes. To minimize the potential for vessel strikes and disturbance to marine mammals, the proposed project will abide by the guidelines of BOEM NTL No. 2016-G01 (Vessel Strike Avoidance and Injured/Dead Protected Species Reporting).

Marine debris has the potential to impact marine mammals through entanglement or ingestion causing serious injury or death. To minimize the impact potential to marine mammals, the proposed project will abide by the guidelines of BSEE NTL No. 2015-G03 (Marine Trash and Debris Awareness and Elimination).

Additionally, BOE Exploration & Production will follow guidance resulting from the Programmatic Biological Opinion on Federally Regulated Oil and Gas Program Activities in the Gulf of Mexico.

Vessel operators associated with activity proposed in this plan will report sightings of any injured or dead aquatic protected species immediately, regardless of whether the injury or death is caused by your vessel. If the injury or death was caused by a collision with the operator's vessel, an entrapment within the operator's equipment or vessel (e.g. moon pool), or an entanglement within the operator's equipment, the operator will further notify BOEM and BSEE within 24 hours of the strike or entrapment/entanglement via email to protectedspecies@boem.gov and protectedspecies@bsee.gov.

BOE Exploration & Production and/or its contractor representatives will provide a dedicated crew member to monitor and continually survey the moon pool area for sea turtles and marine mammals during activity requiring moon pool utilization. Further, BOE Exploration & Production and/or its contractor representatives will provide a dedicated crew member to monitor and continually survey the moon pool area for sea turtles and marine mammals after conclusion of operations and prior to hull door(s) closure and vessel transit. Dedicated crew member will continue observations while to door(s) is closing and maintain communication with the door operator(s) and bridge. Once the door(s) is closed and confirmation that no turtle/mammal has been detected, the observer will secure their position for vessel transit.

Vessels associated with and/or utilized to support activity proposed in this plan will take the most direct route when transiting from onshore support facilities to a well site(s). Vessels associated with and/or utilized to support activity proposed in this plan will not transit the Bryde's whale area.

There are no other IPFs that have the potential to cause impact to marine mammals from the proposed project including wastes sent to shore for treatment or disposal, or other factors or resources identified.

- SEA TURTLES

IPFs that have the potential to cause impacts to sea turtles from the proposed project include emissions, effluents, physical disturbances to the seafloor, and accidents. Several species of turtles occur in the Gulf of Mexico. The Endangered Species Act (ESA) protects turtles designated as endangered or threatened. Species of turtles listed as endangered occurring in the Gulf of Mexico include Green Turtle (*Chelonia mydas*), Hawksbill Turtle (*Eretmochelys imbricata*), Kimp's Ridley Turtle (*Lepidochelys kempii*), Letherback Turtle (*Dermochelys coriacea*), and Loggerhead Turtle (*Caretta caretta*).

Emissions: Noise emissions from the proposed project may have an impact on turtles. Noise levels from drilling and production activity are generally low in intensity and are not expected to have a significant impact to turtles. Operations proposed in this plan will not utilize pile-driving.

Effluents: Discharges from the proposed project will be in compliance with NPDES permit conditions and are expected to have minimal impact on turtles in the area.

Physical Disturbances to the Seafloor: Bottom disturbances to the seafloor from the proposed project could include rig placement, drilling of wells, and installation of pipelines and platforms. Impacts to water column turbidity and distribution of disturbed sediments and associated nutrients could affect turtles. Impacts to turtles from seafloor disturbances are expected to be minimal.

Accidents: An accidental spill or well blowout from the proposed project could cause impacts to turtles ranging from sub-lethal to mortal. Accidental spills would be expected to be small in in size, expeditiously recovered from the surface, and droplets in the water table microbiologically degraded, resulting in short term impacts to turtles. An accidental blowout of the well could have both short term and long term effects on turtles depending on the size and complexity of the event. Effects on turtles could include mortality, bioaccumulation, and habitat degradation. In the event of a spill or blowout, the facility will immediately implement the Regional Oil Spill Response Plan and active controls and countermeasures to minimize the impact to turtles.

Vessel traffic has the potential to impact turtles in the event of vessel strikes. To minimize the potential for vessel strikes and disturbance to turtles, the proposed project will abide by the guidelines of Joint NTL No. 2012-G01 (Vessel Strike Avoidance and Injured/Dead Protected Species Reporting).

Marine debris has the potential to impact turtles through entanglement or ingestion causing serious injury or death. To minimize the impact potential to turtles, the proposed project will abide by the guidelines of BSEE NTL No. 2015- G03 (Marine Trash and Debris Awareness and Elimination).

Additionally, BOE Exploration & Production will follow guidance resulting from the Programmatic Biological Opinion on Federally Regulated Oil and Gas Program Activities in the Gulf of Mexico.

Vessel operators associated with activity proposed in this plan will report sightings of any injured or dead aquatic protected species immediately, regardless of whether the injury or death is caused by your vessel. If the injury or death was caused by a collision with the operator’s vessel, an entrapment within the operator’s equipment or vessel (e.g. moon pool), or an entanglement within the operator’s equipment, the operator will further notify BOEM and BSEE within 24 hours of the strike or entrapment/entanglement via email to protectedspecies@boem.gov and protectedspecies@bsee.gov.

BOE Exploration & Production and/or its contractor representatives will provide a dedicated crew member to monitor and continually survey the moon pool area for sea turtles and marine mammals during activity requiring moon pool utilization. Further, BOE Exploration & Production and/or its contractor representatives will provide a dedicated crew member to monitor and continually survey the moon pool area for sea turtles and marine mammals after conclusion of operations and prior to hull door(s) closure and vessel transit. Dedicated crew member will continue observations while to door(s) is closing and maintain communication with the door operator(s) and bridge. Once the door(s) is closed and confirmation that no turtle/mammal has been detected, the observer will secure their position for vessel transit.

There are no other IPFs that have the potential to cause impact to turtles from the proposed project including wastes sent to shore for treatment or disposal, or other factors or resources identified.

- AIR QUALITY

IPFs that have the potential to cause impacts to air quality from the proposed project include emissions and accidents.

Emissions: Pollutant emissions from the proposed project include Particulate Matter (PM), Sulphur Oxides (SOx), Nitrogen Oxides (NOx), Volatile Organic Compounds (VOC), and Carbon Monoxide (CO) and could cause short term impacts to air quality in the immediate vicinity of the project location.

Calculated emissions are below BOEM exemption levels for additional air quality modeling and can be found in Appendix H of the governing document to which this report is included. The proposed project is not expected to have an impact to on-shore air quality due to the distance from the shoreline.

Accidents: An accidental spill or well blowout from the proposed project could cause impacts air quality. Accidental spills would be expected to be small in in size, expeditiously recovered from the surface, resulting in minor and short term impacts to air quality in the vicinity of the project location. An accidental blowout of the well could have both short term and long term effects on air quality depending on the size and complexity of the event. In the event of a spill or blowout, the facility will immediately implement the Regional Oil Spill Response Plan and active controls and countermeasures to minimize the impact to air quality.

There are no other IPFs that have the potential to cause impact to air quality from the proposed project including effluents, physical disturbances to the seafloor, wastes sent to shore for treatment or disposal, or other factors or resources identified.

- SHIPWRECK SITES

IPFs that have the potential to cause impacts to known or possible shipwreck sites from the proposed project include physical disturbances to the seafloor.

Physical Disturbances to the Seafloor: Bottom disturbances to the seafloor from the proposed project could include rig placement, drilling of wells, and installation of pipelines and platforms. The proposed activities occur within an area of the outer continental shelf defined by BOEM as having moderate archaeological resource potential (see NTL No. 2011-JOINT-G01). An archaeological investigation was performed across the wellsite areas by Echo Offshore using AUV geophysical data. An archaeological assessment of the proposed well locations based on this data set has been included with this plan. No features of archaeological resources were identified within 2,000ft of the proposed well locations.

There are no other IPFs that have the potential to cause impact to shipwreck sites from the proposed project including emissions, effluents, wastes sent to shore for treatment or disposal, accidents, or other factors or resources identified.

- PRE-HISTORIC ARCHAEOLOGICAL SITES

IPFs that have the potential to cause impacts to known or pre-historic archaeological sites from the proposed project include physical disturbances to the seafloor.

Physical Disturbances to the Seafloor: Bottom disturbances to the seafloor from the proposed project could include rig placement, drilling of wells, and installation of pipelines and platforms. The proposed activities occur within an area of the outer continental shelf defined by BOEM as having moderate archaeological resource potential (see NTL No. 2011-JOINT-G01). An archaeological investigation was performed across the wellsite areas by Echo Offshore using AUV geophysical data. An archaeological assessment of the proposed well locations based on this data set has been included with this plan. No features of archaeological resources were identified within 2,000ft of the proposed well locations.

There are no other IPFs that have the potential to cause impact to archaeological sites from the proposed project including emissions, effluents, wastes sent to shore for treatment or disposal, accidents, or other factors or resources identified.

VICINITY IMPACTS

- ESSENTIAL FISH HABITATS

IPFs that have the potential to cause impacts to essential fish habitats from the proposed project include effluents, physical disturbances to the seafloor, and accidents. The Magnuson-Stevens Fishery and Conservation and Management Act protects fisheries through implementation of Fishery Management Plans, which include designating Essential Fish Habitat (EFH) areas. Essential Fish Habitats located in the Gulf of Mexico are managed by the Gulf of Mexico Fishery Management Council plans include Coastal Migratory Pelagics, Coral, Red Drum, Reef Fish, Stone Crab, and Shrimp. Essential Fish Habitats managed by National Oceanic and Atmospheric Administration (NOAA) National Marine Fisheries Service (NMFS) plans include Tuna, Swordfish, Billfish, and Sharks. Designated Essential Fish Habitat (EFH) for Shrimp and Habitat Areas of Particular Concern (HAPC) for Bluefin Tuna are located in the proposed project area and could be impacted. Gulf Sturgeon (Acipenser oxyrinchus desotoi) are listed by the Endangered Species Act (ESA) as threatened and critical habitat designated in the coastal area encompassing Lake Borgne in Louisiana to Suwannee Sound. Smalltooth Sawfish (Pristis pectinata) are listed by the Endangered Species act as endangered and occur in areas from Texas to Florida.

<u>Effluent:</u> Discharges from the proposed project will be in compliance with NPDES permit conditions and are expected to have minimal impact on Essential Fish Habitat in the area.

<u>Physical Disturbances to the Seafloor:</u> Bottom disturbances to the seafloor from the proposed project could include rig placement, drilling of wells, and installation of pipelines and platforms. Impacts to water column turbidity and distribution of disturbed sediments and associated nutrients could affect Essential Fish Habitat. Impacts to those habitats from seafloor disturbances are expected to be minimal and effects temporary.

<u>Accidents:</u> An accidental spill or well blowout from the proposed project could cause temporary and possibly long term impacts to Essential Fish Habitat. Accidental spills would be expected to be small in in size, expeditiously recovered from the surface, and droplets in the water table microbiologically degraded, resulting in short term impacts. An accidental blowout of the well could have both short term and long term effects on Essential Fish Habitat depending on the size and complexity of the event. Effects could include fish mortality, bioaccumulation, and habitat degradation. In the event of a spill or blowout, the facility will immediately implement the Regional Oil Spill Response Plan and active controls and countermeasures to minimize the impact to Essential Fish Habitat.

There are no other IPFs that have the potential to cause impact to Essential Fish Habitats from the proposed project including emissions, wastes sent to shore for treatment or disposal, or other factors or resources identified.

- MARINE AND PELAGIC BIRDS

IPFs that have the potential to cause impacts to marine and pelagic birds from the proposed project include emissions and accidents. Marine and pelagic birds found in the gulf coast include Loons, Grebes, Albatrosses, Petrels, Shearwaters, Tropicbirds, Frigatebirds, Cormorants, Gannets, Boobies, Pelicans, Ducks, Geese, Swans, Phalaropes, Gulls, and Skimmers.

Emissions: Noise emissions from the proposed project may have an impact on marine and pelagic birds in the vicinity of the project location. Noise levels from drilling and production activity are generally low in intensity and are not expected to have a significant impact. Operations proposed in this plan will not utilize pile-driving. Pollutant emissions could also have an impact on marine and pelagic birds in the vicinity, however, those impacts are expected to be short term and minimal.

Accidents: An accidental spill or well blowout from the proposed project could cause impacts to birds ranging from sub-lethal to mortal. Accidental spills would be expected to be small in in size, expeditiously recovered from the surface, and droplets in the water table microbiologically degraded, resulting in short term impacts. An accidental blowout of the well could have both short term and long term effects on birds and habitats depending on the size and complexity of the event. Effects could include mortality, bioaccumulation, and habitat degradation. In the event of a spill or blowout, the facility will immediately implement the Regional Oil Spill Response Plan and active controls and countermeasures to minimize the impact to marine and pelagic birds.

Marine debris has the potential to impact marine birds through entanglement or ingestion causing serious injury or death. To minimize the impact potential to birds, the proposed project will abide by the guidelines of BSEE NTL No. 2015-G03 (Marine Trash and Debris Awareness and Elimination).

There are no other IPFs that have the potential to cause impact to marine and pelagic birds from the proposed project including effluents, physical disturbances to the seafloor, wastes sent to shore for treatment or disposal, or other factors or resources identified.

- PUBLIC HEALTH AND SAFETY

There are no IPFs that have the potential to cause impact to public health and safety from the proposed project including emissions, effluents, physical disturbances to the seafloor, wastes sent to shore for treatment or disposal, accidents, or other factors or resources identified. The project location is located 136 miles from the nearest shoreline. A prior hydrogen sulfide determination has been performed in the area of the proposed drilling operations has been classified as hydrogen sulfide absent.

COASTAL AND ONSHORE IMPACTS

- BEACHES

IPFs that have the potential to cause impact to beaches from the proposed project location include accidents.

Accidents: An accidental spill or well blowout from the proposed project could cause impacts to beaches. Accidental spills would be expected to be small in in size, expeditiously recovered from the surface, and droplets in the water table microbiologically degraded, resulting in short term impacts. An accidental blowout of the well could have both short term and long term effects on beaches depending on the size and complexity of the event. The worst discharge probability estimates the highest chances of catastrophic event making impact to the onshore beaches of Cameron Parish at 0% based on 3 days from spill, 0% based on 10 days from spill, and 4% based on 30 days from spill. Due to the facility distance from shore and the capacity to respond to a worst case discharge, no significant impacts to beaches would be expected. In the event of a spill or blowout, the facility will immediately implement the Regional Oil Spill Response Plan and active controls and countermeasures to minimize the impact to beaches.

There are no other IPFs that have the potential to cause impact to beaches from the proposed project including emissions, effluents, physical disturbances to the seafloor, wastes sent to shore for treatment or disposal, or other factors or resources identified.

- WETLANDS

IPFs that have the potential to cause impact to wetlands from the proposed project location include accidents.

Accidents: An accidental spill or well blowout from the proposed project could cause impacts to wetlands. Accidental spills would be expected to be small in in size, expeditiously recovered from the surface, and droplets in the water table microbiologically degraded, resulting in short term impacts. An accidental blowout of the well could have both short term and long term effects on wetlands depending on the size and complexity of the event. The worst discharge probability estimates the highest chances of catastrophic event making impact to the onshore beaches of Cameron Parish at 0% based on 3 days from spill, 0% based on 10 days from spill, and 4% based on 30 days from spill. Due to the facility distance from shore and the capacity to respond to a worst case discharge, no significant impacts to wetlands would be expected. In the event of a spill or blowout, the facility will immediately implement the Regional Oil Spill Response Plan and active controls and countermeasures to minimize the impact to beaches.

There are no other IPFs that have the potential to cause impact to beaches from the proposed project including emissions, effluents, physical disturbances to the seafloor, wastes sent to shore for treatment or disposal, or other factors or resources identified.

- SHORE AND COASTAL NESTING BIRDS

IPFs that have the potential to cause impacts to shore and nesting birds from the proposed project include accidents. Shore and coastal nesting birds found in the gulf coast include Terns, Pelicans, Plovers, Skimmers, Cranes and Gulls. Piping Plover (Charadrius melodus) and Whooping Crane (Grus americana) are listed by the Endangered Species Act (ESA) as threatened and have critical habitat designated in the coastal areas and beaches.

Accidents: An accidental spill or well blowout from the proposed project could cause impacts to shore and coastal nesting birds. Accidental spills would be expected to be small in in size, expeditiously recovered from the surface, and droplets in the water table microbiologically degraded, resulting in short term impacts. An accidental blowout of the well could have both short term and long term effects on birds depending on the size and complexity of the event. The worst discharge probability estimates the highest chances of catastrophic event making impact to the onshore beaches of Cameron Parish at 0% based on 3 days from spill, 0% based on 10 days from spill, and 4% based on 30 days from spill. Due to the facility distance from shore and the capacity to respond to a worst case discharge, no significant impacts to shore and coastal nesting birds would be expected. In the event of a spill or blowout, the facility will immediately implement the Regional Oil Spill Response Plan and active controls and countermeasures to minimize the impact to birds.

Marine debris has the potential to impact shore and coastal nesting birds through entanglement or ingestion causing serious injury or death. To minimize the impact potential to birds, the proposed project will abide by the guidelines of BSEE NTL No. 2015-G03 (Marine Trash and Debris Awareness and Elimination).

There are no other IPFs that have the potential to cause impact to shore and coastal nesting birds from the proposed project including emissions, effluents, physical disturbances to the seafloor, wastes sent to shore for treatment or disposal, or other factors or resources identified.

- COASTAL WILDLIFE REFUGES

IPFs that have the potential to cause impacts to coastal wildlife refuges from the proposed project include accidents. The nearest wildlife refuges to the proposed project location are the Delta National Wildlife Refuge and the Breton National Wildlife Refuge.

Accidents: An accidental spill or well blowout from the proposed project could cause impacts to wildlife refuges. Accidental spills would be expected to be small in in size, expeditiously recovered from the surface, and droplets in the water table microbiologically degraded, resulting in short term impacts. An accidental blowout of the well could have both short term and long term effects on refuges depending on the size and complexity of the event. The worst discharge probability estimates the highest chances of catastrophic event making impact to the onshore beaches of Cameron Parish at 0% based on 3 days from spill, 0% based on 10 days from spill, and 4% based on 30 days from spill. Due to the facility distance from shore and the capacity to respond to a worst case discharge, no significant impacts to wildlife refuges would be expected. In the event of a spill or blowout, the facility will immediately implement the Regional Oil Spill Response Plan and active controls and countermeasures to minimize the impact to refuges.

There are no other IPFs that have the potential to cause impact to coastal wildlife refuges from the proposed project including effluents, physical disturbances to the seafloor, wastes sent to shore for treatment or disposal, or other factors or resources identified.

- WILDERNESS AREAS

IPFs that have the potential to cause impacts to coastal wilderness areas from the proposed project include accidents. The nearest designated wilderness area to the proposed project location is the Breton Wilderness Area.

Accidents: An accidental spill or well blowout from the proposed project could cause impacts to wilderness areas. Accidental spills would be expected to be small in in size, expeditiously recovered from the surface, and droplets in the water table microbiologically degraded, resulting in short term impacts. An accidental blowout of the well could have both short term and long term effects on wilderness areas depending on the size and complexity of the event. The worst discharge probability estimates the highest chances of catastrophic event making impact to the onshore beaches of Cameron Parish at 0% based on 3 days from spill, 0% based on 10 days from spill, and 4% based on 30 days from spill. Due to the facility distance from shore and the capacity to respond to a worst case discharge, no significant impacts to wilderness areas would be expected. In the event of a spill or blowout, the facility will immediately implement the Regional Oil Spill Response Plan and active controls and countermeasures to minimize the impact to wilderness areas.

There are no other IPFs that have the potential to cause impact to wilderness areas from the proposed project including effluents, physical disturbances to the seafloor, wastes sent to shore for treatment or disposal, or other factors or resources identified.

OTHER IDENTIFIED IMPACTS

No significant impacts are expected to environmental resources from the proposed project based on Impact Producing Factors identified in the Environmental Impact Analysis Worksheet discussed in this report and prior operations and development in the proposed project location.

POTENTIAL IMPACTS FROM ENVIRONMENTAL CONDITIONS

Potential impacts from environmental conditions for the proposed project include hazards to operations, equipment, and personnel from potential adverse weather conditions from significant storm systems during the hurricane season of June through November.

ALTERNATIVES CONSIDERED TO REDUCE IMPACTS

No alternatives to the proposed project to reduce impacts were considered beyond applicable requirements of Lease Sale Stipulations, Notice to Lessees and Operators, and Regulatory Authorities.

MITIGATION MEASURES

No mitigation measures to the proposed project to avoid or reduce impacts are to be implemented beyond applicable requirements of Lease Sale Stipulations, Notice to Lessees and Operators, and Regulatory Authorities.

AGENCIES AND PERSONS CONSULTED

No agencies or persons were consulted regarding potential impacts associated with the proposed project.

PREPARER

Brandon Hebert
Beacon Offshore Energy
16564 E Brewster Rd, Ste 203
Covington, LA 70433

REFERENCES

United States Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region. Notice to Lessees and Operators of Federal Oil, Gas, and Sulphur Leases and Pipeline Right-of-Way Holders Outer Continental Shelf, Gulf of Mexico OCS Region. Biologically-Sensitive Underwater Features and Areas (NTL No. 2009- G39); 2009.

United States Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region. Notice to Lessees and Operators of Federal Oil, Gas, and Sulphur Leases and Pipeline Right-of-Way

Holders Outer Continental Shelf, Gulf of Mexico OCS Region. Deepwater Benthic Communities (NTL No. 2009-G40); 2009.

United States Department of the Interior, Bureau of Safety and Environmental Enforcement, Gulf of Mexico OCS Region. Notice to Lessees and Operators of Federal Oil, Gas, and Sulphur Leases and Pipeline Right-of-Way Holders Outer Continental Shelf, Gulf of Mexico OCS Region. Revisions to the List of Archaeological Resource Surveys and Reports (NTL No. 2011-Joint-G01); 2011.

United States Department of the Interior, Bureau of Safety and Environmental Enforcement, Gulf of Mexico OCS Region. Notice to Lessees and Operators of Federal Oil, Gas, and Sulphur Leases and Pipeline Right-of-Way Holders Outer Continental Shelf, Gulf of Mexico OCS Region. Marine Trash and Debris Awareness and Elimination (NTL No. 2015-G03); 2015.

United States Department of the Interior, Bureau of Safety and Environmental Enforcement, Gulf of Mexico OCS Region. Notice to Lessees and Operators of Federal Oil, Gas, and Sulphur Leases and Pipeline Right-of-Way Holders Outer Continental Shelf, Gulf of Mexico OCS Region. Vessel Strike Avoidance and Injured/Dead Protected Species Reporting (BOEM NTL No. 2016-G01); 2012.

Oil spill response plan number O-1039

Bureau of Ocean Energy Management and National Oceanic and Atmospheric Administration. MarineCadastre.gov National Viewer and Data Registry. [Online] available: http://www.marinecadastre.gov.

Gulf of Mexico Fishery Management Council. Species Listed in the Fishery Management Plans of the Gulf of Mexico Fishery Management Council; 2012.

National Oceanic and Atmospheric Administration, National Marine Fisheries Service. Essential Fish Habitat: A Marine Fish Habitat Conservation Mandate for Federal Agencies, Gulf of Mexico Region. 2010.

National Oceanic and Atmospheric Administration, National Marine Fisheries Service, Office of Protected Resources. [Online] available: http://www.nmfs.noaa.gov/pr/species.

United States Fish and Wildlife Service. Critical Habitat Portal, FWS Critical Habitat for Threatened and Endangered Species. [Online] available: http://criticalhabitat.fws.gov/crithab.

National Oceanic and Atmospheric Administration, National Marine Fisheries Service, Office of Protected Resources. Critical Habitat. [Online] available: http://www.nmfs.noaa.gov/pr/species/criticalhabitat.
Clapp, R. B., R. C. Banks, D. Morgan-Jacobs, and W. A. Hoffman. 1982. Marine Birds of the Southeastern United States and Gulf of Mexico. Part I. Gaviiformes through Pelecaniformes. A final report by the U.S. Fish and Wildlife Service, Office of Biological Services for the U.S. Department of the Interior, Minerals Management Service Gulf of Mexico OCS Office, Metairie, LA. NTIS No. PB82-195850. FWS Report FWS/OBS-82/01. Contract No. 14-12-0001- 29134. 648 pp.

Clapp, R. B., D. Morgan-Jacobs, and R. C. Banks. 1982. Marine Birds of the Southeastern United States and Gulf of Mexico. Part II. Anseriformes. A final report by the U.S. Fish and Wildlife Service, Office of Biological Services for the U.S. Department of the Interior, Minerals Management Service Gulf of Mexico

OCS Office, Metairie, LA. NTIS No. PB82-264995. FWS Report FWS/OBS-82/20. Contract No. 14-12-0001-29134. 505 pp.

Clapp, R. B., D. Morgan-Jacobs, and R. C. Banks. 1983. Marine Birds of the Southeastern United States and Gulf of Mexico. Part III. Charadriiformes. A final report by the U.S. Fish and Wildlife Service, Office of Biological Services for the U.S. Department of the Interior, Minerals Management Service Gulf of Mexico OCS Office, Metairie, LA. NTIS No. PB84-158773. FWS Report FWS/OBS-83/80. Contract No. 14-12-0001-29134. 869 pp.

United States Fish and Wildlife Service. Gulf Restoration, The Importance of the Gulf of Mexico and its Watersheds to Migratory and Beach-nesting Birds. [Online] available: http://www.fws.gov/gulfrestoration/gulfbirds.

United States Fish and Wildlife Service. National Wildlife Refuge System. [Online] available: http://www.fws.gov/reguges.

Collaborative partnership Arthur Carhart National Wilderness Training Center, Aldo Leopold Wilderness Research Institute, Federal Government's Wilderness Training and Research, and University of Montana. [Online] available: http://www.wilderness.net.

APPENDIX R
ADMINISTRATIVE INFORMATION

A) EXEMPTED INFORMATION DESCRIPTION
Proprietary information included in the proprietary copy of this plan is listed below.

- BHL, TVD, and MD information on Form 137
- WCD sand and depth information on Form 137 and supporting documentation
- Certain items and enclosures under Geological and Geophysical information
- Correlative well information used to justify the H2S classification
- Casing summary information
- Charts containing sand tops and bases in the analog wells
- Directional Survey
- Wellbore Schematics

B) BIBLIOGRAPHY
Below is a listing of all referenced material used to development this plan.

- Notice to Lessees No. 2008-G04
- Notice to Lessees No. BOEM 2015-N01
- Notice to Lessees No. 2009-G40
- Notice to Lessees No. 2009-G39
- Notice to Lessees No. 2008-G06
- Notice to Lessees No. 2005-G07
- Notice to Lessees No. 2006-G07
- Notice to Lessees No. 2007-G04
- Notice to Lessees No. BOEM 2016-G01
- Notice to Lessees No. 2015-G03
- Notice to Lessees No. BOEM 2016-G02
- Echo Offshore, 3D Geohazard Assessment, Block 895 / North Half Block 939, Green Canyon Area, Report No. 17-022-50/1115
- Echo Offshore, AUV Archaeological Assessment, Block 895 / North Half Block 939, Green Canyon Area, Report No. 17-021-41
- Echo Ofshore, Site Clearance Letter, Proposed Wellsites A / B / C / D, Block 985 (OCS-G 35879), Green Canyon Area, Report Nos:
  - 20-012-31 / 2018-103 (Wellsite A)
  - 20-012-31 / 2018-104 (Wellsite B)
  - 20-012-31 / 2020-243 (Wellsite C)
  - 20-012-31 / 2020-244 (Wellsite D)