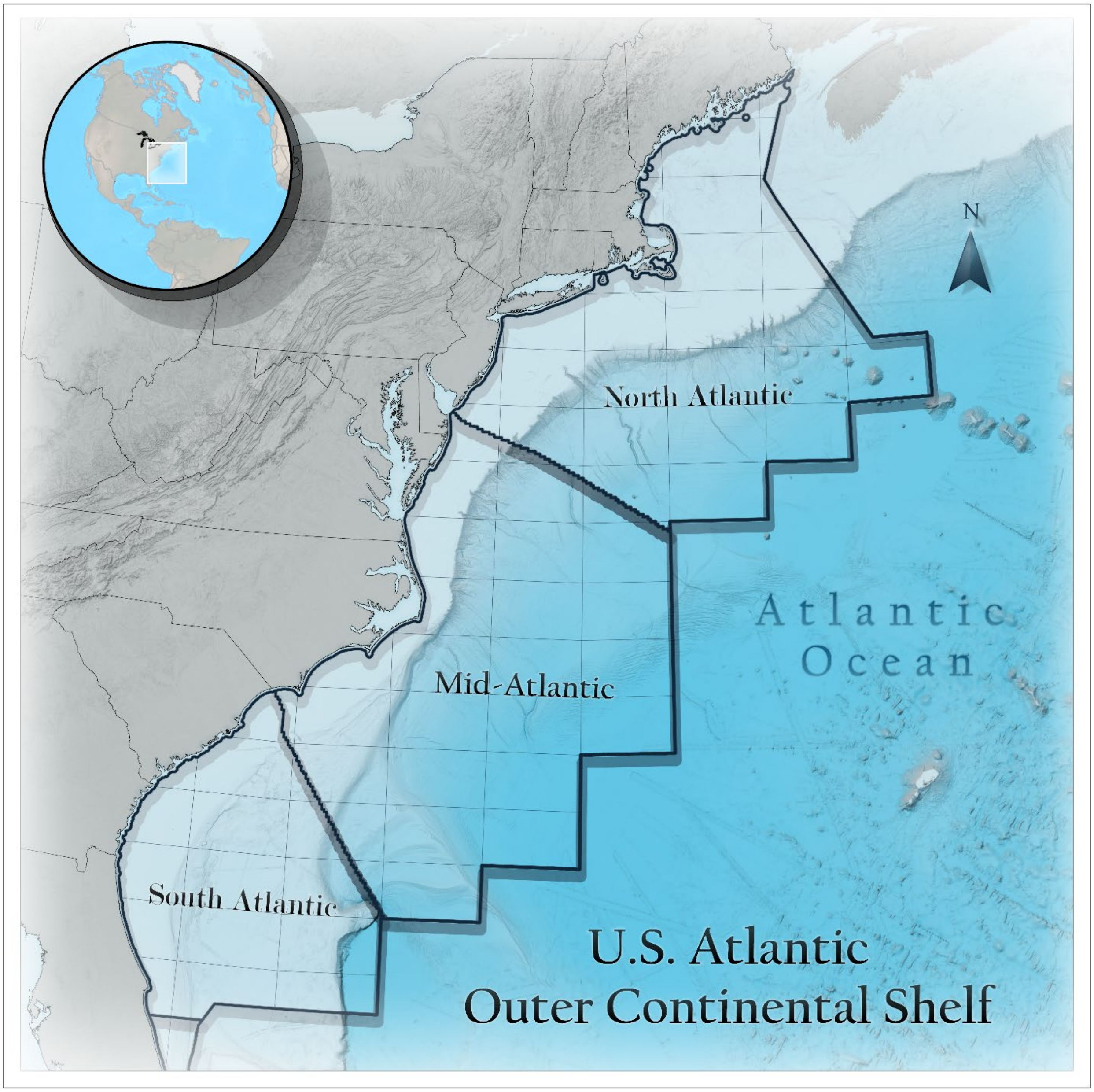
OCS Report
BOEM 2021-085

2021 Assessment of Technically and Economically Recoverable Oil and Natural Gas Resources of the U.S. Atlantic Outer Continental Shelf



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BOEM
Bureau of Ocean Energy Management

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ABREVIATIONS AND ACRONYMS

2D	two-dimensional
3D	three-dimensional
AU	assessment unit
Bbbl	billion barrels
bbl	barrels
bbl/d	barrels per day
BBOE	billion barrels of oil equivalent
BCFG	billion cubic feet of gas
BCFGE	billion cubic feet of gas equivalent
BCT	Baltimore Canyon Trough
BPB	Blake Plateau Basin
BOE	barrels of oil equivalent
BOEM	Bureau of Ocean Energy Management

BSR	bottom simulating reflector
CTSB	Carolina Trough Salt Basin
CBM	coalbed methane
COST	Continental Offshore Stratigraphic Test
DSDP	deep sea drilling project
DST	drillstem tests
FEED	front-end engineering design
FERC	Federal Energy Regulatory Commission
FID	final investment decision
FIS	fluid inclusion study
FIT	Fluid Inclusion Technologies, Inc.
FLNG	floating liquified natural gas
FPS	floating production and storage
FPSO	floating production storage and offloading
Fm.	formation
ft	feet
GBB	Georges Bank Basin
GOM	Gulf of Mexico
GOR	gas-oil ratio
GRASP	Geologic Resource Assessment Program
HC	Hudson Canyon
LNG	liquified natural gas
mbsf	meters below seafloor
mD	millidarcies
mi	miles
mi2	square miles
MMbbl	million barrels of oil
MMBOE	million barrels of oil equivalent
MMCFG	million cubic feet of gas
MMBNGL	million barrels of natural gas liquids
MSGBC	Mauritani –Senegal–The Gambia–Guinea Bissau–Conakry
MTPA	million tons per annum
NCEI	National Centers for Environmental Information
NFW	new field wildcat
NOAA	National Oceanic and Atmospheric Administration
OCS	Outer Continental Shelf
ODP	ocean drilling program
PETRIMES	Petroleum Resources Information Management and Evaluation System
SAR	synthetic aperture radar
SBs	sequence boundaries
SEGE	Southeast Georgia Embayment
SDR	seaward-dipping reflector
Tcf	trillion cubic feet
TCFG	trillion cubic feet of gas
TOC	total organic carbon
UERR	undiscovered economically recoverable resources
U.S.	United States
UTRR	undiscovered technically recoverable resources

1.0 INTRODUCTION

This report summarizes the results of the 2021 Bureau of Ocean Energy Management (BOEM) inventory of undiscovered, technically recoverable oil and gas resources of the U.S. Atlantic Outer Continental Shelf (OCS) (Figure 1). It complies with and fulfills requirements written in subsection (a), paragraphs (1) through (5) and subsection (b) of Section 357 of the Energy Policy Act of 2005. The area assessed comprises the portion of the submerged seabed whose mineral estate is subject to Federal jurisdiction. This resource inventory represents a comprehensive appraisal of data and information populating a distribution of pool/field sizes from an Atlantic analog database. This inventory incorporates and applies modern exploration concepts and key new learnings based on industry exploration activities in northeast-adjacent Nova Scotia, conjugate Northwest Africa, the West African and its conjugate South American Transform Margins, and the East African Transform Margin. It also provides comments/observations on significant exploration and production activity on the international analogs upon which this inventory is based. The outcome and future activities of these analogs may result in additional resource inventory increases. Since the 2016 Assessment, for example, the Guyana-Suriname basin has had multiple discoveries in multiple leased blocks. Prior to the publication of this assessment, a 20th discovery was made on the 6.6-million-acre (~1.5 Atlantic OCS Protractions) Stabroek block offshore Guyana. With estimates of ~11 billion barrels of oil equivalent (BBOE) in late Cretaceous sandstone reservoirs, there are two floating production storage and offloading (FPSO) facilities in production. The first began in 2019 and is producing 130,000 barrels per day (bbl/d). The second came online February 2022 and is ramping up to its 220,000 bbl/d capacity. A third sanctioned FPSO is under construction with a likely start up in late 2023 and a 220,000 bbl/d capacity. Deepwater success after decades of poor results nearshore is also a possibility for the untested U.S. Atlantic OCS areas (ExxonMobil, 2022).

In the absence of new deep-penetration reflection seismic geophysical datasets on the U.S. Atlantic OCS, available vintage data were enhanced through vectorization and/or reprocessing. All wireline logs were digitized. Biostratigraphic data were of variable quality and diverse vintages. The sequence framework developed by GeoSpec (2003) was used as the primary framework, and when integrated with the seismic data, provided reasonable consistency throughout the region. Updated and improved gravity and magnetic data sets were used beginning with the 2016 assessment. Originally available and recent geochemical data were assessed, aggregated, and incorporated. All data were integrated to develop a comprehensive petroleum system focused inventory of potential resources. Since 2016, additional legacy seismic was reprocessed by GeoSpec (a CGG company) and licensed by BOEM. Interpretations from this will be included in future assessments.

Since the most recent comprehensive resource inventory (BOEM, 2016), industry activity in international areas considered appropriate analogs for assessment units (AUs) in the U. S. Atlantic OCS has resulted in significantly altered resource volumes for half (five) of the AUs, with one being reduced. After issuing the 2016 assessment, additional new field wildcat (NFW) drilling has resulted in discoveries in analogous settings in Northwest Africa (Mauritania and Senegal), the Guyana-Suriname basin of Northern South America, and East Africa (Tanzania). Those and earlier discoveries have been delineated and tested in applicable analogous regions. This activity has improved our understanding of discovery size and petroleum systems responsible for those analogs.

2.0 THE ATLANTIC REGION

2.1 LOCATION

Located on the eastern margin of the continental United States (U.S.), the Atlantic OCS extends approximately 1,300 miles (mi) from the Canadian province of Nova Scotia (northeast) to The Bahamas (southwest). The Atlantic Region is divided into the North, Mid-, and South Atlantic Planning Areas (Figure 1). The Straits of Florida Planning Area, the northernmost part of which is shown in Figure 2, is addressed as part of the Gulf of Mexico (GOM) (BOEM, 2021), because GOM AUs extend into that Planning Area. Water depths in the Atlantic OCS range from less than 30 ft to >15,000 ft.

2.2 REGIONAL SETTING

The supercontinent Pangea formed by progressive amalgamation of crustal blocks culminating during the late Paleozoic Alleghanian–Variscan orogeny when all existing continents and fragments were assembled into a single entity (Rast, 1988; Rankin, 1994; Hatcher, 2010; and Mueller et al., 2014). The development of the U.S. Atlantic margin began during the Late Triassic breakup of western Pangea. This breakup began approximately 237–208.5 million years ago and was characterized by region-wide continental rifting (Iturralde-Vinent, 2003; Withjack and Schlische, 2005; Kneller and Johnson, 2011; and Kneller et al, 2012). Subsequently, the North American plate containing the U.S. Atlantic Region and its conjugate margin, the African plate, drifted apart as sea floor spreading opened the current Atlantic Ocean.

As is typical of all Central Atlantic Margins, the geology, petroleum systems, plays, and resultant resource assessment of the region reflect the geometry and transition from the early, complex rift system to the present-day passive margin (Withjack and Schlische, 2005; Sheridan, 1987). A series of four post-rift sedimentary depocenters of Early Jurassic(?)–Holocene age developed linearly along the U.S. part of the margin. From northeast to southwest (Figure 1) these are: the Georges Bank basin, the Baltimore Canyon Trough, the Carolina Trough, and the Blake Plateau basin (including its updip Southeast Georgia Embayment) (Sheridan, 1987). These depocenters and their sedimentary sections vary in size, shape, and thickness (Divins, 2012).

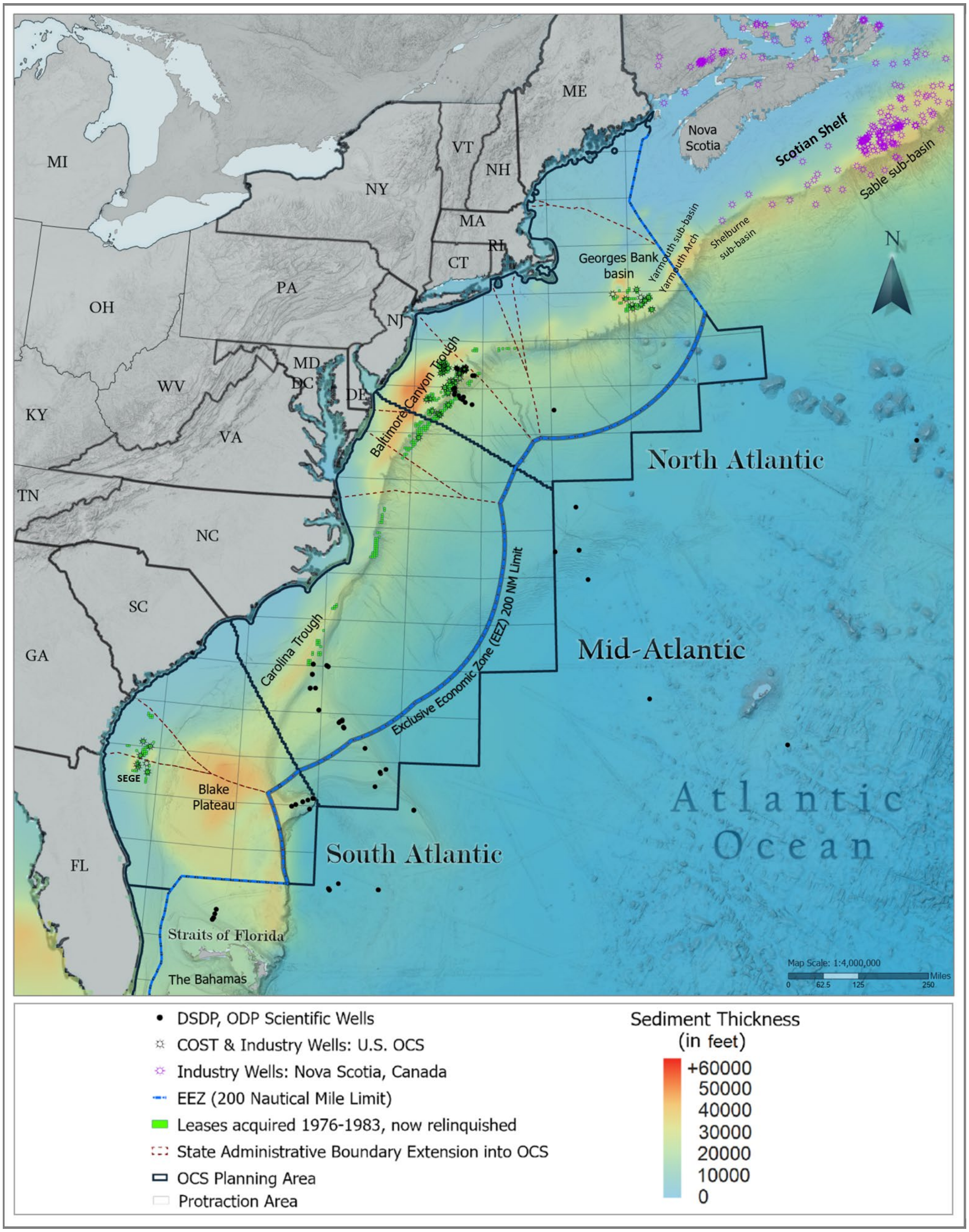

Figure 1. The sediment thickness raster layer comes from 'GlobSed', a 5-arc-minute total thickness grid for the world's oceans and marginal seas. Published in 2019 by the National Centers for Environmental Information (NCEI), this grid was synthesized from earlier publications including those at the National Oceanic and Atmospheric Administration (NOAA). NCEI is organized within NOAA (Straume et al., 2019). Maroon dashed lines show partitioning of the OCS area to show state jurisdiction under the Coastal Zone Management Act.

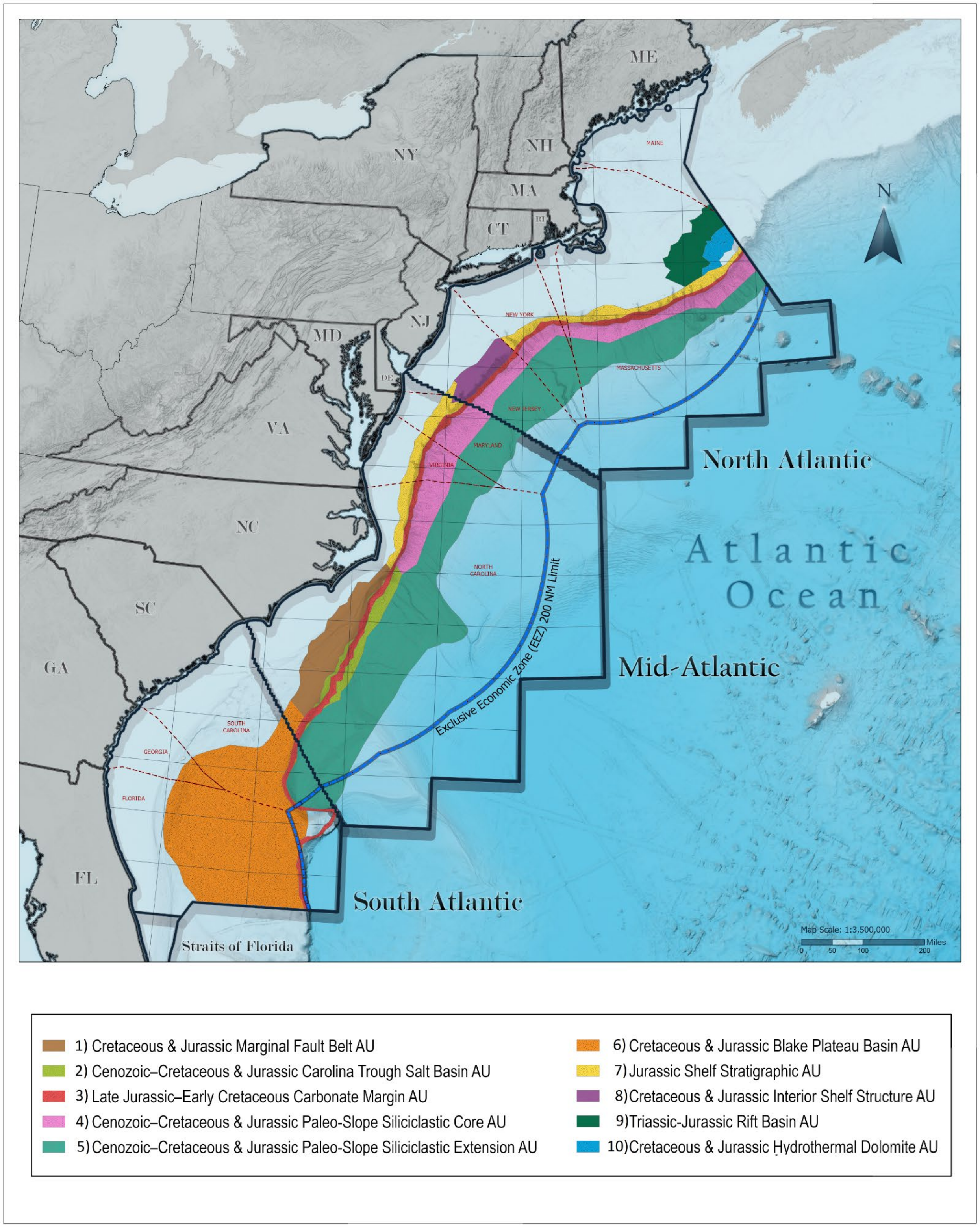

Figure 2. AU locations for U.S. Atlantic OCS. Cartographic elements on this figure are identified on the left side of the Legend of Figure 1.

2.3 STRATIGRAPHIC SUMMARY OF THE U.S. ATLANTIC REGION

Figure 3 illustrates the generalized stratigraphy of the U.S. Atlantic margin calibrated using ages from the Geologic Time Scale of 2004 (Ogg et al., 2008), integrated with the Haq et al. (1987) eustatic sea level curve. Key seismic horizons interpreted by the BOEM staff are also shown as they are defined by geologic ages and the eustatic curve. Even though drilling in the U.S. Atlantic ended in 1984, it continued in Canada offshore Nova Scotia along with the acquisition and processing of modern, deep-penetrating reflection seismic. Development activity on the margin has led to a consistent lithostratigraphic and biostratigraphic framework that informs this assessment on the U.S. Atlantic margin. Therefore, the lithostratigraphic nomenclature derived from the Scotian offshore (CNSOPB, 2009a and b) is used, referenced, and followed in this report.

Late Triassic–Early Jurassic syn-rift sediments consist primarily of interbedded fluvial and lacustrine red beds, shales, and basalts. In some syn-rift basins and sag-phases of depocenter development, evaporites may also have been deposited. A post-rift or breakup unconformity overlies the syn-rift sequence. Farther eastward, towards the opening Atlantic Ocean, a seaward-dipping reflector (SDR) unconformity overlies the SDR complex represented by the East Coast Magnetic Anomaly (Wyer and Watts, 2006). Although these two unconformities appear synchronous, they differ in age: the unconformity overlying the SDRs being as much as 10 Ma younger than the breakup unconformity (Cramez, 2007). No formation names are used for syn-rift strata because established stratigraphic nomenclature exists (and is different) in each of these rift basins.

A marine transgression above these unconformities resulted in a shallow marine environment (Figure 3) within which updip siliciclastics (Mohican Formation (Fm) and equivalents) and downdip limestones, dolomites, and minor evaporites (Iroquois Fm and equivalents) were deposited (CNSOPB, 2009a and b). Evaporites (Figure 3) are documented in localized syn-rift (Wade and MacLean, 1990), and probably post-rift, sag-phase settings offshore Nova Scotia, and various post-rift sag-phase settings on the U.S. Central Atlantic (Amato and Simonis, 1980; McKinney et al., 2005; Elliott and Post, 2012; Post et al., 2012). Reflection seismic and well data along the U.S. and Nova Scotian Atlantic margins indicates that evaporites do not occur in all syn-rift settings, or throughout the lateral extent of the Iroquois Fm, overlying the breakup unconformity, the seaward-dipping reflector unconformity (SDRU), or all SDRs. In the U.S. Atlantic OCS, reprocessed reflection seismic data in the Baltimore Canyon Trough (McKinney et al., 2005) demonstrate that autochthonous evaporites in that depocenter is post-rift, overlying the breakup unconformity. Evaporites overlying SDRs or the overlying SDRU in a setting similar to that described by Jackson et al. (2000) are recognized on seismic data in the Carolina Trough (Dillon et al., 1982), where they form a variety of salt-cored structures.

Sea floor spreading, subsidence of the margin, and sea level rise resulted in the Atlantic becoming broader and deeper (~3,300 ft) by Middle Jurassic (CNSOPB, 2009b). During this period, a carbonate margin was initiated that persisted until the latest Jurassic–earliest Cretaceous (Figure 3). Its development was affected by contemporaneous Late Jurassic–Early Cretaceous siliciclastic deltaic depocenters that locally restricted carbonate sedimentation (Eliuk and Wach, 2014). Because more drilling has taken place offshore Nova Scotia, the Abenaki Fm carbonate margin and its updip lagoonal and downdip facies equivalent marls and carbonate mud are better defined. In Nova Scotia, the Abenaki Fm has four formal members (in ascending order): the Scatarie Limestone Member, the Misaine Shale Member, the Baccaro Limestone Member; and the Artimon Limestone Member (Eliuk, 2004).

Offshore Nova Scotia, the Scatarie is predominantly an oolitic limestone that often shows cyclic deposition. It is typically depicted (Figure 3) as extending from its apparent shoreline to its offshore facies equivalent (Kidston et al., 2005; CNSOPB, 2009a). The oolitic limestones grade into marls and mudstones in deeper water settings. The absence of the overlying Misaine Member (Eliuk, 1978) makes it is difficult to recognize in the proximal setting. The Scatarie is the most areally extensive sequence of the Abenaki Formation (Kidston et al., 2005). Continuing margin subsidence and sea level rise resulted in a marine transgression during which Scatarie carbonates were blanketed by marine shales of the Misaine Member (Kidston et al., 2005; CNSOPB, 2009b). The Misaine interfingers with the updip Mohawk Fm. The Mohawk and Mic Mac formations are interpreted to be primarily updip siliciclastic and lateral equivalents of the other Abenaki Fm members (Kidston et al., 2005; CNSOPB, 2009a). Where recognized, the Misaine separates the underlying Scatarie from the overlying Baccaro limestone members (Eliuk, 1978). The Baccaro Limestone Member is the thickest and best developed carbonate unit of the Abenaki Formation in Nova Scotia. However, its areal extent is limited to a variable, narrow, 9–15 mi wide belt that follows the Jurassic hinge line and defines the seaward limit of the Abenaki platform margin (Kidston et al., 2005). It is composed of numerous stacked, shoaling-upwards, aggrading and prograding parasequences. Over the width of Baccaro belt, a number of laterally equivalent sedimentary facies were developed: lagoon to inner shelf, oolitic shoal, coral-stromatoporoid reef, and beyond this, reef margin foreslope fans (Kidston et al., 2005). The Artimon Member is the youngest and thinnest member of the Abenaki Fm. Its areal distribution is patchy and limited and is not shown in Figure 3. It is composed of argillaceous, cherty limestones representing thrombolytic sponge and stromatoporoid mound deposition with occasional interbedded calcareous shales (Kidston et al., 2005). The associated fossil assemblage infers a reef middle foreslope depositional setting in water depths from 300 to 600 ft, near the limits of the photic zone (Eliuk, 1978). The presence of these sponge-stromatoporoid mounds at the top of the drowned platform margin edge reflects depositional response to a major sea level rise during the earliest Cretaceous (Berriasian).

Offshore Nova Scotia, well and seismic data document an along-strike northeast to southwest change in the geometry of the Abenaki carbonate margin from a progradational, gently dipping ramp-like style with inter-fingering carbonate and clastic facies, to a steeper sigmoidal bank margin, to an eroded margin, and a faulted/eroded margin (Kidston et al., 2005). While not confirmed by wells, reflection seismic data indicates similar changes in the geometry of the Abenaki margin in the U.S. Atlantic OCS.

The Abenaki Fm, and/or its updip equivalents the Mic Mac and Mohawk formations, are recognized in all wells drilled to the Late Jurassic in the U.S. Atlantic OCS. However, the most prospective shelf-edge setting was only targeted by two of the 39 NFW wells in the Atlantic OCS (Kidston et al., 2005). These wells were drilled by Shell et al. in the Baltimore Canyon Trough during 1983 and 1984. They encountered more carbonate-sand-rich beds than the muddier facies, containing a higher percentage of reef frame-builder-rich beds typically found by wells drilled offshore Nova Scotia. Although these biofacies differences may reflect a “sampling” bias, there appear to be significant differences between this area and offshore Nova Scotia (Eliuk and Prather 2005). The Artimon and Baccaro members were recognized in the Shell et al., Wilmington Canyon (WI) 587-1 well (Eliuk and Prather 2005). Similar information was not provided on any other wells in the Baltimore Canyon Trough. Regarding the other Shell et al. wells, Eliuk (2016) stated: "The Misaine and Scatarie age level was never reached and likely such units would be absent since they relate to Laurentian delta shale influx and maybe Callovian glacial drawdown and rapid recovery at the base of the Baccaro that capped the Misaine shale." He further noted that the Artimon is a highly diachronous facies. Just as in offshore Nova Scotia, along strike facies variations and changes in the Abenaki are expected throughout the U.S. Atlantic OCS. The individual members and their sequence stratigraphy have generally not been identified because most of the wells in the region are in the generally non-prospective updip shelf setting. Therefore, projecting facies tracts over any distance is currently problematic.

Spanning the Middle Jurassic–Early Cretaceous, the Verrill Canyon Fm (Figure 3) is the deep-water facies equivalent of the Mohawk, Abenaki, and Mic Mac Fms., as well as the overlying Missisauga Fm in both the U.S. and Nova Scotia (Wade and MacLean, 1990). The Verrill Canyon Fm consists primarily of grey to brown calcareous shale with thin beds of limestone, siltstone, and sandstone. It records deposition in prodelta, outer shelf, and continental slope settings (Wade and MacLean, 1990).

The Missisauga Fm (Figure 3) consists of a series of thick sand-rich deltaic, strandplain, carbonate shoals and shallow marine shelf units. These facies and the formation dominated sedimentation throughout the Early Cretaceous in both offshore Nova Scotia (CNSOPB, 2009b) and the U.S. Atlantic OCS.

In Nova Scotia, the overlying Logan Canyon Fm consists (in ascending order) of four members: the Naskapi, Cree, Sable and Marmora. Those not recognized in the U.S. Atlantic OCS are not shown in Figure 3. The basal, widely-recognized, shale-rich Naskapi Member represents a major, early Aptian (mid-Cretaceous) marine transgression that terminates much of the Missisauga Fm deltaic sedimentation. The sand-rich upper parts of the Logan Canyon are often locally interbedded with shales, silts, and coals. Depositional environments range from coastal plain-lagoonal to outer shelf (CNSOPB, 2009b).

Reflecting the relatively high sea levels of the Late Cretaceous (Figure 3), Dawson Canyon Fm shales, interbedded limestones, and minor sandstones were deposited in deeper marine environments throughout the U.S. Atlantic OCS. These ultimately overwhelmed and transgressed over the more sand-rich siliciclastic deposition of the upper members of the Logan Canyon Fm (CNSOPB, 2009b).

Throughout the region, sea level rise continued during the Late Cretaceous (Figure 3). Offshore Nova Scotia marls and chalky mudstones of the Wyandot Fm were deposited (CNSOPB, 2009b). The Wyandot Fm has not been recognized in the U.S. Atlantic OCS. Latest Cretaceous and Tertiary marine shelf argillaceous limestones, mudstones, sandstones, and conglomerates of the Banquereau Fm were deposited during the subsequent overall falling sea level cycle. Depositional environments ranged from shallow shelf to bathyal. Significant sea level falls are recorded in the major unconformities that occur within the formation (CNSOPB, 2009b).

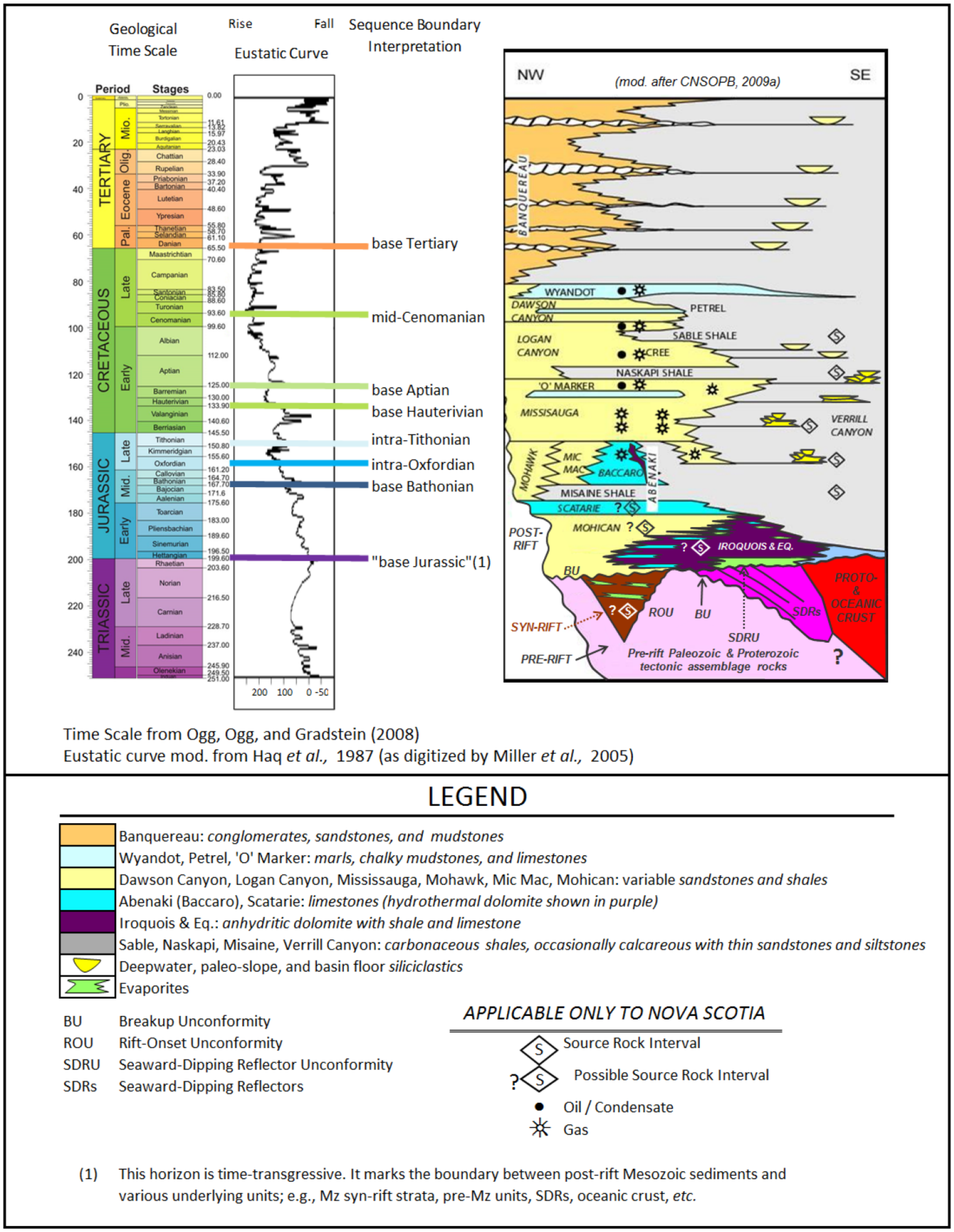

Figure 3. Generalized stratigraphy of the U.S. Atlantic region based on the more heavily explored and drilled northeast-adjacent Nova Scotia offshore. Calibrated using ages from the Geologic Time Scale of 2004 (Ogg et al., 2008), integrated with the Haq et al. (1987) eustatic sea level curve. Key seismic horizons interpreted by BOEM staff represent sequence boundaries initially identified and interpreted by GeoSpec, a CGG company, on GeoSpec's seismic interpretation of the U.S. Atlantic OCS (GeoSpec, 2003).

During the Paleocene, Oligocene, and Miocene (Figure 3), fluvial and deep-water currents cut into and eroded these mostly unconsolidated sediments, transporting them into deeper water slope and abyssal environments throughout the entire region (CNSOPB, 2009b).

The BOEM seismic interpretation in the post-rift interval recognizes eight (8) sequence boundaries (SBs). These form the basis of the BOEM interpretation of the geology, stratigraphy, and hydrocarbon prospectivity of the region (Figure 3). The sequence boundaries (SBs) are based on the GeoSpec (2003) interactive interpretation of the deep-penetration, reflection seismic data with wireline well log, lithostratigraphic, palynological, micropaleontological, and nannopaleontological data and sequence stratigraphic concepts throughout the western Central Atlantic in Nova Scotia and the U.S. The interpreted 'base Jurassic SB' (b J SB) is Jurassic in age over most of the region. However, the seismic horizon is diachronous. It marks the boundary of post-rift Mesozoic sediments and underlying pre-Mesozoic units, older Mesozoic syn-rift strata, SDRs, and oceanic crust. Its interpretation is critical, because it controls and constrains the architecture and thickness of the post-rift Mesozoic and Cenozoic age sections where most hydrocarbon prospectivity is interpreted. The SB-based framework was used to delineate the geographic extent of each of the AUs identified and assessed in the U.S. Atlantic OCS.

2.4 EXPLORATION AND DISCOVERY STATUS

To date, there has been no commercial hydrocarbon production in the U.S. Atlantic OCS. A single phase of oil and gas exploration was conducted from the late 1960s to the mid-late 1980s. Approximately 239,000 line mi of two dimensional (2D) seismic was acquired, processed, and interpreted between 1966 and 1988. In 1982, an early attempt at acquiring a three-dimensional (3D) seismic survey (actually a "pseudo-3D" survey because it consisted of 95 "inlines" on 1,000 ft spacing), was acquired over a four-block area centered on Hudson Canyon (HC) Block 598 area in the Baltimore Canyon Trough (Figure 4).

The BOEM seismic data set in the Atlantic OCS consists of approximately 170,000 line mi of 2D data. To facilitate seismic interpretation and use of well data on workstations, the 2D data and "pseudo-3D" survey described above were digitized, vectorized, and migrated (where necessary). An additional ~12,400 line mi of reprocessed reflection seismic data and approximately 185,000 line mi of depth-converted, time-migrated data in SEG-Y format were licensed from GeoSpec (a CGG Company) prior to the 2016 Assessment. Because these data provide better, more accurate imaging, these data comprise the primary data set used in this resource inventory. Additional reprocessed seismic lines and an updated sequence framework interpretation were licensed from Geospec (a CGG Company) in 2018, 2020, and 2021. BOEM interpretations on this seismic and other newly licensed geochemical and paleontological interpretations will be incorporated into the 2026 Assessment.

In the U.S. Atlantic Region, excluding the Straits of Florida Planning Area, nine lease sales were held from 1976–1983 resulting in 410 leases being acquired on 2,334,198 acres. Fifty-one (51) wells were drilled (Figure 4). These consist of five Continental Offshore Stratigraphic Tests (COST wells) drilled between 1975 and 1979, and 46 industry wells were drilled between 1978 and 1984. Using the classification of Lahee (1944), 39 of these wells were NFW wells; the remaining 7 (in the HC 598 area) were outpost/delineation/or extension wells.

The North, Mid-, and South Atlantic Planning Areas (Figure 2) constitute an area of ~406,700 mi^2. Ignoring the clustering of wells in the various depocenters, this equates to a NFW drilling density of 1 well per ~10,500 mi^2, or 1 well per 1.5 Atlantic OCS protractions. Considering only the areas of the currently identified AUs, and assuming all the wells were drilled within them, which they are not, the NFW density would be 1 for every 4,000 mi^2, or 1 NFW for approximately half of each OCS protraction (~7,500 mi^2).

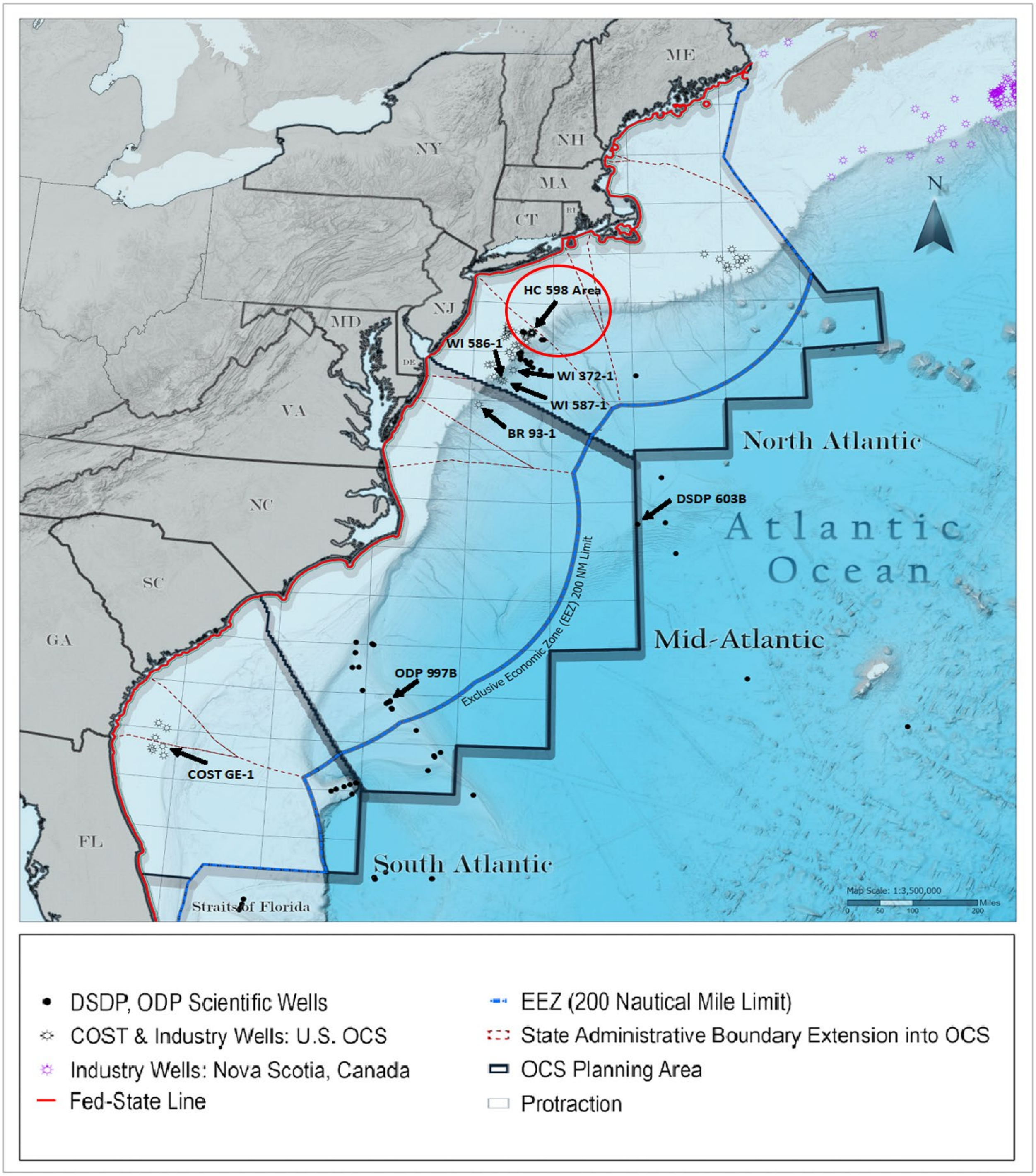

Figure 4. Location of Hudson Canyon 598 area (circled) and wells referenced in the text.

To date only three AUs have been tested with drilling:

- Late Jurassic-Early Cretaceous Atlantic Carbonate Margin (AU 3);
- Cenozoic-Cretaceous and Jurassic Paleo-slope Siliciclastic Core (AU 4); and
- Cretaceous-Jurassic Interior Shelf Structure (AU 8).

Four AUs have had no oil and gas wells drilled within their areas:

- Cretaceous and Jurassic Atlantic Marginal Fault Belt (AU 1);
- Cenozoic–Cretaceous and Jurassic Carolina Trough Salt Basin (AU 2);
- Cenozoic–Cretaceous and Jurassic Paleo-slope Siliciclastic Extension (AU 5); and
- Cretaceous and Jurassic Blake Plateau Basin (AU 6).

Wells within the areas of AUs 7, 9, and 10 targeted other objectives so these AUs remain untested. Additionally, AUs 3 and 4 have only four wells between them making the Atlantic OCS largely unexplored.

The HC 598 area (Figure 4), consisting of blocks HC 598, HC 599, HC 642, and HC 643, is located on the shelf in the Baltimore Canyon Trough (BCT) in approximately 450 ft of water. It is the only area where a non-commercial discovery was made during this exploration phase. The trap is a seismically-defined anticlinal structure bounded on its updip side by a listric down-to-the-basin fault with an associated crestal graben. All eight wells drilled on this structure had natural gas shows, most of which were "wet" gas (natural gas containing significant percentages of heavier hydrocarbons such as ethane, propane, often butane, and occasionally pentane. Variable volumes of gas, with differing gas-oil ratio (GOR) values, were successfully drillstem tested in six wells. Additional information summarizing these test results are provided under the Cretaceous and Jurassic Interior Shelf Structure AU section. Reservoir compartmentalization indicated by detailed cross sections incorporating wireline log correlations, mud log shows, petrophysical calculations using the wireline log data, tests, etc., could not be resolved with the seismic data available at the time, including the "pseudo-3D" survey. The leases were ultimately relinquished, probably due to a combination of issues; i.e., the stratigraphic and structural compartmentalization of the reservoirs that would have necessitated a large number of wells and limited per well recovery, distance from shore (approximately 100 mi), and lack of onshore and offshore infrastructure.

2.5 REGION LEVEL ENGINEERING, TECHNOLOGY, AND TRANSPORTATION

There are no engineering or technology issues that would limit exploration and production in the region, because current drillship capabilities allow drilling in 12,000 ft of water to depths of 40,000 ft. As of mid-2021, the Perdido Spar, moored in approximately 8,000 ft of water, is the deepest production facility in the world. Production from wells in three fields within a 30-mile radius, currently including the deepest water subsea completion in the world (in 9,626 ft of water), is gathered, processed, and exported from the facility (Shell, 2021). The deepest waters in the world in which FPSOs operate are also in the GOM. The *Turritella* FPSO operated by Shell at their Stones field in 9,500 ft of water represents the deepest currently operating FPSO in the world (Shell, 2020). ENI's recently completed *Coral Sul* floating liquified natural gas (FLNG) vessel with a gas liquefaction capacity of 3.4 million tons per annum (MTPA) is on schedule for first cargo later in 2022 at Mozambique's Coral field in ~6,500 ft of water (ENI, 2022). FLNG production at this water depth makes all Atlantic AUs at least partly accessible.

This report estimates 20% of Undiscovered Technically Recoverable Resources (UTRR) to be found in deepwater and 70% in ultra-deepwater. Water depths are categorized here using limits from a BOEM 2019 oil and gas deepwater report, wherein shallow water was defined as <1,000 ft, deepwater as ≥1,000 ft and <5,000 ft, and ultra-deepwater as ≥5,000 ft (BOEM, 2019). Given the distance from shore and deepwater depths where these potential resources may exist, and the lack of infrastructure in this frontier area, floating production and storage (FPS) may be the best option. Oil is currently being produced from 162 FPSOs globally as of the summer 2021 (Offshore Magazine, 2021a). FPSOs have advantages of a smaller infrastructure footprint and potential avoidance of environmentally sensitive areas by eliminating the need for pipelines to shore. This also means interactions with fewer regulating bodies and other competing interests (such as fishing, shipping, etc.). Additionally, there is the lower initial capital investment and potential for quicker times to production for frontier areas. The Liza phase 1 offshore Guyana began production in December 2019, just under 5 years from first discovery with the Liza-1 well in May 2015 (ExxonMobil, 2019).

The value of existing infrastructure either for direct use or tie-in cannot be overstated. For example, production from the Perdido Spar in the GOM flows into an oil pipeline approximately 77 mi away and a natural gas pipeline 107 mi away (Shell, 2021) rather than through a dedicated pipeline spanning the 237 mi from the spar to shore. It is not possible to build-out existing oil and/or gas pipeline transportation systems and infrastructure into the Atlantic OCS because there is no hydrocarbon production in the onshore coastal regions adjoining the Atlantic OCS.

Two options exist for natural gas production in the Atlantic OCS and are to an extent dependent on the volume of gas discovered as either associated gas (gas associated with oil production), or non-associated gas (gas with no, or minimal, liquid content). These would potentially replace shale/resource play gas from the onshore eastern U.S. Appalachian basin in domestic U.S. markets or be exported as liquified natural gas (LNG). Incorporation of OCS gas into the U.S. domestic market would be simple, as that market has expanded with supplies from Appalachia. Its use as LNG would be more complex. Many of the FPSO advantages also exist for FLNG but there are additional disadvantages. Currently, production rates are around half those of shore-based LNG via pipeline, and costs per ton are roughly double. Traditional economies of scale are therefore more complicated with longer investment returns deterring FLNG development of large fields (Kelleher, 2018). However, price reductions are expected as FLNGs become more standard. Distances from shore to the center of each of the 10 Atlantic AUs ranges from ~75 to ~175 mi. Per mile pipeline costs needed in predominantly deep and ultra-deepwater depths may make FLNGs the best option for potential gas resources.

The first FLNG was Petronas' *Satu* with operations beginning in 2016 at the Kanowit gas field offshore Sarawak, Malaysia. In 2019 *Satu* relocated to eastern Malaysia (Sabah) along with a second from Petronas, PFLNG *Dua* (Petronas, 2021). Shell's *Prelude,* located offshore Northwest Australia, is currently the largest FLNG with capacity to produce 3.6 mtpa (Oil and Gas Journal, 2021). Golar's *Hilli Episeyo*, which was the first FLNG from a converted vessel, produces from the

Sanaga and Ebomé fields offshore Cameroon (offshore-mag, 2021b). These are the 4 FLNGs currently in operation with several more proposed, sanctioned, or under construction (Kelleher, 2018).

Passage of H.R.2029 (2015) repealed the export of crude oil. However, the Natural Gas Act of 1938 prohibits the export of natural gas from the U.S. if it poses a threat to national interests. Exemptions can be applied for and obtained from the U.S. Department of Energy. As of April 2020, dual purpose import/export terminals at Cove Point, MD and Elba Island, GA, are operational. Another, at Jacksonville, FL, has been approved by the Federal Energy Regulatory Commission (FERC) but is not currently under construction (FERC, 2021). Large demand/supply differences equating to price differences between domestic and international markets, along with competition from inexpensive, onshore domestic production, would encourage exportation. While subsea completions connected to facilities like spars, or an FPSO, appear the most likely options for development of potential Atlantic OCS oil resources, natural gas production via FLNG remains less certain.

2.6 METHODOLOGY

BOEM implemented several important changes to the 2021 National Assessment to improve the process of assessing geologic plays/AUs and standardizing risking methodologies at the play/petroleum system and prospect/pool level for all four OCS regions. This improved methodology provides a more consistent approach at the regional level and ensures: (1) that component parts are developed using a singular BOEM methodology; and (2) that the aggregation of regional assessments into a national assessment includes components and results that were developed using an aligned corporate approach.

BOEM’s assessors assigned risk to petroleum system components for each AU on the Atlantic OCS. These components include risk factors and appropriate timing that result in a hydrocarbon accumulation. The specific risk components assessed are:

- Hydrocarbon fill;
  - ✓ Presence of a quality, effective, mature source rock, and
  - ✓ Effective expulsion and migration.
- Reservoir;
  - ✓ Presence of reservoir facies, and
  - ✓ Reservoir quality.
- Trap;
  - ✓ Presence of trap, and
  - ✓ Effective seal mechanism.

The outcome of these assessments is summarized in Table 1. The assessed scores are in the Appendix.

U.S. Atlantic OCS

Assessment Unit	Probability of Success		
	Petroleum System	Prospect	Total Exploration
01 Cretaceous & Jurassic Atlantic Marginal Fault Belt	0.340	0.180	0.062
02 Cenozoic - Cretaceous & Jurassic Carolina Trough Salt Basin	0.500	0.340	0.169
03 Late Jurassic - Early Cretaceous Atlantic Carbonate Margin	0.290	0.180	0.050
04 Cenozoic - Cretaceous & Jurassic Paleo Slope Siliciclastic (core)	0.290	0.180	0.053
05 Cenozoic - Cretaceous & Jurassic Paleo Slope Siliciclastic (extension)	0.180	0.120	0.022
06 Cretaceous & Jurassic Blake Plateau Basin	0.290	0.180	0.050
07 Jurassic Shelf Stratigraphic	0.250	0.140	0.035
08 Cretaceous & Jurassic Interior Shelf Structure	0.720	0.140	0.101
09 Triassic - Jurassic Rift Basin	0.390	0.250	0.099
10 Cretaceous & Jurassic Hydrothermal Dolomite	0.240	0.140	0.034

Table 1. U.S. Atlantic AUs with probability of success at the petroleum system (play) and prospect level (pool). The overall chance of success is estimated as a product between these two risk components.

For the 2021 Atlantic resource inventory, BOEM staff used an enhanced reflection seismic database, gravity and magnetic data sets and displays, subsurface well data from existing U.S. and Nova Scotian drilling, supplemented with geochemical data and sea surface slicks identified on updated satellite synthetic aperture radar (SAR) data to constrain the areal extents of the AUs. A global database provides appropriate analog guidance for potential field sizes and hydrocarbon volumes. Taken holistically, these data facilitate a petroleum system approach to define the AUs.

For the purposes of this Atlantic OCS resource inventory, AUs are informally defined by BOEM staff as a single or composite petroleum system and associated hydrocarbon trap(s). This is a modification of the AU definition used by the USGS which describes AUs as consisting of a mappable volume of rock within a petroleum system that encompasses accumulations (discovered and undiscovered) that share similar geologic traits (Charpentier, 2008). Accumulations within an AU constitute a sufficiently homogeneous population such that the chosen methodology of resource assessment is applicable. AUs can be conceptual or established/proven based on the occurrence or postulation of the petroleum system (Klett et al., 2000b; Klett et al., 2005; BOEM, 2021).

Since the 2011 Atlantic Assessment, BOEM has used global analogs for its assessment of the Atlantic AUs. The conjugate Northwest African margin and the Atlantic margin were both explored in the 1980s. Although there was more success there than on the U.S. margin, results from primarily shallow water, shelf-focused exploration were also generally discouraging. In contrast to the exploration moratoria that were imposed on the U.S. Atlantic OCS in the mid-1980s, companies episodically continued to acquire acreage, deep reflection seismic, and drill wells in the offshore areas of the various countries of Northwest Africa. These efforts always used what were considered at the time as state-of-the-art acquisition and processing technology and practices, interpretation techniques, etc. Exploration also took place on the shallow water shelves in other areas of the African and South American Atlantic margin concurrent with exploration conducted in the U.S. Atlantic OCS. Greater success was encountered in Nigeria, Gabon, Cabinda (Angola), Angola, and Brazil than other parts of the African and South American margins. These are not appropriate analogs, however, for the U.S. Atlantic Margin because of mobile substrates.

While regional plate tectonic restorations focus the analog investigation on conjugate Northwest Africa, publicly available geological and geophysical data document and identify other areas whose geological setting and evolution, although not necessarily the age of the formations, are comparable to the U.S. Atlantic Margin. More detailed geologic and petroleum system analyses and evaluation were conducted in those areas; e.g., the South Viking Graben of the U.K. North Sea, the West African and its conjugate South American Transform Margins, and the East African Transform Margin. Literature-based research, government regulatory websites, and Wood McKenzie's PetroView database were the primary resources used to characterize their petroleum system elements, processes, and any associated discovered reserves and resources.

Analogs considered appropriate for this U.S. Atlantic resource inventory were ultimately selected based on similar or equivalent tectonic or structural setting, with comparable petroleum system components, such as source, reservoir, and seal. Environment of deposition, lithology, depth of burial, diagenetic history, porosity and permeability, and trap type also influenced selection. Although a petroleum system of the same age was desirable, geologic age of reservoir, which was previously the sole criteria, was less important. Analogs provided additional data, for example, play area in square mi (mi^2), NFW density (a proxy for prospect density), discovery/pool/field size, discovered pool/field density, estimates of present-day exploration maturity, an estimate of exploration success rate, etc. Consequently, these analogs and their data provide the foundation for this resource inventory.

Since 2007, giant oil and gas fields with reserves and resources of 500 million barrels of oil equivalent (MMBOE) and greater have been discovered in deepwater areas on the Northwest African Margin (Brownfield, 2016; PetroView, 2020) that is conjugate to the U.S. Atlantic Margin, the West African (PetroView, 2020) and South American Transform Margins (PetroView, 2020), and the East African Transform Margin (ENI, 2021; ENI 2022; PetroView, 2020). These U.S. Atlantic OCS analogs, benefitted from modern data, technology, and exploration concepts, during this new phase of exploration in historically underexplored areas. The number and size of discoveries have increased the reserves and resources in our analogs from an estimated ~4.5 BBOE in 2007 to over 36 BBOE for the 2016 resource inventory (BOEM, 2016), to over 50 BBOEs today (PetroView, 2020). This ten-fold plus increase continues to be revised upwards with new discoveries from the Guyana-Suriname basin leading the way (Exxon, 2022).

Prospect (~pool) risk addresses more specific risk scenarios applicable to the probabilities of success on an individual prospect where petroleum system (~play) risk does not exist. Prospect level risks are related to the level of hydrocarbon fill, reservoir, and trap components. Some amount of petroleum system risk was assigned to all Atlantic AUs, which were defined as conceptual for this assessment. Multiple risks exist at both the prospect and play level. The product of these two numbers is the total risk. Total risk accounts for all necessary components of a hydrocarbon accumulation. If a petroleum system were to be established in any AU, the result would be to eliminate that petroleum system risk in that AU with only risk remaining at the prospect level. The result would be that inventoried resources would dramatically increase, typically ~300%, in a conceptual AU whose petroleum system risk is removed (play established). Those potentially higher values are not reflected in this resource inventory.

As part of this 2021 resource Inventory, all petroleum system and prospect level risks were reviewed and modified based on updates to the BOEM-wide risking methodology and the continued evolution of the analogs. The subjective assessment methodology models a range of field/pool sizes on a truncated lognormal distribution populated with analog discoveries. These inputs are restricted with a lower limit of 1 MMBOE, as typical for USGS international assessments (Klett et al., 2000a). The upper limit is usually equal to the largest field discovered in the analog(s), but consideration is given to the exploration maturity of each analog and whether it's reasonable for larger fields to have remained undiscovered. No distributions exceeded the largest analog fields for this assessment. Model volumes outside the upper and lower limits were truncated/removed from the distribution. The distributed volume is sampled over 10,000 trials using BOEM's Geologic Resource Assessment Program (GRASP). The current version of GRASP was adapted by BOEM from the Geological Survey of Canada's Petroleum Resources Information Management and Evaluation System (PETRIMES) suite of programs.

Table 2 reports the size of the Atlantic AUs and the number of OCS blocks included in each. A block pool density number is also derived from the analogs (Table 2). GRASP uses this number along with the risk and acreage to determine pool number for each sampling. The pool sizes are a function of the mean of this lognormal distribution. A final summation of the pool volumes is calculated by GRASP and the results are presented in a percentile table of total BOE, oil, and gas (Table 3). The probability of occurrence is reported as a minimum, mean, and maximum.

U.S. Atlantic OCS

AU	Area		blk/pool density	# Prospects			# Pools			Probability	
	Mi^2	Blocks		Min	Mean	Max	Min	Mean	Max	Gas	Oil
1	7373	819	15	152	303	455	0	21	123	0.8	0.2
2	4923	547	15	54	107	161	0	19	80	0.7	0.3
3	8092	899	20	125	250	375	0	15	105	0.8	0.2
4	16873	1875	15	347	694	1042	0	42	254	0.5	0.5
5	55282	6142	110	233	465	698	0	9	100	0.5	0.5
6	37789	4199	80	146	292	437	0	18	119	0.2	0.8
7	7698	855	15	204	407	611	0	15	125	0.8	0.2
8	2807	312	25	45	89	134	0	9	39	0.8	0.2
9	4481	498	40	25	50	75	0	5	35	0.2	0.8
10	1719	191	50	14	27	41	0	1	17	0.2	0.8

Table 2. AUs from Figure 1, indicating unit size, pool density per block, estimates of pools and prospects (minimum, mean, and maximum), and probable hydrocarbon type for each AU.

3.0 ATLANTIC ASSESSMENT UNITS

Figure 2 shows the areal extent of each AU defined by BOEM in the U.S. Atlantic Region. Descriptions and discussions of each AU will be addressed in the following order:

1. Cretaceous and Jurassic Atlantic Marginal Fault Belt AU
2. Cenozoic–Cretaceous and Jurassic Carolina Trough Salt Basin AU
3. Late Jurassic–Early Cretaceous Atlantic Carbonate Margin AU
4. Cenozoic–Cretaceous and Jurassic Paleo-Slope Siliciclastic Core AU
5. Cenozoic–Cretaceous and Jurassic Paleo-Slope Siliciclastic Extension AU
6. Cretaceous and Jurassic Blake Plateau Basin AU
7. Jurassic Shelf Stratigraphic AU
8. Cretaceous and Jurassic Interior Shelf Structure AU
9. Triassic–Jurassic Rift Basin AU
10. Cretaceous and Jurassic Hydrothermal Dolomite AU.

The first 5 AUs contain nearly 90% of the total estimated UTRR in the U.S. Atlantic OCS. The remaining 5 AUs contain an estimated 10% of the UTRR in the region (Table 3). The Cenozoic–Cretaceous and Jurassic Paleo-Slope Siliciclastic Core and Extension AUs are discussed together.

3.1 CRETACEOUS AND JURASSIC MARGINAL FAULT BELT AU

Confined to the Mid-Atlantic Planning Area, the undrilled Cretaceous and Jurassic Marginal Fault Belt conceptual AU (Figure 5) occurs in a seismically defined area of ~7,400 mi^2 in the updip region of the undrilled Carolina Trough (Figure 2). Water depths in the AU range from approximately 1,000–4,000 ft. Productive analogs to seismically identified features in the AU are located in the updip areas of the onshore GOM Mesozoic basins of East Texas, South Arkansas, and Mississippi-Alabama-Florida (Wendlandt and Shelby, 1948; Sigsby, 1976; Foote et al.,1988; and Halvatzis, 2000). Field sizes, based on current cumulative production in analog fields, range from less than 1 MMBOE to more than 500 MMBOE according to production records from Alabama (Geological Survey of Alabama, State Oil and Gas Board, 2021), Florida (Florida Dept. of Environmental Protection, 2021), and various production sources from Mississippi (including Frew, 1992). Faulting and associated oil and gas traps in this updip setting were recognized along the updip margin of the onshore northern GOM in the early 1900s (Foley, 1926). Subsequently, it was determined that down structural dip salt movement was the primary cause of this faulting and the resulting hydrocarbon traps (Hughes, 1968; Jackson and Wilson, 1982; and Frew, 1992). Dillion et al. (1982) recognized a similar down-to-the basin fault system in the most updip part of the Carolina Trough salt basin and inferred that faulting was caused by seaward salt flow.

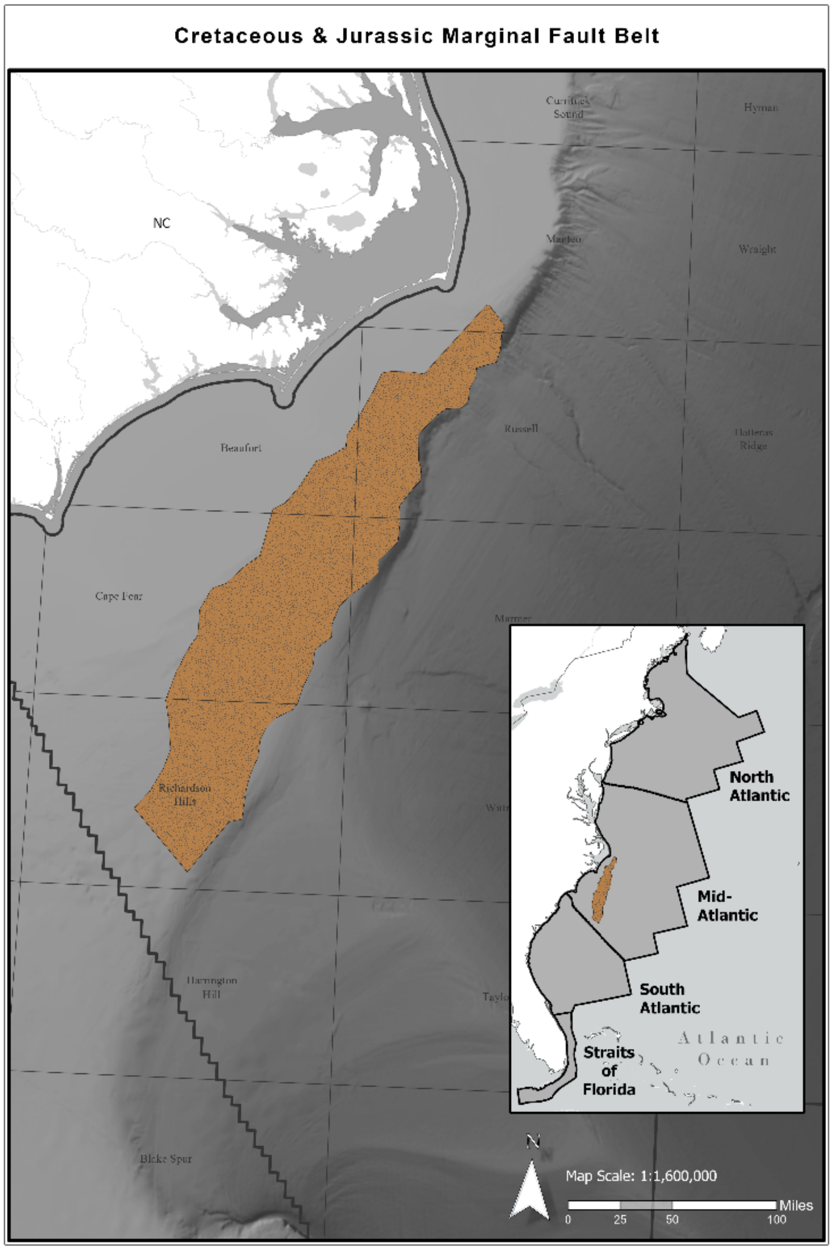

Figure 5. Cretaceous and Jurassic Atlantic Marginal Fault Belt, AU 1 (brown polygon). Protraction area boundaries and names are shown along with state abbreviations. Planning area names are on the inset map and its boundaries are the solid black lines seen on both maps.

For this resource inventory, the enhanced depth-converted, time-migrated, deep-penetration, reflection seismic data often provides better delineation of the faults and the graben system(s), and therefore potential hydrocarbon traps. Source rocks in the analog area are laminated lime mudstones of Oxfordian age. Algal- and bacterially-derived organic matter predominates in the source interval with mean total organic carbon (TOC) values ranging from 2–6% (Sassen et al., 2005). Source rocks have yet to be identified in this undrilled AU. However, indirect hydrocarbon indicators suggest source rocks are present and that generation–expulsion–migration can be interpreted as having occurred. These hydrocarbon indicators include sea surface slick anomalies identified on satellite synthetic aperture radar (SAR) data, and seismically identified possible gas chimneys and fault-related amplitude anomalies in the sedimentary strata adjacent to faults identified by BOEM staff. Anticipated reservoirs are siliciclastics and carbonates in rollover structures, fault traps, or combination structural-stratigraphic traps (Hughes, 1968; Ottmann et al., 1973; Locklin, 1984; Frew, 1992). Regionally sealing lithologies in the updip paleo shelf area may not be as effective as farther basinward due to a higher percentage of sandstone rich intervals. However, regional marine transgressions in the Cretaceous and Jurassic (Figure 3) indicate the presence of potential sealing intervals. On their poster panels, Coleman et al. (2014) show sealing intervals even farther updip, in Pamlico Sound of North Carolina, based on wireline log character.

The Cretaceous and Jurassic Marginal fault belt has a mean of 947 MMBOEs (Table 3) due to a good block pool density (Table 2). It has an average geographical size (Table 2) with a chance of success that is also in the middle at 6.2% (Table 1). The pool distribution from its analogs is typical but with a higher limit on the upper truncation. This indicates the possibility for larger pools to be discovered and positively influences the overall UTRR.

BASIN	**2021 Undiscovered Technically Recoverable Resources (UTRR)**								
	UTRR Oil (Bbbl)			UTRR Gas (Tcf)			UTRR BOE (Bbbl)		
Assessment Unit	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Atlantic OCS	**0.644**	**4.312**	**9.938**	**5.943**	**34.085**	**70.102**	**1.701**	**10.377**	**22.412**
1. Cretaceous & Jurassic Atlantic Marginal Fault Belt	0.000	0.188	0.959	0.000	4.263	16.083	0.000	0.947	3.820
2. Cenozoic–Cretaceous & Jurassic Carolina Trough Salt Basin	0.000	0.511	1.910	0.000	6.709	17.955	0.000	1.704	5.104
3. Late Jurassic–Early Cretaceous Atlantic Carbonate Margin	0.000	0.183	0.477	0.000	4.054	20.045	0.000	0.904	4.043
4. Cenozoic–Cretaceous & Jurassic Paleo Slope Siliciclastic (core)	0.000	2.391	14.227	0.000	13.400	42.157	0.000	4.775	21.728
5. Cenozoic–Cretaceous & Jurassic Paleo Slope Siliciclastic (extension)	0.000	0.531	2.276	0.000	2.891	24.957	0.000	1.045	6.716
6. Cretaceous & Jurassic Blake Plateau Basin	0.000	0.138	0.636	0.000	0.192	0.764	0.000	0.172	0.772
7. Jurassic Shelf Stratigraphic	0.000	0.057	0.293	0.000	1.269	6.612	0.000	0.283	1.469
8. Cretaceous & Jurassic Interior Shelf Structure	0.000	0.041	0.179	0.000	0.929	1.700	0.000	0.207	0.482
9. Triassic–Jurassic Rift Basin	0.000	0.236	1.143	0.000	0.329	0.266	0.000	0.295	1.190
10. Cretaceous & Jurassic Hydrothermal Dolomite	0.000	0.036	0.314	0.000	0.050	0.018	0.000	0.044	0.317

Table 3. UTRR by AU for oil, gas, and total in BOE. Some total mean values may not equal the sum of the component values due to independent rounding.

3.2 CENOZOIC–CRETACEOUS AND JURASSIC CAROLINA TROUGH SALT BASIN AU

The conceptual Cenozoic–Cretaceous and Jurassic Carolina Trough Salt Basin (CTSB) AU (Figure 6) is located downdip (basinward) from the Cretaceous and Jurassic Marginal Fault Belt AU (Figure 2). This AU is undrilled, and covers an area of nearly 5,000 mi^2, entirely within the

Mid-Atlantic Planning Area. Present-day water depths in this AU range from approximately 8,000 ft to greater than 9,000 ft. Resources associated with the Late Jurassic–Early Cretaceous Carbonate Margin AU that bisects the area are assessed separately.

Although source rocks have yet to be identified in this AU, they can be inferred by sea surface slicks identified using SAR data (NPA, 2018), chemosynthetic communities, methane venting at the sea floor, and reflection seismic data (Paull et al., 1995; Paull et al., 1996; Taylor et al., 2000; Ruppel, 2008). Siliciclastic reservoirs are interpreted to be the primary targets, although carbonates deposited in high-energy environments may also occur. The reservoir element of the petroleum system has not been confirmed by drilling. Therefore, although regional correlations suggest that reservoirs may occur, they remain a risk factor. Vertical salt movement is interpreted to provide cross-stratal migration conduits connecting deeper, mature oil and gas source rocks with younger reservoirs.

Using 2D seismic reflection data and side-scan sonar data, between 25 and 30 salt "diapirs" have been interpreted in the Carolina Trough salt basin (Dillon et al., 1982; Popenoe, 1984; Carpenter and Amato, 1992). The exact number of salt structures interpreted depends on the volume and quality of seismic data available to delineate these salt structures and the confidence level of the interpreter.

No information is provided in Dillon et al. (1982), Popenoe (1984), or Carpenter and Amato (1992) regarding the processing sequence that was applied to the reflection seismic data they used. This is a critical point, because it is not known what percentage of these data, if any, was migrated. The data used by those authors are displayed in the time domain except for Figure 21 of Dillon et al. (1982), which is noted as being depth-converted. The lack of information on processing is significant, because 2D seismic data imaging is substantially improved by migration which attempts to put reflected energy into its proper location. Depth-conversion of the seismic data also improves its imaging. In the case of the U.S. Atlantic OCS 2D seismic data set, improved, accurate imaging is especially important in areas where the present-day water bottom dips steeply on the continental slope, and correspondingly the water depth increases substantially over a short distance. In areas of steep dip, 2D seismic data is generally processed with insufficient velocity analyses to accurately image the structure of the area. Yilmaz (2001) provides reasons to convert seismic information from time to depth and information on the techniques used.

Unfortunately, because of the steep, near vertical nature of virtually every interpreted salt body, even the best-acquired and processed 2D seismic reflection data cannot accurately depict their geometry. This is because the 2D data are recorded in a single vertical plane, rather than as an infilled volume or cube of data as is done in 3D seismic acquisition and processing. With a 2D seismic line, it is not always possible to determine where the reflected energy on the line is originated, either in or out of the plane of the data, and how far away. Although multiple closely spaced 2D lines can improve the definition of a feature, there are still geometric issues related to migration of the reflectors in the single vertical plane of the data. 3D seismic data provides a more precise (although still not perfect) salt body depiction. However, no 3D data have ever been acquired in this AU. Therefore, the exact location, size, and geometry of these features in this AU are subject to some uncertainty.

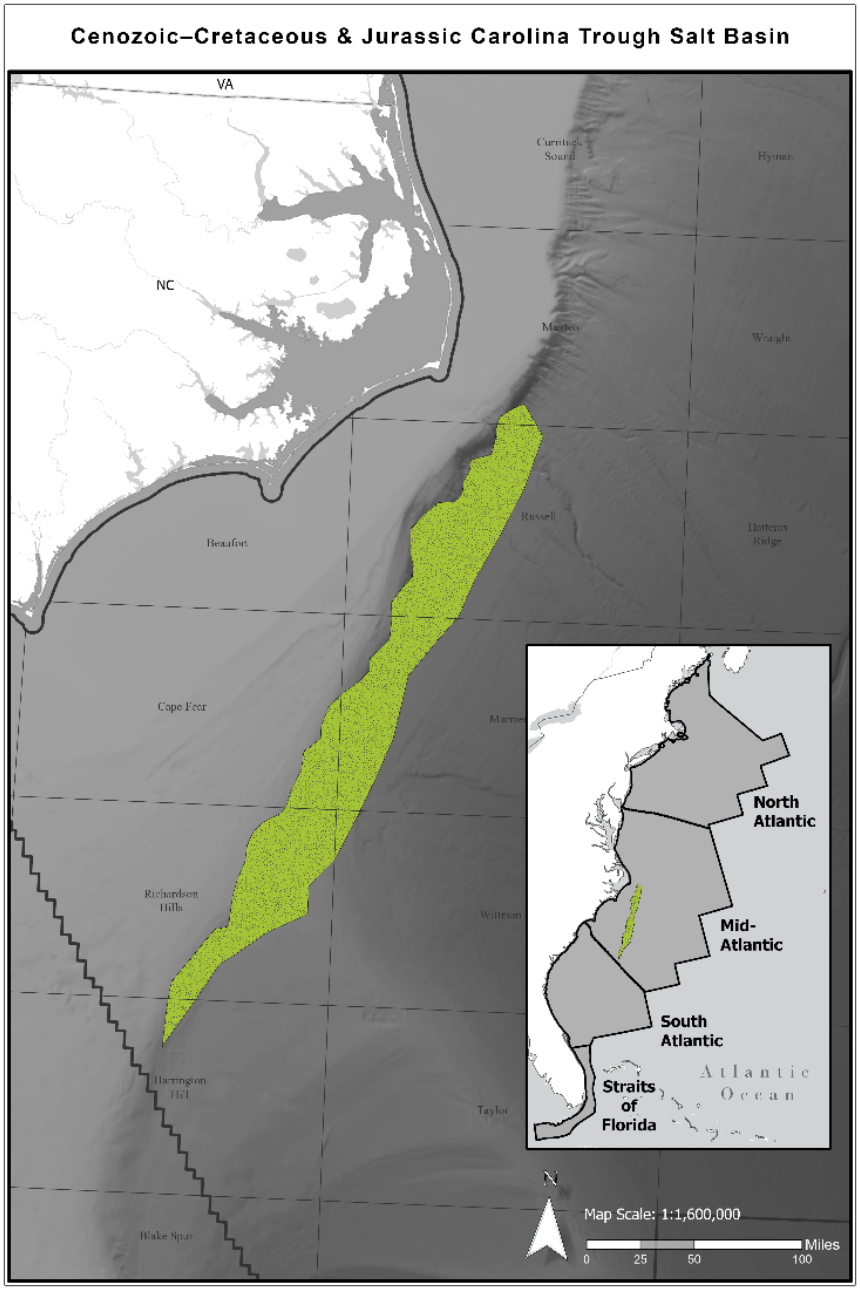

Figure 6. Cenozoic–Cretaceous and Jurassic Carolina Trough Salt Basin, AU 2 (green polygon). Protraction area boundaries and names are shown along with state boundaries and abbreviations. Planning area names are on the inset map and its boundaries are the solid black lines seen on both maps.

The "regional" 2D seismic grid available to the BOEM throughout much of this AU ranges from ~1.25 to ~3.25 mi in a "dip" (approximately NW–SE) direction, and from ~3 to ~7 mi in a "strike" (approximately NE–SW) direction. In some cases, subsequent surveys were acquired on grids oriented slightly differently. As a result, the reflection seismic data density grid on some salt features is ~1 mi or less. Most of the salt bodies interpreted by BOEM staff for this resource inventory are controlled by two or more 2D seismic lines. Those lines, although 2D, have been depth-converted and time-migrated.

Although subject to considerable error, the 2D seismically identified area of individual salt bodies generally ranges between a few square miles (mi^2) and >15 mi^2 (Popenoe, 1984; Carpenter and Amato, 1992). These size ranges are confirmed by the more recent BOEM interpretations of depth-converted, time-migrated versions of the data. The geometry of these structures is somewhat speculative because of the imaging issues associated with the 2D reflection seismic data.

Several salt bodies have bathymetric expression, either reaching the sea floor or being close enough to deform it. Because of possible trap breaching, the crests of these salt bodies are interpreted to be less prospective due to trap integrity than their flanks. Deeper salt bodies, such as those more than 5,000 ft below the sea floor may provide hydrocarbon traps on their crests or their flanks. The largest salt bodies would be preferred targets because of their potential for larger hydrocarbon traps. The deep waters in this AU would impart higher exploration and development costs. Several important questions with respect to geologic interpretation remain: Are the depicted salt bodies connected to autochthonous salt or are they detached? Are some of the salt bodies actually high-angle toe thrusts? Are there overhangs of salt under which prospective hydrocarbons traps may exist? Are there salt features near the paleo carbonate margin?

The Northwest African conjugate margin Mauritania–Senegal–The Gambia–Guinea Bissau–Conakry (MSGBC) basin, contains similar salt-related structures such as diapirs, toe thrusts, detached salt bodies, etc., that are productive and prospective (Brownfield, 2016; Maier, 2006) making the area an excellent analog for this AU. Additionally, the two regions have a shared geologic history as conjugate margins separated during the breakup of Pangea, with syn-rift Triassic to Early Jurassic evaporites that would later form the salt structures common to both. However, the Albian (Early Cretaceous) and Late Cretaceous-aged sources and younger siliciclastic reservoirs of MSGBC (USGS Senegal, 2016) were deposited after several hundred mi of drift separated the North American and African plates (Blakey, 2020). Any potential Jurassic source rocks or carbonate reservoirs would have been earlier in the post-rift phase with only a few hundred mi of separation between the plates (Blakey, 2020). The potential for syn-rift lacustrine source rocks when the areas were still adjacent also exists. This makes the great successes at MSGBC highly prospective for the CTSB. Analog resources came from Wood Mackenzie's PetroView database and operator reports. Using the selection criteria for analogs described in the METHODOLOGY, those selected for this AU resulted in a range of discovery size from ~4 MMBOE to 890 MMBOE and totaled nearly 7.5 BBOE (PetroView, 2020). Field size distribution was truncated at 500,000 MMBOE for the high end, as was the case for the 2016 assessment. The lower limit was 1 MMBOE just like all Atlantic AUs.

The CTSB has a mean of 1.704 BBOEs giving it the second largest UTRR (Table 3). It has a good block pool density (Table 2) and the best overall chance of success at 16.9% (Table 1). Its acreage is less than the median (Table 2), but its analogs contain numerous large fields allowing for the potential discovery of similarly large pools within the CTSB.

3.3 LATE JURASSIC–EARLY CRETACEOUS CARBONATE MARGIN AU

The Late Jurassic–Early Cretaceous Carbonate Margin AU (Figure 7) of the U.S. Atlantic OCS of eastern North America contains shallowing-upwards sequences recording the progradation and aggradation of the Abenaki platform margin during that time. Although deeper, older parts of this carbonate margin complex (Prather, 1991) may be prospective, the youngest, most basinward bank edge, generally represented by the Baccaro Member of the Abenaki Fm, is interpreted to have the highest potential (Kidston et al., 2005; Offshore Energy Research Association, 2011). Seismic and subsurface data offshore Nova Scotia identifies this prospective bank edge as a variable, narrow zone 9–15 mi wide. In the U.S. Atlantic OCS, seismic data and a limited number of wells suggest that the conceptual Late Jurassic–Early Cretaceous Carbonate Margin AU, a continuation of a prospective belt offshore Nova Scotia, is also a narrow band, typically averaging less than 10 mi wide. Kidston et al. (2005) documented along-strike changes in the geometry of the Abenaki carbonate margin offshore Nova Scotia. From northeast to southwest, the margin evolved from a progradational, gently dipping ramp-like margin with interfingering carbonate and clastic facies, to a steeper sigmoidal bank margin, to an eroded margin, and a faulted/eroded margin (Kidston et al., 2005). Seismic data in the U.S. Atlantic OCS also illustrates changes in margin geometry along strike. Extending from the U.S.–Canadian border through the North, Mid-, and South Atlantic Planning Areas towards The Bahamas (Figure 2), this AU covers an area of ~8,100 mi2 in water depths from ~3,500–6,500 ft.

Deep Panuke, a 1999 natural gas discovery on the shallow water shelf offshore Nova Scotia, is the analog for this AU. The field, delineated with 12 wells, is ~12 mi long and ~1 mi wide. Wells in the reservoir contained 33–330 ft of dry gas pay and had a common gas-water contact. Five wells were tested, with the average test being >50 MMCFG per day. Dolomitized, fractured reservoirs at Deep Panuke are associated with the Late Jurassic Abenaki Fm (Baccaro Member), that EnCana (2006) informally designated as the Abenaki 4 and 5 carbonate margin (Figure 3) in reefal and reef-adjacent depositional environments (Kidston et al., 2005; Wierzbicki et al., 2006; Eliuk, 2010). Prior to the discovery, Harvey (1993) and Harvey and Macdonald (1990 and 2012) used seismic and well data to model, recognize, and identify porosity in the Abenaki at the future location of Deep Panuke, delineating and de-risking reservoir occurrence.

Conjugate to Nova Scotia, limited exploration for equivalent carbonates has taken place offshore Morocco. A biodegraded heavy (10°–15° API) oil discovery was made in 1969 in porous dolomitic limestone intervals (karstified?) at Cap Juby on the Moroccan margin. Recoverable reserves at Cap Juby have been estimated at 40–70 MMbbl (Kidston et al., 2005). A more recent attempt by Cairn Energy PLC (now Capricorn Energy PLC) et al. to locate, extend, and define the area of better oil quality in the Middle Jurassic below the Late Jurassic heavy oil was unsuccessful (Cairn Energy PLC, 2014).

Geochemical analyses of condensates in the Deep Panuke field analog (Zumberge, 2010) indicate that their source rock contained a mixture of algal and terrestrial organic matter. Biomarkers are consistent with a paralic-deltaic marine shale source of Jurassic age, similar to the Verrill Canyon Fm, which is the basinward facies equivalent of the Abenaki (Figure 3) that ranges in age from Early Jurassic to Early Cretaceous (Wade and MacLean, 1990). Terpane/sterane thermal maturity ratios indicate Deep Panuke condensates are much more mature than Panuke and other Scotian Shelf condensates and oils, with multiple periods of charging, consistent with possible gas washing (Zumberge, 2010). Diamondoid methyladamantane/methyldiamantane thermal maturity ratios also show Deep Panuke condensate more mature than Panuke oils with reservoirs in overlying, younger (Early Cretaceous) siliciclastic reservoirs (Zumberge, 2010). Top seals for the reservoir at Deep Panuke are overlying, nonporous limestones of the informal Abenaki 6 and 7 (EnCana, 2006; Weissenberger et al., 2006).

Before the Deep Panuke discovery, NFW drilling for Abenaki carbonate margin traps took place offshore Nova Scotia and the U.S. Atlantic OCS. Pre-discovery of Deep Panuke, Kidston et al. (2005) classified seven wells as bank edge NFWs and nine other NFWs as having targeted carbonates behind, or siliciclastics in front of, the bank edge. All were dry holes. Shell (operator), Amoco, and Sun Oil Co. drilled three wells (Wilmington Canyon (WI) 586-1, WI 587-1, and WI 372-1) during 1983–1984 in the southern Baltimore Canyon Trough (BCT) in the current North Atlantic Planning Area of the U.S. Atlantic OCS (Figure 4 and Figure 8).

The Shell et al. wells in the BCT targeted various potential carbonate margin trap types in present-day water depths ranging from 5,838 to 6,952 ft. Despite areally large structural/stratigraphic closures with significant vertical relief and porous limestone reservoirs, no significant hydrocarbon shows were encountered in any of the wells (Prather, 1991). All the wells were abandoned as dry holes with minor gas indications recorded by mud logging equipment.

The wells drilled offshore Nova Scotia and by Shell et al. in the BCT were similar enough to apply the same formation terminology and an analogous vertical depositional progression, including a regional Berriasian–Valanginian drowning event. A significant difference was that the wells in the BCT encountered strata richer in carbonate sand. Two of the BCT wells, WI 586-1 and WI 587-1 (Figure 8), were drilled behind the margin edge where reef-flat sands would be more commonly expected (Eliuk and Prather, 2005). Muddier facies with more reef frame-builder-rich beds are encountered on the Nova Scotia margin (Eliuk and Prather, 2005). Most of NFWs in Nova Scotia were located nearer the steep margin between the “double-flexure”, or slightly down-ramp from a distally steepened ramp (Eliuk, 1978; Eliuk and Prather, 2005; Wierzbicki et al 2006).

In this AU, a variety of carbonate lithologies; limestone, dolomitized limestone, or dolostone, the latter probably due to secondary alteration (as is the reservoir at Deep Panuke), could be anticipated to provide reservoirs. Any overlying impermeable carbonates or shales could provide top seals. Depending on location within this region-spanning AU, any or all petroleum system elements and processes may be risks. Additionally, vertical cross-stratal migration conduits are likely to be necessary to connect the mature source rocks with shallower, younger reservoirs.

Fluid Inclusion Technologies, Inc. (FIT), a Schlumberger company, provided insights into the petroleum systems in this AU as part of a fluid inclusion stratigraphic project that incorporated the WI 587-1, WI 372-1, and WI 586-1 wells (Figure 4 and Figure 5). The WI 587-1 (Figure 4 and Figure 5) was interpreted by Eliuk and Prather (2005) to have tested an areally extensive region of near-shelf margin domal or plateau-like features. These were slightly argillaceous, chalk or chalk-like deposits of high porosity but low permeability, with little or no apparent age gap between the chalky limestone and the overlying shale. These "mesas" were interpreted by Eliuk and Prather (2005) as deep-water (not slope) constructional features. A similar sponge reef at the top of the shelf-edge in the Artimon Member of the Abenaki Fm in Demascota G-32 offshore Nova Scotia is interpreted to have formed in water depths between ~330 and 660 ft (Eliuk, 1978). Although at WI 587-1, Eliuk and Prather (2005) interpret more rapid pelagic and benthic sedimentation.

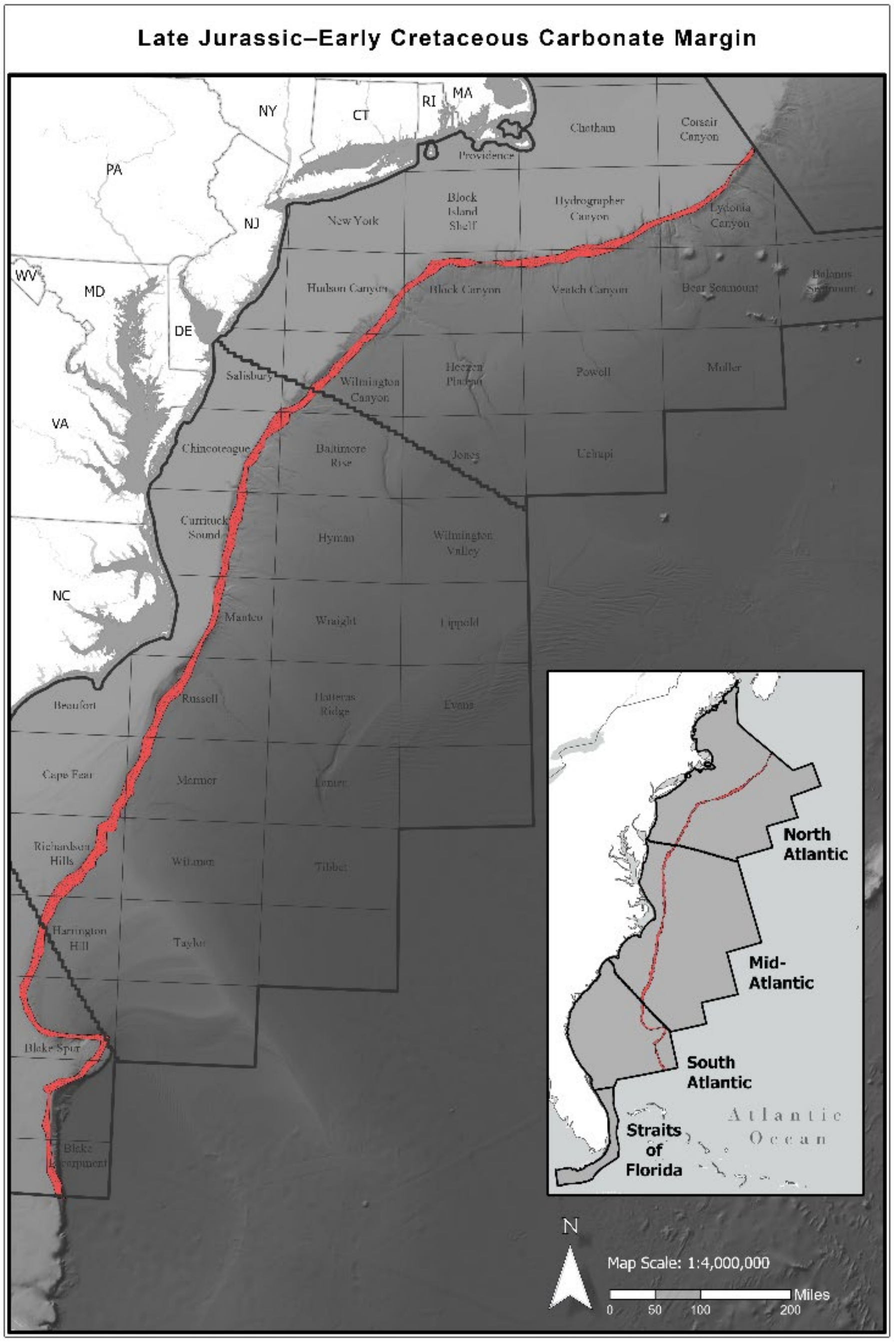

Figure 7. Late Jurassic–Early Cretaceous Carbonate Margin, AU 3 (red polygon). Protraction area boundaries and names are shown along with state boundaries and abbreviations. Planning area names are on the inset map and its boundaries are the solid black lines seen on both maps.

Fluid Inclusion Technologies, Inc. (2015a) performed a fluid inclusion stratigraphy (FIS) analysis on 251 cuttings samples from 8,560–14,500 ft in the WI 587-1. Indications of anomalous dry gas below 11,020 ft with increases in C1-C4 species with depth denote a possible maturation profile within largely tight rock. From 11,400–12,680 ft gas, wet gas, and intermittent sulfur species of probable thermal origin deeper are interpreted. This interval is interpreted as the Baccaro Member of the Abenaki Fm (Figure 3), which also contains the productive interval from Deep Panuke (Wierzbicki et al., 2006). Rare, white-fluorescent oil inclusions are identified at 12,530 ft, suggesting a migration event. Below 12,860 ft dry gas anomalies and minor sulfur species of probable thermal origin indicate mature gas migration from greater depth.

Farther basinward, on the edge of the Abenaki carbonate margin, the WI 372-1 well (Figure 4 and Figure 8) tested the landward side of a high-relief build-up (Eliuk and Prather, 2005). The age of the shallow-water carbonates in WI 372-1 is younger, Early Berriasian, than similar facies in the more shelfward WI 587-1 (Eliuk and Prather, 2005) (Figure 8). Shallow-water carbonate sedimentation continued at the margin in the area of WI 372-1 resulting in a 'pinnacle-like' feature, a *keep-up* carbonate interpreted to represent a relatively rapid rate of carbonate accumulation (Sarg, 1988), after which deposition had ceased in the updip area of WI 587-1 (Eliuk and Prather, 2005).

No significant shows were noted by conventional petrophysical analysis, although the chromatograph on the mud log indicates some minor occurrences of methane, ethane, and propane. Potential source rocks in the well were found to be organic-lean, gas-prone, and thermally immature. The well was abandoned as a dry hole. FIS analysis was performed on a total of 143 cuttings samples from 9,170–11,631 ft in WI 372-1 (Fluid Inclusion Technologies, Inc., 2015b) (Figure 4 and Figure 8). Rare, yellow-fluorescent, moderate gravity oil inclusions, and rare, blue-fluorescent, upper-moderate gravity light oil or condensate inclusions, indicate minor migration events. Additionally, possible non-fluorescent gas inclusions were identified at all depths and could indicate the presence of a separate gas charge in the section.

These data are encouraging because Prather (1991) noted downlap of the upper Albian sequence boundary (LKI) on the upper Berriasian sequence boundary (LKIII) at the WI 372-1 location. This implied that the Berriasian shelf-margin carbonates were exposed locally on the sea floor, or possibly the sea surface, for roughly 46 million years before a top seal of sufficient thickness to be resolved seismically was deposited (Prather, 1991).

At Deep Panuke, the top seal for the Abenaki 5 reservoir consists of non-porous, argillaceous carbonates and shales of the overlying Abenaki 6 and 7 cycles (EnCana, 2006; Weissenberger et al., 2006), not overlying younger downlapping shales. The Shell et al. WI 586-1 (Figure 4 and Figure 8) was drilled landward (~3.25 mi northwest) from the WI 587-1. Its primary objective was a thin carbonate of Early Cretaceous age located over a prograding "clastic wedge" as identified and described by Edson and Carpenter (1986). Eliuk and Prather (2005) describe the feature as a landward "flexure" with ~500 ft of relief, with an area of approximately 70 mi^2 within fault and simple closure (Prather, 1991). The shallow objective was at a depth of ~9,000 ft or just ~3,200 ft below the mudline and therefore immature for thermal hydrocarbon generation. The well encountered the expected late Early Cretaceous margin high-energy facies (Edson and Carpenter, 1986).

Although no significant shows were identified during mud logging, the chromatograph recorded traces of methane, ethane, and propane. Conventional cores and petrophysical analysis of wireline well logs also failed to find any significant shows (Nichols, 1986). A conventional core taken in the interval had good porosity, ranging from 10–24% (averaging ~17% over the 22 ft of recovered core). Permeability was fair–poor, ranging from 0.042–12.2 millidarcies (mD), averaging 2.45 mD (Cummings, 1984). No obvious cross-stratal migration conduits between this shallow objective and deeper more thermally mature zones are obvious on seismic. The underlying Early Cretaceous–Late Jurassic carbonate shelf is predominantly limestone with intervals of terrigenous siliciclastic material, both as interbeds and as disseminated sand, silt, and clay (Edson and Carpenter, 1986). Although no significant shows were encountered in this interval, traces of methane through butane were encountered in the FIS analysis (Fluid Inclusion Technologies, Inc., 2015d, e), suggesting thermogenic gas.

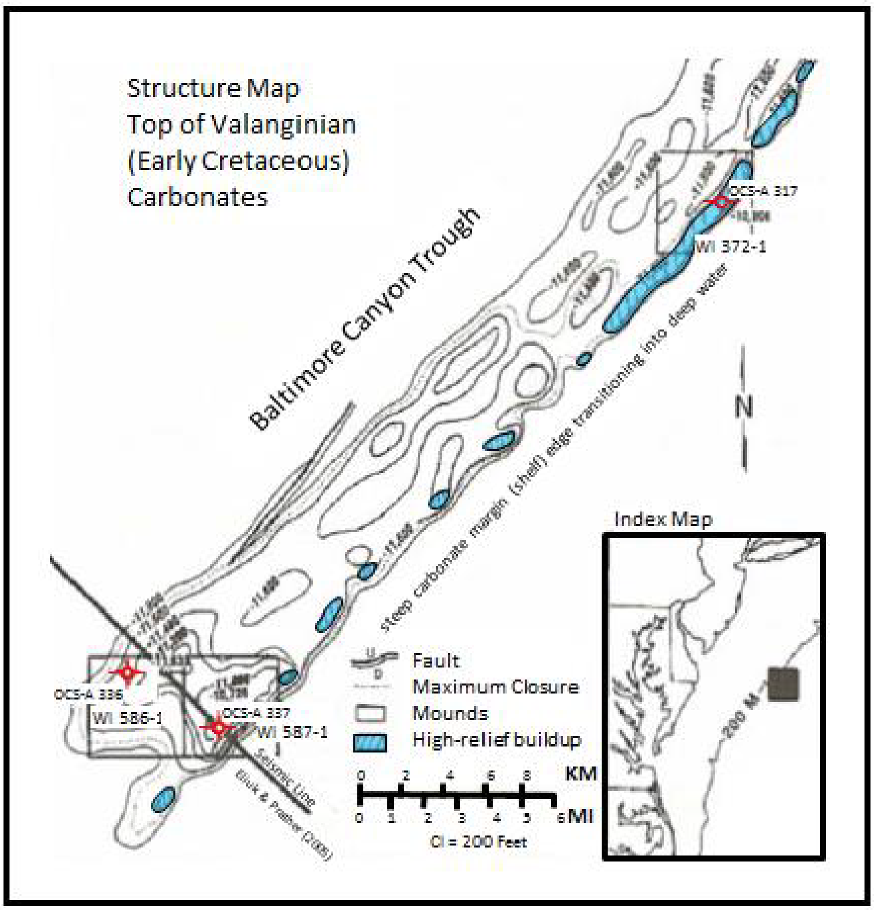

Figure 8. U.S. Atlantic OCS, Baltimore Canyon Trough, structure map top of the Valanginian (Early Cretaceous) carbonates showing location of WI 372-1, WI 587-1, and WI 586-1 wells discussed in text (modified after Eliuk and Prather, 2005).

FIS analysis was performed on a total of 382 drill cutting samples from 7,970–16,000 ft in WI 586-1 (Fluid Inclusion Technologies, Inc., 2015d). Conventional geochemical analysis determined low source rock potential and the stratigraphic section is thermally immature to a depth of ~12,000 ft. Below that depth, palynomorph colors suggest borderline maturity (Miller et al., 1986; Fry, 1986). Dry gas spectra with trace wet gas species encountered below 9,060 ft., and dry gas anomalies with acetic acid below 11,650 ft, could be indicative of nearby oil or condensate. Trace sulfur species of probable thermal origin were also seen in the deeper section. The remainder of the analyzed section (14,300–16,000 ft) contained strong wet gas to gas-condensate responses that initially built with depth to about 14,800 ft, possibly indicating a diffusion profile through tight rock. Migration events are suggested.

Microthermometric analysis was performed at 14,460 ft and 15,480 ft by Fluid Inclusion Technologies, Inc. (2015e). At 14,460 ft, homogenization temperatures from aqueous inclusions range from 84–109˚C, suggesting maximum burial temperature near 109˚C. For the 15,480 ft sample, analysis indicates a maximum burial temperature of 106˚C. Current burial temperatures are estimated to be about 70˚C and 75˚C for each sample respectively. The higher past thermal maturity is also seen in the moderate amount of dead hydrocarbon stain for this sample. For a more detailed analysis on the FIS and microthermometry for these wells, see BOEM's 2016 Atlantic Assessment (BOEM, 2016).

Preservation of trapped hydrocarbons related to a combination of seal presence, lithification, and integrity represents a significant risk factor in this AU. Modeling of possible hydrocarbon trap charge and structural development must be evaluated on a prospect-by-prospect basis. An intra-Abenaki top seal, as at Deep Panuke, makes identifying and quantifying seal risk in this AU difficult. BOEM staff has identified possible hydrocarbon indicators on seismic data in parts of this AU. These include flat spots within the shelfward dipping carbonate margin beds, and amplitude anomalies similar to those identified pre-discovery at Deep Panuke by Harvey (1993), and Harvey and Macdonald (1990 and 2012). Where present, these may help better assess prospect risk.

Deep Panuke, the single field in Nova Scotia that has been used as the analog (Wierzbicki et al., 2006), is now plugged and abandoned. The field came on-line in August 2013 and was shut in May 2018. Over the nearly 5 years it produced 147 billion cubic feet of gas (BCFG) or just a quarter of the operator's mean estimate of 632 BCFG. This reduction led to a decrease in 2021 UTRR estimates compared to the previous Atlantic Assessment for the AU (BOEM, 2016).

The Late Jurassic–Early Cretaceous Carbonate Margin has the 5th largest UTTR with a mean of 904 MMBOEs (Table 3). Its acreage is low at 55.0% of the average but it has a high block pool density (Table 2) and an average chance of success of 5.0% (Table 1). Importantly, almost all the fields from the distribution are greater than 10 MMBOEs leading to larger pool sizes in the modeled output.

3.4 CENOZOIC–CRETACEOUS AND JURASSIC PALEO-SLOPE SILICICLASTIC CORE AND EXTENSION AUs

The Cenozoic–Cretaceous and Jurassic Paleo-Slope Siliciclastic Core AU (Figure 9) is interpreted to occur in the North and Mid-Atlantic Planning Areas. The more distal Cenozoic–Cretaceous and Jurassic Paleo-Slope Siliciclastic Extension AU (Figure 10) is recognized in the North, Mid-, and South Atlantic Planning Areas (Figure 2). Both AUs are conceptual.

The location of the U.S. Atlantic carbonate margin generally progrades basinward and aggrades with time, becoming younger and shallower basinward. Consequently, it is possible that many of the margins have a paleo-slope siliciclastic depositional system downdip (basinward) from it. The "core" AU is closer to its various carbonate margins and the "extension" AU is more distal (Figure 2). The AU locations depicted in Figure 2 are based on the position of the youngest carbonate margin. These are the most basinward AUs of the U.S. Atlantic OCS. Present-day water depths for these AUs range from approximately 4,500–8,000 ft (core) to approximately 8,500–10,500 ft (extension). Coarse-grained lithofacies of siliciclastic turbidites and mass flow deposits on the paleo-slope and basin floor, where present, could constitute reservoir facies. Grant et al. (2013), Erlich and Inniss (2014), Hodgson and Rodgriguez (2015), and others have described comparable deep and ultra-deepwater plays, often using similar differentiating characteristics to those used by the BOEM to define its "core" and "extension" as separate AUs.

Reservoirs in the "core" AU area (Figure 9) are siliciclastics deposited on paleo-slope and uppermost paleo-basin floor settings (Figure 3). These reservoirs potentially represent a range of depositional geometries and types including channel fill, amalgamated channel fill, and relatively small-scale sheet sands and lobes deposited as point bar, levee overbanks and crevasse splays, and slope fans (Grant et al., 2013). Traps are both combination structural-stratigraphic and stratigraphic. Identifying and delineating potential reservoir and updip sealing mechanisms in both AUs is often difficult (Grant et al., 2013; Hodgson and Rodgriguez, 2015; and Sayers, 2015). The "core" AU comprises approximately 17,000 mi^2. Several analogs are considered applicable. Most appropriate for the combination structural-stratigraphic rollover traps are the Jurassic-age siliciclastic reservoirs of the South Viking Graben of the UK North Sea (Turner and Allen, 1991; Branter, 2003; Brehm, 2003; Fletcher, 2003a and b; Gambaro and Donagemma, 2003; Hook et al., 2003; Wright, 2003). Other analogs for structural-stratigraphic and stratigraphic traps in the "core" AU include the Cretaceous-age reservoirs of deepwater fields of the Tano basin (offshore Ghana and Côte d'Ivoire) and the Sierra-Leone-Liberian basin (offshore Sierra Leone and Liberia) of the African Transform Margin (Jewell, 2011), the passive margin of the Guyana-Suriname basin, and the Woodbine fields of the southern part of the onshore East Texas basin.

Farther basinward, in the "extension" AU (Figure 10), hydrocarbon traps are interpreted to be primarily stratigraphic. In this AU, unconfined basin-floor fans, stacked/amalgamated channels and lobes, and amalgamated sand-rich channels are typical (Grant et al., 2013). This AU is estimated to encompass approximately 55,000 mi^2. Appropriate analogs include fields and discoveries from the South Viking Graben (United Kingdom sector, Fletcher, 2003b), the West African, South American, and East African Transform Margin (Jewell, 2011), and the onshore Texas downdip Woodbine (Bunge, 2011).

Although these AUs have similar petroleum system elements and processes they are considered independent rather than dependent. Their depositional slope types/profiles favor different reservoir and trapping configurations (Grant et al., 2013; Hodgson and Rodgriguez, 2015), source rock development, organic matter type, and petroleum system processes (trap formation, generation–expulsion–migration–accumulation, critical moment, and preservation time). These characteristics vary as a function of paleo location, overburden thickness or present burial depth, and heat flow.

The analogs used for these AUs have seen their total reserve/resource volumes grow over ten-fold since 2007 (when BOEM staff researched and developed the first version of this analog database) from ~4.5 BBOE to over 50 BBOE. The field/discovery analogs used in determining field/pool size in these AUs were a mixture of producing fields, some of which have been fully or nearly depleted, and discoveries in various stages of delineation, final investment decision (FID), front-end engineering design (FEED), or development. Data sources have included production and reserves data from Wood Mackenzie's PetroView, the United Kingdom, the Texas Railroad Commission, various country reports of field/discovery size, as well as industry and company reports and presentations. The analogs used by BOEM staff contain reserves/resources ranging from 1 MMBOE to +1 BBOE, with over approximately 50% of those exceeding 200 MMBOE with notable discoveries in Guyana and Tanzania since the 2016 Atlantic Assessment (PetroView, 2020).

A significant data point for potential reservoir and source rocks is deep sea drilling project (DSDP) 603B (Figure 4) that is located ~250 mi east of Cape Hatteras, North Carolina. At DSDP 603B, variable source rock intervals of Late and Early Cretaceous age have TOC values between 0.57 and 20.4%. Type II / II-III and III kerogen, with Type III predominating, were described (Herbin et al., 1987; Katz, 1987; Stein et al., 1989). Typically, source rocks, unless there are large quantities of sulfur present, are considered immature at vitrinite reflectance (Ro) values of less than 0.6 (Peters and Cassa, 1994). The organic matter in DSDP 603B sediments, in so far as it is not recycled, is immature, increasing only slightly from a vitrinite reflectance (Ro) of ~0.20% in the shallowest Tertiary sample studied to about Ro 0.30–0.35% in the Barremian to Valanginian (Rullkötter et al., 1987). Rock-eval pyrolysis T_{max} values from the well confirm the immature nature of these potential source rocks. The threshold needed for maturity is a pyrolysis T_{max} greater than ~435°C (Peters and Cassa, 1994). Within Tertiary strata, pyrolysis T_{max} values increase from about 38O°C to about 415°C. In Cretaceous age sediments, most are close to 425°C (Rullkötter et al., 1987). The petroleum system process of generation–expulsion–migration–accumulation has not taken place this far basinward because of the lack of sufficient overburden and/or heat flow. Therefore, the downdip (southeastern) boundary for the "extension" AU must occur shoreward (westward) from DSDP 603B.

Dickson and Christ (2011) developed a methodology for approximating a line beyond which the onset of maturity for hydrocarbon generation may occur. Essentially, sediment thickness and regional heat flow data can be used to determine when a sedimentary package would enter the hydrocarbon generating window. They also determined that at a sediment thickness of more than ~13,000 ft, the deepest (approximately 3,300 ft) of those sediments would be mature for oil generation. The location of source rocks within that sediment interval, the organic matter type, and its richness remain unknown. The organic matter type, its kinetics, and level of thermal stress determine the predominant hydrocarbon type(s) generated and their percentages. No inferences regarding the type or volume of oil and/or gas generated-expelled-migrated can be made with any reasonable degree of confidence, because these are unknown throughout wide areas of these AUs.

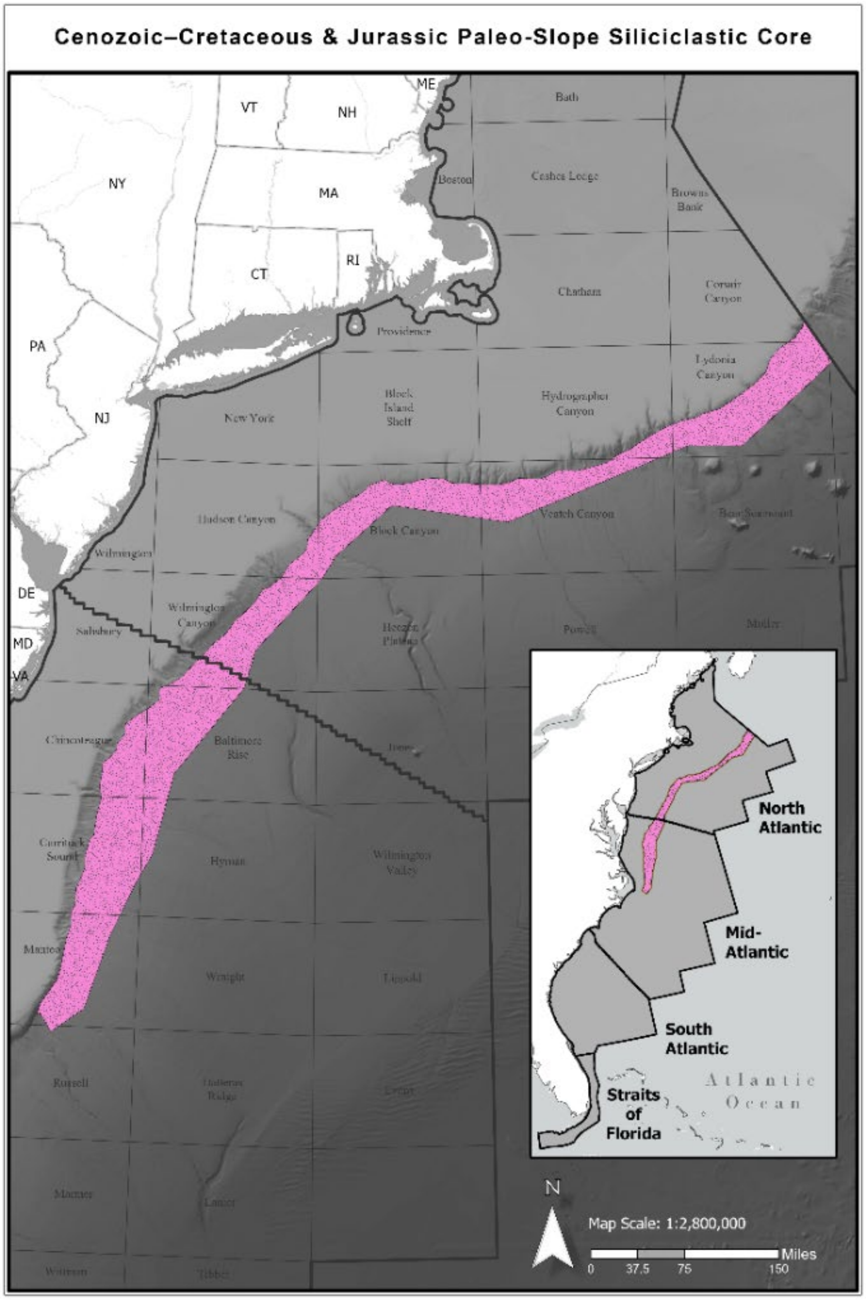

Figure 9. Cenozoic-Cretaceous and Jurassic Paleoslope Siliciclastic Core, AU 4 (pink polygon). Protraction area boundaries and names are shown along with state boundaries and abbreviations. Planning area names are on the inset map and its boundaries are the solid black lines seen on both maps.

The exact location of the line best depicting the onset of maturity cannot be determined. However, general credence to a location in the area depicted by Dickson and Christ (2011) is established by ODP 997B (Figure 4). Updip (landward) from the Dickson and Christ (2011) maturity onset line, ODP 997B (Figure 4) was drilled on Blake Ridge, a significant topographic feature in the U.S. Central Atlantic (Mid-Atlantic Planning area). The ridge is formed by a thick post-Eocene sediment drift (Tucholke et al., 1977) that overlies essentially horizontal, pre-Neogene sediments (Tucholke and Mountain, 1979). Below the bottom simulating reflector

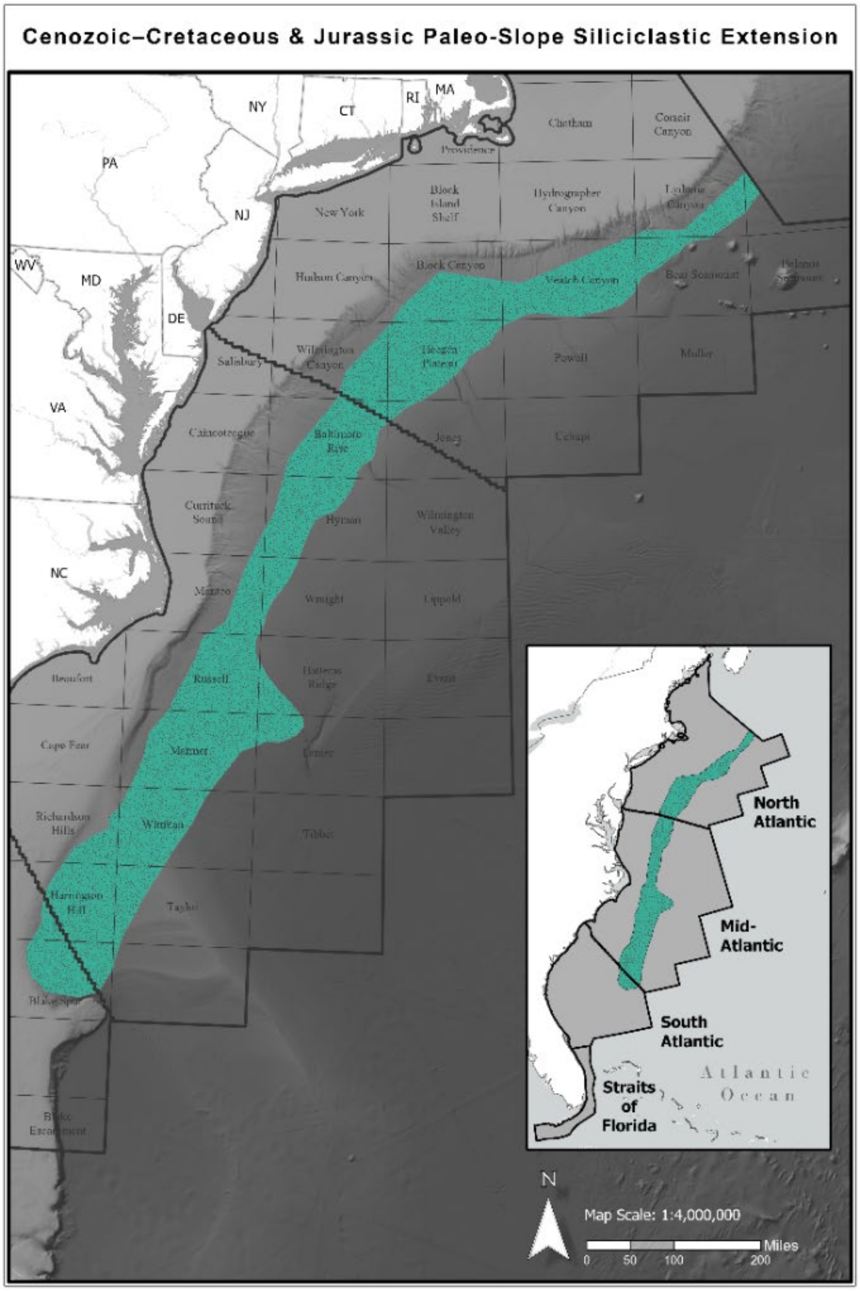

Figure 10. Cenozoic–Cretaceous and Jurassic Paleo-Slope Siliciclastic Extension, AU 5 (green polygon). Protraction area boundaries and names are shown along with state boundaries and abbreviations. Planning area names are on the inset map and its boundaries are the solid black lines seen on both maps.

(BSR) that marks the interpreted base of the gas hydrate in ocean drilling program (ODP) 997B, Paull et al. (1996) state: “Microscopically visible oil occurred from ~500 to 620 meters below sea floor (mbsf). This observation, coupled with the occurrence of higher molecular weight hydrocarbon gases, suggests some migration of oil and gas.” The sediments containing this “oil” are Late Miocene age. Lithologically, it is a diatom-rich interval within a generally homogeneous, dark greenish-gray, nannofossil-bearing clay and claystone (Paull et al., 1996). A mixture of microbial and thermal gases is encountered within and below the hydrate stability zone. The

ODP 997B site is thermally immature with a Ro of 0.3% near the total depth. Therefore, the thermally-derived gases must have migrated from older, deeper, more mature source rocks. Based on their carbon isotope ratios, the corresponding source rock would be attributed to marine facies with a maturity within the oil window, Ro ~0.6% to 1.0% (Wehner et al., 2000). Candidate, organic-rich, marine facies have been encountered and described in DSDP 534A and 391C in the Blake Bahama basin, and DSDP 105 and 603B farther north in the offshore area east of North Carolina (Katz and Pheifer, 1982; Herbin et al., 1983; Herbin et al., 1986; Summerhayes and Masran, 1983).

DSDP 603B and the Shell et al. Baltimore Rise (BR) 93-1 well (Figure 4) provide insights into reservoir deposition in these plays. DSDP 603B contains an Early Cretaceous (Valanginian to Barremian age) turbidite unit approximately 980 foot thick, 45% of which is siltstone-sandstone in grain size. The turbiditic sequence is topped by ~130 ft of clean, uncemented sands of ?Barremian–Aptian age (Sarti and von Rad, 1987). Located on the paleo basin floor, sedimentological and seismic data favor the hypothesis that the turbidite complex consisted of an elongated, channel-levee-interchannel system that developed during the Valanginian–Barremian and extended seaward from the depositional base-of-slope to the lower continental rise (Sarti and von Rad, 1987).

BR 93-1, approximately 230 mi to the northeast (Figure 4), targeted a large, faulted structure related to the 'Gemini Fault System' (Poag et al., 1990). The anticipated reservoirs in this trap were interpreted to have been in the updip, shelf-margin delta system that sourced the downdip turbidite fan complex described in DSDP 603B (Sarti and von Rad, 1987). BR 93-1 encountered no charged reservoirs or conventionally identifiable hydrocarbon shows in this interval (Prather, 1991). Water depths during deposition of these strata were estimated to have ranged between 130 and 590 ft, middle to outer shelf depositional environment (Prather, 1991), rather than the lower slope and abyssal environments of DSDP 603B. However, several zones in the Early Cretaceous in BR 93-1 had TOC content exceeding 1%, with Type III (gas-prone) kerogen predominating. The deepest interval in the well approached, or was in, the oil maturity window (Amato, 1987). BR 93-1, the last well drilled and completed during the initial and only phase of exploration in the U.S. Atlantic OCS, was the only well to target this reservoir objective. A fluid inclusion stratigraphic study completed in late 2015 by FIT provides additional insights related to the BR 93-1 well, with samples from undifferentiated Tertiary at 7,140 ft through to interpreted Berriasian at 17,740 ft (Fluid Inclusion Technologies, Inc., 2015c). Below 17,050 ft (Berriasian?), stronger wet gas spectra were noted. Minor sulfur species of possible thermal origin were identified from 17,290–17,420 ft. Rare, blue-fluorescent, upper-moderate gravity and yellow-fluorescent, unknown gravity liquid petroleum inclusions were identified in silty shale, sandstone, and carbonate at 17,110 ft suggesting migration events. Rare, dead stain was identified at 17,260 ft and 17,420 ft. FIT did not interpret gas maturity in this well and the potential for oil generation was interpreted below ~16,500 ft. For a more detailed analysis on the FIS for the BR 93-1 well see the 2016 Atlantic Assessment (BOEM, 2016).

In both AUs, the petroleum system elements considered of highest risk are the presence of reservoir and source rocks. Reservoir risks (Grant et al., 2013) are related to several points. If the lithology of the provenance rocks eroded to become the potential reservoirs is not quartz-rich, then mudstones rather than sandstones would be the result of erosion and transport into the areas of these AUs. Paleogeography and drainage area are also considerations, because big, sand-rich systems typically require large rivers with long source-to-sink distances, typically 300 mi or more in an Atlantic Margin-style setting (Grant et al., 2013). Too low a sediment volume results in an insufficient amount of coarse-grained facies (potential reservoirs) reaching the depositional slope and basin floor. The shelf setting and its geometry influence sand transport and sorting because a broad shelf allows reservoir intervals to be cleaned up and concentrated. The geometry of the depositional slope and/or basin-floor also affects reservoir distribution and trapping configurations (Grant et al., 2013). The presence and type of organic matter in potential source rocks are risks. As noted above, ODP and DSDP wells confirm the presence of thin, immature source rocks in basinward ultra-deepwater settings. Sealing lithologies should be abundant in these AUs as fine-grained sediments predominate in both. Overburden in conjunction with heat flow will determine the maturity and timing of generation–expulsion–migration from any source rocks present.

Examples of potential hydrocarbon traps similar to those in analogs have been demonstrated with existing seismic data interpretations by BOEM staff. This seismic data grid ranges from approximately 4 mi (in a dip direction) by 6 mi (in a strike direction) in parts of the North Atlantic Planning Area to approximately 20 mi by 100 mi in much of the Mid- and South Atlantic Planning Areas. This affects the ability to accurately delineate prospect geometries and density along strike in these AUs.

Migrated, mature hydrocarbons in BR 93-1 and ODP 997B provide positive indications of generation–expulsion–migration in the area of the wells in these AUs. Although not in commercial volumes at those locations, this supports the presence and maturity of organically rich source rocks and possibly migration conduits between mature source rocks landward from the ODP and DSDP wells as suggested by Dickson and Christ (2011). Potential reservoirs have been encountered updip (on the paleo-shelf) and downdip in DSDP 603B (Sarti and von Rad, 1987). Timing of generation–expulsion–migration–accumulation from any source rocks and the accumulation and preservation of those hydrocarbons are possible risks depending on the depositional setting and trap/seal/hydrocarbon charge timing. It is important to recognize and acknowledge that based on the analogs, the reward size may exceed several hundred million barrels of oil (MMbbl) or trillions of cubic ft (Tcf)of natural gas in an individual trap.

The “core” has by far the greatest resource potential with over 4.5 times the average UTRR (Table 3). It has the 3rd largest acreage and a great block pool density (Table 2). Its analogs contain large fields leading to a high limit on the upper truncation of the pool distribution. Selecting from this distribution of larger pool sizes while having the highest number of modeled pools (Table 2), leads to its exceptional UTRR (Table 3). It’s overall chance of success is moderate at 5.3% (Table 1).

The “extension” has a mean UTRR of 1.045 BBOEs (Table 3) due in part to an acreage nearly 4 times (3.76) larger than the average (Table 2). The analogs are very similar to those from the “core”, including large fields leading to a high limit on the upper truncation of the pool distribution. Opposing these positive influences is a poor block pool density (Table 2) and low chance of success at 2.2% (Table 1).

3.5 CRETACEOUS AND JURASSIC BLAKE PLATEAU BASIN AU

The conceptual Cretaceous and Jurassic Blake Plateau Basin AU (Figure 11) encompasses the undrilled Blake Plateau basin (BPB) downdip from the Southeast Georgia Embayment (SEGE), an area of approximately 38,000 mi2 (Figure 2). This AU area is interpreted to be predominantly in the South Atlantic Planning Area extending slightly into the Mid-Atlantic Planning Area (Figure 11). Water depths over this AU range between 2,000 and 3,600 ft. A continental shelf stratigraphic test (COST) well was drilled in the SEGE in 1977 followed by six industry NFWs from 1979 to 1980. All wells were drilled shoreward of the main depocenter in the BPB and were plugged and abandoned providing no results considered positive at that time. Encountered sediments were thermally immature due to insufficient overburden and thermal gradient. Five (5) of the 7 wells reached Paleozoic basement, often described in drilling reports as metamorphosed sedimentary rocks such as quartzite. The BPB AU has more potential for mature source rocks due to its thicker sediment interval relative to the SEGE (Figure 1).

There are a limited number of identifiable potential analog basins for this AU. Two of the best explored analogs are the South Florida basin (SFB) onshore Florida (Pollastro et al., 2001), and the Paris basin (PB) (Perrodon and Zabek, 1990; Wendebourg and Lamiraux, 2002). Exploration success rates and reserves per discovery are low in both analog basins (Pollastro et al., 2001; Perrodon and Zabek, 1990).

In the SFB, carbonate source rocks immediately underlie the carbonate reservoirs (Pollastro et al., 2001). Organic-rich, Early Jurassic black shales are the source rocks for overlying Late Jurassic carbonate and underlying Late Triassic siliciclastic reservoirs in the BPB. Given the nature of the source rocks in the analog basins and considering a similar depositional setting likely in the BPB, it is believed the BPB has a higher likelihood of oil-prone source rocks than many other areas of the Atlantic OCS. Intraformational evaporites or impermeable carbonates (marls) typically provide local and regional seals in both analog basins (Perrodon and Zabek, 1990). Even though the large, regional, basin-scale structures in both basins have not proven effective hydrocarbon traps, they may have localized reservoir development and focused local hydrocarbon migration with most fields situated preferentially on one of their flanks. Characterized by low–moderate relief structures with relatively thin reservoir intervals, these stratigraphic and combination stratigraphic-structural traps are subtle and difficult to image seismically (Pollastro et al., 2001; Perrodon and Zabek, 1990).

The 2016 Assessment details a Fluid Inclusion Stratigraphy (FIS) analysis in the COST GE-1, a well with no significant shows and poor to fair organic matter preservation (Core Laboratories, Inc., 1977) in organically lean drill cuttings (Smith, 1978). Drilled in 136 ft of water and ~25 mi updip of the BPB AU boundary, this stratigraphic test reached a TD of 13,254 ft in weakly metamorphosed units (Scholle, 1979) radiometrically dated as Devonian (Simonis, 1979). Microthermometric analysis was performed in an Early Cretaceous interval at 9,040 ft and 10,860 ft by Fluid Inclusion Technologies, Inc. (2015g). Lateral migration of fluids from deeper in the adjacent BPB's thicker sediment depocenter were supported by FIS samples from the well. This included thermogenic hydrocarbons in thermally immature zones of insufficient organic content, and aqueous inclusions with anomalously high salinities. Comparatively, source rocks in the SFB and PB analogs are within depositional environments containing anhydrite and minor salt stringers. These evaporites were conducive to organic matter preservation by supporting anoxic conditions. The relatively shallow depth to basement and lack of encountered evaporites preclude possible migration from deeper within the SEGE. For additional information see BOEM's 2016 Atlantic Assessment (BOEM, 2021).

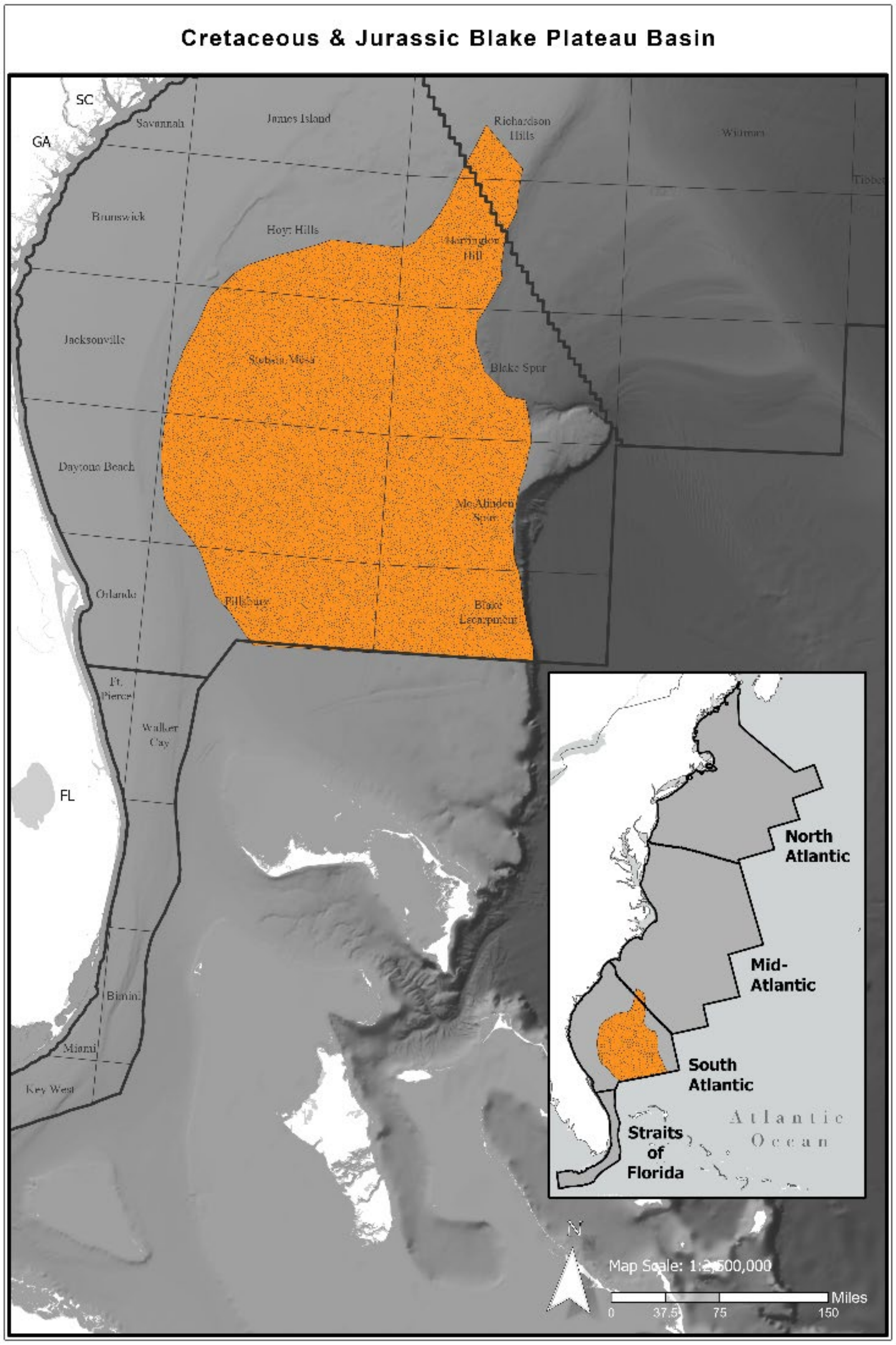

Figure 11. Cretaceous and Jurassic Blake Plateau Basin, AU 6 (orange polygon). Protraction area boundaries and names are shown along with state boundaries and abbreviations. Planning area names are on the inset map and its boundaries are the solid black lines seen on both maps.

Drilling results from the updip, shallow water SEGE led the BOEM staff not to consider that area as likely for any hydrocarbon resources because the wells failed to find any significant thickness of mature source rocks or regional top seals. Only the wells closest to the BPB, such as the COST GE-1, had indications of migrated hydrocarbons that are inferred to have originated from the deep depocenter. However, the larger, deeper main BPB is undrilled. Expectations, based on the SFB and PB analogs, are low. Drilling ~1,100 NFWs in the SFB and PB analogs resulted in 32 fields with reserves of >1 MMBOE, 10 fields of >10 MMBOE of reserves, and only 3 fields with >40 MMBOE (Florida Dept. of Environmental Protection, 2016). However, acknowledging our uncertainty about this undrilled basin, we recognize that the BPB could, if successfully explored in the future, have the largest positive assessment adjustment percentage of any AU in the Atlantic OCS.

The Cretaceous and Jurassic Blake Plateau Basin has the second largest acreage but a poor block pool density (Table 2). Its 5.0% total chance of success is average (Table 1). It's UTRR is the second lowest with a mean of 172 MMBOEs (Table 3). All but a few of its analogs had fields less than 20 MMBOEs leading to a low upper limit for the pool distribution sizes used in the GRASP model.

3.6 JURASSIC SHELF STRATIGRAPHIC AU

Updip from the Late Jurassic–Early Cretaceous Carbonate Margin AU, the conceptual Jurassic Shelf Stratigraphic AU (Figure 12) covers an area of ~7,700 mi² (Figure 2) in current water depths between ~200–2,600 ft. As defined, no wells have been drilled in this AU specifically targeting these objectives. The unsuccessful LC 410-1 was the only well within its area and it was a Georges Bank Basin (GBB) well targeting a structural closure of interpreted carbonate reservoirs. Trending along much of the North and Mid-Atlantic Planning Areas, the AU is bisected by the Cretaceous and Jurassic Interior Shelf Structure AU.

The reservoir element of the petroleum system is anticipated to consist of limestones and/or dolomites, as in the onshore GOM analog fields, such as Walker Creek (Arkansas), Oaks (Louisiana), and Little Cedar Creek (Alabama). Although minor faulting may occur, the AU is considered primarily stratigraphic because reservoir facies define and control the hydrocarbon trap. Chimene (1991) provides a detailed discussion on the Walker Creek field (Arkansas), the largest of the analog fields. Throughout the onshore analog area, Oxfordian-age laminated lime mudstones are confirmed as the source for Jurassic shelf reservoirs (Sassen, 1990). The source component in this AU is considered probable but unproven as wells drilled along trend in the Cretaceous and Jurassic Interior Shelf Structure AU often lack hydrocarbon shows. In addition to possible intraformational source rocks (typical of the analogs), deeper carbonate formations are also probable source rocks (Sassen and Post, 2008; Sassen, 2010). Trap seals are interpreted to be non-porous carbonate units, possibly with minor evaporite intervals or thicker evaporite units that overlie or are laterally adjacent to the reservoirs.

Even though the vintage (1966 through 1988) seismic data available to assess this AU were not acquired with a high enough frequency content to identify these stratigraphic traps, some areas of interest in this AU can be identified. Current state-of-the-art deep penetration reflection seismic acquisition and processing parameters would better image the stratigraphy in these carbonate depositional environments, with a higher likelihood of identifying prospects in this AU. Analog fields appropriate for this AU have produced between 2 and 80 MMbbl prior to their abandonment (Geological Survey of Alabama, State Oil and Gas Board, 2021; Louisiana Department of Natural Resources [SONRIS Lite], 2021; Arkansas Oil and Gas Commission, 2021).

The Jurassic Shelf Stratigraphic has a mean of 283 MMBOEs (Table 3) due to a low 3.5% overall chance of success (Table 1) and an average areal size (Table 2). The block pool density is good (Table 2), but the analog pool distribution is less than average with most fields below 20 MMBOEs.

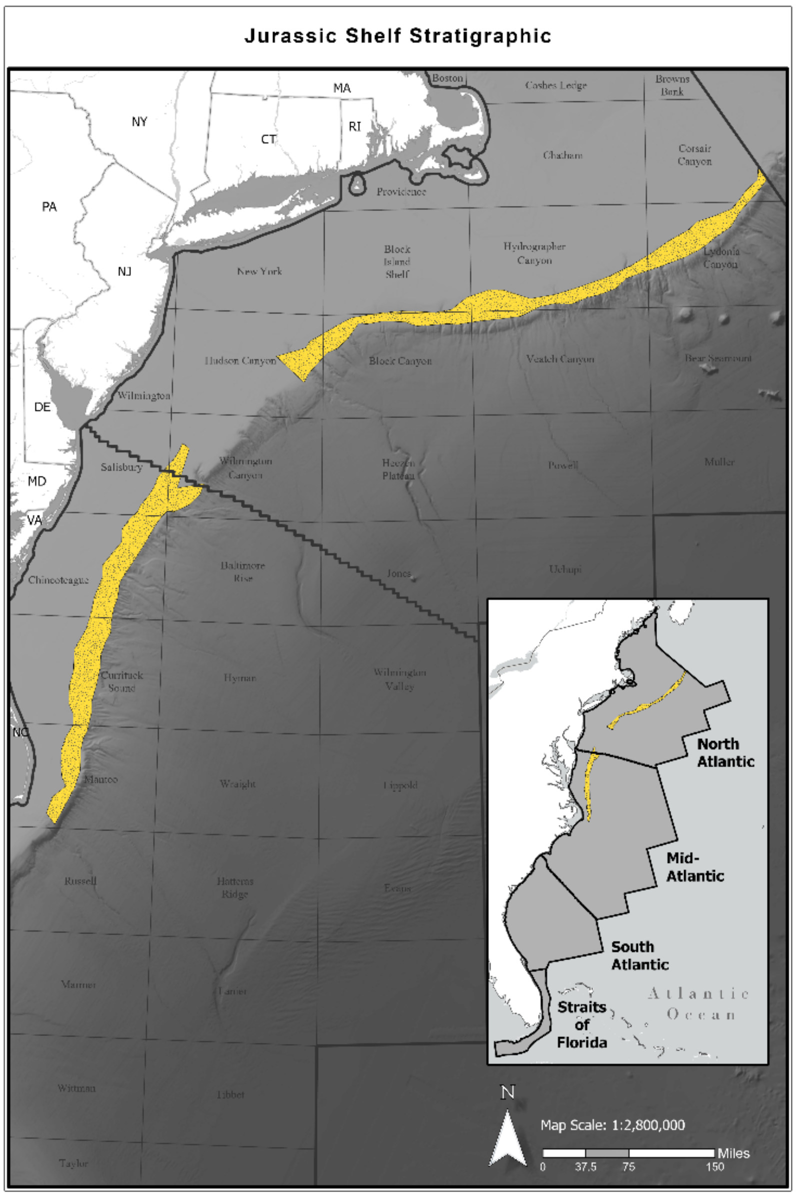

Figure 12. Jurassic Shelf Stratigraphic, AU 7 (yellow polygons). Protraction area boundaries and names are shown along with state boundaries and abbreviations. Planning area names are on the inset map and its boundaries are the solid black lines seen on both maps.

3.7 CRETACEOUS AND JURASSIC INTERIOR SHELF STRUCTURE AU

The Cretaceous and Jurassic Interior Shelf Structure AU (Figure 13) occurs over an area of approximately 2,800 mi² (Figure 2) in the Baltimore Canyon Trough in water depths ranging from 150 to 3,000 ft. This AU is recognized in the North Atlantic Planning Area with a small portion extending into the Mid-. With updates to BOEM's petroleum system risking, this AU was modeled as conceptual for 2021. This is a departure from the previous assessment (BOEM, 2016) where it was evaluated as an established AU. The unconventional nature of this potential resource contributes to the conceptual modeling of the AU. By modeling as conceptual, these factors are accounted for in a petroleum system risk with a value less than 1. The AU is confined to an area of generally listric, down-to-the-basin faulting and associated compensating faults of the 'Gemini Fault System' (Poag, 1987).

These faults provide migration conduits that facilitate the movement of hydrocarbons generated and expelled from mature older Jurassic age source rocks into siliciclastic reservoirs of younger Jurassic and Cretaceous age, and form structural traps for these hydrocarbons (Prather, 1991; Sassen and Post, 2008; Sassen, 2010). Evidence of this is in satellite sea surface slick data where dozens were identified within this AU's boundary, including several third rank seeps. Of the 3 ranks (1, 2, and 3) this has the lowest confidence. However, it is still more likely to be related to a natural seep than those identified as "other" for those that are indeterminate or "pollution" for those suspected or known to be related to a manmade source.

This AU was relatively well explored by 14 NFWs drilled between 1978 and 1981. This effort resulted in a single gas-condensate discovery in the Hudson Canyon (HC) 598 area (Figure 4), the largest structure on the Gemini Fault System. Following the non-commercial discovery, seven appraisal wells were drilled in the four-OCS block unit area.

Cased hole drill stem tests (DSTs) were attempted through perforations on all eight wells, with natural gas successfully tested in six. DSTs were typically after a mud cleanup acid treatment followed by a low volume acid treatment to establish connectivity between the well bore and the formation. Late Jurassic zones tested at rates as high as 18.9 MMCFG; averaging ~5 MMCFG on variable chokes. Typical condensate yield was ~4 barrels (bbl) of average 43° API condensate per MMCFG. Rates were variable, often declining over time. Flow times ranged from 3 to 33 hours, averaging 13 hours. A Late Cretaceous zone was also tested. The initial flow rate was calculated to be over 600 bbl of oil per day of 48° API oil, with the well depleting during testing. Molecular and isotopic properties of condensate samples from tested reservoirs show that the same or a similar source rock provides the hydrocarbons for all of them. The condensates are enriched in diamondoids and $_{13}$C, showing similarities to condensates from laminated lime mudstone source rocks (Sassen and Post, 2008; Sassen, 2010).

An unpublished BOEM analysis of the HC 598 area integrated seismic interpretation, wireline log correlations, mud gas shows encountered while drilling, detailed petrophysical analyses of wireline logs, all sidewall and conventional core data, and analysis of all test data. At least 70 reservoir compartments were identified. The DST results indicated that most tested intervals have very low permeability and/or have limited drainage areas. This implied a lack of continuity and communication between zones indicated productive by petrophysical and core analyses.

BOEM staff assigned a resource range for a first-phase development scenario using multi-laterals and fracs for the HC 598 area of between ~85 and ~254 billion cubic feet of gas equivalent (BCFGE), with a mean of ~160 BCFGE. Commerciality for the HC 598 area is currently considered unlikely for a variety of reasons; for example reservoir continuity and compartmentalization, flow baffles, production rates, and development costs.

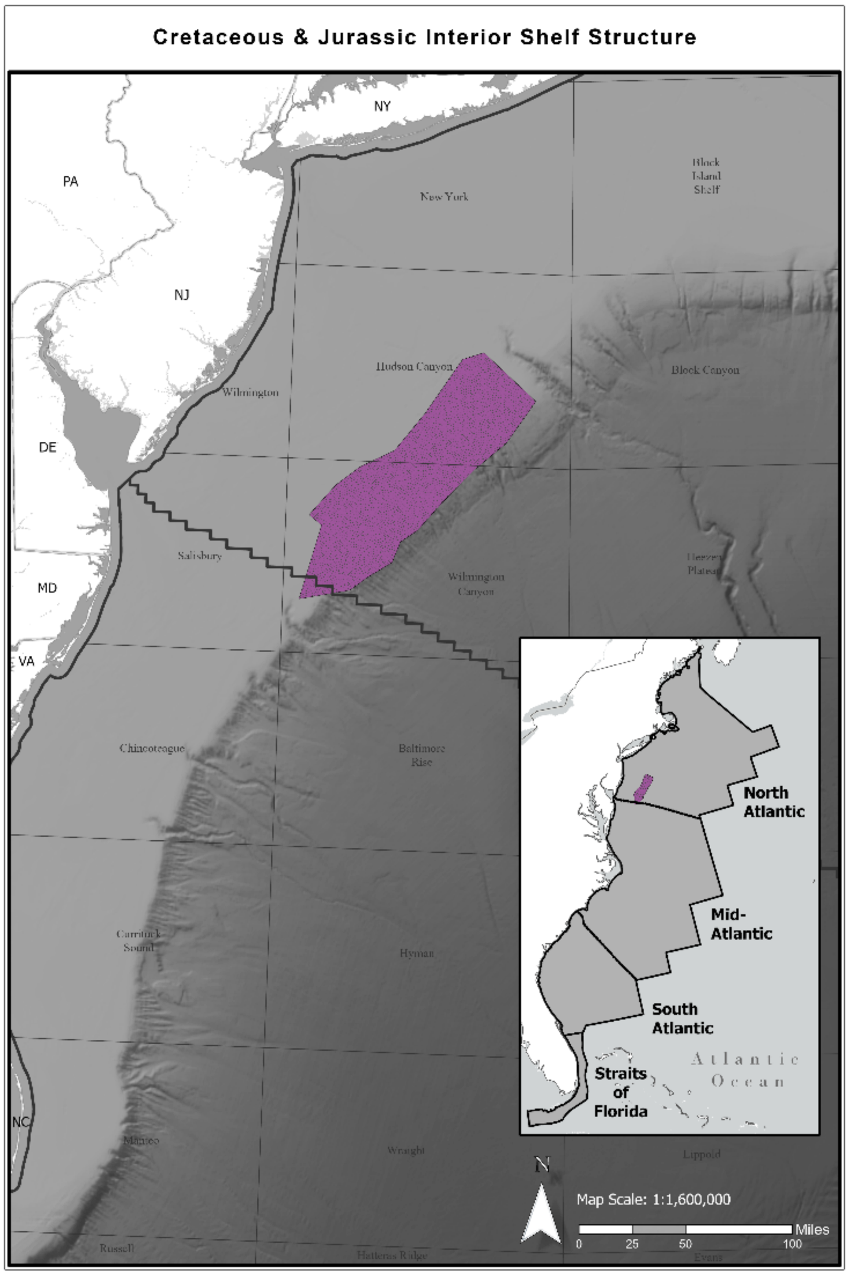

Figure 13. Cretaceous and Jurassic Interior Shelf Structure, AU 8 (purple polygon). Protraction area boundaries and names are shown along with state boundaries and abbreviations. Planning area names are on the inset map and its boundaries are the solid black lines seen on both maps.

Based on the fair results in the HC 598 area, the petroleum system was evaluated at a 72% chance of success. This is the highest of the AUs and twice the 35% success average of the others (Table 1). Risks also exist for individual prospects as demonstrated by other structures drilled and tested without success in similar trapping configurations along the Gemini Fault System. These risks are related to the presence or absence of anti-regional dip associated with the trap-forming faults, how and when those faults function as migration conduits connecting older/deeper/mature source rocks with younger reservoirs, if/when those faults seal or leak the hydrocarbon accumulation, the local nature of the source rocks, the occurrence of permeability in the siliciclastic reservoirs, the presence of traps with minimum rock porosity-permeability volumes, and the presence of effective regional/local top seals.

The Cretaceous and Jurassic Interior Shelf Structure ranks 8th for UTRR at 207 MMBOEs (Table 3) due its very small acreage (Table 2). Its block pool density is average along with its analog pool distribution. Due to the favorable results at Hudson Canyon, it has a 10.1% overall chance of success (Table 1).

3.8 TRIASSIC–JURASSIC RIFT BASIN AU

The Triassic–Jurassic Rift Basin AU (Figure 14) is a ~4,500 mi^2 area within the North Atlantic Planning Area (Figure 2), truncated to the north-northeast by the U.S.–Canadian boundary. Water depths in this conceptual AU range from ~150 to 800 ft. The Georges Bank basin (GBB) and Yarmouth basin (Figure 1) overlap this AU.

At least 30, and possibly as many as another 20, Triassic–Jurassic rift basins are documented in the onshore Eastern U. S. Between 1890 and 1998, 80 wells were drilled for oil and gas exploration with some type of reported oil and/or gas show reported in 27 (34%) of the wells. No economic conventional oil and gas or coalbed methane (CBM) accumulations have been found (Coleman et al., 2015; Post and Coleman, 2015). At least seven undrilled basins and basin complexes (groups of subbasins), have been identified in the U.S. OCS (Post and Coleman, 2015).

Post-rift, transpressional/contractional stress affected all onshore (Withjack et al., 2012) and offshore (Post and Coleman, 2015) Late Triassic–Early Jurassic rift basins in the eastern U.S. This stress resulted in basin inversion and concurrent or subsequent erosion of the uppermost (youngest) syn-rift strata. Observed in all onshore and offshore rifts, this represents a common, shared, objective observation and a risk factor that affected all rift basins in the region. Several methodologies estimate the amount of erosion to vary within basins and possibly within individual subbasins and depocenters. Typically, the erosion ranges from ~3,000–10,000 ft, with most onshore basins having closer to 10,000’ of late syn-rift material eroded (Pratt et al., 1988; Steckler et al., 1993; Malinconico, 2002; Post and Coleman, 2015). Eliminating this thickness of strata from the late syn-rift would erosionally remove any reservoirs, traps, and hydrocarbons from this part of the section. Hydrocarbon traps not eroded might also be subject to being breached, flushed with fresh water, or having their overlying top seals fractured.

Reprocessed, depth-converted, time-migrated deep-penetration reflection seismic data display rift-related, faulted structures primarily north of the GBB in the Yarmouth basin (Schlee and Klitgord, 1988; Post and Coleman, 2015). These data clearly indicate a sag phase of basin development associated with the Yarmouth basin. This is unique, occurring in no other onshore or offshore Late Triassic–Early Jurassic rift basin of the eastern U.S. (Post and Coleman, 2015). Seismic data quality, especially at depth, is not uniform, because not all data in the area was reprocessed. Consequently, a proxy was developed to locate extent of the underlying Yarmouth Late Triassic–Early Jurassic rift basin. This was a practical solution where the seismic data was reprocessed. In those cases, an overlying sag phase of basin development was always easily recognized as was the underlying Triassic–Jurassic Rift Basin AU. Where the deep seismic data was poor, the deeper rift structure could not be delineated. However, the overlying sag phase of basin development could always be identified and used to locate the underlying rift.

Seismic data, and geohistory modeling based on the interpretation of those data, indicate less inversion/erosion in the Yarmouth basin as documented by the preserved, relatively thick, post-rift sag phase of sedimentation/basin development (Post et al., 2011; Post and Coleman, 2015). Consequently, potential late syn-rift and possibly post-rift, sag phase hydrocarbon traps are preserved in the Yarmouth basin, increasing the probability that significant hydrocarbon prospectivity may exist.

Macgregor (1995) used data from 105 rift basins to characterize rift basins into three broad categories: simple rifts, locally inverted rifts, and regionally inverted rifts. Although the number of rifts in each category was not specified, Macgregor (1995) found that only 62% of the regionally inverted rifts had any conventional oil and/or gas, only 19% of these basins had fields of 250 MMBOE, and none had fields of 2 billion barrel of oil equivalent (BBOE). In contrast, 92% of all locally inverted rifts had some oil and gas, and 76% had fields of 250 MMBOE, and 16% had fields with 2 BBOE. Some oil and/or gas was found in 93% of the simple rifts, and 37% of those had 250 MMBOE fields, while 8% had fields of 2 BBOE fields. All onshore and offshore Late Triassic–Early Jurassic rift basins in the U.S. (except the Yarmouth basin) are regionally inverted rifts. Therefore, their lack of conventional discoveries is not unexpected. A literature review based on Macgregor (1995) shows that a preserved sag phase of basin development is characteristic of either a locally inverted or simple rift. The Yarmouth basin with its preserved sag phase of development is the only example of a locally inverted Late Triassic–Early Jurassic rift in the eastern U.S. (Coleman et al., 2015; Post and Coleman, 2015). For that reason, its hydrocarbon prospectivity might be better than the other onshore and offshore Late Triassic–Early Jurassic rift basins of the Eastern U.S.

Because the target structures in the Yarmouth basin are undrilled, their prospectivity is speculative. Ductile strata, whose nature is unknown, appear to core the deepest parts of these structures and facilitate their formation. There is no conclusive evidence to determine the nature of this ductile material. However, there is a general geometric similarity between the inversion structures in Yarmouth basin and those in the various rift grabens of the West Natuna basin of Indonesia where the ductile unit is shale (Macgregor, 1995; Maynard et al., 2002; Hakim et al., 2008; Cherdasa et al., 2013; Manur and Jacques, 2014).

Petroleum system elements are found in every major onshore eastern U.S. Late Triassic–Early Jurassic rift basin, and it is therefore reasonable to expect that they will be found in the Yarmouth basin (Post and Coleman, 2015). Sealing mudstone and shale lithologies are likely throughout the syn-rift, sag phase and within the post-rift sedimentary interval. Petroleum system processes

(Magoon and Dow, 1994) that acted on and influenced the petroleum system elements are documented in every onshore eastern U.S. Mesozoic rift basin (Coleman et al., 2015). Although not proven by drilling, source rocks and generation–expulsion–migration are inferred because satellite sea-surface slicks are interpreted in the Yarmouth basin area (Post and Coleman, 2015).

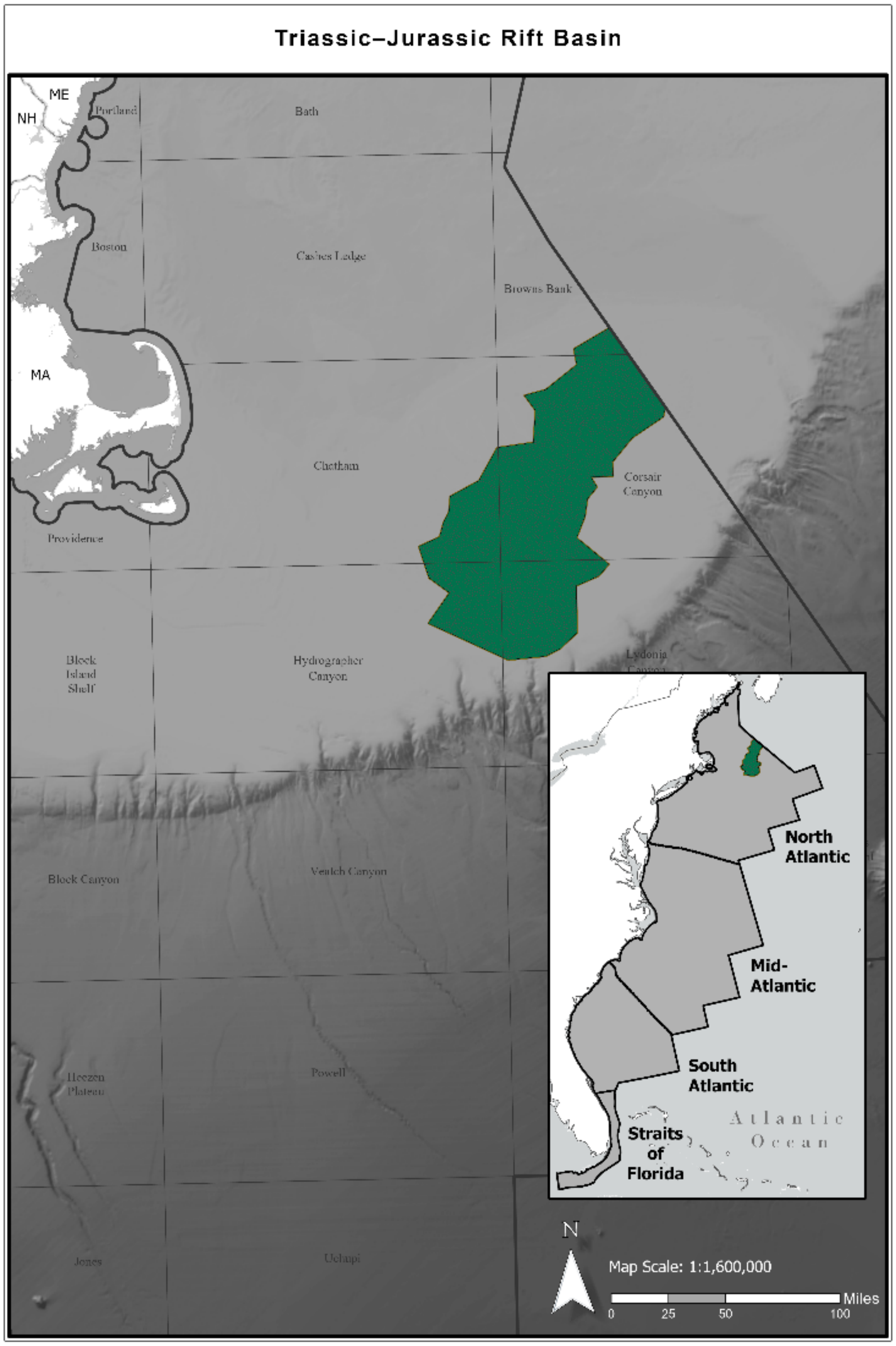

Figure 14. Triassic–Jurassic Rift Basin, AU 9 (green polygon). Protraction area boundaries and names are shown along with state boundaries and abbreviations. Planning area names are on the inset map and its boundaries are the solid black lines seen on both maps.

Failure to date to locate commercial, conventional oil or gas fields in the east coast Mesozoic rift basins implies that a rift basin with slightly different characteristics might be the key to breaking that paradigm. Late syn-rift traps may be preserved because seismic data identifies a sag phase of development in the Yarmouth basin indicating less inversion and erosion. Geohistory models indicate that if source rocks are present and of typical richness in the Yarmouth, they did not expel their hydrocarbons before the post-rift strata were deposited, indicating a second phase of hydrocarbon expulsion and trap charge may have occurred (Post et al., 2011; Post and Coleman, 2015). The Yarmouth basin is the sole eastern U.S. Late Triassic-Early Jurassic rift with local inversion only and may therefore be the most prospective for hydrocarbon accumulations. (Post and Coleman, 2015).

Analogs for the Triassic–Jurassic Rift Basin AU were found in the Vulcan Graben of offshore NW Australia. In this area, complex rift-related structures contain hydrocarbons in Triassic and Jurassic siliciclastic reservoirs with production and/or reserves estimated to range between ~2 and 300 MMBOE per field/discovery (Geoscience Australia, 2008). Additional analogs are found in the Viking graben of the North Sea wherein pre-rift sources charged Early-Middle Jurassic sandstone reservoirs in rift-related, faulted structural traps (Gautier, 2005). Analog fields' production ranges covered the extent of the field size distribution for this AU (Oil and Gas Authority UK, 2020).

Productive inversion structures similar to those interpreted in the undrilled Triassic–Jurassic Rift Basin AU are also documented in the West Natuna basin (Maynard et al., 2002; Burton and Wood, 2010). Estimated reserves in this basin range from ~1–2.4 BBOE, with the largest field having ~400 MMBOE (Howes and Tisnawijaya, 1995; Howes, 1997; Manur and Jacques, 2014). These structurally analogous West Natuna basin fields were not used in the field size distribution for this AU because it is believed there are significant differences in reservoir age, depth of burial, and petrophysical characteristics, especially permeability. Data for onshore eastern U.S. Late Triassic–Early Jurassic rift basins in Coleman et al. (2015) and Post and Coleman (2015) average ~13% porosity and ~70 mD of permeability. These values are significantly lower than the average porosity of ~20% and permeability of 500 mD for the locally inverted Late Oligocene–Early Miocene reservoirs of the KH field in the West Natuna basin (Pollock et al., 1984).

The Triassic–Jurassic Rift Basin has a mean of 295 MMBOEs (Table 3) due to its small acreage (Table 2) and middling block pool density (Table 2). The overall chance of success is good at 9.9% (Table 1). Its analogs include large fields leading to a good pool distribution with most pools over 10 MMBOEs and many over 100 MMBOEs.

3.9 CRETACEOUS AND JURASSIC HYDROTHERMAL DOLOMITE AU

The area of the conceptual Cretaceous and Jurassic Hydrothermal Dolomite AU (Figure 15) remains unchanged from the 2013 seismic data reinterpretation in the northern part of the GBB in the North Atlantic Planning Area (Figure 1 and Figure 2). The AU is interpreted to occur over an area of ~1,700 mi^2, in water depths that range from ~100 to 1,100 ft. This AU is associated with the crest and northwest flank of the Yarmouth Arch in the U.S. OCS (Figure 1).

The Yarmouth Arch is a significant structural element of the eastern North American Central Atlantic. It is likely related to the assembly of Pangea and its subsequent breakup (Pe-Piper et al., 2010). Wade (1990) provided the most information on the Yarmouth Arch and its relationship to the Georges Bank and Scotian basins. He described the arch as a buried complex of approximately north-northeast-trending basement elements consisting of several blocks that formed the boundary between the Georges Bank basin and the Shelburne subbasin of the Scotian basin (Figure 1). Seismic data cited by Wade (1990) indicated that the arch was an early-formed, topographically and structurally positive feature that limited communication between the Georges Bank and Scotian basins. Maps in Deptuck et al. (2015) support this interpretation. As noted above, because the nature of the ductile strata that at depth cores the inversion structures in the west-adjacent Yarmouth basin (Post and Coleman, 2015), the presence or volume of salt in that basin is speculative. Allochthonous and autochthonous salt structures are only found east of the Yarmouth Arch, in the Sable sub-basin (Figure 1) (Wade, 1990; and Deptuck et al., 2015). Given this understanding and the uncertainty of the nature of the ductile formation in the Yarmouth basin, BOEM currently interprets the Yarmouth Arch to separate salt-poor depocenters on the southwest (the Georges Bank and Yarmouth basins) from salt-rich basins and subbasins offshore Nova Scotia on the northeast. Early(?) Jurassic and early Middle Jurassic strata pinch out on the flanks of the arch (Wade, 1990). Later, during the Early and Middle Jurassic, the arch separated carbonate-rich strata of the GBB from predominantly siliciclastic units of the Scotian basin (Wade, 1990). The influence of the arch diminishes later in the Jurassic and through the present-day. It maintained a mild influence on later units based on stratigraphic thicknesses, facies changes, and erosional patterns. Wade (1990) suggested that the large amplitude, linear magnetic anomalies trending south from the vicinity of Yarmouth, Nova Scotia, toward the Yarmouth Arch, suggested a possible structural relationship between the two areas.

Because the AU has not been drilled the petroleum system elements and processes are speculative. The petroleum system may have similarities to some of those found in wells drilled in the GBB. Although source rocks have not been directly confirmed, satellite-identified, sea-surface slicks occur in this AU, including a seepage slick third rank (NPA, 2018). This and the other slicks of lower confidence (priority unassigned ranking) suggest that source rocks, and generation–expulsion–migration may have occurred, or may be occurring. Reservoirs in the Cretaceous and Jurassic Hydrothermal Dolomite AU would be formed by hydrothermal dolomitization associated with the upward circulation of deeper, hotter fluids along fault systems resulting in limestone host rock being altered to dolomite, reducing the rock volume and forming sags associated with the trap. Albian-Scipio, the largest oil field in the Michigan basin, and similar fields in the Michigan and Appalachian basin, are considered analogs for this AU with the hydrocarbon seal being typically provided by either limestone that has not been dolomitized or a "tite" caliche zone (Davies and Smith, 2006; and references therein). Reserves for analog fields for this AU range from less than 1 MMBOE to 500 MMBbl. Total reserves established in all analog fields appear to be in the 1 BBOE range. Data sources were developed using extrapolations of

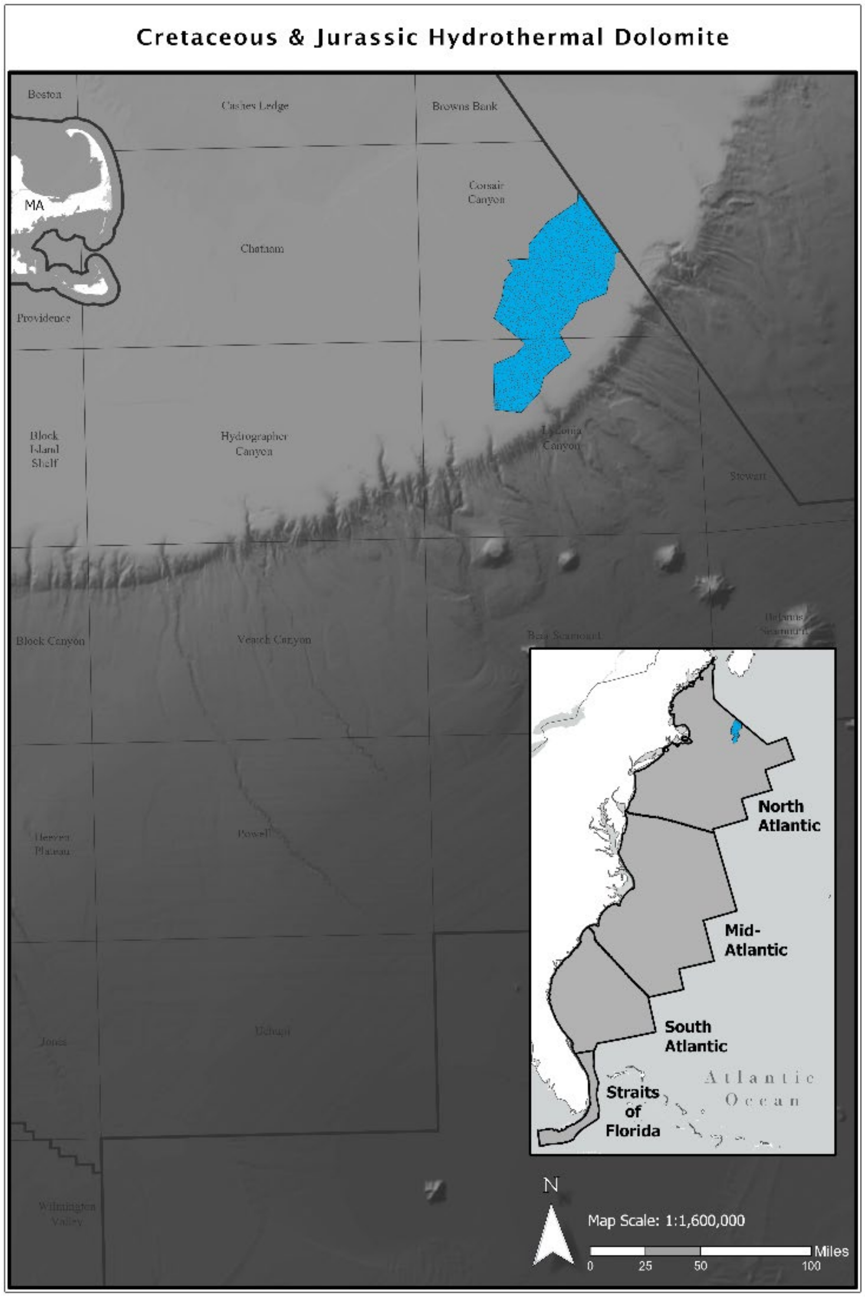

Figure 15. Cretaceous and Jurassic Hydrothermal Dolomite, AU 10 (blue polygon). Protraction area boundaries and names are shown along with state abbreviations. Planning area names are on the inset map and its boundaries are the solid black lines seen on both maps.

annual production data from the New York State Department of Environmental Conservation, the Michigan Department of Environmental Quality, and various historical data sources. Swezey et al. (2015) assessed undiscovered resources in the analog Michigan basin area (which includes most of the State of Michigan, as well as parts of Illinois, Indiana, Minnesota, Ohio, and Wisconsin) at mean values of 723 MMbbl, ~2 trillion cubic feet of gas (TCFG), and ~110 million barrels of natural gas liquids (MMBNGL).

The Cretaceous and Jurassic Hydrothermal Dolomite has the lowest mean of 44 MMBOEs (Table 3) due to it having the smallest acreage (Table 2) and the second lowest chance of overall success (Table 1). Additionally, its block pool density was poor resulting in a low number of mean pools (Table 2).

4.0 UNDISCOVERED TECHNICALLY RECOVERABLE RESOURCES

Undiscovered resources are resources postulated, based on geologic knowledge and theory, to exist outside of known fields or accumulations (BOEM, 2021). Technically recoverable resources are those that may be produced with natural pressure, artificial lift, pressure maintenance, or other secondary recovery methods, but without any consideration of economic viability. They are hydrocarbon resources that can be removed from the subsurface with conventional extraction techniques; that is, technology whose usage is considered common practice. Technically recoverable resources include moderate- to high-gravity crude oil, condensate, and gas, but do not include low-gravity “heavy” oil, oil shale, shale gas, and gas hydrates.

Estimates of undiscovered recoverable resources for the U.S. Atlantic Region are presented in two categories: undiscovered technically recoverable resources (UTRR) and undiscovered economically recoverable resources (UERR). UTRR values for individual AUs are shown in Table 3 with 95th and 5th percentiles, and the mean. This range of estimates corresponds to a 95-percent probability (a 19 in 20 chance) and a 5-percent probability (a 1 in 20 chance) of there being more than those volumes present, respectively. The 95- and 5-percent probabilities are considered reasonable minimum and maximum values; the mean is the average or expected value. Estimates of the UTRR for oil on the U.S. Atlantic OCS range from 0.372 Bbbl at the P95 percentile to 12.800 Bbbl at the P5 percentile with a mean of 4.312 billion barrels (Bbbl) (Table 3). Estimates of the total gas endowment range from 1.549 to 86.527 Tcf with a mean of 34.085 Tcf. The AUs in the Atlantic Region are ranked by mean UTRR in BBOE in Figure 16. The UTRR values by Planning Area and water depth categories, respectively at the 95th, mean, and 5th percentiles are presented in Table 4.

The AUs in the Atlantic Region are ranked based on mean-level UTRR in BBOE in Figure 16. The concentration of resources in select AUs, often in deepwater, becomes apparent in this column graph. The top 2 AUs have nearly two-thirds (62.4%) of the mean BOEs. With the Atlantic being a frontier area, having limited data control and conceptual AUs, the uncertainty of these estimates is significant.

The UTRR values by planning area and water depth for the 95th, mean, and 5th categories are presented in Table 4. Resources are concentrated in the Mid- with 58.4% of mean BOEs, in part due to its larger size. The Mid- is twice the area of the South and a fifth larger than the North. This corresponds to 42.1% of the AU acreage in the Mid-, 30.0% in the North, and 27.9% in the South. The South has less than 5% of mean resources. Hydrocarbon ratios are split with oil constituting 41.5% of the Atlantic’s mean BOEs.

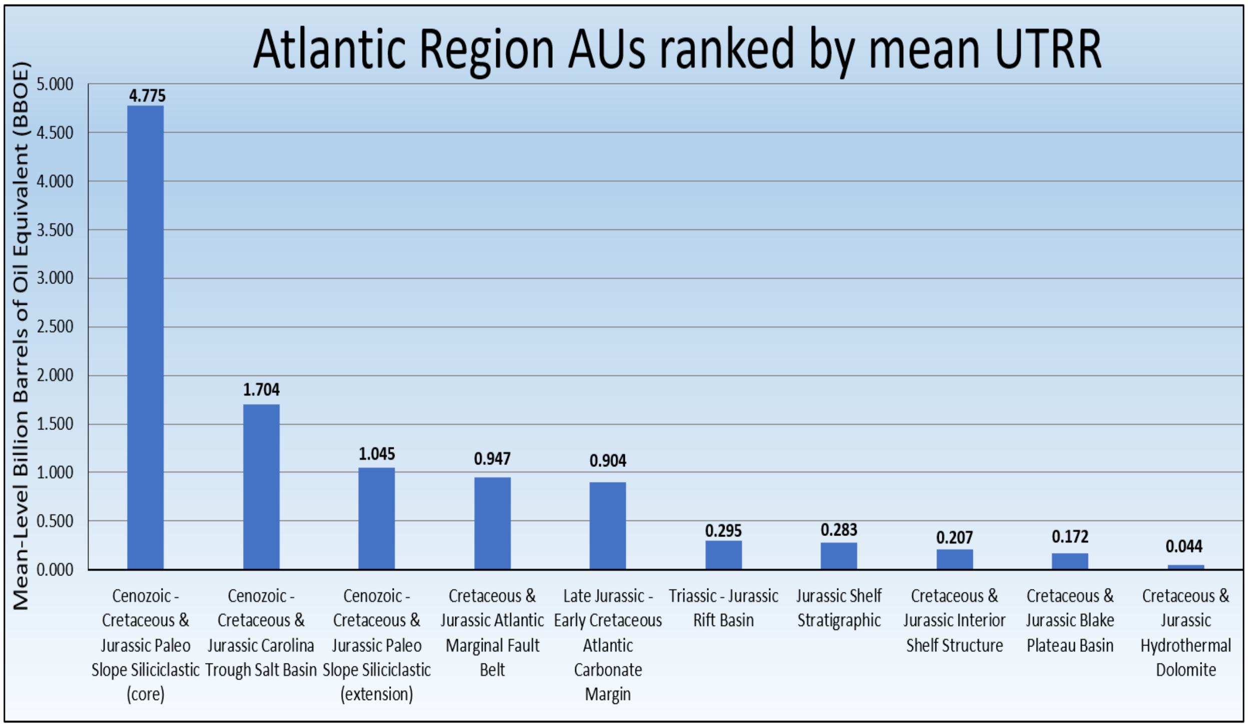

Figure 16. Atlantic OCS AUs ranked by mean UTRR.

Region	**2021 Undiscovered Technically Recoverable Resources (UTRR)**								
Planning Area	**Oil (Bbbl)**			**Gas (Tcf)**			**BOE (Bbbl)**		
Water Depth (m)	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Total Atlantic OCS	**0.644**	**4.312**	**9.938**	**5.930**	**34.085**	**70.102**	**1.701**	**10.377**	**22.412**
0-200	0.015	0.348	0.822	0.112	2.745	6.482	0.035	0.836	1.976
200-800	0.032	0.411	0.928	0.263	5.265	13.421	0.078	1.347	3.316
>800	0.000	3.554	11.528	0.000	26.076	73.913	0.000	8.194	24.680
North Atlantic	**0.040**	**1.867**	**6.360**	**0.353**	**11.497**	**38.003**	**0.102**	**3.913**	**13.122**
0-200	0.003	0.282	0.923	0.016	1.270	2.515	0.005	0.508	1.371
200-800	0.002	0.146	0.321	0.003	1.704	4.387	0.003	0.449	1.101
>800	0.000	1.439	5.757	0.000	8.524	33.574	0.000	2.956	11.731
Mid Atlantic	**0.003**	**2.247**	**6.301**	**0.038**	**21.422**	**49.023**	**0.009**	**6.058**	**15.024**
0-200	0.000	0.066	0.215	0.000	1.475	4.749	0.000	0.328	1.060
200-800	0.001	0.222	0.568	0.008	3.501	10.896	0.002	0.845	2.507
>800	0.000	1.959	5.800	0.000	16.446	40.256	0.000	4.886	12.963
South Atlantic	**0.000**	**0.198**	**0.573**	**0.000**	**1.166**	**3.622**	**0.000**	**0.406**	**1.218**
0-200	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
200-800	0.000	0.043	0.190	0.000	0.060	0.285	0.000	0.054	0.241
>800	0.000	0.155	0.403	0.000	1.107	3.810	0.000	0.352	1.081

Table 4. UTRR by planning area and water depth. Some total mean values may not equal the sum of the component values due to independent rounding.

The 200m and 800m water depth boundaries are due to economic considerations related to the UERR. Figure 17 shows how little AU acreage is shoreward of the 200m bathymetry. Of this shallower water acreage, most lies within the North and none in the South. Correspondingly, just 8.1% of the total mean BOEs are interpreted <200m water depth, of which 60.8% are in the North. Nearly 80% of the Atlantic OCS AU acreage and their mean UTRR are in water depths >800m (Figure 17 and Table 5). While the entire Atlantic OCS was evaluated for hydrocarbons, areas outside of the AUs were not interpreted as prospective and therefore were not modeled in GRASP.

5.0 UNDISCOVERED ECONOMICALLY RECOVERABLE RESOURCES

The BOEM GRASP model utilizes various distribution files focused on four main economic and engineering components to estimate UERR. The distributions from these four components are applied to UTRR to develop an estimate of economically recoverable resources. GRASP uses selected engineering parameters and oil and gas price pairs to calculate a net present value of an undiscovered field. The four main components are broken down as follows:

- Engineering assumptions;
- Costs of Exploration and production;
- Scheduling of design, fabrication and installation of infrastructure; and
- Distributions of oil and gas price pairs.

To account for variations in the economic value of gas relative to oil, BOEM applies oil and gas price pairs at different market adjustments to gas. For the 2021 assessment, five different British thermal units (BTU)-based gas price adjustments are analyzed. In these adjustments, the oil price remains the same while the gas price is set at values of 20, 30, 40, 60 and 100 percent of its market value relative to oil. The adjustment values are chosen based on past market fluctuations. For the 2021 assessment of UERR, BOEM assessed 50 different price pairs across all five gas price adjustments and ten modeled oil prices per barrel. In contrast, the 2016 assessment used four gas price adjustments and 48 price pairs. The 30 percent adjustment volume is reported for both 2016 and 2021 assessments. The gas conversion used for BOEs is 5.62 MCFG per barrel of oil, unchanged from BOEM's 2016 assessment (BOEM, 2016).

Major inputs affecting UERR are the UTRR, the size of the pools, the water depth, and the distance from shore. Figure 18 and Figure 19 show that a majority of mean UTRR are projected to be uneconomic at the 3 reported prices points. Correspondingly, the Atlantic is a frontier basin with no oil and gas infrastructure and an overwhelming majority of resources in deep and ultra-deepwater, far from shore. At the lowest price point reported, only a quarter (28%) would be economic. At 160/bbl, which corresponds to the historical high seen briefly in 2008 when adjusted for inflation (Trading Economics, 2021; McMahon, 2021), only 45.5% of UTTRs would be economic. Compared to the U.S. GOM, where oil and gas infrastructure and facilities are established, 78% of the mean UTRR become economic at the $160 price point. For the GOM at the $40/bbl, 40.4% is economic. This is a similar percent to what is economic for the Atlantic during the most favorable economic environment modeled (BOEM, 2021).

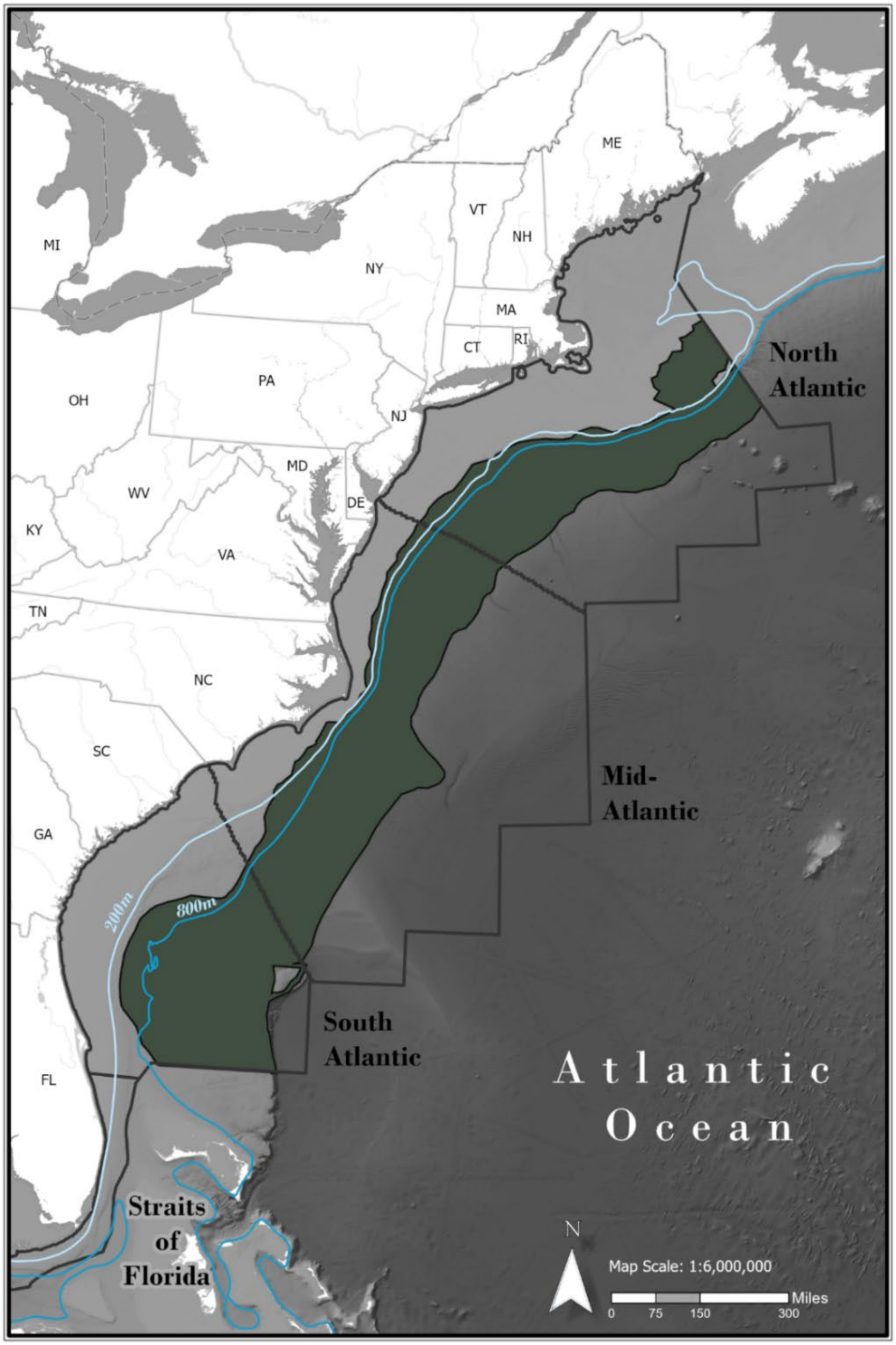

Figure 17. The 200m (light blue) and 800m (blue) isobaths for the U.S. Atlantic OCS overlain on the collective assessment area (dark green polygon) representing all combined acreage from the 10 AUs. Isobaths generated from GEBCO 2021 gridded bathymetric dataset (GEBCO, 2021). Planning areas and state boundaries and their labels are shown.

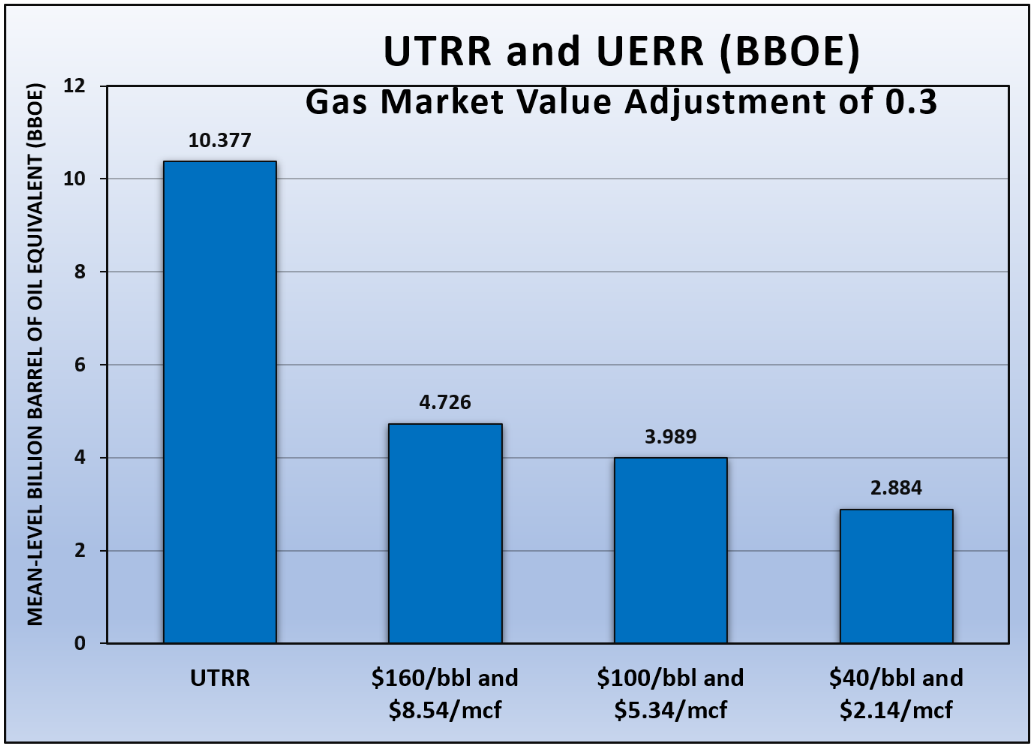

Figure 18. Portions of mean UTRR that are economic under three price pairs for the Atlantic Region.

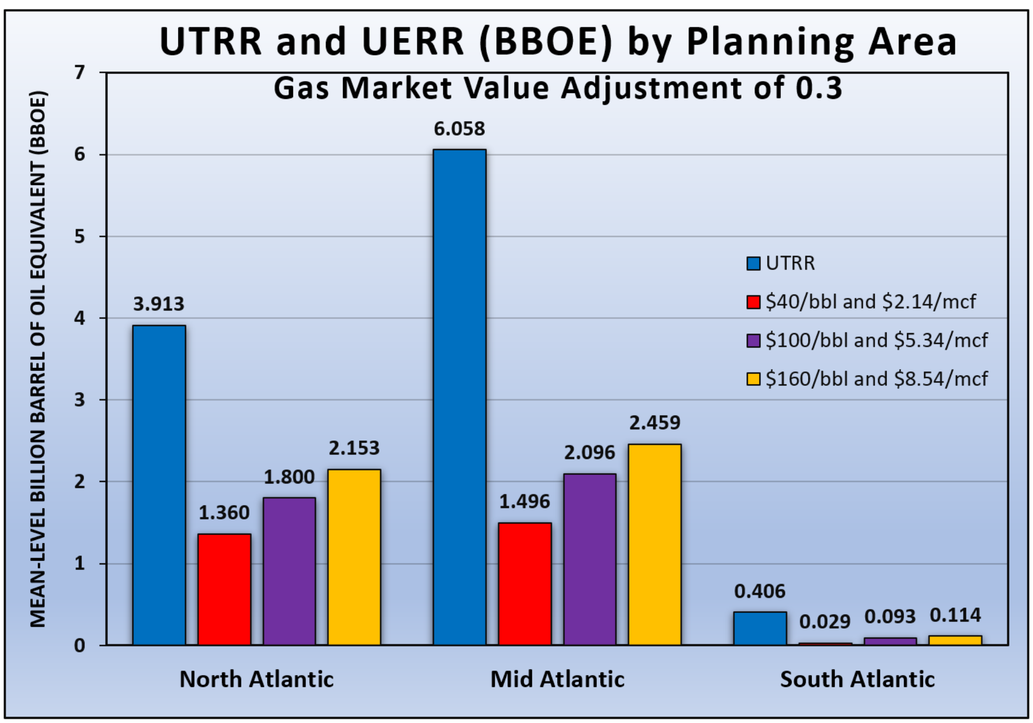

Figure 19. Portions of mean UTRR that are economic under three price pairs for each planning area.

[Figure 19](#) highlights the expected resources at both the UTRR and the UERR for 3 price pairs for each planning area. The North is modeled to have the best economics associated with its resources as 34.8%, 46.0%, and 55.0% of mean BOE are economic at the $40, $100, and $160 price points respectively. The South is the least economic with 7.1%, 22.9%, and 28.1% economic at these same price points. The Mid- is in the middle with 24.7%, 34.6%, and 40.6% modeled economic at the $40, $100, and $160 prices respectively. However, given its much larger mean UTRR, the Mid- generates the largest mean UERR for each price point in BOEM's model (Figure 19 and Table 5).

Region	2021 Undiscovered Economically Recoverable Resources (UERR) at the Mean-Level Gas Market Value Adjustment of 0.3														
Planning Area	$30/bbl and $1.60/mcf			$40/bbl and $2.14/mcf			$60/bbl and $3.20/mcf			$100/bbl and $5.34/mcf			$160/bbl and $8.54/mcf		
Water Depth (m)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)	Oil (Bbbl)	Gas (Tcf)	BOE (Bbbl)
Total Atlantic OCS	**2.056**	**0.000**	**2.056**	**2.884**	**0.000**	**2.884**	**3.511**	**0.000**	**3.511**	**3.825**	**0.919**	**3.989**	**3.948**	**4.375**	**4.726**
0-200	0.186	0.000	0.186	0.259	0.000	0.259	0.306	0.000	0.306	0.326	0.021	0.329	0.333	0.093	0.349
200-800	0.154	0.000	0.154	0.232	0.000	0.232	0.302	0.000	0.302	0.341	0.058	0.351	0.357	0.318	0.413
>800	1.716	0.000	1.716	2.394	0.000	2.394	2.902	0.000	2.902	3.158	0.840	3.308	3.258	3.964	3.964
North Atlantic	**1.050**	**0.000**	**1.050**	**1.366**	**0.000**	**1.366**	**1.611**	**0.000**	**1.611**	**1.726**	**0.498**	**1.815**	**1.770**	**2.249**	**2.153**
0-200	0.167	0.000	0.167	0.223	0.000	0.223	0.257	0.000	0.257	0.270	0.018	0.273	0.274	0.061	0.285
200-800	0.062	0.000	0.062	0.091	0.000	0.091	0.120	0.000	0.120	0.133	0.023	0.137	0.137	0.113	0.157
>800	0.818	0.000	0.818	1.046	0.000	1.046	1.224	0.000	1.224	1.309	0.457	1.390	1.343	2.071	1.711
Mid Atlantic	**0.999**	**0.000**	**0.999**	**1.496**	**0.000**	**1.496**	**1.852**	**0.000**	**1.852**	**2.021**	**0.421**	**2.096**	**2.082**	**2.118**	**2.459**
0-200	0.018	0.000	0.018	0.036	0.000	0.036	0.050	0.000	0.050	0.056	0.003	0.057	0.058	0.033	0.064
200-800	0.092	0.000	0.092	0.140	0.000	0.140	0.179	0.000	0.179	0.197	0.035	0.203	0.203	0.205	0.239
>800	0.889	0.000	0.889	1.319	0.000	1.319	1.623	0.000	1.623	1.768	0.383	1.836	1.821	1.880	2.155
South Atlantic	**0.009**	**0.000**	**0.009**	**0.029**	**0.000**	**0.029**	**0.060**	**0.000**	**0.060**	**0.093**	**0.000**	**0.093**	**0.111**	**0.013**	**0.114**
0-200	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
200-800	0.000	0.000	0.000	>0.000	0.000	>0.000	0.004	0.000	0.004	0.012	0.000	0.012	0.017	0.000	0.017
>800	0.009	0.000	0.009	0.028	0.000	0.028	0.056	0.000	0.056	0.081	0.000	0.081	0.095	0.013	0.097

Table 5. UERR with a gas market value adjustment of 0.3. Some total mean values may not equal the sum of the component values due to independent rounding.

Table 5 shows the mean UERR by water depth for the entire Atlantic OCS and by planning area. The percentage of UERR in <200m, 200–800m, or >800m water depths are comparable to their UTRR percentages for the same water depths. This is seen across the price pairs. Expectations that the higher costs associated with deeper water, farther from shore development would reduce UERR percentages, especially at lower prices, wasn't strongly seen. The AUs in deeper water often had analogs with larger fields, which would model larger pools. More hydrocarbons in a single pool can be developed for less cost. Fields produced by FPS, whether FPSO or FLNG, do not require infrastructure to shore and therefore differ less substantially in cost as a function of water depth. The Atlantic has a greater likelihood of hydrocarbon production from FPS than the GOM, due to its frontier status. Lastly, some differences may be obscured by model uncertainty.

6.0 ACKNOWLEDGEMENTS

This report was built largely on the 2016 Atlantic Assessment and the work of the late Paul Post and the 2016 team he helped lead. Their efforts advanced greatly from prior reports. This latest inventory (2021) relied on analog activity updates, minor changes to risking methodology, and a continued pursuit of new datasets for additional improvements. The support and review of this report by BOEM management and reviewers was much appreciated.

Right. Paul Post in Carnival garb.

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8.0 APPENDIX

Play and Prospect Risk Analysis Form

Assessment Province:	Atlantic	**Assessment Unit Name:**	1) K & J Atlantic Marginal Fault Belt
Assessor(s):	Dominic Smith	**Assessment Unit UAI:**	AAABAMAB
Date:	March 2020	**Assessment:**	2021 National Assessment

Risk Components and Associated Elements		**Play Chance Factors**		**Prospect Chance Factors**	
For each component, a quantitative probability must be assigned as defined below.		**Enter Element Success in this Column**	**Component Success (Component Probability = Lowest Probability in group)**	**Enter Element Success in this Column**	**Component Success (Component Probability = Lowest Probability in group)**
1. Hydrocarbon Fill component	**1**		***0.7000***		***0.6000***
a. Presence of a Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.	1a	0.7000		0.6000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.	1b	0.7000		0.6000	
2. Reservoir component	**2**		***0.7000***		***0.5000***
a. Presence of reservoir facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.	2a	0.8000		0.7000	
b. Reservoir quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity, and permeability.	2b	0.7000		0.5000	
3. Trap component	**3**		***0.7000***		***0.6000***
a. Presence of trap					
Probability of presence of the trap with a minimum rock volume.	3a	0.7000		0.6000	
b. Effective seal mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.	3b	0.9000		0.7000	
Overall Play Chance (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**0.34**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the Play exists (where all play chance factors = 1.0)***					**0.18**
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	***0.0617***

Probabilities are as follows:	
Component Probably Exists	**1.0 - 0.8**
Component will Possibly Exist	**0.8 - 0.6**
Equally Likely Component is Present or Absent	**0.6 - 0.4**
Component is Possibly Lacking	**0.4 - 0.2**
Component is Probably Lacking	**0.2 - 0.0**

NOTE: If any probability is 0, the Petroleum System does not exist.

Comments:

Play and Prospect Risk Analysis Form

Assessment Province:	Atlantic	Assessment Unit Name:	2) Cz - K & J Carolina Trough Salt Basin
Assessor(s):	Dominic Smith	Assessment Unit UAI:	AAABAMAC
Date:	March 2020	Assessment:	2021 National Assessment

Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill component	1		***0.8000***		***0.7000***
a. Presence of a Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.	1a	0.8000		0.7000	
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.	1b	0.8000		0.7000	
2. Reservoir component	2		***0.7000***		***0.6000***
a. Presence of reservoir facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.	2a	0.8000		0.7000	
b. Reservoir quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity, and permeability.	2b	0.7000		0.6000	
3. Trap component	3		***0.9000***		***0.8000***
a. Presence of trap Probability of presence of the trap with a minimum rock volume.	3a	0.9000		0.8000	
b. Effective seal mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.	3b	0.9000		0.8000	
Overall Play Chance (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**0.50**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the Play exists (where all play chance factors = 1.0)***					**0.34**
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	***0.1693***

Probabilities are as follows:

Component Probably Exists	**1.0 - 0.8**
Component will Possibly Exist	**0.8 - 0.6**
Equally Likely Component is Present or Absent	**0.6 - 0.4**
Component is Possibly Lacking	**0.4 - 0.2**
Component is Probably Lacking	**0.2 - 0.0**

NOTE: If any probability is 0, the Petroleum System does not exist.

Comments:

Play and Prospect Risk Analysis Form

Assessment Province:	Atlantic	Assessment Unit Name:	3) LJ–EK Atlantic Carbonate Margin
Assessor(s):	Dominic Smith	Assessment Unit UAI:	AAABAMAA
Date:	March 2020	Assessment:	2021 National Assessment

Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill component	1		*0.6000*		*0.5000*
a. Presence of a Quality, Effective, Mature Source Rock					
Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.	1a	0.7000		0.6000	
b. Effective Expulsion and Migration					
Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.	1b	0.6000		0.5000	
2. Reservoir component	2		*0.6000*		*0.5000*
a. Presence of reservoir facies					
Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.	2a	0.7000		0.6000	
b. Reservoir quality					
Probability of effectiveness of the reservoir, with respect to minimum effective porosity, and permeability.	2b	0.6000		0.5000	
3. Trap component	3		*0.8000*		*0.7000*
a. Presence of trap					
Probability of presence of the trap with a minimum rock volume.	3a	0.8000		0.7000	
b. Effective seal mechanism					
Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.	3b	0.8000		0.7000	
Overall Play Chance (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			0.29		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors*					0.18
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	*0.0504*

[1] ***Assumes that the Play exists (where all play chance factors = 1.0)***

Probabilities are as follows:	
Component Probably Exists	1.0 - 0.8
Component will Possibly Exist	0.8 - 0.6
Equally Likely Component is Present or Absent	0.6 - 0.4
Component is Possibly Lacking	0.4 - 0.2
Component is Probably Lacking	0.2 - 0.0

NOTE: If any probability is 0, the Petroleum System does not exist.

Comments:

Play and Prospect Risk Analysis Form

Assessment Province:	Atlantic	Assessment Unit Name:	4) Cz–K & J Paleo Slope Siliciclastic Core
Assessor(s):	Dominic Smith	Assessment Unit UAI:	AAABAMAI
Date:	March 2020	Assessment:	2021 National Assessment

Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill component	1		0.6000		0.5000
a. Presence of a Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.	1a	0.6000		0.5000	
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.	1b	0.6000		0.5000	
2. Reservoir component	2		0.7000		0.6000
a. Presence of reservoir facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.	2a	0.7000		0.6000	
b. Reservoir quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity, and permeability.	2b	0.7000		0.6000	
3. Trap component	3		0.7000		0.6000
a. Presence of trap Probability of presence of the trap with a minimum rock volume.	3a	0.7000		0.6000	
b. Effective seal mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.	3b	0.9000		0.8000	
Overall Play Chance (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			0.29		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the Play exists (where all play chance factors = 1.0)***					0.18
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	0.0529

Probabilities are as follows:

Component Probably Exists	1.0 - 0.8
Component will Possibly Exist	0.8 - 0.6
Equally Likely Component is Present or Absent	0.6 - 0.4
Component is Possibly Lacking	0.4 - 0.2
Component is Probably Lacking	0.2 - 0.0

NOTE: If any probability is 0, the Petroleum System does not exist.

Comments:

Play and Prospect Risk Analysis Form					
Assessment Province: Atlantic	Assessment Unit Name: 5) Cz–K & J Paleo Slope Siliciclastic Extension				
Assessor(s): Dominic Smith	Assessment Unit UAI: AAABAMAJ				
Date: March 2020	Assessment: 2021 National Assessment				
Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill component	1		0.5000		0.4000
a. Presence of a Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.	1a	0.5000		0.4000	
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.	1b	0.5000		0.4000	
2. Reservoir component	2		0.6000		0.5000
a. Presence of reservoir facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.	2a	0.6000		0.5000	
b. Reservoir quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity, and permeability.	2b	0.6000		0.5000	
3. Trap component	3		0.6000		0.6000
a. Presence of trap Probability of presence of the trap with a minimum rock volume.	3a	0.6000		0.6000	
b. Effective seal mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.	3b	0.9000		0.9000	
Overall Play Chance (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			0.18		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the Play exists (where all play chance factors = 1.0)***					0.12
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	0.0216

Probabilities are as follows:	
Component Probably Exists	1.0 - 0.8
Component will Possibly Exist	0.8 - 0.6
Equally Likely Component is Present or Absent	0.6 - 0.4
Component is Possibly Lacking	0.4 - 0.2
Component is Probably Lacking	0.2 - 0.0

NOTE: If any probability is 0, the Petroleum System does not exist.

Comments:

Play and Prospect Risk Analysis Form

Assessment Province:	Atlantic	Assessment Unit Name:	6) K & J Blake Plateau Basin
Assessor(s):	Dominic Smith	Assessment Unit UAI:	AAABAMAF
Date:	March 2020	Assessment:	2021 National Assessment

Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill component	1		*0.6000*		*0.5000*
a. Presence of a Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.	1a	0.7000		0.6000	
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.	1b	0.6000		0.5000	
2. Reservoir component	2		*0.6000*		*0.5000*
a. Presence of reservoir facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.	2a	0.7000		0.6000	
b. Reservoir quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity, and permeability.	2b	0.6000		0.5000	
3. Trap component	3		*0.8000*		*0.7000*
a. Presence of trap Probability of presence of the trap with a minimum rock volume.	3a	0.8000		0.7000	
b. Effective seal mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.	3b	0.9000		0.8000	
Overall Play Chance (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			0.29		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the Play exists (where all play chance factors = 1.0)***					0.18
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	*0.0504*

Probabilities are as follows:

Component Probably Exists	**1.0 - 0.8**
Component will Possibly Exist	**0.8 - 0.6**
Equally Likely Component is Present or Absent	**0.6 - 0.4**
Component is Possibly Lacking	**0.4 - 0.2**
Component is Probably Lacking	**0.2 - 0.0**

NOTE: If any probability is 0, the Petroleum System does not exist.

Comments:

Play and Prospect Risk Analysis Form

Assessment Province:	Atlantic	Assessment Unit Name:	7) Jurassic Shelf Stratigraphic
Assessor(s):	Dominic Smith	Assessment Unit UAI:	AAABAMAD
Date:	March 2020	Assessment:	2021 National Assessment

Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill component	1		0.5000		0.4000
a. Presence of a Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.	1a	0.6000		0.5000	
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.	1b	0.5000		0.4000	
2. Reservoir component	2		0.7000		0.6000
a. Presence of reservoir facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.	2a	0.8000		0.7000	
b. Reservoir quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity, and permeability.	2b	0.7000		0.6000	
3. Trap component	3		0.7000		0.6000
a. Presence of trap Probability of presence of the trap with a minimum rock volume.	3a	0.7000		0.6000	
b. Effective seal mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.	3b	0.9000		0.8000	
Overall Play Chance (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			0.25		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] *Assumes that the Play exists (where all play chance factors = 1.0)*					0.14
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	0.0353

Probabilities are as follows:

Component Probably Exists	1.0 - 0.8
Component will Possibly Exist	0.8 - 0.6
Equally Likely Component is Present or Absent	0.6 - 0.4
Component is Possibly Lacking	0.4 - 0.2
Component is Probably Lacking	0.2 - 0.0

NOTE: If any probability is 0, the Petroleum System does not exist.

Comments:

Play and Prospect Risk Analysis Form

Assessment Province:	Atlantic	Assessment Unit Name:	8) K & J Interior Shelf Structure
Assessor(s):	Dominic Smith	Assessment Unit UAI:	AAABAMAE
Date:	March 2020	Assessment:	2021 National Assessment

Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill component	1		*0.9000*		*0.7000*
a. Presence of a Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.	1a	0.9000		0.8000	
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.	1b	1.0000		0.7000	
2. Reservoir component	2		*0.8000*		*0.4000*
a. Presence of reservoir facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.	2a	1.0000		0.8000	
b. Reservoir quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity, and permeability.	2b	0.8000		0.4000	
3. Trap component	3		*1.0000*		*0.5000*
a. Presence of trap Probability of presence of the trap with a minimum rock volume.	3a	1.0000		0.5000	
b. Effective seal mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.	3b	1.0000		0.9000	
Overall Play Chance (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			0.72		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] *Assumes that the Play exists (where all play chance factors = 1.0)*					0.14
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	*0.1008*

Probabilities are as follows:	
Component Probably Exists	1.0 - 0.8
Component will Possibly Exist	0.8 - 0.6
Equally Likely Component is Present or Absent	0.6 - 0.4
Component is Possibly Lacking	0.4 - 0.2
Component is Probably Lacking	0.2 - 0.0

NOTE: If any probability is 0, the Petroleum System does not exist.

Comments:

Play and Prospect Risk Analysis Form

Assessment Province:	Atlantic	Assessment Unit Name:	9) Tr– J Rift Basin
Assessor(s):	Dominic Smith	Assessment Unit UAI:	AAABAMAG
Date:	March 2020	Assessment:	2021 National Assessment

Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill component	1		*0.7000*		*0.6000*
a. Presence of a Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.	1a	0.7000		0.6000	
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.	1b	0.7000		0.6000	
2. Reservoir component	2		*0.7000*		*0.6000*
a. Presence of reservoir facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.	2a	0.7000		0.6000	
b. Reservoir quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity, and permeability.	2b	0.7000		0.6000	
3. Trap component	3		*0.8000*		*0.7000*
a. Presence of trap Probability of presence of the trap with a minimum rock volume.	3a	0.9000		0.8000	
b. Effective seal mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.	3b	0.8000		0.7000	
Overall Play Chance (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			0.39		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the Play exists (where all play chance factors = 1.0)***					0.25
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	*0.0988*

Probabilities are as follows:

Component Probably Exists	1.0 - 0.8
Component will Possibly Exist	0.8 - 0.6
Equally Likely Component is Present or Absent	0.6 - 0.4
Component is Possibly Lacking	0.4 - 0.2
Component is Probably Lacking	0.2 - 0.0

NOTE: If any probability is 0, the Petroleum System does not exist.

Comments:

Play and Prospect Risk Analysis Form

Assessment Province:	Atlantic	**Assessment Unit Name:**	10) K & J Hydrothermal Dolomite
Assessor(s):	Dominic Smith	**Assessment Unit UAI:**	AAABAMAH
Date:	March 2020	**Assessment:**	2021 National Assessment

Risk Components and Associated Elements		Play Chance Factors		Prospect Chance Factors	
For each component, a quantitative probability must be assigned as defined below.		Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)	Enter Element Success in this Column	Component Success (Component Probability = Lowest Probability in group)
1. Hydrocarbon Fill component	1		***0.6000***		***0.5000***
a. Presence of a Quality, Effective, Mature Source Rock Probability of efficient source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the reservoirs.	1a	0.7000		0.6000	
b. Effective Expulsion and Migration Probability of effective timing of expulsion and migration of hydrocarbons from the source rock to the reservoirs.	1b	0.6000		0.5000	
2. Reservoir component	2		***0.5000***		***0.4000***
a. Presence of reservoir facies Probability of presence of reservoir facies with a minimum net thickness and net/gross ratio.	2a	0.6000		0.5000	
b. Reservoir quality Probability of effectiveness of the reservoir, with respect to minimum effective porosity, and permeability.	2b	0.5000		0.4000	
3. Trap component	3		***0.8000***		***0.7000***
a. Presence of trap Probability of presence of the trap with a minimum rock volume.	3a	0.8000		0.7000	
b. Effective seal mechanism Probability of effective seal mechanism for the trap and effective preservation of hydrocarbons in the prospects after accumulation.	3b	0.8000		0.7000	
Overall Play Chance (1 * 2 * 3) *Product of All Subjective Play Chance Factors*			**0.24**		
Average Conditional Prospect Chance[1] (1 * 2 * 3) *Product of All Subjective Conditional Prospect Chance Factors* [1] ***Assumes that the Play exists (where all play chance factors = 1.0)***					**0.14**
Exploration Chance *(Product of Overall Play Chance and Average Conditional Prospect Chance)*				**Overall Exploration Chance**	***0.0336***

Probabilities are as follows:

Component Probably Exists	**1.0 - 0.8**
Component will Possibly Exist	**0.8 - 0.6**
Equally Likely Component is Present or Absent	**0.6 - 0.4**
Component is Possibly Lacking	**0.4 - 0.2**
Component is Probably Lacking	**0.2 - 0.0**

NOTE: If any probability is 0, the Petroleum System does not exist.

Comments:

Department of the Interior (DOI)

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island communities.

Bureau of Ocean Energy Management (BOEM)

The Bureau of Ocean Energy Management works to manage the exploration and development of the Nation's offshore resources in a way that appropriately balances economic development, energy independence, and environmental protection through oil and gas leases, renewable energy development, and environmental reviews and studies.