BSEE Bureau of Safety and Environmental Enforcement

BOEM BUREAU OF OCEAN ENERGY MANAGEMENT

INFORMATION/BRIEFING REPORT

Date: November 19, 2019

Prepared By:

Scott A. Angelle
Director, Bureau of Safety and Environmental Enforcement (BSEE)

Walter D. Cruickshank
Acting Director, Bureau of Ocean Energy Management (BOEM)

Subject: Gulf of Mexico Data and Analysis/ Leasing, Drilling and Production
Gulf of Mexico Shallow Water Potential Stranded Assets

INTRODUCTION

The purpose of this briefing report is to provide data and analyses pertaining to leasing, production, drilling, royalties, financing, and resources trends on the Outer Continental Shelf (OCS) in the Gulf of Mexico (GOM) Shelf area (Shelf), and to advise a path forward for the nation regarding special case royalty relief in the Shelf area to avoid waste, accomplish conservation of resources, to stimulate production as contemplated by the Outer Continental Shelf Lands Act (OCSLA, at 43 USC 1332 (3), 43 USC 1334(a), 43 USC 1334(g) and 1337(a)(3)) and its implementing regulations (30 CFR Part 203). For purposes of this report, the Shelf is defined as the portions of the OCS in water depths less than 200 meters (m). After a careful and detailed review of both Shelf and Deepwater data, it is apparent that the GOM is functioning as two distinct provinces – one active and one in sharp decline, as evidenced by Table 1.

This information/briefing report is a comprehensive presentation of the sharp decline of the GOM Shelf; however, this is not a new observation. The Issue Paper entitled, "Shallow Water Gulf of Mexico Decline," dated March 14, 2019 (Attachment 1), documents that BSEE's predecessor agency, the Minerals Management Service, had identified as early as two decades ago (1999), the decline of the following factors associated with the Shelf: leasing, discoveries, reserves, average field sizes, and production.

Previous attempts to address these issues included regulations offering shallow water deep-drilling royalty incentives, and modifications to newly issued shallow water leases, such as royalty suspension volumes and drilling stipulations to allow lessees to earn longer lease terms. Despite those efforts, the Shelf has continued its decline.

In addition to the BSEE and BOEM staff research, this informational/briefing report references data from the external study contracted by BSEE, BOEM, and the Bureau of Land Management (BLM). This November 2018 study is entitled, *2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Gulf of Mexico International Comparison*, and was prepared by IHS Markit (IHS REPORT).

Table 1. – Comparison of Characteristics of Gulf of Mexico Shelf to Deepwater

CHARACTERISTICS	SHELF	DEEPWATER
DOMINANT COMMODITY	Natural gas	Oil
FIRST WELL DRILLED	1947	1974
FIRST PRODUCTION	1947	1977
WELLS DRILLED	47,765	5,485
PLATFORMS INSTALLED (ALL TIME)	6,991	80
PLATFORMS REMOVED (ALL TIME)	5,102	9
RATIO OF PLATFORM INSTALLATION TO REMOVAL (ALL TIME)	1.37 to 1	8.8 to 1
PLATFORMS INSTALLED (LAST TWENTY YEARS)	1,300	50
PLATFORMS REMOVED (LAST TWENTY YEARS)	3,438	7
RATIO OF PLATFORM INSTALLATION TO REMOVAL (LAST TWENTY YEARS)	(0.37 to 1)	7.1 to 1
PLATFORMS INSTALLED (LAST FIVE YEARS)	13	9
PLATFORMS REMOVED (LAST FIVE YEARS)	516	5
RATIO OF PLATFORM INSTALLATION TO REMOVAL (LAST FIVE YEARS)	(.025 to 1)	1.8 to 1
PLATFORMS INSTALLED (CALENDAR YEAR 2018)	0	2
PLATFORMS REMOVED (CALENDAR YEAR 2018)	97	1
PRODUCING PLATFORMS	954	61
% GOM OIL PRODUCTION (2017)	11%	89%
% GOM NATURAL GAS PRODUCTION (2017)	33%	67%
% GOM LEASES	33%	67%
ROYALTY RATE FOR MAJORITY LEASES	16.67%	18.75%
% LEASES HELD BY MAJORS*	5%	54%
% LEASES HELD BY NON-MAJORS*	95%	46%
AVERAGE RESERVOIR SIZE (MMBOE) LAST TEN YEARS	0.83 MMBOE	9.0 MMBOE (10.8x larger)
% GOM OPERATORS/PUBLIC COMPANIES	57%	89%
% GOM OPERATORS/ PRIVATE COMPANIES	43%	11%
% BY LOCATION OF GOM PROPERTIES SUBJECT TO BANKRUPTCY (2015-2018)	76.66%	23.34%
% CHANGE IN OIL PRODUCTION LAST TWENTY YEARS	(-77%)	198%
% CHANGE IN NATURAL GAS PRODUCTION LAST TWENTY YEARS	(-92%)	NO CHANGE
% CHANGE OF WELLS DRILLED FROM 2008 TO 2018	(-89%)	(-5%)
% CHANGE NUMBER OF PRODUCING WELLS LAST TWENTY YEARS	(-61%)	73%
LEASED ACREAGE	4,043,997	9,790,291
% AREA LEASED ACREAGE	6.10%	10.41%

"Majors" is defined as those lease holders in the Top 30 Oil & Gas Companies by 2017 Revenue.
This includes Exxon Mobil, Royal Dutch Shell, BP, TOTAL, Eni, Chevron, Marathon, Petrobras, Equinor (Statoil), ConocoPhillips, & their subsidiaries.

CONSERVATION OF RESOURCES IS A DOI RESPONSIBLITY
The OCS Lands Act authorizes the Secretary of the Interior to issue regulations in the interest of conservation of OCS natural resources. The term "conservation" is not defined in the statute, but it is discussed in the legislative history and testimony provided by the U.S. Geological Survey Conservation Division during the consideration of the 1978 amendments. The OCS Lands Act legislative history indicates that "conservation" was used in a broad sense. The Senate Committee considering the 1978 amendments to the OCS Lands Act stated that the term "conservation" includes both attaining maximum production and protecting the mineral resource from waste. (OCSLA 43 USC 1334(a)) Conservation of remaining GOM shelf hydrocarbon resources may necessitate proactive action by DOI. Conservation of OCS resources also promotes economic efficiency. This means that leasing, development, and production activities should be carried out in a manner that will increase if not maximize the net economic value to society from the development of OCS resources.

BACKGROUND
The largest fields in a hydrocarbon basin tend to be discovered early in the exploration cycle, while smaller fields are generally discovered in the mature phase of exploration. (Baud, et al., 2002). By all accounts, the GOM Shelf is a mature oil and natural gas basin, first produced more than 70 years ago. Thus, the remaining Shelf opportunities are increasingly limited in size. "Mature fields may still have potential but since they are presumably marginal targets a special effort is required to pursue these high-risk, small-upside opportunities." (Kaiser & Siddhartha, 2018). Smaller companies usually make those special efforts "…because the size of the projects does not often meet the scale requirements for the majors." (Diffley, et al., 2010). Historically, Shelf fields were largely the domain of the major oil companies, who sold them to large independents, and who, after additional production, sold the assets to smaller companies. (Kaiser & Siddhartha, 2018). The current lease ownership reflected in Figure 1 illustrates a distinction between the two basins in terms of ownership; major companies own the majority of the Deepwater leases and "non-major" companies own the majority of the Shelf leases.

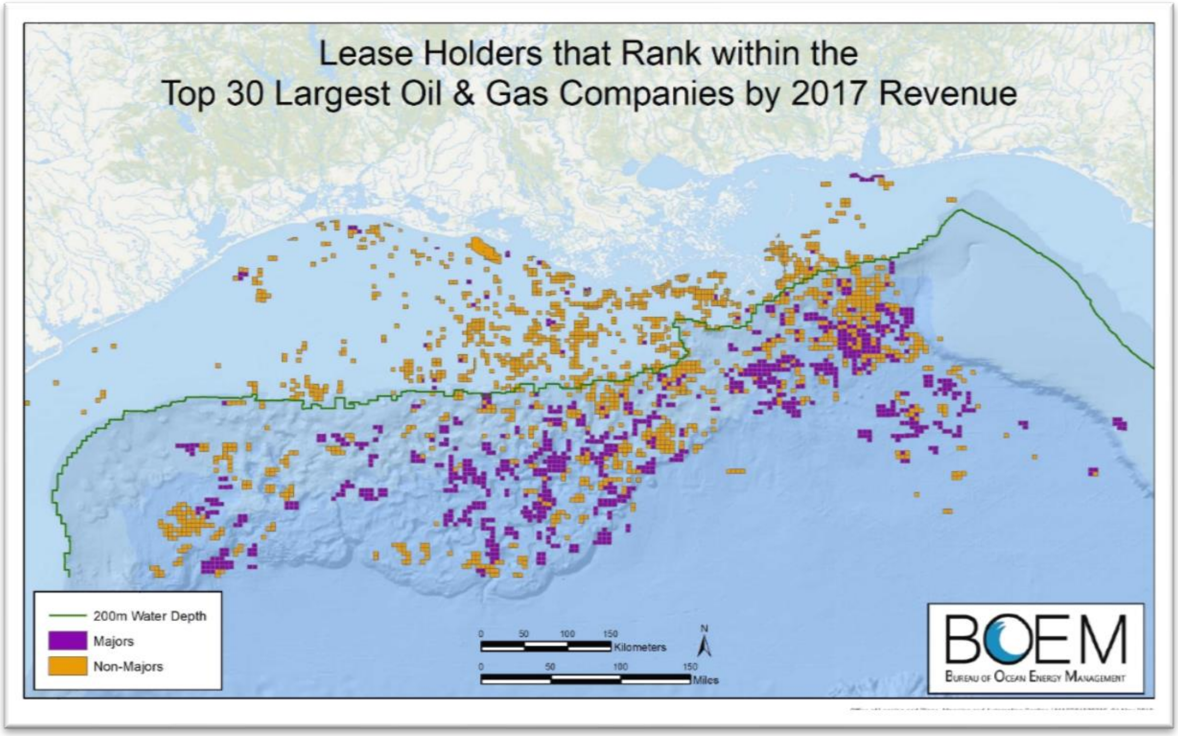
The IHS Report states:

> "…the U.S. GOM shelf is limited in terms of resource availability. With the expected field sizes matching the small reserve size under this study, the best hope for such projects on the shelf is reliance on existing facilities and infrastructure. The market conditions do not favor development of the small reserves in the U.S. GOM shelf on a stand-alone basis. With the wave of decommissioning continuing strong in the shelf—more than 100 structures being decommissioned each year—the establishment of efficient policy solutions that encourage such developments could be necessary."[1]

[1] IHS Report, *2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Gulf of Mexico International Comparison*, page 35

Figure 1 – Lease Ownership Patterns in the Gulf of Mexico

Gulf of Mexico Region Active Leases
(as of April 15, 2019)



* "Majors" is defined as those lease holders in the Top 30 Oil & Gas Companies by 2017 Revenue. This includes Exxon Mobil, Royal Dutch Shell, BP, TOTAL, Eni, Chevron, Marathon, Petrobras, Equinor (Statoil), ConocoPhillips, & their subsidiaries.

As the steward of the Nation's offshore mineral resources, the Department of the Interior (DOI) is concerned with the diminishing economic opportunities, and thus the likelihood of resource development, on the Shelf. Although reversing the natural decline may not be possible, promoting the recovery of the remaining resources on the Shelf, while protecting the interests of the American public, is consistent with policy established by Congress under OCSLA (see, e.g., 43 U.S.C. §§ 1332(3), 1337(a)(3)) and may be accomplished by adapting policies to the current economic and geologic realities. It is important to safely and responsibly extract economically recoverable hydrocarbons, while the infrastructure to do so is still in place. Companies evaluate the economics of projects, and "As long as the net revenue generated by a structure is greater than its direct operating cost, the structure will likely continue to produce." (Kaiser & Siddhartha, 2018). Once production from a structure drops below that economic threshold, however, the wells are typically abandoned and the platform is scheduled for removal, making it nearly impossible, absent some unforeseen technological advances or substantial increases in commodity prices, to justify the re-installation of platforms with only a fraction of the reservoir remaining.

Consequently, the remaining resources may be stranded for the foreseeable future, which reduces the potential public benefit from the development of OCS oil and gas resources as these resources would not be produced and the associated royalties would not be recovered.

Reserves are defined as hydrocarbons that are commercially recoverable by application of development projects to known accumulations. They are discovered, recoverable, commercial, and remaining. These volumes are expected to be produced; however, contingent resources may be more at risk of not being produced. Contingent resources are hydrocarbons from known accumulations that are potentially recoverable by application of development projects, but which may not be recovered. In some cases, contingent resources have been identified by a previously drilled and plugged well, and capital expenditures are required to access these volumes. In water depths less than 200 meters, the remaining volumes of hydrocarbons in each category are estimated to be as follows:

Reserves: 254 MMBO, 1,875 BCF

Contingent resources (discovered resources): 179 MMBO, 4,567 BCF

October 1, 2019 NYMEX pricing: $53.60/BO, $2.36/MMBTU (~$2.36/MCF)

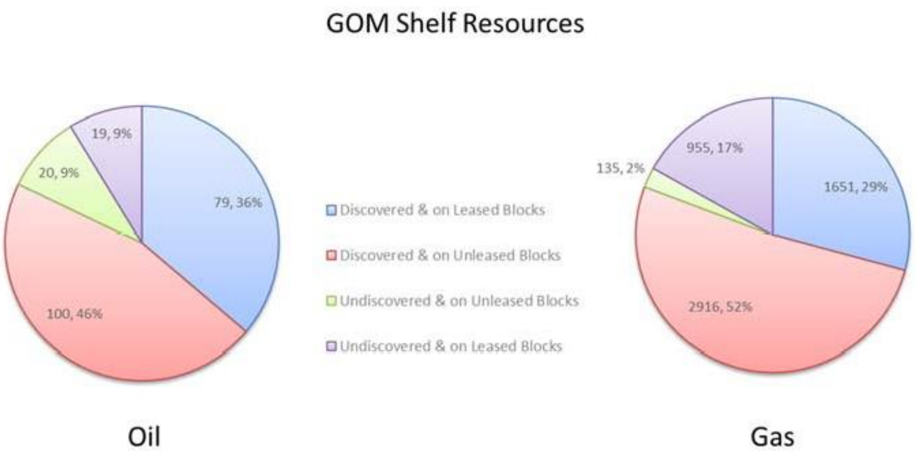
Using the definitions provided above, it is assumed that reserves will be recovered, while contingent resources are at risk of not being developed and produced. Using NYMEX pricing of October 1, 2019, this equates to $20 billion of potential stranded value in water depths less than 200 meters. The government's royalty share would be a portion of this $20 billion, depending on each lease's applicable royalty rate (the majority of GOM Shelf leases have a 16.67% royalty rate) and allowable costs. Without a significant increase in drilling activity, there is a significant risk that many of these resources might never be developed, and as a result, the potential royalties might be lost.

The discovered contingent resources estimates (179 MMBO and 4,567 BCF) for the Shelf can be subdivided into those on leased (79 MMBO and 1,651 BCF) and unleased (100 MMBO and 2,916 BCF) blocks. In addition, there are additional undiscovered resources on the Shelf. These resources are difficult to quantify since they have never been penetrated by wells, but it is estimated that there may be about 19 MMBO and 955 BCF of undiscovered resources on leased Shelf blocks, and about 20 MMBO and 135 BCF on unleased Shelf blocks.

Figure 2 – Gulf of Mexico (GOM) Shelf Resource Estimates

Labels show the estimated volumes in MMBO (oil) and BCF (gas) and the percentage of the total that volume represents.

Figure 2 shows the estimated distribution of discovered and undiscovered resources remaining on the Shelf, and the portions of each that are on leased versus unleased acreage.



Opportunities may exist for DOI to incentivize additional Shelf exploration and development activity. Any royalty relief or other policy designed to incentivize the discovery and development of remaining Shelf resources should be implemented before lessees and operators remove existing platforms and other infrastructure to avoid stranding assets of the United States of America.

BOEM and BSEE are each able to target different groups of leases to address the Shelf decline. BOEM has the statutory authority to incentivize new leasing with categorical royalty relief. BSEE's statutory authority can target existing leases when discretionary royalty relief would promote additional development or increased production.

Historically, BOEM and its predecessors issued leases in shallow water blocks (less than 200m) with a 16.67% royalty rate. During a period of higher oil and gas prices, in March of 2008, the royalty rate for all GOM leases was increased to 18.75%. Following a sharp decline in shallow water activity, a steep decrease in BOEM's assessment of shallow water hydrocarbon resources, and low natural gas prices, beginning with Sale 249 in 2017, BOEM issued leases in shallow water blocks with a 12.5% royalty rate.

RECENT LEASE SALES

The August 2016 lease sale (Sale 248) received no bids for shallow water blocks. In the March 2017 lease sale (Sale 247), a total of 22 shallow water blocks received bids.[2] In the August 2017 lease sale (Sale 249), the first sale to offer the 12.5% royalty rate, only 10 shallow water blocks received bids. However, because BOEM announced its decision to offer the 12.5% royalty rate only a few weeks before the lease sale, it is likely that companies were unable to incorporate the royalty change into their bidding strategy.

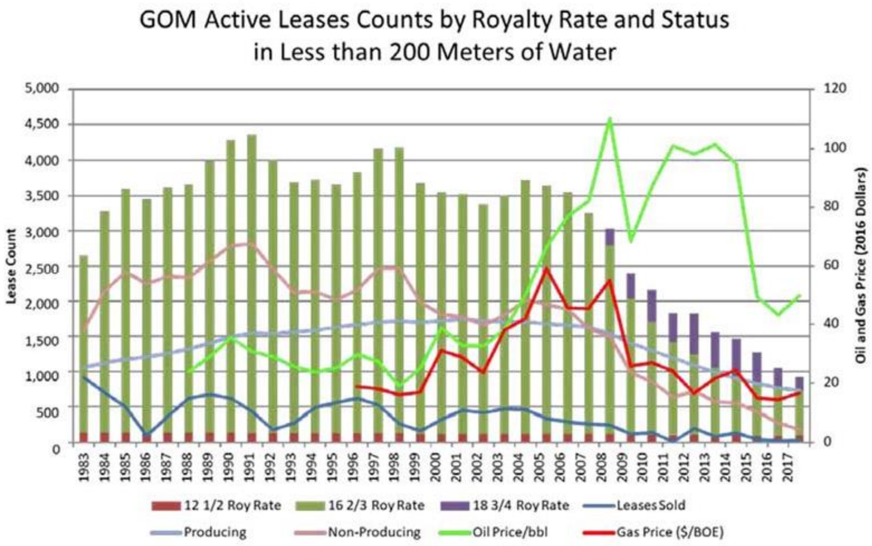
By contrast, in the March 2018 lease sale (Sale 250) companies bid on 43 shallow water blocks, almost 30% of the blocks that received bids in Sale 250. Continuing this trend, 32 shallow water blocks received bids in the August 2018 lease sale (Sale 251), 22% of the total number of blocks that received bids. In the March 2019 lease sale (Sale 252) there were 25 bids for shallow water blocks, 11% of the total number of blocks that received bids.

Yet, by the August 2019 lease sale, (Lease Sale 253), interest in shallow water was waning again, notwithstanding the 12.5% royalty rate. There were only 19 blocks receiving bids for shallow water blocks, 8% of the total number of blocks that received bids, of which no blocks had more than 1 bidder, a sign of very little interest. Additionally, it should be noted that out of the 5375 shallow water blocks available for bidding, only 19 blocks received bids for a 0.35% ratio (approximately 1/3 of 1 percent) when measuring interest to availability.

While the recent use of a 12.5% royalty rate slightly increased bidding interest in Sales 250 and 251, that interest appears to be short lived and shallow water blocks are only a fraction of such interest a decade ago. In 2008, when oil prices averaged $100 per barrel and the gas price was nearly $9 per mmbtu, a total of 252 shallow water blocks received bids in the lease sales (Sales 206 and 207) held that year (Central and Western planning area sales, respectively).

[2] These sales included an 18.75 percent royalty.

Figure 3 – Gulf of Mexico Shelf Leases by Royalty Rates



OBSERVATIONS

- Majority of active Shelf leases have 16.67% royalty rate.
- Decrease in number of active Shelf leases past 10-15 years.
- Decrease in number of Shelf leases receiving bids past 15 years.
- Shelf leasing activity more closely follows natural gas prices than oil prices past 10 years.
- Number of non-producing Shelf leases less than number of producing leases past decade.
- Very few active, non-producing Shelf leases compared to historical levels

Under existing regulations, companies can submit "End-of-Life" royalty relief requests (for individual leases) and "Special Case" royalty relief requests (for individual leases or projects). The "End-of-Life" royalty relief regulations (30 C.F.R. §§ 203.50 -203.56), which were issued in 1998, were intended to promote increased production from producing leases with inadequate revenues to sustain production (63 Fed. Reg. 2605 (1998)). The "Special Case" royalty relief regulations (30 C.F.R. § 203.80), which were issued in 2002 (67 Fed. Reg. 1862 (2002)), were intended to address situations where royalty relief would increase production on leases or projects that were ineligible for relief under established programs, but circumstances, such as a sudden drop in prices or unusually high original royalty rates, could result in a substantial amount of the remaining resources being unproduced. (65 Fed. Reg. 69259 (2000)). The process for evaluating "End-of-Life" royalty relief requests is specified in both the regulations and in a Notice to Lessees and Operators, in which the pool of qualifying leases is narrowly defined.

The process for evaluating “Special Case” requests is less defined in the regulations.

Because the process, as well as the information to be submitted for evaluating “Special Case” requests, is not specifically prescribed by regulation, over the years BSEE developed an evaluation method.[3] BSEE currently evaluates “Special Case” royalty relief requests by assessing the economic need for such relief with a detailed, quantitative analysis of each proposed project or lease. Relief, by regulation, is granted only if, and in the amount, necessary to make a development project economic. A key variable in making that economic determination is the discount rate.

Relying on research conducted by BOEM, BSEE has historically allowed operators to use discount rates up to 15% when submitting their project cash flow analyses. However, many operators claim they need higher rates of return than 15% to risk additional capital or entice lenders to invest in Shelf opportunities. If BSEE utilized discount rates higher than 15%, BSEE may be able to approve special case royalty relief for projects that are estimated to generate internal rates of return greater than 15%. This change could incentivize operators to invest additional capital and recover otherwise stranded resources. However, any such change should be driven by research conducted by a non-industry organization with experience calculating discount rates. BOEM is uniquely qualified and has historically provided this service to the Department of the Interior. BOEM recently undertook an effort to do this and published its findings in a November 2019 report, entitled *Recommended Discount Rates and Policies Regarding Special Case Royalty Relief for Oil and Gas Projects in Shallow Water*, and in a BOEM *Economic Assumptions for BSEE Discretionary Royalty Relief Applications*, effective November 19, 2019, all of which are attached as Exhibit A. You will note this publication provides a water depth specific discount rate range. This will allow the Department of Interior to manage royalty relief issues individually in the two distinct provinces of the Gulf of Mexico, rather than the historic “one size fits all” approach.

If royalty relief incentivizes investment that would not otherwise occur, there are ancillary benefits, not only for the Shelf, but also for the region and Nation. According to BOEM’s MAG-PLAN Gulf of Mexico Model and accompanying analyses, for every million-dollar investment in shallow water, the total economic impact, including the reinvestment of state and local taxes, yields approximately $1.7 to $2 million in additional economic activity. This includes the purchase of indirect inputs associated with the companies that supply the industry with goods and services, as well as the induced spending from the additional household income generated from direct and indirect spending.

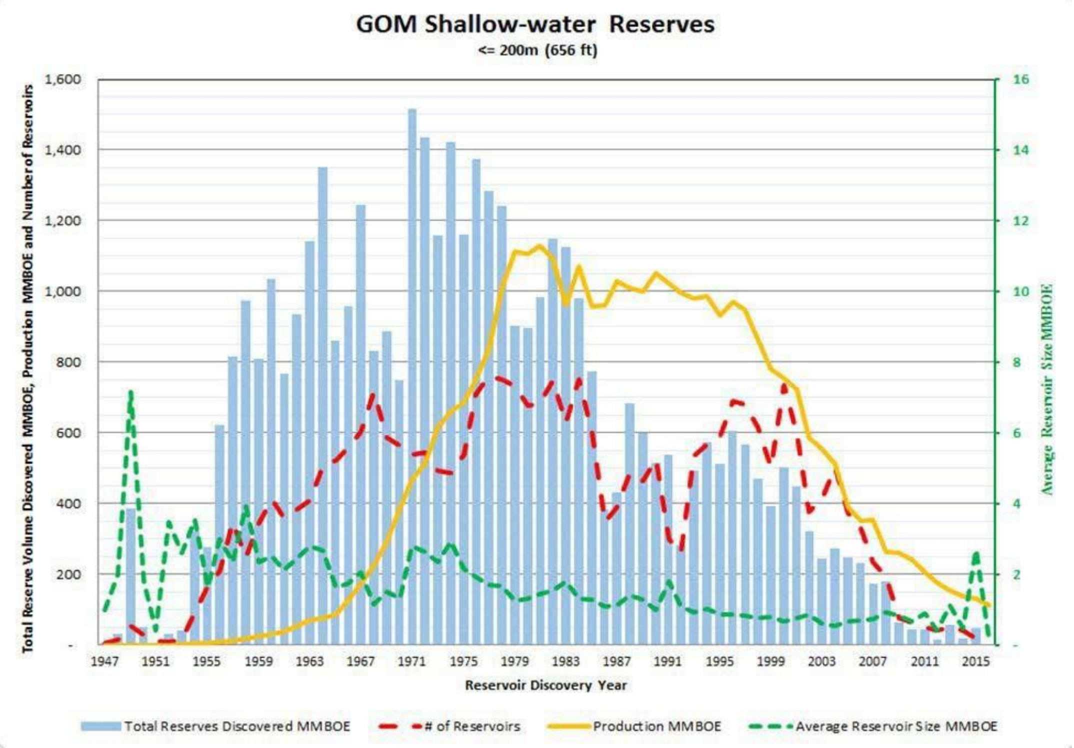
[3] BSEE has received eleven formal requests under the “Special Case” regulations since the rule was promulgated in 2002.

TREND ANALYSIS

In most respects, the Shelf and Deepwater areas function as separate and distinct oil and natural gas basins. Unlike Deepwater, the Shelf has produced for many decades and is considered very mature.

On the Shelf, the total reserves discovered, number of reservoirs discovered, and average reservoir size have, for the most part, all steadily declined for the past two decades or more. See Figure 4.

Figure 4– Gulf of Mexico Shelf Reserves



OBSERVATIONS

- Total Shelf reserves discovered per year generally decreasing for the past five decades
- Number of Shelf reservoirs discovered per year decreasing for the past two decades
- Sharp decrease in Shelf production for the past two decades
- Average reservoir size discovered generally decreases with time

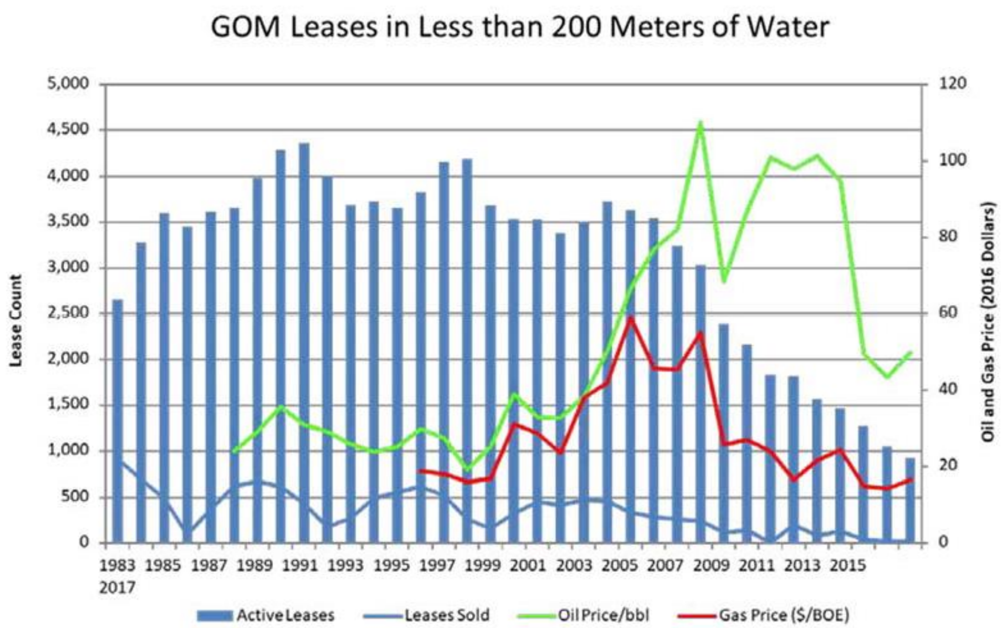
LEASING

As Figures 3 and 5 illustrate, Shelf leasing activity and the number of active Shelf leases have steadily declined over the past decade, as have natural gas prices, for the most part, over that same time period. Deepwater leasing activity has declined to a lesser extent over the past five to ten years, as illustrated on Figures 6 and 7. The data illustrate that Shelf leasing activity follows natural gas prices more closely than oil prices, whereas Deepwater leasing activity correlates more closely with oil than natural gas prices. This is expected, given that the Shelf is a natural gas-prone basin, whereas the Deepwater is a more oil-prone basin.

Exhibit B is a set of maps illustrating Shallow Water and Deepwater active leases during various time periods, first measured from 1940. We have included a hyperlink https://www.bsee.gov/what-we-do/conservation/gulf-of-mexico-shallow-water-province to the section of the BSEE Website focusing on the Gulf of Mexico Shallow Water Province; which includes a time lapse video illustrating the changes in active leases in both the Shallow Water and Deepwater since 1940.

> "Dwindling commercial prospects, sustained low oil and gas prices, reduced budgets, operator bankruptcies, and the success of onshore shale development means that drilling and installation activity in the shallow water has been dramatically curtailed in recent years."
>
> "Review of Shallow Water GOM Structure Inventory Offers Preview of Decommissioning Requirements" Center for Energy Studies, Louisiana State University - March 1, 2018

Figure 5 – Gulf of Mexico Shelf Leasing

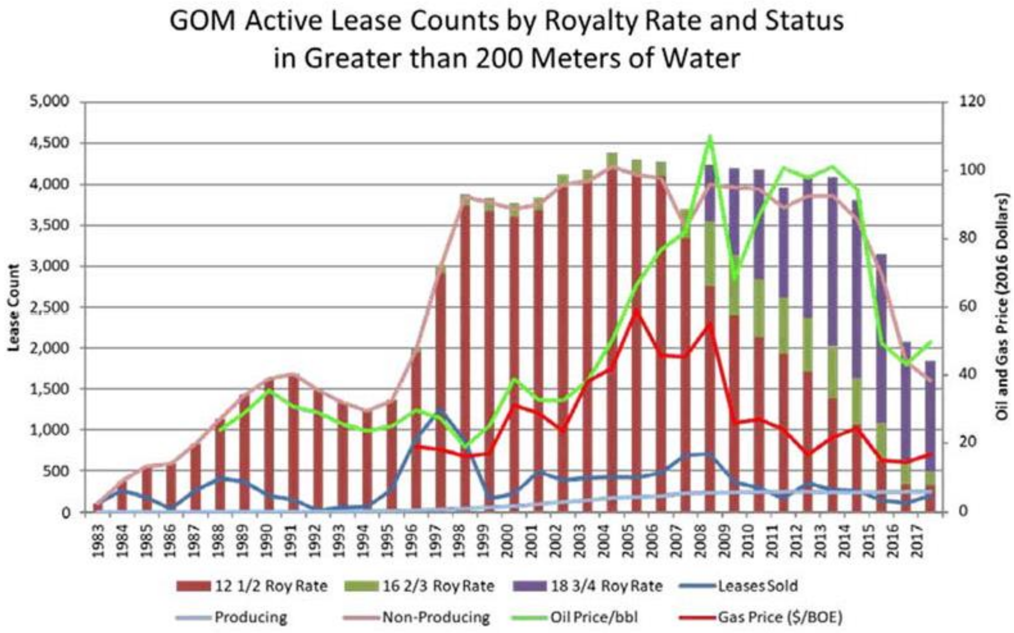


> "Most of the producing assets in shallow waters of the Gulf of Mexico (GOM) offshore are past their peak production and have been witnessing a steep fall in production during the last 15 years."
>
> "Gulf of Mexico Shallow Water – the Downside"
>
> OffshoreTechnology.com
> April 6, 2011

OBSERVATIONS

- Decrease in number of active Shelf leases over the past 10-15 years
- Decrease in number of Shelf leases receiving bids over the past 15 years
- Shelf leasing activity more closely follows natural gas prices than oil prices over the past 10 years

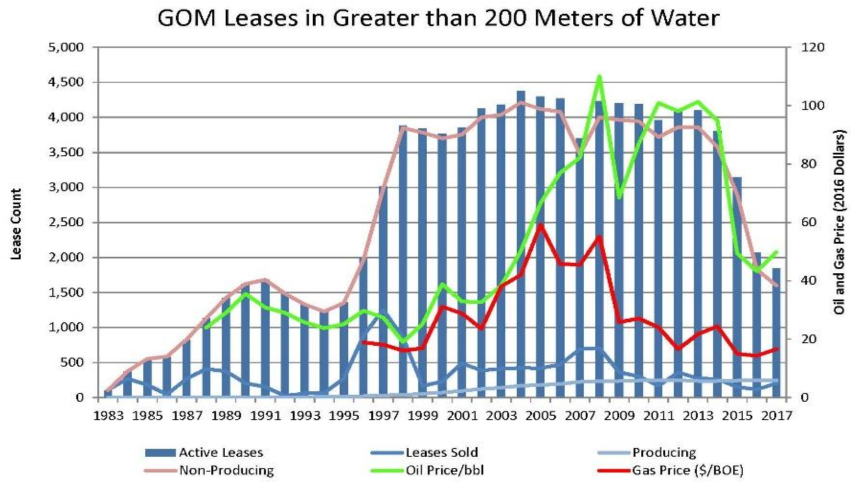
Figure 6 – Gulf of Mexico Deepwater Active Leases by Royalty Rates



OBSERVATIONS

- Majority of active Deepwater leases have 18.75% royalty rate
- Decrease in number of active Deepwater leases over the past 5 years only
- Decrease in number of Deepwater leases receiving bids over the past 5-10 years
- Deepwater leasing activity correlates with oil prices over the past 5 years, but appears largely independent of natural gas prices
- Number of non-producing Deepwater leases decreased over the past 5 years, but number of producing Deepwater leases has remained steady, and number of non-producing Deepwater leases still much higher than number of producing ones

Figure 7 – Gulf of Mexico Deepwater Leasing



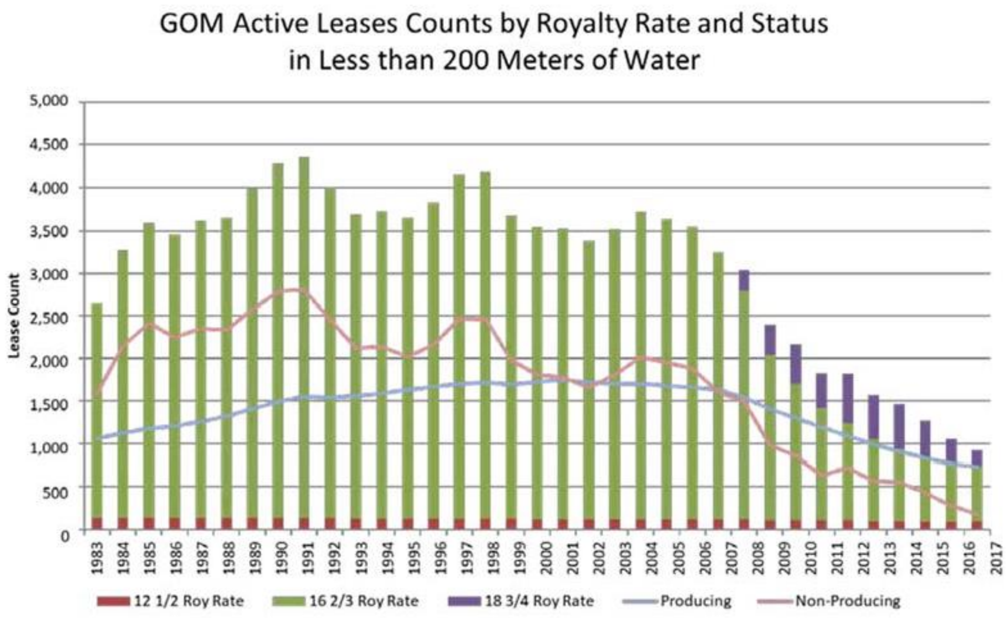
OBSERVATIONS

- Decrease in number of active Deepwater leases over the past 5 years only
- Decrease in number of Deepwater leases receiving bids over the past 5-10 years
- Deepwater leasing activity correlates well with oil prices past 5 years, but appears largely independent of natural gas prices
- Number of non-producing Deepwater leases decreased over the past 5 years, but number of producing Deepwater leases has remained steady, and number of non- producing Deepwater leases still much higher than number of producing ones

Figures 5, 8, and 9 also show that Shelf operators are not holding inventories of non-producing leases, as they have historically. Since 2008, there have been more producing than non-producing leases on the Shelf, which represents a reversal of previous trends, indicating reduced interest for future exploration and development opportunities on the Shelf.

The story is different in the Deepwater. Companies have demonstrated a continued interest in building inventory for Deepwater exploration and development, since non-producing Deepwater leases still significantly outnumber producing ones, which have maintained a steady level over the past decade.

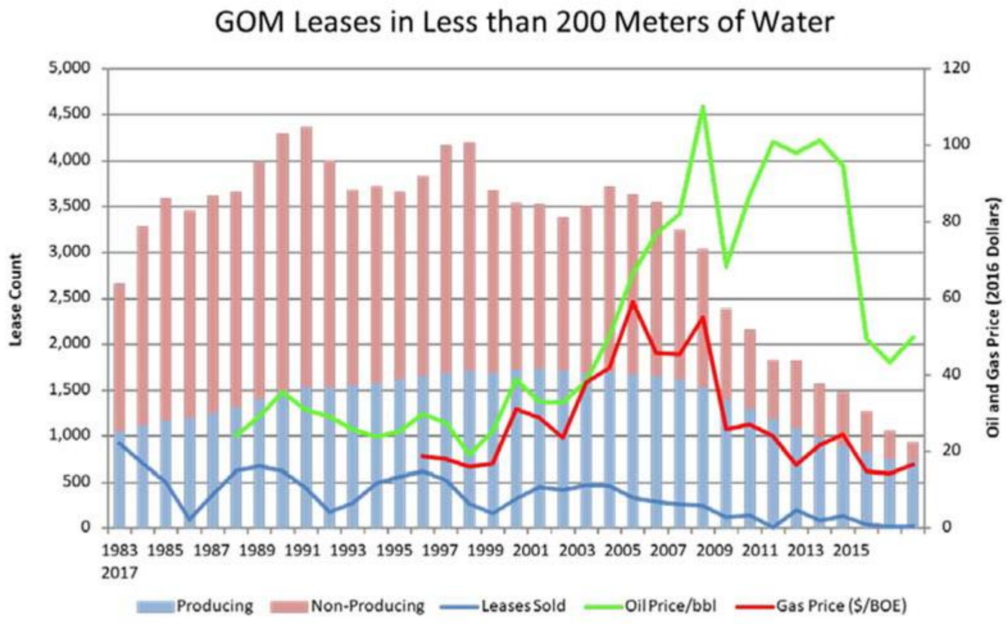
Figure 8 – Gulf of Mexico Shelf Active-Lease Royalty Rates



OBSERVATIONS

- Majority of active Shelf leases have 16.67% royalty rate
- Decrease in number of active Shelf leases over the past 10-15 years
- Number of non-producing Shelf leases less than number of producing leases over the past decade
- Very few active, non-producing Shelf leases compared to historical levels

Figure 9 – Gulf of Mexico Shelf Producing vs. Non-Producing Leases



OBSERVATIONS

- Decrease in number of active Shelf leases over the past 10-15 years
- Decrease in number of Shelf leases receiving bids over the past 15 years
- Shelf leasing activity more closely follows natural gas prices than oil prices past 10 years
- Number of non-producing Shelf leases less than number of producing leases over the past decade.
- Very few active, non-producing Shelf leases compared to historical levels

PRODUCTION

Oil and natural gas production on the GOM Shelf has declined significantly over the past two decades (77% and 92% declines, respectively), while Deepwater oil production has increased 198% over that same period (Figures 10 and 11). The Deepwater natural gas production trend is less relevant because the Deepwater area is primarily an oil basin, so Deepwater natural gas production is largely associated gas.

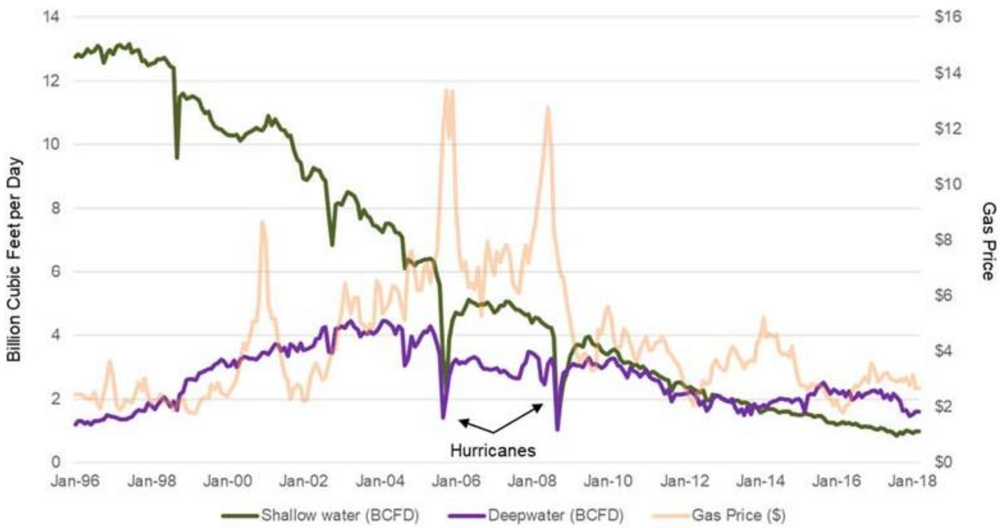
Exhibit C is a set of maps illustrating Shallow Water and Deepwater production during various time periods, first measured from 1940. We have included a hyperlink https://www.bsee.gov/what-we-do/conservation/gulf-of-mexico-shallow-water-province to the section of the BSEE Website focusing on the Gulf of Mexico Shallow Water Province; which includes a time lapse video illustrating the changes in production in both the Shallow Water and Deepwater since 1940.

Figure 10– Gulf of Mexico Oil Production by Water Depth

OBSERVATIONS

- Decrease in Shelf oil production over the past two decades
- General increase in Deepwater oil production over the past two decades
- Upward trend in Deepwater oil production interrupted from about 2005-2009 (Hurricanes Katrina, Rita, Gustav, and Ike) and again from about 2010-2014 (post-Macondo)

Figure 11 – Gulf of Mexico Natural Gas Production by Water Depth



OBSERVATIONS

- Decrease in Shelf natural gas production over the past two decades
- Deepwater natural gas production relatively constant over the past 5 years.
- Deepwater natural gas production trend less relevant because Deepwater area is primarily an oil basin and Deepwater natural gas production is largely a function of the natural gas-oil-ratio of producing reservoirs

In addition to production declines, the Shelf has also faced declines in the number and size of new discoveries.

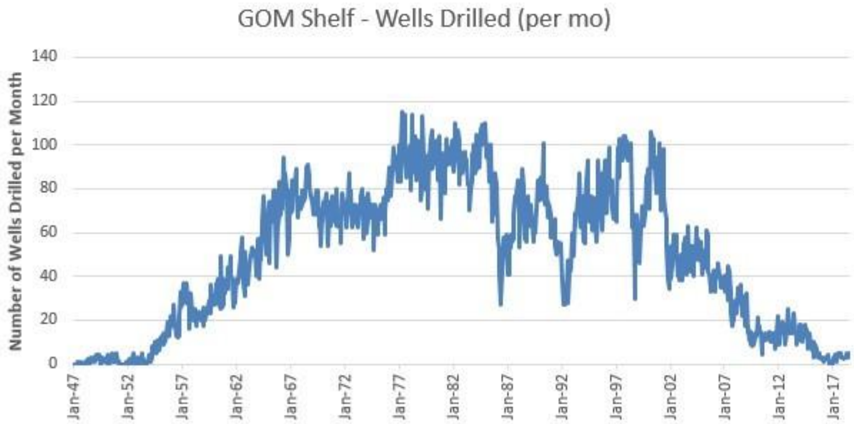
The total Shelf reserves discovered per year have generally been decreasing over the past five decades, and the number of Shelf reservoirs discovered per year has been decreasing over the past two decades. This demonstrates the statement described in the introduction above that average reservoir size generally decreases with time as larger fields in a basin are usually discovered first and because the Shelf is a mature basin, any effort to maximize recovery of the remaining, marginal resources will likely require fiscal incentives.

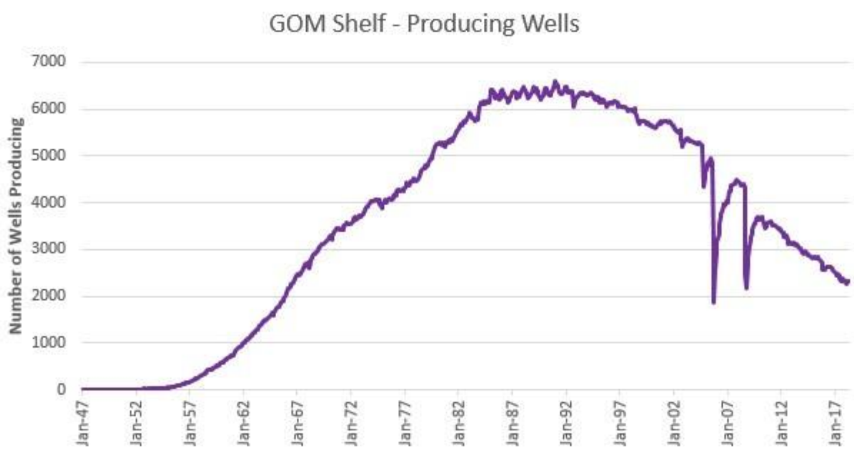
As listed on Table 1, the average reservoir size discovered in Deepwater over the past 10 years has been 10.8 times larger than the reservoir size discovered on the Shelf.

DRILLING

Figure 12 illustrates an 82% decline in Shelf drilling, and a 48% decline in the number of producing Shelf wells, over the past two decades. Figure 13 compares Shelf drilling to commodity prices

Figure 12 – Gulf of Mexico Shelf Wells Drilled and Shelf Wells Producing





OBSERVATIONS

- Decrease in Shelf drilling over the past two decades
- Decrease in number of Shelf wells producing over the past three decades

During the period 2000-2010, the Deepwater areas of GOM offshore reported a number of significant oil and gas discoveries. While the GOM shallow water reported eight discoveries, the Deepwater areas reported 34 discoveries.

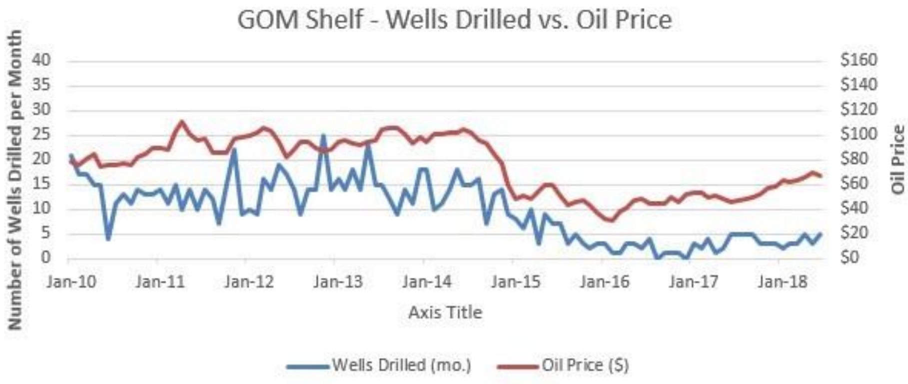
"Gulf of Mexico Shallow Water – the Downside"

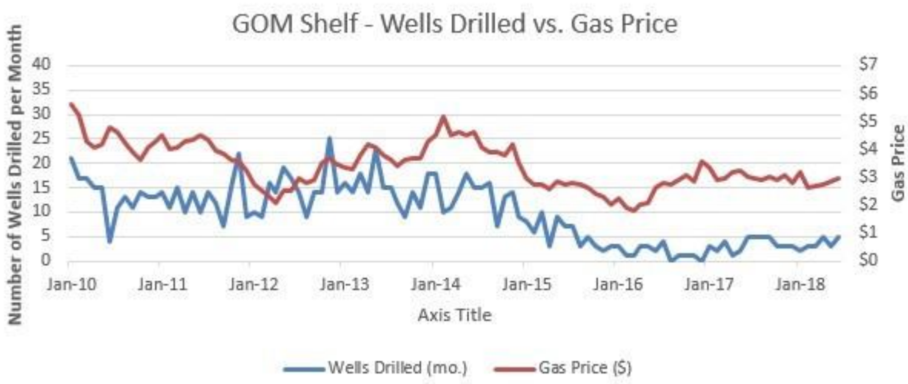
OffshoreTechnology.com
April 6, 2011

Large discoveries in Deepwater during the period 2008–2010 have, however, increased the attractiveness of Deepwater. International oil companies with a greater appetite for risk, a technological edge and the necessary financial prowess have been making investments in the Deepwater of the GOM offshore and exiting from their shallow water assets.

OffshoreTechnology.com
April 6, 2011

Figure 13 – Gulf of Mexico Shelf Drilling vs. Commodity Prices





OBSERVATIONS

- Correlations between Shelf drilling and commodity prices over the past five years, with particularly good correlation to oil prices
- Data from 2010-2012 suggest slight lag between rebounds in oil prices and rebounds in Shelf drilling

PLATFORMS
As Shelf drilling and production declined over the past two decades, the number of active Shelf platforms followed suit. As shown in Table 1 and depicted in Figure 14, over the past 20 years, the installation of new platforms has sharply declined. Over 70% of all Shelf platforms ever installed have been decommissioned. As these Shelf platforms are removed and pipelines are decommissioned, the infrastructure to process and transport production from nearby wells and facilities disappears, negatively affecting the economics for workovers and drilling future sidetracks or new wells. This decline in Shelf infrastructure creates a domino effect further affecting the economics of Shelf exploration and development and discouraging investment in additional development to support remaining infrastructure.

Data from Table 1 of this report indicates that approximately seven thousand (7,000) production platforms have been installed and approximately 5,100 production platforms have been removed since 1947 in the Gulf of Mexico shallow water province. Only 1,300 of these platforms were installed in the last 20 years while 3,500 of these platforms have been removed in this same twenty (20) year period; resulting in a 0.37 to 1 installation to removal ratio. The data from Table 1 illustrates an even more profound impact when these data points are compared for the last five years with only 13 platforms installed and 516 removed, resulting in a 0.025 to 1 installation to removal ratio. Further, in 2018, no platforms in the Shelf area were installed and 97 were removed. This trend is clearly indicative of a mature and declining hydrocarbon basin.

Exhibit D is a set of maps illustrating Shallow Water and Deepwater structures during various time periods, first measured from 1940. We have included a hyperlink https://www.bsee.gov/what-we-do/conservation/gulf-of-mexico-shallow-water-province to the section of the BSEE Website focusing on the Gulf of Mexico Shallow Water Province; which includes a time lapse video illustrating the changes in the number and type of structures in both the Shallow Water and Deepwater since 1940.

Figure 14 – Shallow water platforms installed and removed within the past 20 years

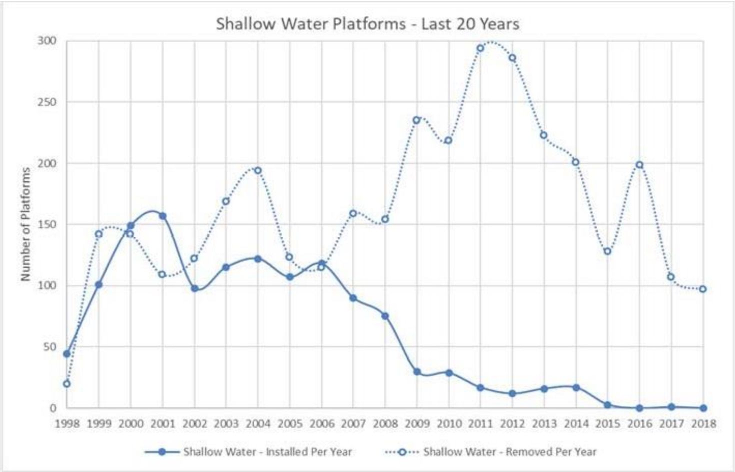


Figure 14-(cont.) Deepwater platforms installed and removed within the past 20 years

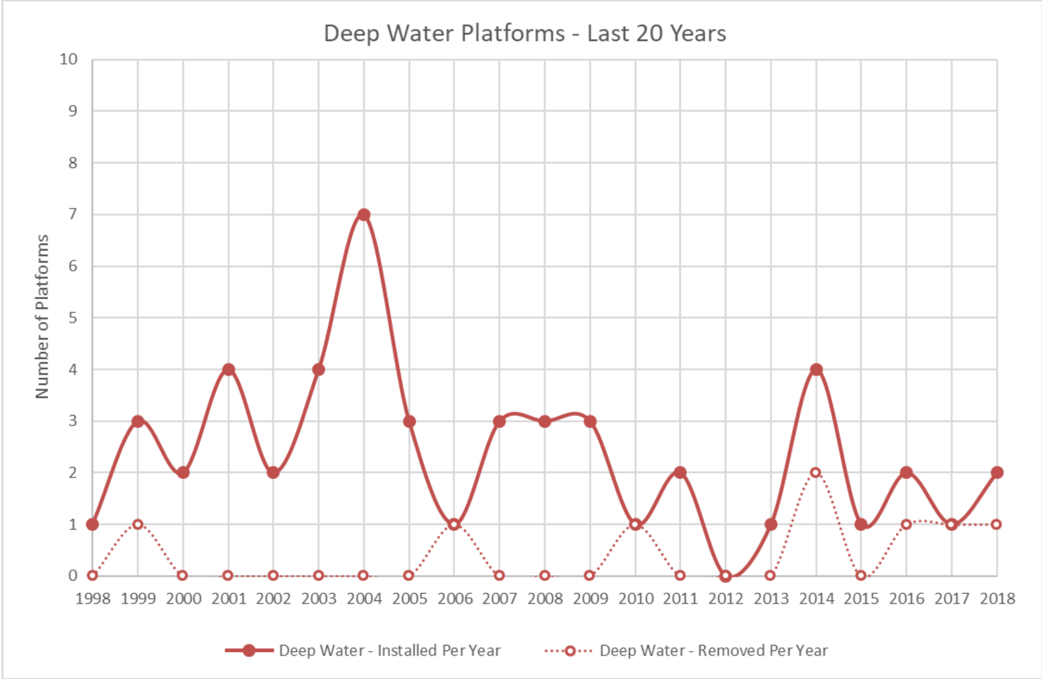
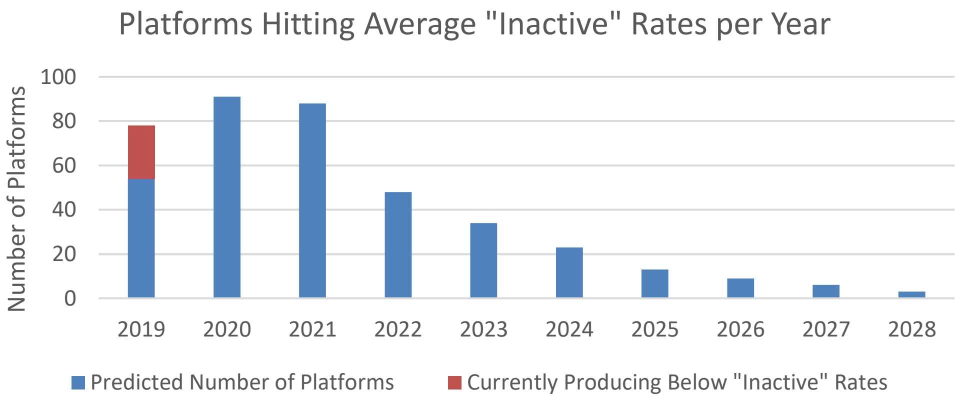


Figure 15 – Platforms with production declining to levels below 500 bbls oil per month and 12.3 MMCF per month (historical average rates at which Shelf platforms permanently ceased production).



As Figure 15 shows, over 230 of the nearly 600 active Shelf platforms could permanently cease production within the next three years.

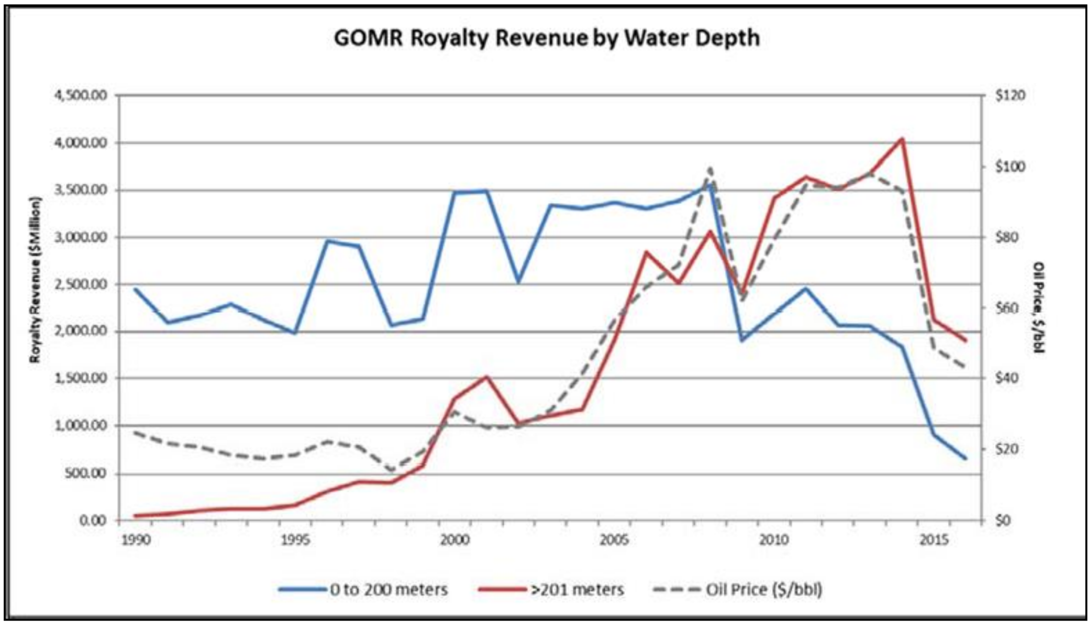
These same platforms are expected to produce about $260 million in federal royalties over the next three years. As production from each lease ceases, the lease would terminate within a year, after which the lessee has one year to decommission all infrastructure on that lease (platforms, wells, pipelines, etc.). We estimate about only 300 or more Shelf platforms will remain in production beyond 2027, therefore, the opportunity to capitalize on the more expansive and critical infrastructure is rapidly vanishing if the nation wishes to avoid stranding its oil and gas resources.

ROYALTIES

The contribution of federal Deepwater royalty revenue has surpassed that from the Shelf, although royalties from Shelf production are still significant.

Future royalties from this area are expected to continue to decline as a result of the 82% decline in Shelf drilling over the last two decades (Figures 16 and 17).

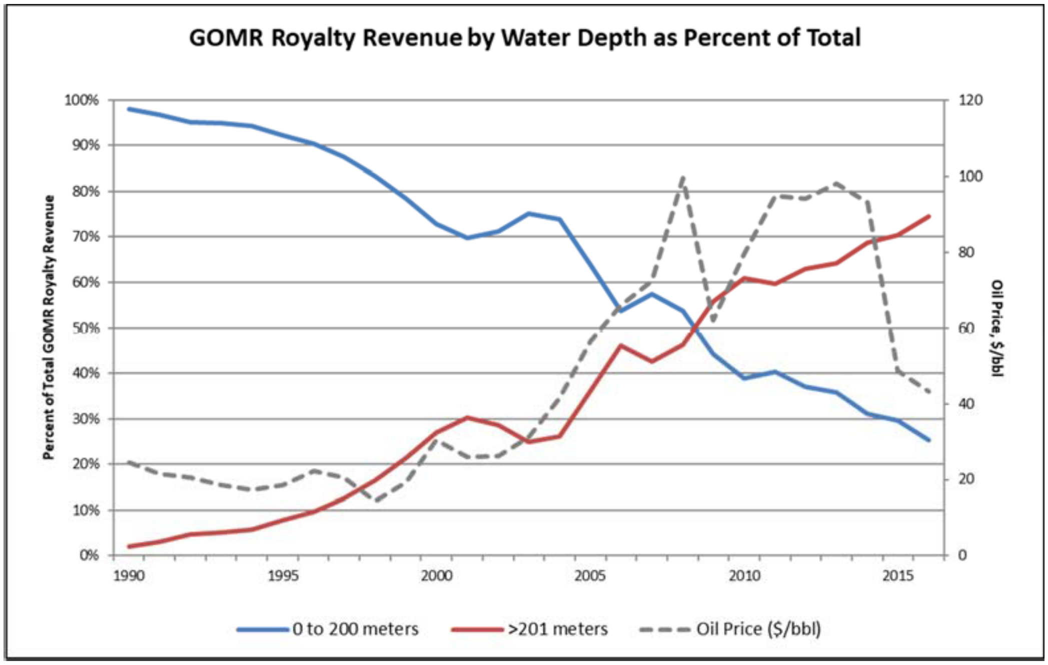
Figure 16 – Gulf of Mexico Royalty Revenue Contributions by Water Depth



OBSERVATIONS

- Royalty revenue from Deepwater has surpassed that from the Shelf
- Royalty revenue from Shelf still significant
- Royalty revenue highly dependent upon commodity prices

Figure 17 – Gulf of Mexico Royalty Revenue Contributions



OBSERVATIONS

- Percentage of royalty revenue from Deepwater has surpassed that from the Shelf
- Royalty revenue from Shelf still significant portion of total

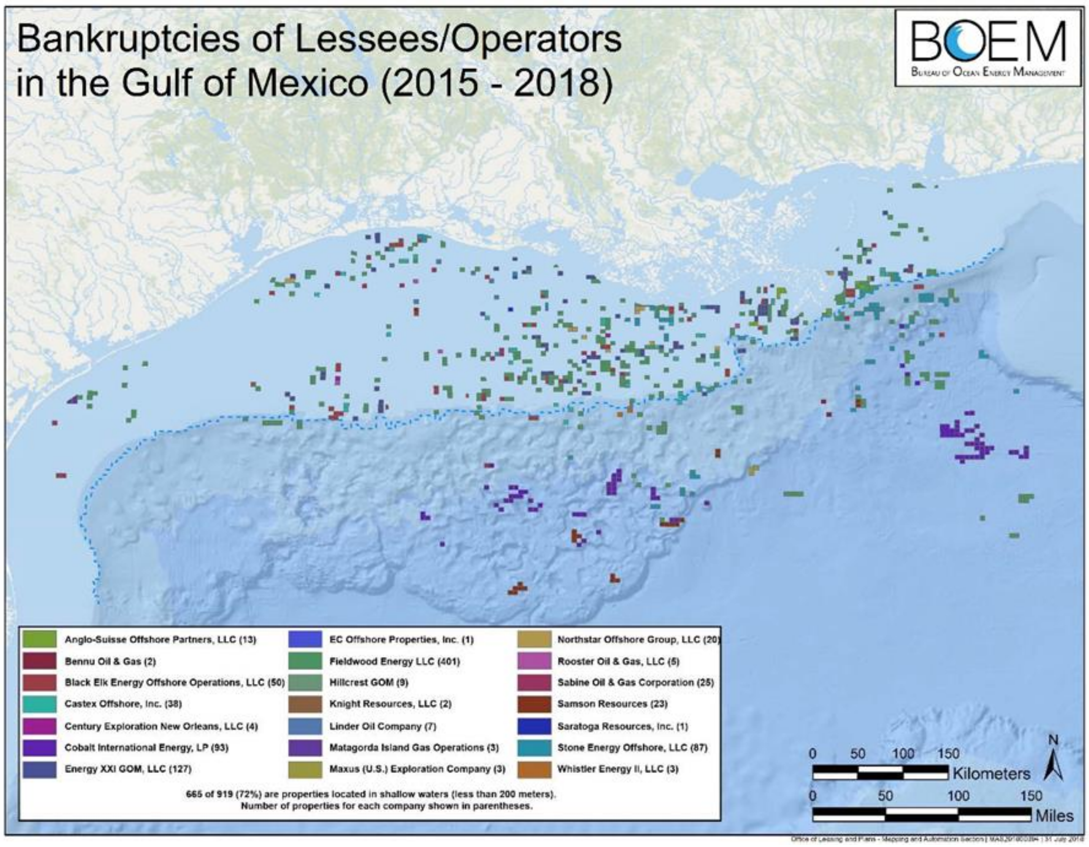
FINANCING

Many Deepwater operators are multi-national, fully integrated companies, while many of the operators focused on the Gulf of Mexico Shelf are smaller companies. In fact, 89% of Deepwater operators are publicly held companies, many of which appear on nationally published rankings of financial size. Typically, shallow water operators are small, independent companies, 43% of which are privately held.

It should be noted that independent, shallow water operators are not on the sidelines or simply "sitting" on capital while waiting for royalty rates to be reduced prior to the deployment of this capital. Rather, they are forced to seek "less than interested" equity investors or debt-financing from wary financial markets. Some contributing factors in the declining interest in shallow water financing include margins not matching the risk, a plethora of bankruptcies, and the amount of expected recoverable hydrocarbons being too small. This creates a "shot clock" dilemma for the Nation, as a continued decline in Shelf production accelerates the removal of platforms and potentially strands the remaining resources.

Accessing capital from equity markets and commercial financing is very challenging for most shallow water operators. This likely results from the amount of expected recoverable hydrocarbons (small discoveries) not being worth the risk, with the average reservoir size for the last ten years in Deepwater at 10.8 times larger than the average reservoir size on the Shelf (9.0 MMBOE to 0.83 MMBOE). Additionally, Gulf of Mexico operators have experienced substantial bankruptcy filings since 2015, with nearly 80% of the GOM Shelf properties subject to bankruptcy; providing further evidence of financial challenges in the province. See Figure 18.

Figure 18 - Bankruptcies of Lessees/Operators in the Gulf of Mexico (2015 – 2018)



New Competition from Mexico

The challenge of the amount of the smaller discoveries is accentuated by the observation that two of the largest Shelf lessees and platform owners have begun to look elsewhere to deploy capital despite their significant assets in the GOM Shelf. These operators have recently acquired acreage in Mexico's territory of the Gulf of Mexico. Despite more burdensome lease and fiscal terms for Mexico offshore concessions/leases and the historic instability of that region, these operators have nonetheless elected to invest capital there, where risk-adjusted returns are expected to be better than the GOM Shelf. The political and fiscal risks associated with the country of Mexico's offshore opportunities appear to be offset by the larger discoveries of this yet to be developed province. No doubt, with over 47,000 wells drilled in the mature fields of the shallow waters of the U.S. Gulf of Mexico, the remaining discoveries are likely to be outperformed by this new competition from Mexico.

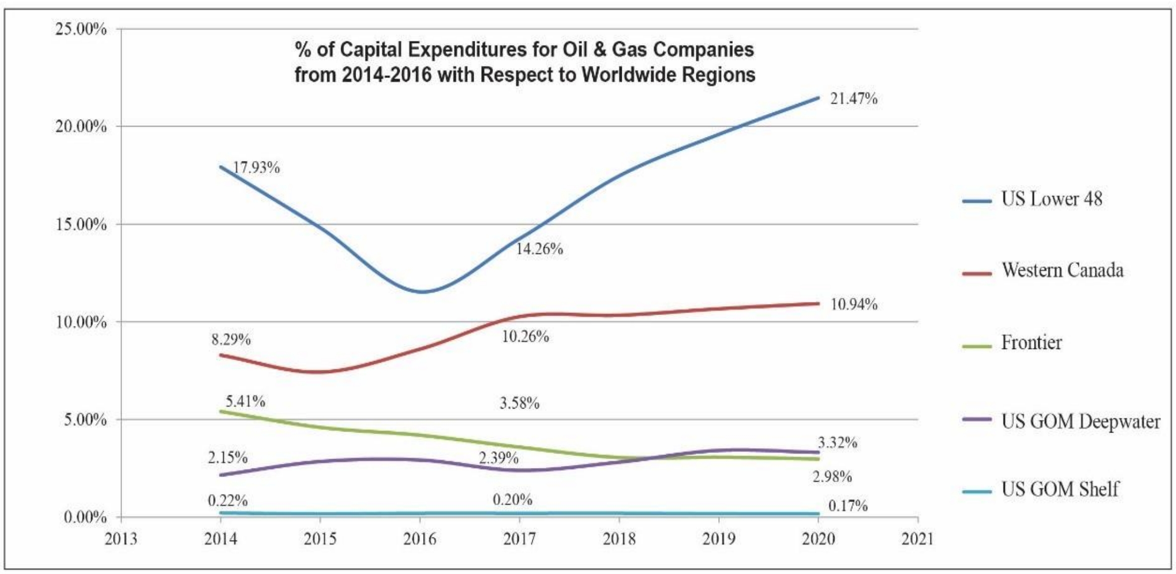
Additionally, research indicates that the financial markets view the U.S. Shelf with a less than robust outlook. For the last several years, the overall oil and natural gas equity markets have not been very active, and the GOM Shelf is thought of as the least desirable basin in the U.S. (onshore and offshore), for both the public and private equity investment communities. See Figure 19 for a comparison of the capital expenditure history and projections for the future of various basins as calculated by Wood-MacKenzie. It should be noted the Shelf has experienced anemic investment for at least the past four years, and this anemic performance is forecasted to continue. Several reasons listed below contribute to this negative outlook.

Contributing Factors of Declining Interest in Shelf Financing

- Amount of expected recoverable hydrocarbons is too small
- Financial markets cannot point to an abundance of successful operators on the Shelf
- Plethora of bankruptcies
- High-cost Basins vs. Onshore Basins
- Margins do not match risk
- Onshore shale plays have changed competition
- Public companies with primarily Shelf assets often trade at a discount to public companies with primarily onshore assets with a similar production profile
- Heightened awareness of hurricane risk
- Predominantly a natural gas province
- Too few players in the province
- Asset retirement obligations looming

Figure 19 – Comparison of Upstream Capital Expenditures and Forecasted Expenditures by Basin (2014-2020)

Regional upstream capex by year, nominal 2016 terms	Source: Wood Mackenzie					© Wood Mackenzie Limited									
Region	2014	Total %	2015	Total %	2016	Total %	2017	Total %	2018	Total %	2019	Total %	2020	Total %	
Africa (Central)	23,727	3.64%	18,975	3.83%	13,437	3.35%	12,227	2.90%	11,776	2.71%	12,434	2.77%	9,850	2.24%	
Africa (North)	11,363	1.74%	11,372	2.29%	10,735	2.68%	11,738	2.78%	14,362	3.30%	15,223	3.39%	11,367	2.58%	
Africa (Southern & East)	903	0.14%	1,247	0.25%	1,031	0.26%	2,946	0.70%	6,583	1.51%	9,737	2.17%	12,948	2.94%	
Africa (West)	23,624	3.62%	16,962	3.42%	14,765	3.68%	13,099	3.10%	13,716	3.15%	9,861	2.20%	10,790	2.45%	
Australasia	50,111	7.69%	37,846	7.64%	21,808	5.44%	15,996	3.79%	9,211	2.12%	11,626	2.59%	18,324	4.16%	
Caucasus	6,494	1.00%	6,453	1.30%	5,105	1.27%	4,072	0.96%	3,259	0.75%	3,182	0.71%	3,091	0.70%	
Central Asia	15,071	2.31%	12,848	2.59%	11,306	2.82%	13,282	3.15%	13,431	3.09%	13,985	3.11%	11,093	2.52%	
Eastern Asia	42,195	6.47%	33,877	6.84%	34,872	8.70%	35,318	8.37%	32,251	7.42%	29,575	6.58%	26,705	6.07%	
Europe (Central & Eastern)	2,426	0.37%	1,445	0.29%	1,307	0.33%	1,862	0.44%	2,397	0.55%	2,588	0.58%	2,385	0.54%	
Europe (North West)	28,608	4.39%	20,938	4.23%	16,733	4.18%	16,370	3.88%	14,280	3.28%	19,301	4.30%	18,171	4.13%	
Europe (Southern)	1,678	0.26%	1,073	0.22%	1,082	0.27%	872	0.21%	588	0.14%	498	0.11%	525	0.12%	
Europe (UK)	19,832	3.04%	15,606	3.15%	10,313	2.57%	8,745	2.07%	6,530	1.50%	4,789	1.07%	3,757	0.85%	
Indian Sub-continent	5,553	0.85%	4,492	0.91%	4,336	1.08%	4,152	0.98%	6,259	1.44%	6,311	1.40%	3,474	0.79%	
Latin America (Andean)	14,941	2.29%	11,587	2.34%	9,613	2.40%	8,896	2.11%	8,215	1.89%	8,377	1.86%	7,804	1.77%	
Latin America (Atlantic)	28,510	4.37%	28,000	5.65%	24,419	6.09%	26,199	6.21%	25,276	5.81%	23,040	5.13%	22,497	5.11%	
Latin America (Central)	15,869	2.43%	13,532	2.73%	11,970	2.99%	12,377	2.93%	13,044	3.00%	11,401	2.54%	10,017	2.28%	
Middle East - NW Arabia	35,694	5.47%	30,281	6.11%	28,841	7.20%	34,435	8.16%	41,887	9.63%	41,336	9.20%	38,105	8.66%	
Middle East - SE Arabia & Iran	27,202	4.17%	24,304	4.90%	23,075	5.76%	22,391	5.31%	19,908	4.58%	17,685	3.94%	16,399	3.73%	
N America (Frontier)	35,277	5.41%	22,772	4.60%	16,814	4.20%	15,120	3.58%	13,281	3.05%	13,793	3.07%	13,127	2.98%	Frontier: areas with limited exploration activities and no known significant oil & gas discoveries
N America (US GoM Deepwa-ter)	14,036	2.15%	14,115	2.85%	11,721	2.92%	10,092	2.39%	12,256	2.82%	15,348	3.42%	14,596	3.32%	GOM Deepwater: areas with water depth greater than 400m
N America (US GoM Shelf)	1,405	0.22%	848	0.17%	802	0.20%	846	0.20%	874	0.20%	817	0.18%	752	0.17%	GOM Shelf: areas with water depth less than 400m (shallow waters)
N America (USL48)	116,910	17.93%	73,397	14.81%	46,221	11.53%	60,178	14.26%	75,991	17.47%	88,031	19.60%	94,491	21.47%	USL 48: basins located onshore in the lower US 48 states
N America (Western Canada)	54,064	8.29%	36,790	7.42%	34,469	8.60%	43,317	10.26%	44,950	10.33%	47,925	10.67%	48,133	10.94%	Western Canada: mostly located in southwestern Manitoba, southern Saskatchewan, Alberta, northeastern British Columbia and the southwest corner of the Northwest Territories
Russia	49,739	7.63%	37,625	7.59%	32,186	8.03%	32,160	7.62%	31,480	7.24%	31,398	6.99%	32,472	7.38%	
South East Asia	26,742	4.10%	19,177	3.87%	13,758	3.43%	15,303	3.63%	13,136	3.02%	10,971	2.44%	9,294	2.11%	
Grand Total	651,970	100%	495,560	100.00%	400,719	100.00%	421,993	100.00%	434,941	100.00%	449,235	100.00%	440,165	100.00%	



Gulf of Mexico Service Companies

It should also be noted that many of the service company contractors have been "hit" very hard by the substantial decline in Shelf activity. Many of these service providers (work boat companies, equipment rental companies, food service companies, and logistics companies) are also key to providing services to the Deepwater Gulf of Mexico. According to the Louisiana Association of Business and Industry (LABI), there is a concern beginning to be expressed on the Gulf coast over a potential loss of the critical mass of service companies necessary to continue serving the Deepwater if the Shelf activity does not rebound soon. LABI also expressed concern regarding declining onshore activity in Louisiana. In other words, the two provinces are linked when it comes to workforce, and it takes a healthy and sustainable level of activity to keep both provinces economically viable. This is an additional challenge for the Department of the Interior, the steward of the OCS.

Resources

The resource endowment is a fundamental uncertainty for offshore oil and gas leasing. The uncertainty associated with the existence and quantity of oil and gas resources can only be resolved through lease acquisition and subsequent drilling of OCS acreage. Companies must spend millions, in some cases billions of dollars to acquire, analyze, and develop leases to discover and ultimately produce new oil and natural gas reserves that are undiscovered today. BOEM estimates the amount of Undiscovered Technically Recoverable Resources (UTRR) of the OCS in the National Resource Assessment.

The above-referenced IHS Report states

> "[n]atural gas fields face significant challenges to drive offshore exploration and development on the shelf and deepwater areas of the GOM, even despite its relatively low government take. Potential natural gas projects are met with marginal or negative internal rates of return in the base case scenario, reflecting the value of current gas commodity prices. These projects also face stiff competition from the abundance of onshore natural gas supply from shale and associated gas."[4]

[4] IHS Report, *2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Gulf of Mexico International Comparison, page 34*

Table 2 below shows the change in resource endowment by water depth category. As can be seen in the table, the 2016 Assessment indicates that shallow water oil resources in both the Central and Western planning areas are significantly lower than reported in 2011. The oil resources increased in water depths deeper than 200 meters. The natural gas resources declined in all water depths. A reduced endowment of oil and gas resources will offer fewer economic opportunities for companies to acquire leases, and to explore for oil and natural gas.

Table 2 – Comparison of Mean UTRR 2011 and 2016 National Assessments

	Oil (Bbbl)			**Gas (Tcf)**		
Water Depth (meters)	2011	2016	Percent Change	2011	2016	Percent Change
0-200	3.25	2.11	-35%	107.72	60.98	-43%
200-800	5.01	6.18	24%	14.06	10.99	-22%
800+	35.05	36.52	4%	81.57	58.30	-29%

The decline primarily reflects a re-evaluation of the original resource endowment, likely due to disappointing exploration results. The 2016 National Assessment recognizes that few and relatively small fields have been discovered recently.

DISCUSSION

The data illustrates that all aspects of Shelf activity have been in decline for decades. Since the Shelf is a mature oil and natural gas basin, the quality and quantity of remaining economic opportunities are expected to continue to diminish with time, absent some unforeseen technological advances or substantial increases in commodity prices. A reasonable goal, therefore, might be to maximize the economic extraction of remaining GOM Shelf hydrocarbons.

The primary fiscal lever available to DOI to stimulate Shelf activity for a mature region is through royalty relief incentives. Given their different authorities, BOEM and BSEE are each able to target different groups of leases to address the decline in Shelf activity.

BOEM has the authority to offer royalty relief incentives for new Shelf leases through the leasing process. BSEE's authority can be used to target existing Shelf leases when a lease is approaching the end of its economic life (and lowering royalties would keep it producing longer) or for special cases when a company is seeking to develop certain resources that require relief to become economic. Although applications for "End-of-Life" or "Special Case" royalty relief have been rare in the Gulf of Mexico since the programs were established in 1998 and 2002 (despite significant fluctuations in commodity prices since that time), there has been an uptick in submitted applications.

In order to protect the American public and help ensure that only the necessary amount of royalty relief is granted via BSEEs discretionary authority, approvals could be structured with safeguards. For example, relief could be conditioned on commodity-price or production-volume thresholds beyond which the lease or project would lose relief. A simpler and more certain royalty relief formulation could be for BSEE to grant a value of suspended royalties.

The royalty suspension could be a certain dollar value removing the need for volume or price adjustments, but maintaining protection for the American public. This is the BOEM recommended relief as described on page 2 of the previously referenced report, BOEM's *Recommended Discount Rates and Policies Regarding Special Case Royalty Relief for Oil and Gas Projects in Shallow Water*, dated November 2019. An additional safeguard could include a requirement that the operator meet certain minimum expenditures and submittal of a summary upon completion of the work.

Based on the evolving nature of the leaseholding and infrastructure inventories in and economics of the Gulf of Mexico Shallow Water Province, as well as the types of applications contemplated in recent years, BSEE was focused on answering two principal questions regarding the parameters of permissible royalty relief: First, can BSEE approve applications for royalty relief on a "project" basis that include operations in multiple, non-adjacent locations and leases; and Second, can BSEE approve royalty relief for projects that include exploratory operations when doing so would also promote development or increased production of discovered resources. In answering both of these questions in the affirmative, BSEE worked closely with the Department's Office of the Solicitor to ensure that its conclusions were consistent with all applicable laws and regulations.

Research conducted by the Gulf of Mexico Region, Production and Development Staff, indicates applications on a “project” basis including multiple leases and exploratory wells is a new approach being considered (likely because of the significant decline in the economics of a single lease in the GOMSWP) by applicants. The combination of the opinions of the Department of the Interior, Office of the Solicitor and the use of BOEM’s *Economic Assumptions for BSEE Discretionary Royalty Relief Applications,* effective November 19, 2019 (Exhibit A) could perhaps combine to unlock capital and thus help the nation avoid stranding its oil and gas resources, without a change in policy or regulations, but rather simply following historic practices and application of the law.

Anticipated Impacts of Federal Revenue Sharing to Eligible States from advised Path Forward

Attachment 2, Issue Paper dated October 15, 2019, provides background on the anticipated impacts on Federal revenue sharing to eligible states are a result of the advised path forward of this report. You will note the Gulf of Mexico Energy Security Act (GOMESA) royalty revenue, and the states’ share by water depth, indicates royalties from the Shallow Water province (water depth of 200 meters or less) peaked five years ago. This Issue Paper estimates neutral or positive impacts of revenue sharing to the eligible states as a result of the advised path forward within this report.

Concern for Loss of Fish Habitat Due to Platform Removal

Although not part of this research project, it is important to note during this research effort, BSEE officials were contacted by Congressional staff members, staff members of the Louisiana Department of Wildlife and Fisheries, and officials with the Coastal Conservation Association, regarding their concern for the accelerated loss of fish habitat with the recent accelerated rate of platform and infrastructure removal. An obvious solution to the stranding of the nation’s oil and natural gas resources, the loss of fish habitat and fishing economy; all occurring because of the removal of platforms and infrastructure, would be to usher in public policy to assist the uneconomic platforms and infrastructure, scheduled for decommissioning, to become economic; all for the nation’s benefit. It should be noted that the loss of fish habitat, as explained by the concerned parties, is beyond the current “Rigs to Reefs” activities. In an effort to further the conversation, BSEE hosted a meeting in early November 2019 with Bureau of Ocean Energy Management (BOEM), the National Oceanographic and Atmospheric Administration (NOAA) National Marine Fisheries Service (NMFS), the U.S. Coast Guard (USCG), the U.S. Army Corps of Engineers (USACE), the Environmental Protection Agency (EPA), and representatives from the five Gulf Coast states; namely, Texas, Louisiana, Mississippi, Alabama and Florida. Follow-up additional meetings are being scheduled to further investigate this issue.

We have included a hyperlink

https://www.bsee.gov/what-we-do/conservation/gulf-of-mexico-shallow-water-province

to the section of the BSEE Website focusing on the Gulf of Mexico Shallow Water Province; which includes a video of coexistence of fish population and platform infrastructure.

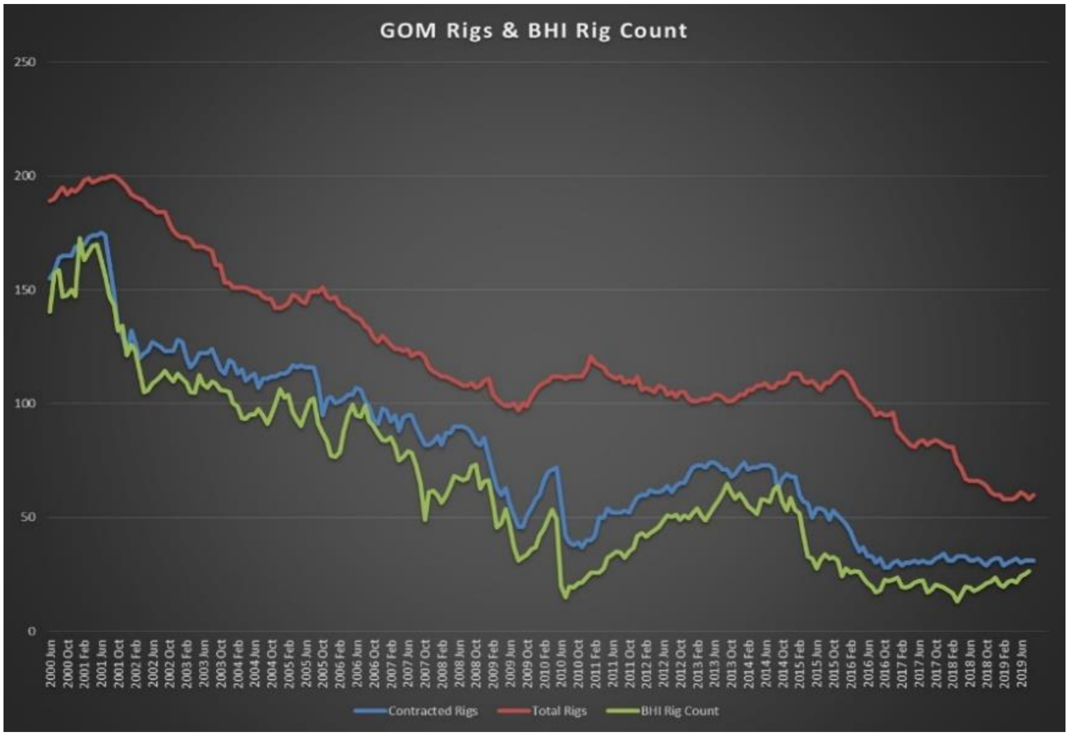
Deepwater Province and Rig Count

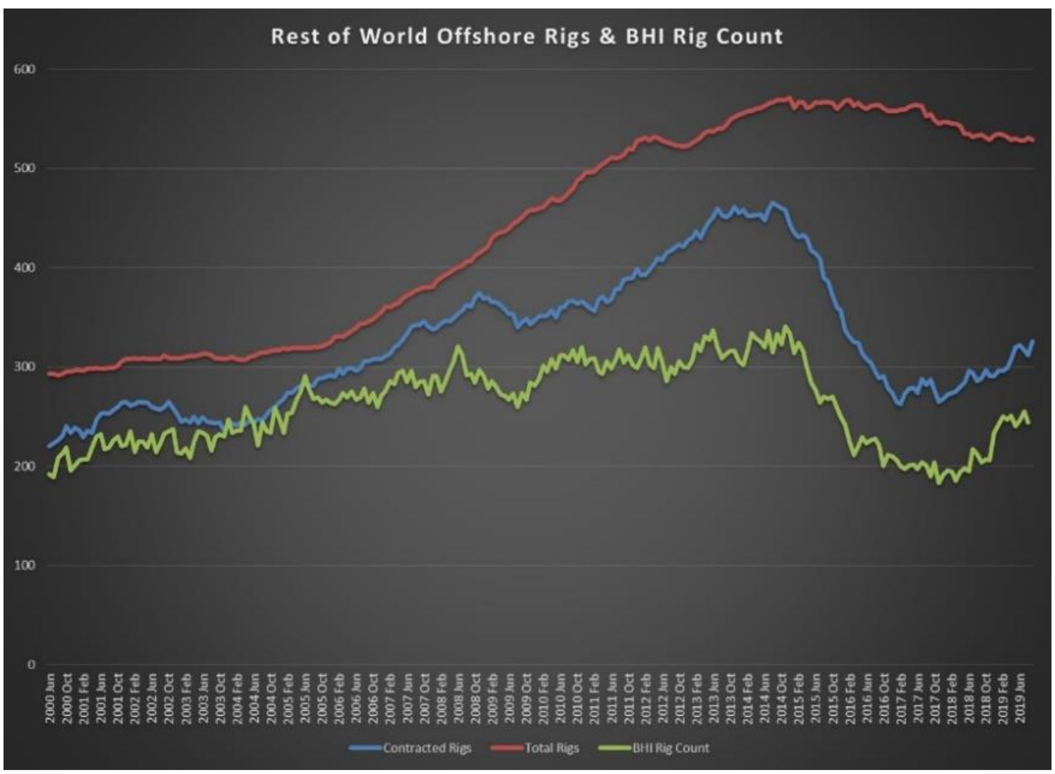
Nothing contained in this report is intended to suggest that the Deepwater province of the Gulf of Mexico is not in need of incentives to stimulate drilling and production; however, that research was outside the scope of this assignment. That said, the above-referenced IHS Report indicates that the Deepwater province has its own challenges attracting capital in an increasingly competitive world market.

Figure 20 shows that there was a global surge in the increase of existing rigs in 2006-2012 (red line), building a Deepwater fleet based on the speculation that worldwide demand for oil would need to be supplied from deeper water depths in the coming years. Yet, in the Gulf of Mexico, the decline in the total rigs over the same period (red line) is likely due to rigs moving out of the region or being decommissioned while not being replaced with new builds. The rigs constructed in recent years were built to higher specs, reducing the need for a larger volume of rigs.

Figure 20 - Baker Hughes Rig Count: Gulf of Mexico vs Rest of World Offshore

(Source: Baker Hughes and Rig Logix)





BOEM Path Forward

ONGOING BOEM ANALYSIS FOR FUTURE LEASES

The OCSLA requires royalty rates of at least 12.5% on new leases, but allows leases to be offered with royalty suspension volumes. As discussed, BOEM's recent lease sales have included a 12.5% royalty rate for shallow water (i.e., less than 200m) leases, and BOEM continues to study bidding and leasing activity to determine if a royalty suspension would be beneficial in attracting additional bidding interest. The external study contracted by BSEE and BOEM, titled 2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Gulf of Mexico International Comparison, prepared by IHS Global Inc., (IHS REPORT) and completed in November 2018 is currently being analyzed to inform options for decision making in future lease sales.

OPTIONS FOR EXISTING LEASES

BSEE has possible options for issuing royalty relief to avoid stranding assets of the nation's oil and gas resources. As previously mentioned, the above referenced IHS Report, *2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Gulf of Mexico International Comparison* states:

> "…the U.S. GOM shelf is limited in terms of resource availability. With the expected field sizes matching the small reserve size under this study, the best hope for such projects on the shelf is reliance on existing facilities and infrastructure. The market conditions do not favor development of the small reserves in the U.S. GOM shelf on a stand-alone basis. With the wave of decommissioning continuing strong in the shelf—more than 100 structures being decommissioned each year—the establishment of efficient policy solutions that encourage such developments could be necessary."[7]

[7]IHS Report, *2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Gulf of Mexico International Comparison*, page 35

BSEE Path Forward

BSEE Headquarters will transmit to the BSEE regions 1) the November 2019 report, entitled *Recommended Discount Rates and Policies Regarding Special Case Royalty Relief for Oil and Gas Projects in Shallow Water*, and the BOEM water depth specific discount rate range for royalty relief evaluation within the BOEM *Economic Assumptions for BSEE Discretionary Royalty Relief Applications*, effective November 19, 2019 all of which are attached on Exhibit A and 2) the Department of the Interior, Office of the Solicitor opinions regarding the parameters of permissible royalty relief.

Application & Review Requirements:

(Additional BSEE Safeguards to Maximize Transparency and Value to the Nation)

1. In order to establish what relief is necessary to make the project economic and to ensure that it would promote development, BSEE will obtain from the applicant their anticipated capital expenditures, a commitment to meet certain minimum expenditures, and a commitment to provide a summary of their actual expenditures upon completion of the work. BSEE will provide that failure to meet the minimum expenditure commitment (subject to a specified tolerance) will lead to the forfeiture of relief.

2. For applications that include exploratory wells, BSEE will assume no "dry hole" risk and use a P50 estimate of the resources in analyses.

3. Drilling of the defined project should commence within 36 months, consistent with a strategy to promote development by preventing current infrastructure from becoming uneconomic and platforms being scheduled for removal, resulting in stranded oil and gas resources of the nation. BSEE will provide that failure to commence operations within this specified time period, or to achieve milestones set forth in a reasonable schedule of activity, will lead to a forfeiture of relief.

4. To ensure that relief is limited to the amount necessary to make the project economic, you will include as a condition of approval certain thresholds, such as value of suspended royalties and/or commodity price ceilings, at which royalty relief would no longer apply. Please refer to BOEM's recommendation on page 2 of their *Recommended Discount Rates and Policies Regarding Special Case Royalty Relief for Oil and Gas Projects in Shallow Water*, dated November 2019; wherein BOEM recommends that BSEE consider providing the royalty relief in the form of a value of suspended royalties for approved special case royalty relief applications.

5. To ensure that the project is properly directed toward the promotion of development or increased production, you will include as a condition of any approval a requirement to conduct well operations targeting discovered resources before relief would be extended to other production from the lease

or project. This does not prevent the relief from being approved on other wells in the defined project; however, under this criterion that relief would not be realized until well operations targeting discovered resources are completed at the targeted location. Further, the total royalty relief approved by BSEE for the project shall be limited to the amount necessary to make economic the development or increased production of discovered resources.

In order to protect the American taxpayer, to ensure relief is warranted, and to ensure the proper amount of relief is granted, BSEE will perform an independent Geological & Geophysical and economic analysis of the project based on information submitted by the applicant and any proprietary information in BSEE's possession.

6. To meet the requirements of the regulations, the project must include, but is not necessarily limited to, the development of discovered resources by operations that require at least a permit to drill.

7. BSEE will require as a condition of approval that the activities be conducted primarily from existing infrastructure, but applications could also include the installation of new infrastructure.

8. Approval by the Regional Director is required.

References

Baud, Richie (2019, March 14) *Shallow Water Gulf of Mexico Decline-* Bureau of Safety and Environmental Enforcement Gulf of Mexico

Baud, R. D., Peterson, R. H., Richardson, G. E., French, L. S., Regg, J., Montgomery, T., . . . Dorner, M. (2002). *Deepwater Gulf of Mexico 2002: America's Expanding Frontier.* New Orleans: U.S. Department of the Interior.

Diffley, J., Bonakdarpour, M., Norton, S., Rosbash, T., Fullenbaum, R., & O'Neil, B. (2010). *The Economic Impact of the Gulf of Mexico Offshore Oil and Natural gas Industry and the Role of the Independents.* Lexington, MA: IHS Global Insight (USA), Inc.

Federal Register. (1998, January 16). Royalty Relief for Producing Leases and Certain Existing Leases in Deep Water, Final rule. *63*(11), pp. 2605-2626.

Federal Register. (2000, November 16). Relief or Reduction in Royalty Rates - Deep Water Royalty Relief for OCS Oil and Natural gas Leases Issued After 2000, Proposed rule. *67*(10), pp. 69259-69275.

Federal Register. (2002, January 15). Relief or Reduction in Royalty Rates - Deep Water Royalty Relief for OCS Oil and Natural gas Leases Issued After 2000, Final rule. *67*(10), pp. 1862-1880.

Kaiser, M. J., & Siddhartha, N. (2018). Review of producing shallow-water structures highlights market economics. *Offshore*.

IHS Global, Inc. *2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Gulf of Mexico International Comparison*, (2018).

Bureau of Ocean Energy Management *Economic Assumptions for BSEE Discretionary Royalty Relief Applications*, Effective November 19, 2019, 2019

BOEM Economics Division (2019, November) *Recommended Discount Rates and Policies Regarding Special Case Royalty Relief for Oil and Gas Projects in Shallow Water*

Acknowledgements

Data, graphs, and analyses in this document were provided by a vast number of BSEE, BOEM, and ONRR employees.

Attachment 1

ISSUE PAPER TITLE: Shallow Water Gulf of Mexico Decline
DATE: March 14, 2019

I. KEY POINTS

- BSEE's predecessor agencies recognized the declining shallow-water Gulf of Mexico (GOM) production and activity many years ago.
- Previous administrations implemented initiatives aimed at this issue.
- Previous efforts to extend the life of the Gulf of Mexico (GOM) shallow-water area did not stop the downward spiral.

II. BACKGROUND

The GOM "shallow-water" is often defined as water depths less than 200 m (656 ft) or 1,000 ft (305 m), although sometimes slightly shallower or deeper thresholds are used. For purposes of this document, an exact definition is not necessary since the focus here is to provide an overview of certain historical reports and agency programs that identified, and attempted to address, declining shallow-water activity, regardless of the exact threshold used to distinguish shallow- from deep water.

Shallow-water oil and gas production have been on decline since about 1997 (Brewton, 2009), (Karl, 2007), (Melancon, 2004), (Melancon, 2003), (Melancon, 2002), (Melancon, 2001), (Melancon, 2000), and (Melancon, 1999). Shallow-water leasing activity similarly declined from about 1996 through 1999, although it recovered somewhat from 2000 through 2004 before resuming that decline (Baud, 2000), (Baud, 2002), (Richardson, 2004), (French, 2005), (Peterson, 2007), (Richardson, 2008), and (Nixon, 2009).

It is interesting to note that shallow-water production and activity began their downward spirals just as the deepwater production and activity were ramping up. The industry shift from shallow to deep water began with major oil and gas companies selling off shallow-water assets to smaller companies and shifting their focuses to the emerging deepwater frontier (Richardson, 2004). This shift may have been expedited by the Deepwater Royalty Relief Act of 1995, which offered significant royalty incentives on deepwater leases, and also by the realization that production rates from deepwater wells far exceeded those in shallow water (Baud, 2000), (Richardson, 2004), (French, 2006), and (Richardson, 2008).

Previous administrations were also aware of declining shallow-water discoveries, reserves and field sizes (Baud, 2000), (Baud, 2002) (Richardson, 2004) (Richardson, 2008), and (French, 2006). The shallow-water GOM was seen as a mature basin, whereas the deepwater area offered better potential for the discovery of numerous new fields containing large reservoirs (Baud, 2002), (Richardson, 2004).

BSEE's predecessor agencies recognized and projected declining shallow-water production as far back as 1999 (Melancon, 1999). The decreasing gas production was of particular concern since shallow-water oil production declines were offset by deepwater increases, but the deepwater area was more oil-prone than gas-prone (Melancon, 1999), (Melancon, 2000), (Minerals Management Service, 2001), and (Minerals Management Service, 2003). Some efforts were made by previous administrations to address these concerns. For example regulations were issued (30 CFR 203.30 through 203.49) providing royalty relief incentives for drilling ultra-deep and deep-gas wells in the shallow-water GOM. Also, newly-issued leases included incentives such as royalty suspension volumes and drilling stipulations to earn longer lease terms. However, despite those efforts the shallow-water GOM continued its downward spiral.

III. PREPARED BY: Richie Baud, BSEE Gulf of Mexico OCS Region, Regional Supervisor of Production and Development, (504) 736-2675

References

Baud, R., Peterson, R., Doyle, C. and G. Richardson. 2000. *Deepwater Gulf of Mexico: America's Emerging Frontier.* New Orleans : U.S. Department of Interior, 2000.

Baud, R., Peterson, R., Richardson, E., French, L., Regg, J., Montgomery, T., Williams, T., Doyle, C., and M. Dorner. 2002. *Deepwater Gulf of Mexico 2002: America's Expanding Frontier.* New Orleans : U.S. Department of Interior, 2002.

Brewton, A., Baud, R., Yam, F., Almasy, L., DeCort, T., Uli, M., Riches, T., Kazanis, E., Josey, A., and R. Bongiovanni. 2009. *Gulf of Mexico Oil and Gas Production Forecast: 2009 - 2018.* New Orleans : U.S. Department of the Interior, 2009.

French, L., Kazanis, E., Labiche, L., Montgomery, T., and G. Richardson. 2005. *Deepwater Gulf of Mexico 2005: Interim Report of 2004 Highlights.* New Orleans : U.S. Department of Interior, 2005.

French, L., Richardson, G., Kazanis, E., Montgomery, T., Bohannon, C., and M. Gravois. 2006. *Deepwater Gulf of Mexico 2006: America's Expanding Frontier.* New Orleans : U.S. Department of Interior, 2006.

Karl, K., Baud, R., Boice, A., Bongiovanni, R., DeCort, T., Desselles, R., and E. Kazanis. 2007. *Gulf of Mexico Oil and Gas Production Forecast: 2007-2016.* New Orleans : U.S. Department of the Interior, 2007.

Melancon, J., and R. Baud. 1999. *Gulf of Mexico Outer Continental Shelf Daily Oil and Gas Production Rate Projections From 1999 Through 2003.* New Orleans : U.S. Department of Interior, 1999.

—. 2000. *Gulf of Mexico Outer Continental Shelf Daily Oil and Gas Production Rate Projections From 2000 Through 2004.* New Orleans : U.S. Department of Interior, 2000.

Melancon, J., Baud, R., Boice, A., Bongiovanni, R., DeCort, T., Desselles, R., and E. Kazanis. 2004. *Gulf of Mexico Oil and Gas Production Forecast: 2004-2013.* New Orleans : U.S. Department of the Interior, 2004.

Melancon, J., Bongiovanni, R., and R. Baud. 2001. *Gulf of Mexico Outer Continental Shelf Daily Oil and Gas Production Rate Projections From 2001 Through 2005.* New Orleans : U.S. Department of Interior, 2001.

—. 2002. *Gulf of Mexico Outer Continental Shelf Daily Oil and Gas Production Rate Projections From 2002 Through 2006.* New Orleans : U.S. Department of the Interior, 2002.

Attachment 1

—. 2003. *Gulf of Mexico Outer Continental Shelf Daily Oil and Gas Production Rate Projections From 2003 Through 2007.* New Orleans : U.S. Department of the Interior, 2003.

Minerals Management Service. 2003. *Gulf of Mexico OCS Deep Shelf Gas Update: 2001-2002.* New Orleans : U.S. Department of the Interior, 2003.

—. 2001. *The Promise of Deep Gas in the Gulf of Mexico.* New Orleans : U.S. Department of the Interior, 2001.

Nixon, L., Shepard, N., Bohannon, C., Montgomery, T., Kazanis, E., and M. Gravois. 2009. *Deepwater Gulf of Mexico 2009: Interim Report of 2008 Highlights.* New Orleans : U.S. Department of Interior, 2009.

Peterson, R., Richardson, E., Bohannon, C., Kazanis, E., Montgomery, T., Nixon, L., Gravois, M., and G. Klocek. 2007. *Deepwater Gulf of Mexico 2007: Interim Report of 2006 Highlights.* New Orleans : U.S. Department of Interior, 2007.

Richardson, E., Nixon, L., Bohannon, C., Kazanis, E., Montgomery, T., and M. Gravois. 2008. *Deepwater Gulf of Mexico 2008: America's Offshore Energy Future.* New Orleans : U.S. Department of Interior, 2008.

Richardson, G., French, L., Baud, R., Peterson, R., Roark, C., Montgomery, T., Kazanis, E., Conner, G., and M. Gravois. 2004. *Deepwater Gulf of Mexico 2004: America's Expanding Frontier.* New Orleans : U.S. Department of Interior, 2004.

Attachment 2

DATE: October 15, 2019

ISSUE PAPER TITLE: <u>Anticipated Impacts of Federal Revenue Sharing to Eligible States as a Result of the application of</u>

1) **The Department of the Interior, Office of the Solicitor opinions regarding the parameters of permissible royalty relief.**

2) **Bureau of Ocean Energy Management's (BOEM's) updated published *Economic Assumptions for BSEE Discretionary Royalty Relief Applications*, effective November 19, 2019.**

Background

Revenue sharing for states from OCS activities is derived from two statutory sources: Section 8(g) of the Outer Continental Shelf Lands Act (OCSLA) and the Gulf of Mexico Energy Security Act of 2006 (GOMESA). OCSLA provides coastal states 27 percent of federal revenues from bonuses, rents, and royalties from leases within three nautical miles of the seaward boundary of that state, while GOMESA provides the states of Texas, Louisiana, Mississippi, and Alabama 37.5 percent of federal revenues from bonuses, rents, and royalties from qualified leases issued after December 20, 2006.

Of importance and worth noting is the recent drilling and production activity over the last several years in the shallow water GOM*; specifically, there has been a 77 percent decline in oil production and a 92 percent decline in gas production over the last twenty years. The number of new wells drilled from 2008 to 2018 has declined by 89 percent, and the number of wells in production has declined by 61 percent.

Complicating this issue of declining production in the GOM shallow water province is the realization that uneconomic infrastructure is being removed at an unprecedented rate; thus putting the nation on a "shot clock" to establish new production prior to stranding much of its remaining oil and gas resources in this province. Since the commencement of shallow water production in 1947, a total of 6,991 production platforms have been installed while 5,102 have been removed for an all-time installation to removal ratio of 1.37 to 1. A view of these statistics over the last twenty years indicates 1,300 production platforms installed with 3,438 removed for a twenty year installation to removal ratio of 0.37 to 1. This trend continues to accelerate when viewing data from the last five years as only 13 platforms have been installed in the GOM shallow water province while 516 have been removed; resulting in a 0.025 to 1 installation to removal ratio. Furthermore, in 2018, no platforms were installed and 97 were removed.[1]

The revenue sharing impacts to states under the application of items 1 and 2 above are expected to be neutral to positive depending on the frequency of received and approved applications. It is possible, but unlikely that some of these projects may have moved forward without the application of items 1 and 2 above and that a reduced royalty rate would lead to less Federal revenues. However, we believe that this is unlikely and that in the aggregate, federal revenues will be neutral to positive.

Additionally, although not an impact on federal revenue sharing, but worth noting, is the potential for state revenues to increase resulting from the economic activity of increased drilling. The ancillary benefits for the region and Nation, according to the Bureau of Ocean Energy Management's (BOEM) MAG-PLAN Gulf of Mexico Model and accompanying analyses, for every million-dollar investment in shallow water, the total economic impact, including the reinvestment of state and local taxes, yields approximately $1.7 to $2 million in additional economic activity. This includes the purchase of indirect inputs associated with the companies that supply the industry with goods and services as well as the induced spending from the additional household income generated from direct and indirect spending.

Scenario 1:

Impact to Federal Revenue Sharing to States resulting from the application of items 1 and 2 above, limited to production from waters 200 meters or less, through production from existing wells:

Impact: None.

The BSEE application of items 1 and 2 above only applies to production from new wells.

Scenario 2:

Impact to Federal Revenue Sharing to States resulting from the application of items 1 and 2 above, limited to production from waters 200 meters or less, through production from new wells.

Impact: Neutral/Positive.

Based on the recent GOM shallow water activity it is likely that the current decline of new wells drilled and thus new production will continue. The attached figure, prepared by the Office of Natural Resource Revenue (ONRR) illustrates the stagnation in GOMESA royalties paid to the states over the last several years from the GOM shallow water province. Without a reversal in the steep decline of new GOM shallow water drilling activity, it is only logical to conclude, absent some unforeseen and dramatic increase in commodity prices, this province will be a diminishing source of revenue shared with the states. Conversely, if the application of items 1 and 2 above is successful by attracting new investment leading to new wells being drilled in the GOM shallow water province, that is otherwise not occurring, the new production will provide additional revenue to share with the eligible states. New drilling activity and the resulting production may also improve the economics of other fields sharing the same infrastructure. The continued or increased production from these associated fields may provide additional revenues to share with states.

Scenario 3:

Impact to Federal Revenue Sharing to States resulting from the application of items 1 and 2 above on production from new wells if natural gas and oil commodity prices increase.

Impact: It is difficult to predict the impact to revenue sharing if the application of items 1 and 2 above is implemented to stimulate new drilling AND there is subsequently an increase in commodity prices. Since the GOM shallow water province is primarily a natural gas province, a commodity price increase is relatively unlikely given the United States Energy Information Administration's *Annual Energy Outlook 2019 with projections to 2050*, dated January 24, 2019 wherein "Natural gas prices remain comparatively low during the projection period."[2] Nonetheless, to mitigate this possibility, the application of items 1 and 2 above contemplates a commodity price cap at which royalty rates would return to original contracted rates.

*There are currently **866** total active shallow water leases, **69** (7.9%) of which are subject to 8(g), **208** (24%) of which are subject to GOMESA, and **3** (0.3%) of which are subject to both.

61 out of 69 (88.4%) of the active 8(g) leases are currently in production, **36** out of 208 (17.3) of the active GOMESA active leases are currently in production, and **zero** of 3 (0%) which are subject to both are in production.

[1]BSEE BOEM Joint Report dated November 19, 2019 *Gulf of Mexico Data and Analysis/ Leasing, Drilling and Production Special Case Royalty Relief*

[2]U.S. Energy Information Administration *Annual Energy Outlook 2019*, page 12

PREPARED BY: BSEE and BOEM Staff

Attachment 2

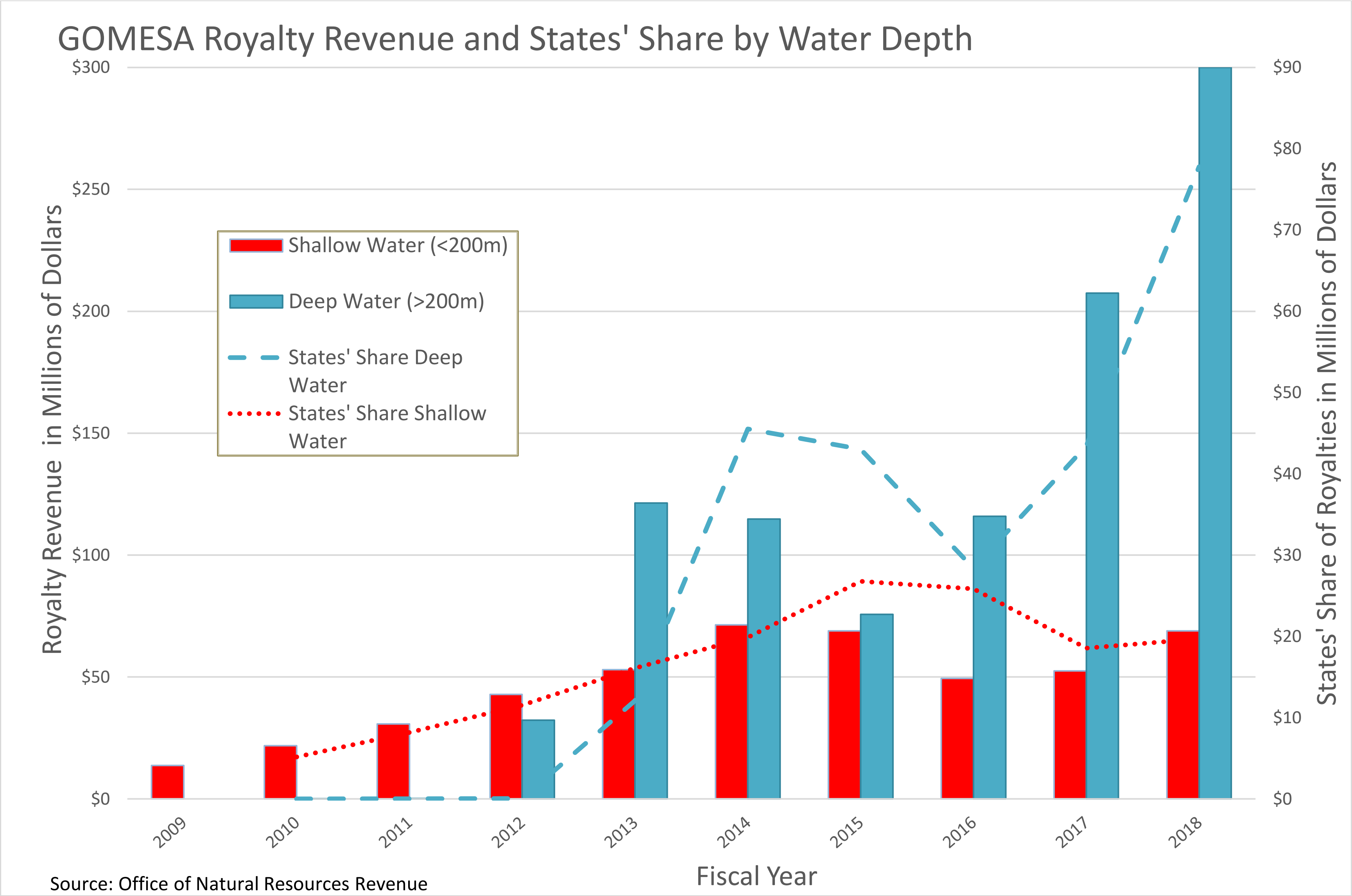


Exhibit A

BOEM Economic Assumptions for BSEE Discretionary Royalty Relief Applications

Effective November 19, 2019

Updated table of economic parameters:

Parameter	Minimum	Most Likely	Maximum	Dependency
Version of RSVP		2.14		
Year of Initial Oil Price		2019		
Initial Oil Price, landed (2019$/bbl)	$49.69	$60.40	$70.06	
Real Oil Price Growth Rate 1	-1.85%	-1.34%	0.33%	
Year Second Oil Scenario Starts	2nd rates are first applied to infer 2023 price from 2022			
Real Oil Price Growth Rate 2	-0.09%	1.65%	2.47%	
Year Third Oil Scenario Starts	3rd rates are first applied to infer 2029 price from 2028			
Real Oil Price Growth Rate 3	-0.03%	1.83%	2.79%	
Year of Initial Gas Price		2019		
Initial Gas Price, landed (2019$/Mcf)	$2.24	$2.74	$3.23	+1 with Oil Start Price
Real Gas Price Growth Rate 1	1.10%	1.94%	2.51%	+1 with Oil Growth Rate 1
Year Second Gas Scenario Starts	2nd rates are first applied to infer 2023 price from 2022			
Real Gas Price Growth Rate 2	1.56%	2.43%	3.54%	+1 with Oil Growth Rate 2
Year Third Gas Scenario Starts	3rd rates are first applied to infer 2029 price from 2028			
Real Gas Price Growth Rate 3	0.38%	0.97%	3.50%	+1 with Oil Growth Rate 3
Federal Income Tax Rate		21%		
Base year for Discounted Cash Flow	Year of Application Date			
Discount Rate Range for Gulf of Mexico Shallow Water (0-200m)	0%		25%	
Discount Rate Range for All Other Areas	10%		15%	
Random Number Seed		104		
Overhead Cost Allowance		5%		

Exhibit A

Recommended Discount Rates and Policies Regarding Special Case Royalty Relief for Oil and Gas Projects in Shallow Water

Bureau of Ocean Energy Management

Economics Division

November 2019

Exhibit A

Table of Contents

Summary

The Bureau of Ocean Energy Management (BOEM) has conducted analyses to help inform the Bureau of Safety and Environmental Enforcement's (BSEE) policies and procedures for applying Special Case Royalty Relief (SCRR) for certain shallow water oil and gas projects in the Gulf of Mexico. In this report, BOEM presents its research and recommendations regarding the appropriate discount rates to use when computing the net present value of cash flows within SCRR applications. BOEM recommends that companies should self-report discount rates, but that BSEE should impose a 25 percent upper bound on reported discount rates for shallow water leases. This policy would allow companies to earn appropriate rates of return, and would protect the government's right to receive fair amounts of royalty payments. BOEM also provides some analysis regarding the form of royalty relief. In particular, a Value of Suspended Royalties (VSR) offers some appealing features, and BOEM recommends that BSEE work with BOEM and the Office of Natural Resources Revenue (ONRR) to further examine the potential use of a VSR.

Exhibit A

Chapter 1: Introduction

Section 1.1: Project Background

The Bureau of Ocean Energy Management (BOEM) sets royalty rates for oil and gas leases in federal waters. In the most recent Gulf of Mexico (GOM) lease sales, BOEM has set a 12.5% royalty rate for shallow water leases (water depths less than 200 meters) and a 18.75% royalty rate for deepwater leases (water depths of 200 meters or more); existing leases can have royalty rates of 12.5%, 16.67%, or 18.75% (in either shallow or deep water). Royalties help ensure the public receives a fair return for leasing federal submerged lands. However, situations can arise in which companies are unwilling to develop certain oil and gas resources at the prevailing royalty rate because doing so would not yield a sufficient rate of return. In these situations, an operator may apply for certain types of royalty relief.[3] The Bureau of Safety and Environmental Enforcement (BSEE) administers discretionary royalty relief programs.

The oil and gas resources of the federal shallow water GOM region have been explored and developed for more than 65 years. As a result, the most profitable oil and gas projects have been developed, and a number of marginal accumulations are currently leased but may not be profitable (and thus may not be pursued) at current royalty rates. Operators of existing leases may apply to BSEE to obtain SCRR for certain oil and gas development activities. When analyzing SCRR applications, an important consideration is the extent to which the relief shifts the project from being unprofitable to being profitable. Therefore, reviews of SCRR applications often entail calculations of the profitability of the project with and without royalty relief. A key component of these determinations is an interest rate (or discount rate) used to compute the net present value (NPV) of expected cash inflows and outflows. A discount rate accounts for the time value of money, as well as the uncertainty associated with future cash flows. In general, the higher BSEE sets the discount rate, the more royalty relief would be required to make a particular project profitable. Therefore, the appropriate discount rate should facilitate the development of oil and gas resources, while minimizing the loss of government revenue.

This paper provides BOEM's research, analyses, and recommendations regarding the appropriate discount rates to use when evaluating shallow water SCRR applications. BOEM also suggests BSEE consider providing royalty relief in the form of a Value of Suspended Royalties (VSR). A VSR would protect the taxpayer and reduce lessee uncertainty. Section 1.2 provides a numerical illustration of how different discount rates can affect the NPV of an oil and gas project. Chapter 2 provides a theoretical framework for determining and understanding the appropriate discount rate in a particular situation. Chapter 3 describes the available data regarding discount rates. Chapter 4 provides BOEM's analysis regarding the appropriate form of royalty relief. Chapter 5 summarizes BOEM's findings and recommendations.

[3] More information regarding royalty relief programs is available at: https://www.boem.gov/Royalty-Relief-Information/ (BOEM 2019).

Exhibit A

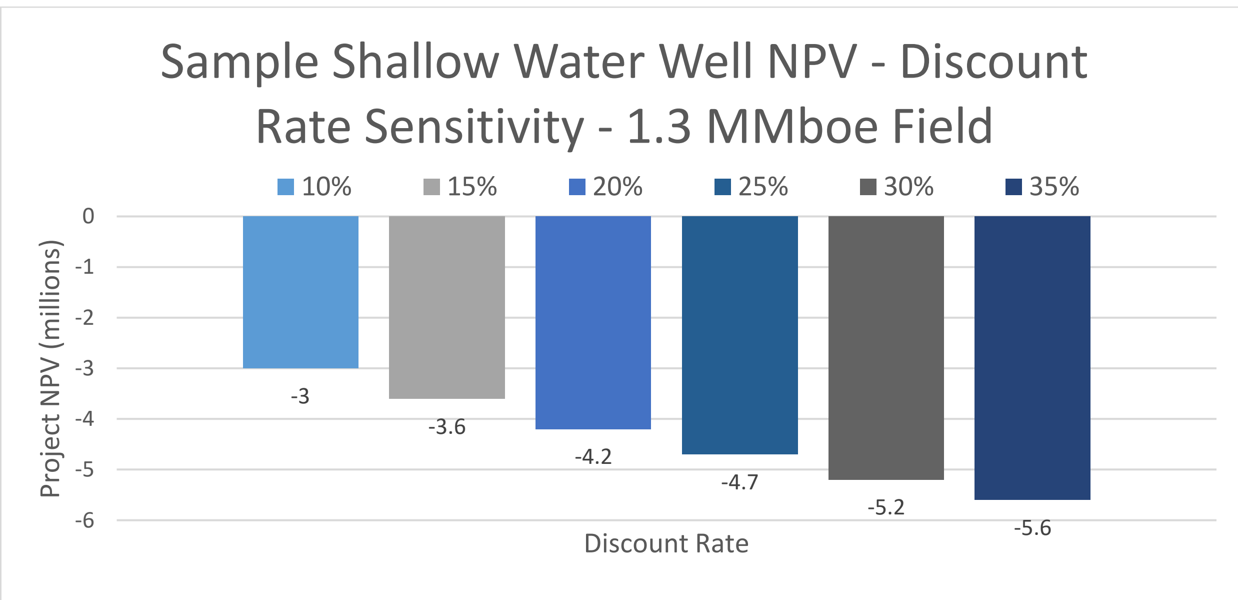
Section 1.2: Numerical Illustration of Discount Rates Impacting Net Present Value

Discount rates have significant impacts on oil and gas project evaluations. This section will present a numerical example of how discount rates can affect profitability, which will inform the analyses in subsequent sections.

$$NPV = \sum_{t=1}^{T} \frac{Expected\ Cash\ Flows}{(1+DR)^t} \qquad \text{(Equation 1)}$$

In Equation 1, NPV is computed by applying a discount rate (DR) to expected cash flows in each time period (t), and then summing the values for each time period. Figure 1 displays the NPV of a hypothetical 1.3 MMboe (million barrels of oil equivalent) shallow water project using discount rates ranging from 10-35%. As the discount rate increases, the NPV of a project decreases. Therefore, more royalty relief would be required to change the project's NPV to zero. For this sample project, each five-percentage point change in the applied discount rate changes the project NPV by roughly one-half of a million dollars.

Figure 1: Example Regarding Discount Rates and NPVs



A higher discount rate will generally reduce the NPV of an oil and gas project and require a larger amount of royalty relief to be economic. However, there is a limitation on the extent to which royalty relief can offset a negative NPV. At very high discount rates, reducing the royalty rate, even to zero percent, may not be sufficient to bring the project NPV to zero. Under Special Case Royalty Relief, royalty relief is provided to turn an uneconomic project economic. That is, BSEE provides royalty relief to change the NPV of a project from being negative to being non-negative. This highlights the importance of applying an optimal discount rate that allows BSEE to assess whether royalty relief is appropriate and, if so, to grant an amount of relief that allows a company to earn an appropriate rate of return (while protecting the government's right to receive fair amounts of royalty payments).

Exhibit A

Chapter 2: General Discussion of Discount Rates

Section 2.1: Introduction

This chapter provides a theoretical framework for determining and understanding the appropriate discount rates in the context of SCRR applications[4]. In particular, this chapter describes how various risks faced by shallow water operators influence discount rates.

Businesses typically determine which projects to pursue by assessing the size and timing of expected cash inflows and outflows. The timing of cash flows is important because money received sooner is more valuable than money received later. In addition, the owners of businesses prefer certainty and seek to minimize risk regarding the size and timing of cash flows. However, the cash flows from oil and gas projects are subject to numerous uncertainties. Therefore, businesses need a framework to value these uncertain cash flows. A common framework is to use risk-adjusted discount rates (RADRs), which entails applying higher discount rates for riskier projects.[5]

$$\mathrm{DR} = \mathrm{WACC} + \mathrm{IHR} + \mathrm{SWRA} \qquad \text{(Equation 2)}$$

Inkpen and Moffett (2011) decompose discount rates as shown in Equation 2, where:

- DR: Discount rate applied to expected cash flows
- WACC: Weighted average cost of capital
- IHR: Incremental hurdle rate
- SWRA: Shallow water risk adjustment

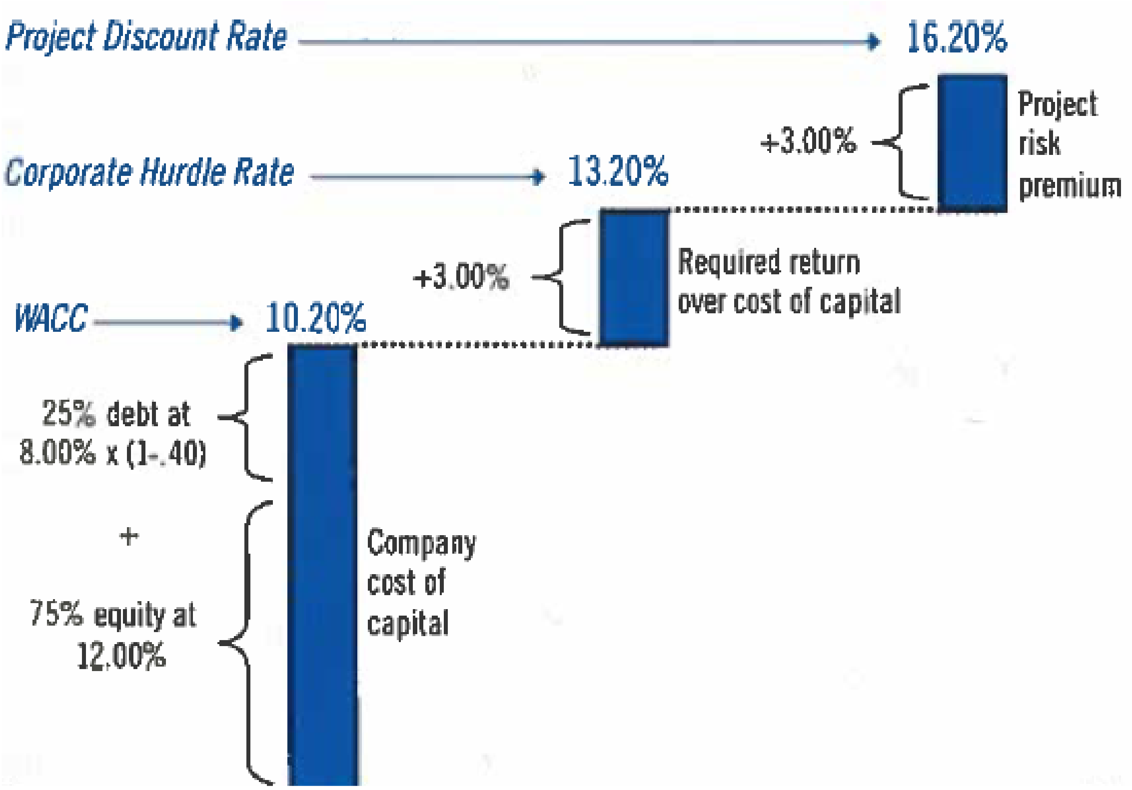
In other words, companies will expect to earn at least as much as their weighted average cost of debt and equity capital. In addition, if companies have multiple profitable investment opportunities (and a limited budget), they will require more than the WACC (an incremental hurdle rate) in order to pursue an average-risk project. Finally, a GOM shallow water project, particularly one for which royalty relief would be requested, likely faces additional risks compared to a company's average project. For example, the probability that a marginal project will be profitable overall is more sensitive to deviations of variables (such as reserves and prices) from their expected values. In addition, the most profitable areas of the shallow water GOM have already been developed, which limits the likelihood of a highly profitable outcome. Therefore, businesses will likely require a higher discount rate to compensate for these risks.

[4] This paper generally refers to *nominal* discount rates, which do not remove expected inflation. One can convert nominal discount rates to *real* discount rates (which do remove expected inflation) as:
Real discount rate = [(1+ nominal discount rate)/(1 + expected inflation rate)] -1
(where all variables are entered as decimals).

[5] An alternate approach is to discount cash flows using a lower discount rate than in Equation 2, and to then to decrease the resultant net present value by a reserve adjustment factor (Society of Petroleum Evaluation Engineers 2018). There has also been some research regarding the use of option theory related to oil and gas projects, but these methods are not often used in practice (Dickens and Lohrenz 1996).

Exhibit A

Figure 2: Components of a Risk-Adjusted Discount Rate



Source: Inkpen and Moffett (2011)

Figure 2 presents a hypothetical example from Inkpen and Moffett (2011) regarding the components of a risk-adjusted discount rate. In this example, an oil and gas company is analyzing the profitability of a particular project. The company is financed by 75% equity and 25% debt. Suppose the cost of equity is 12%, the cost of debt is 8%, and the corporate tax rate is 40%. The weighted average cost of capital of these funding streams is 10.2% (see Section 2.2 for more information).[6] Due to competing investment projects, this company has an average incremental hurdle rate of 3% (and a total corporate hurdle rate of 13.2%). Finally, the particular project under consideration is riskier than the company's average project, so the company adds a 3% percent risk premium. This yields a total project discount rate of 16.2%. Therefore, this company will use a discount rate of 16.2% to compute the net present value of cash flows from this project. Sections 2 through 4 will describe these components of discount rates in more detail. Section 5 will qualitatively discuss how discount rate policies can affect society as a whole.

[6] The current corporate tax rate is 21%. If this 21% corporate tax rate were applied to the example in Figure 2 (and assuming other variables did not adjust), the WACC would equal 10.58% (and the project discount rate would equal 16.58%). The WACC would increase because there would be less of a tax shield associated with debt financing (see Section 2.2).

Exhibit A

Section 2.2: Weighted Average Cost of Capital

When analyzing an oil and gas project, a company will expect to earn at least the weighted average cost of its debt and equity financing in order to undertake the project.

$$WACC = \left(\frac{E}{V}\right) R_E + \left(\frac{D}{V}\right) R_D (1 - T_C) \qquad \text{(Equation 3)}$$

Equation 3 is the formula for the WACC (Corporate Finance Institute 2019), where:

- E: Market value of total equity
- D: Market value of total debt
- V=E+D (the total market value of debt and equity combined)
- R_E: Cost of equity
- R_D: Cost of debt
- T_C: Corporate income tax rate

The first part of Equation 3 represents the portion of a company's cost of capital represented by required returns on equity. In particular, equity investors will require a rate of return commensurate with a company's collective risk profile. There are numerous risks associated with oil and gas projects, such as price volatility, uncertainty regarding reserves, and variability of input costs. Since investors often can diversify their equity holdings, a common assumption is that equity investors will only receive compensation for risks that cannot be eliminated through diversification[7]. However, given the numerous sources of uncertainty for oil and gas companies, as well as the interdependence between energy markets and the broader economy, many of the risks cannot be diversified away. In addition, many shallow water oil and gas operators are privately-held companies, which further limits their ability to diversify risks. Therefore, for most oil and gas companies, the required return on equity capital is high.

The second part of Equation 3 represents the cost of debt financing (since debt interest payments are tax deductible, one considers the after-tax cost of debt financing). One can roughly think of the cost of debt as the sum of a risk-free interest rate, often approximated by the interest rate on a U.S. Treasury bond or bill, plus a premium to compensate lenders for the possibility that some or all of a loan may not be paid back on schedule. U.S. Treasury yields have been low in recent years. However, given the various risks associated with oil and gas development, lenders often require a sizable risk premium. This is particularly the case for smaller companies and companies experiencing financial difficulties. Therefore, the cost of debt (and the overall WACC for oil and gas companies) can be substantial.

[7] This is the core assumption of the Capital Asset Pricing Model, a widely-used framework for determining required rates of return (Sharpe 1964). Other theories of asset prices incorporate additional factors in their models, such as a company's size and the ratio of a company's book equity to its market equity (Fama and French 1993).

Exhibit A

Section 2.3: Incremental Hurdle Rate

At any point in time, oil and gas companies likely have several potential projects under consideration. The minimum requirement for these projects is that they yield a return that is greater than (or equal to) the WACC. However, in many cases, a company will have multiple profitable projects under consideration. A company may be able to obtain additional funding to pursue more or all of these projects, but to the extent a company is unable or unwilling to do this, the company will apply a framework for deciding which projects to pursue. In the context of understanding discount rates, an appropriate framework is to think in terms of an incremental hurdle rate that represents the rate of return above the WACC that would induce a company to undertake a particular project relative to other projects. This incremental hurdle rate will thus vary through time given market conditions.

In practice, other factors may influence oil and gas investment decisions. For example, the size of the project (and the resulting overall profits earned) will be an important factor. U.S. shallow water projects are typically smaller than other projects (such as deepwater projects) and thus may not be as lucrative, particularly if certain factors make the projects mutually exclusive. Therefore, all else being equal, an average company will require a higher rate of return for a small shallow water project. However, the size of the oil and gas company may also affect its incremental hurdle rate. In particular, large companies may require a higher incremental hurdle rate than smaller companies because large companies have more (and larger) investment options. This has resulted in a trend of major oil and gas companies leaving the shallow water GOM to focus on larger projects (for example in the deepwater GOM) that offer more potential upside. The remaining operators of shallow water projects are thus smaller companies that are willing to accept smaller overall returns on projects.

Companies may also chose projects that recover their costs more quickly than other projects. In general, shallow water projects recover their costs faster than deepwater projects, but slower than onshore projects. In addition, spillover effects from a particular project to other future projects can influence development decisions. For example, pursuing a particular oil and gas project could position a company to pursue similar projects in the future through cost efficiencies or technological improvements. This issue would tend to lead companies to pursue alternatives to shallow water projects, since the future prospects for GOM shallow water projects are significantly less than for other areas. In addition, the shallow water GOM produces a higher percentage of natural gas (compared to oil) than the deepwater GOM. Natural gas is unlikely to be very profitable given the boom in, and the cost advantages of, onshore natural gas production.

Given the various factors discussed above, the extent to which an average shallow water project requires a higher or lower incremental hurdle rate than other projects will depend on the magnitude of these factors.

Exhibit A

Section 2.4: Shallow Water Risk Adjustment

The discount rate for SCRR applications should account for the risks of these shallow water projects. These projects are by definition only marginally economic or uneconomic (often due to their limited oil and gas resources). Therefore, the likelihood that these projects will be profitable is sensitive to any deviations of economic variables (such as market prices, discovered resources, and development costs) from their projected values. A primary determinant of the risk adjustment should be the uncertainty of the oil and gas production likely to arise from a particular project. The risk adjustment should also account for the fact that there is a very low probability of a much higher than expected return because the most resource-rich areas of the shallow water GOM have already been developed. There is a higher probability of a large downside return (if the oil and gas resources turn out not to be present or are unobtainable for some reason). Finally, shallow water operators in the Gulf of Mexico face infrastructure-related risks associated with operating in a declining province. For example, older infrastructure requires more repairs, and longer-term infrastructure gaps (such as the eventual unavailability of certain platforms or pipelines) could arise. Therefore, the discount rate should be adjusted upwards to account for these risks.

Section 2.5: Societal Considerations

The analysis of discount rates in prior sections focused on discount rates used by oil and gas companies when making investment decisions. This is appropriate because companies ultimately determine whether to pursue certain projects, and because federal policy regarding this issue has typically focused on the extent to which royalty payments (and the resulting royalty relief) determine whether a project is economic to pursue. However, when considering policy decisions, it is appropriate to consider the costs and benefits of policy options from the perspective of society as a whole. In the analysis of discount rates, a societal viewpoint highlights the effects of decisions by an oil and gas industry on other actors in an economy. A societal viewpoint also highlights the risks of setting the discount rate too high or too low.

When an oil and gas company undertakes a discounted cash flow analysis in its decision-making process, it does not incorporate numerous effects on society as a whole. Some of these effects are beneficial, such as increased government revenues, lower energy prices, and less dependence on substitute energy sources. On the other hand, some of these effects, such as potential environmental effects, may be negative (depending on the alternatives). An important issue that is not sufficiently captured in an individual company's analysis is the viability of the shallow water GOM province as a whole, and whether the collective decisions of many companies will leave oil and gas resources undeveloped for the foreseeable future.

The OCS Lands Act authorizes the Secretary of the Department of the Interior to issue regulations in the interest of conservation of OCS natural resources.[8] Conservation of OCS resources promotes economic efficiency, and from an economic perspective, leasing, development, and production activities should be carried out in a manner that will increase the net economic value to society from the development of OCS resources. In the context of GOM shallow water development,

[8] 43 U.S.C. § 1334(a)

conservation of resources is a concern because much of the infrastructure to support shallow water activities, such as production platforms, are required to be removed not long after oil and gas production ceases; BSEE (2018) describes the decommissioning requirements for wells and platforms. Once infrastructure is removed, it is unlikely that similar infrastructure will be re-installed in the future because of the significant costs involved. Therefore, oil and gas companies, and society as a whole, may eventually lose the option to develop these shallow water assets even if economic conditions become more favorable in the future. Therefore, one can view the determination of discount rates as a policy lever to better account for these societal interests. While this is not the core analytical question at issue in this paper, it is useful to keep this perspective in mind.

It is also informative to consider the risks to society of setting discount rates too low or too high. If the government sets discount rates too low, certain projects may not be pursued (that may have been pursued if appropriate discount rates were used). As mentioned previously, society may also lose the value of the option to develop certain shallow water oil and gas resources in the future. If the government sets discount rates too high, it will encourage royalty-relief applications for projects that would have proceeded without royalty relief. Thus, the government would lose a fair amount of royalty revenue. In addition, for very marginal projects, setting the discount rate too high may lead to the conclusion that no amount of royalty relief would make these projects economic (and thus the projects would not be pursued). These effects highlight the need to select optimal discount rates that appropriately balance society’s varied interests.

Chapter 3: Analysis of Data Sources for Discount Rates

The discount rates the government uses for evaluating SCRR applications should be similar to the rates companies use when evaluating similar upstream oil and gas investment opportunities. Unfortunately, the discount rates companies use, and the evaluation techniques they employ, differ across companies and are proprietary. There are several methods for estimating companies' discount rates. These methods include (1) measuring the cost of capital from financial data, (2) estimating the average return on upstream oil and gas investments, and (3) surveying companies to elicit their discount rates. There are various data and confidentiality limitations regarding methods 1 and 2. Therefore, this Chapter will summarize the available data from surveys and related reports. Section 3.1 will describe discount rate data from the Society of Petroleum Evaluation Engineers (SPEE). Section 3.2 will describe some other relevant data sources.

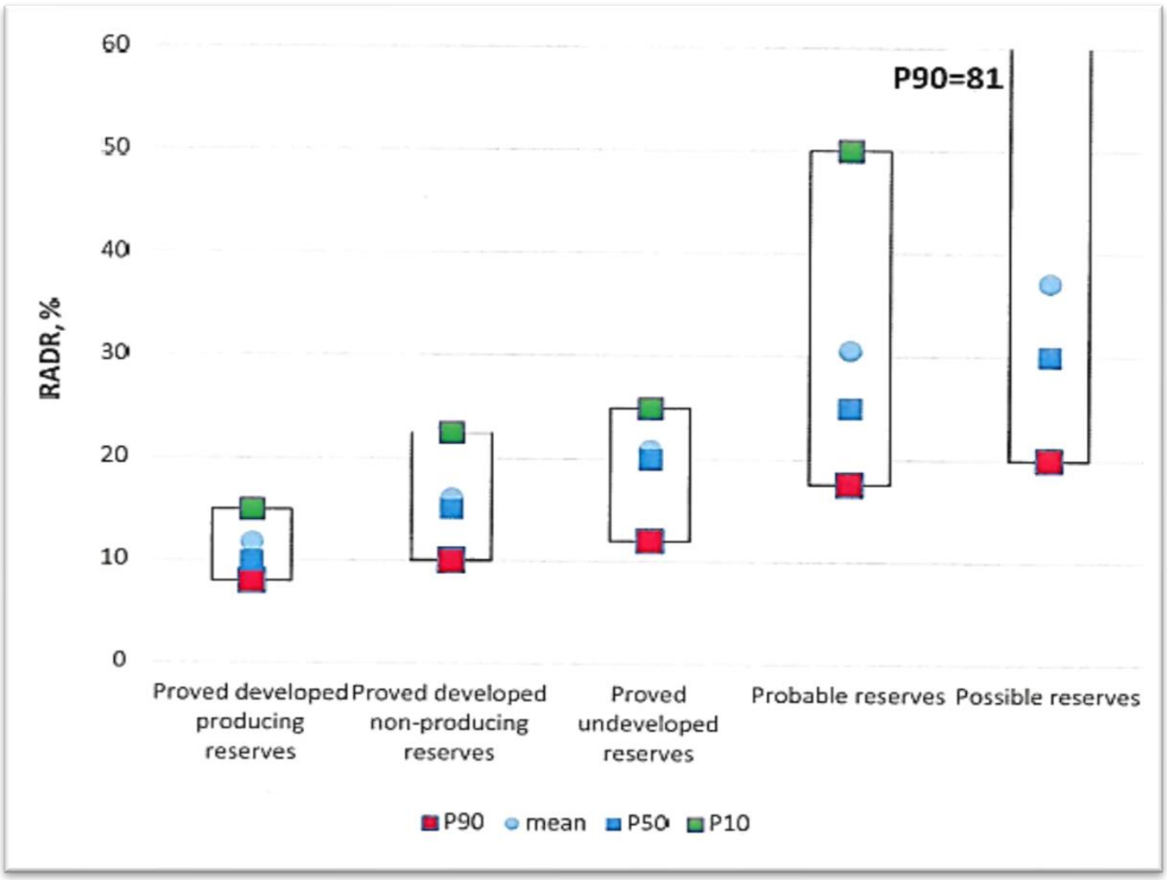
Section 3.1: Society of Petroleum Evaluation Engineers Data

The SPEE conducts an annual survey of their members regarding upstream resource evaluation topics. The survey asks members a wide range of questions, including questions about SPEE member companies' risk-adjusted discount rates (RADRs) used for different types of projects. BOEM acquired reports that summarized the data from the 2016, 2017, and 2018 surveys. The majority of survey responses came from employees of either exploration and production companies or oil and gas consulting companies, whose job functions primarily entail property valuation, reserves estimation, or acquisition and divestiture activities. The surveys do not differentiate between offshore and onshore evaluation methods. In the 2018 SPEE survey, almost 80% percent of respondents were located in the United States, and the vast majority of them spent a significant amount of time evaluating resources in the United States. When asked for reasons why RADRs were used to evaluate assets, 88% of respondents to the 2018 survey stated that reserve risk made the use of RADRs appropriate in their evaluations. Other reasons that were cited in over 33% of responses include price uncertainty, expense uncertainty, mechanical risk, and political regulatory uncertainty.

The 2018 SPEE survey asked members for the actual RADRs used when evaluating projects targeting certain categories of reserves; the results of the survey are presented in Figure 3. As one would expect, the less certainty companies had regarding the volume of recoverable resources, the higher the RADR used to evaluate these projects. Creating asset decline curves and cash flow models is straightforward when the asset being evaluated is proved developed or producing. While there is risk involved with any investment decision, the reserve risk is mitigated when companies are more certain about the recoverable resource. This is why *proved* reserves require a lower RADR than *probable* reserves.

In Figure 3, the 2018 SPEE survey results show that the median RADR used for probable reserves appears to be around 25%. Similarly, the 2016 and 2017 SPEE surveys found that the median RADR used for probable reserves was 25%. The 2016, 2017, and 2018 surveys found that the median RADR for proved developed producing reserves was approximately 10%. These differences illustrate that discount rates used for asset evaluations vary depending on the reserve classifications.

Figure 3: Risk Adjusted Discount Rate by Resource Classification - 2018 SPEE Survey Results



A limitation of the data in Figure 3 is that some of the survey responses relate to RADRs used for purposes somewhat different from oil and gas exploration and development. For example, RADRs are also used for asset acquisitions and overall corporate valuations. The 2017 SPEE survey presented results for the different categories of use (the SPEE data for other years did not provide these breakouts). The 2017 SPEE data found that the mean RADR used for oil and gas field development was 19.5% (sample size=24), and the mean RADR used for decisions to drill exploration wells was 17.4% (sample size=20). However, there were wide ranges of RADRs used.

Exhibit A

Section 3.2: Other Data Sources

Other than SPEE data, there is limited alternate survey data regarding discount rates used by oil and gas companies. Below are a few sources that were found.

The Texas Comptroller of Public Accounts (2018) describes the RADRs used to assess oil and gas properties. This report developed an average range of discount rates of 14.62%-20.81%, and described some contexts that would allow for deviations from this range. For example, this study applied a 2 percent increase in RADRs for offshore properties.

Oil and Gas Journal (2018) presents discount rate data from Wood Mackenzie's 2017 and 2018 annual surveys of upstream oil and gas companies. The discount rates for various project categories in 2017 and 2018 were:

- Unconventional projects: 14.0% in 2017; 14.1% in 2018
- Deepwater projects: 15.9% in 2017; 14.8% in 2018
- Exploration projects: 15.8% in 2017; 14.8% in 2018

The Oxford Institute for Energy Studies (2019) emphasizes the risks of oil and gas projects in the context of a long-run transition towards renewable energy sources. This study cites survey results that a deepwater project has an average 18% discount rate (it does not cite a discount rate for shallow water).

Section 3.3: Analysis of Available Data

The SPEE surveys (for 2016, 2017, and 2018) provide the most detailed discount rate data. These surveys report that the median discount rate used for probable reserves was approximately 25%. While informative, some of the survey responses related to discount rates for uses other than oil and gas exploration and field development. The 2017 SPEE survey was the only survey to provide discount rates specifically for these categories. The 2017 SPEE survey found that the mean RADR used for field development was 19.5%, and the mean RADR used for exploration wells was 17.4%. These mean values are roughly consistent with the other data sources found. However, as described in Chapter 2, shallow water projects for which royalty relief would be sought have above-average risks. Therefore, companies will likely apply above-average discount rates when evaluating these projects. However, given the myriad of factors that affect discount rates, there is no formula that BSEE can apply to precisely estimate the appropriate discount rate for a particular SCRR application. Therefore, BSEE needs to set a generally-applicable discount rate policy that accounts for the various factors described in this paper. BOEM recommends that BSEE allow companies to self-report discount rates, but to impose an upper bound of 25%. This 25% upper bound on discount rates allows companies to earn appropriate rates of return, and protects the government's right to receive appropriate royalty payments.

Chapter 4: Form of Royalty Relief

Section 4.1: Royalty Suspension Value, Royalty Suspension Volume, or Lower Royalty Rate?

Although the main purpose of this paper is to provide analyses and recommendations regarding the appropriate discount rates for shallow water SCRR applications, utilizing the appropriate policy to deliver the intended relief to operators is very important. Traditionally, BSEE has provided SCRR in the form of a reduced royalty rate on all production from a lease up to a specific price and production volume threshold. However, as will be described in this chapter, a lower royalty rate is an inefficient form of royalty relief. BSEE has the authority to use a variety of royalty suspension policies as provided in its regulations[9], including (but not limited to):

- A lower royalty rate.
- A Royalty Suspension Volume (RSV): A fixed volume of initial production that is royalty-free as long as prices remain below a pre-determined price threshold.
- A Value of Suspended Royalties (VSR): A predetermined dollar amount that the operator does not pay in royalties. Once the lessee's calculated royalties exceed the VSR, royalty payments resume as provided in the lease.

BOEM recommends that BSEE consider applying royalty relief using a VSR formulation because it provides a number of benefits to operators and the government. A VSR yields the most optimal and timely royalty relief, and provides operators with a consistent benefit in all price cases. Since a VSR is a defined benefit where a value of royalties is the limiting factor, a VSR does not require additional triggers, such as inflation adjustments, price thresholds, or volume limits. When prices deviate from the forecast, only the rate at which the VSR benefit is consumed is affected; the intended value remains constant. By comparison, the amount of relief granted from an RSV or from a lower royalty rate can vary widely if prices or volumes diverge from their projections; the potential of significant price or volume increases also necessitate thresholds to ensure practical limits to royalty benefits. Due to a VSR's design, thresholds are unnecessary and an operator can be certain that they will receive the full amount of the intended benefit at any price, and can build the VSR into their cash flow analyses with confidence.

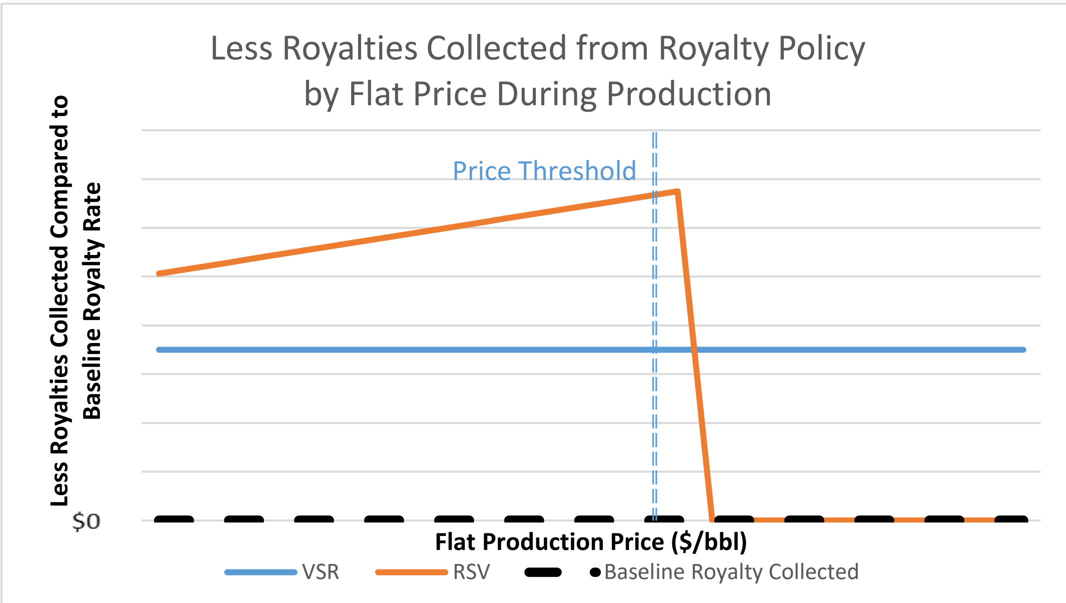
An RSV has been a common form of royalty relief issued by BOEM and BSEE (and their predecessors). However, RSV policies generally suffer from several significant drawbacks due to the necessity of price thresholds to limit the potential royalty relief. A project granted an RSV receives an intended benefit based on a specific price forecast; the derived value of the benefit is calculated by multiplying the royalty rate by the price forecast and the predetermined production volume. The thresholds must be set at the time of the relief determination and are unlikely to reflect actual oil and gas prices or production over time. Price and volume thresholds function as the limits of the royalty suspension benefit. Given the volatility in commodity prices, the actual benefit derived from an RSV policy can vary widely. If actual prices are higher than forecasted, but remain below the price threshold, the benefit granted by the RSV increases beyond the intended benefit. If prices are lower than forecast, the RSV provides less monetary benefit than intended as the amount of paid royalties are lower than forecasted. In either case, the value of the benefit is not as intended.

[9] 30 CFR Part 203

Exhibit A

When prices are above the price threshold, additional undesirable effects occur. First, the value of RSV policies experience a "cliffing" effect, that whenever prices breach the price threshold the value of the project drops sharply as a result. Figure 4 illustrates the "cliffing" effect that RSVs have once the price threshold is breached. In this graph, when the price breaches the threshold, the amount of suspended royalties drops to zero, and the value of the project drops immediately. Second, production that occurs above the price threshold is not royalty free, but continues to count toward the royalty suspension volume, essentially "wasting" the benefit of the RSV. These undesirable effects could cause operators to produce in a suboptimal fashion to avoid these effects.

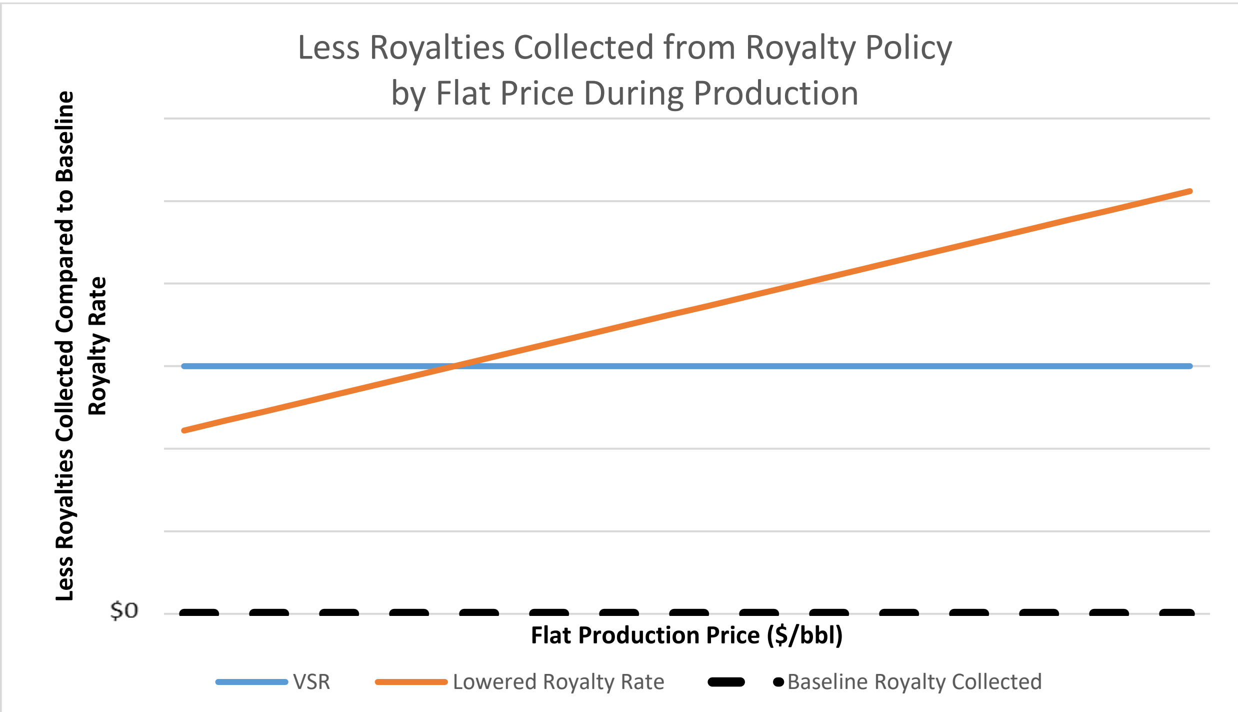
Figure 4 – RSV "cliffing" effect, compared to VSR



On the other hand, a VSR does not require price or volume thresholds and thus does not suffer from the same "cliffing" or "wasting" effects discussed previously. Higher than forecasted prices or production volume simply consumes the intended benefit at a faster rate, which is more beneficial to the operator's cash flow; at lower than forecasted prices or production, the VSR is consumed slower and thus provides more benefit than a royalty suspension policy. Many of the drawbacks of the RSV approach are not applicable, as a VSR provides the intended benefit in any price scenario.

A VSR policy also compares favorably to a lowered royalty rate traditionally used in BSEE royalty relief applications. A lowered royalty rate still requires price and volume thresholds to limit the maximum benefit and inherits all of the related drawbacks (discussed above). A lower royalty rate provides significantly less downside price protection to the operator than a VSR; as prices drop the benefit of a lower royalty rate also drops, whereas a VSR's defined benefit lasts longer at lower prices since it is consumed slower. Another major drawback of a lower royalty rate is that it does not improve cash flow as quickly as a royalty suspension policy. Suspended royalties provide a greater present value on a dollar-for-dollar basis than the remaining paid royalty stream by returning capital as fast as possible; the operator would still pay partial royalties with a lower royalty rate. Figure 5 below illustrates that at low prices a VSR provides more relief to the operator than a lower royalty rate. At high prices, a lower royalty rate delivers significantly more benefit than intended. The use of price and volume thresholds along with a lower royalty rate can limit the over-provision of royalty relief, but use of the thresholds result in the undesirable ”cliffing” and “wasting” effects discussed previously.

Figure 5 - Illustration of Less Royalties Collected with VSR vs. Lowered Royalty Rate



A VSR approach could also provide certain administrative benefits to the operator and the government. Price thresholds require annual inflation adjustments, specialized tracking overhead when accounting for suspension volumes, and additional workload if royalties have to be returned to the operator due to prices close to the threshold. A VSR does not require price thresholds or suspension volumes, and thus would not suffer from these issues. However, a VSR could raise other administrative issues and BOEM recommends BSEE discuss this form of royalty incentive with the Office of Natural Resources Revenue.

Exhibit A

Section 4.2: VSR Examples

This section uses cash flow data from an SCRR application to illustrate the effects of different discount rates and royalty relief policies. Figure 6 shows the effect that the discount rate has on the NPV of the SCRR project at various royalty rates. Figure 6 displays this relationship for the following royalty rates:

- 16.67%: The baseline royalty rate for the example project.
- 12.50%: The current royalty rate for shallow water leases.
- 7.59%: The royalty rate at which the project would have a zero NPV at a 25% discount rate.
- 0%: A zero royalty example for comparative purposes.

For all royalty rates, the project NPV decreases as the discount rate increases. A VSR policy would entail a VSR amount that would fill the gap between the dashed zero NPV line and the NPV of the project at a particular royalty rate and discount rate. However, since the VSR benefit would be not be received all at once (but rather at the rate royalties would not have to be paid), the amount of the VSR will be slightly higher than this gap. At a 25% discount rate:

- At a 16.67% royalty rate (and no VSR), the project would have an NPV of -$5.42 million.
- At a 12.50% royalty rate (and no VSR), the project would have an NPV of -$2.93 million.

Figure 7 illustrates the amount of VSR required to move up to the dashed black zero NPV line in Figure 6 from either the 16.67% or 12.50% royalty cases over a range of discount rates. Note that above a 34% discount rate, the project is below zero NPV even with a 0% royalty rate. At a 25% discount rate, the following VSR amounts would bring project NPV to zero:

- A $6.63 million VSR at a 16.67% royalty rate
- A $3.45 million VSR at a 12.5% royalty rate

Exhibit A

Figure 6 - Project NPV by Discount Rate and Policy

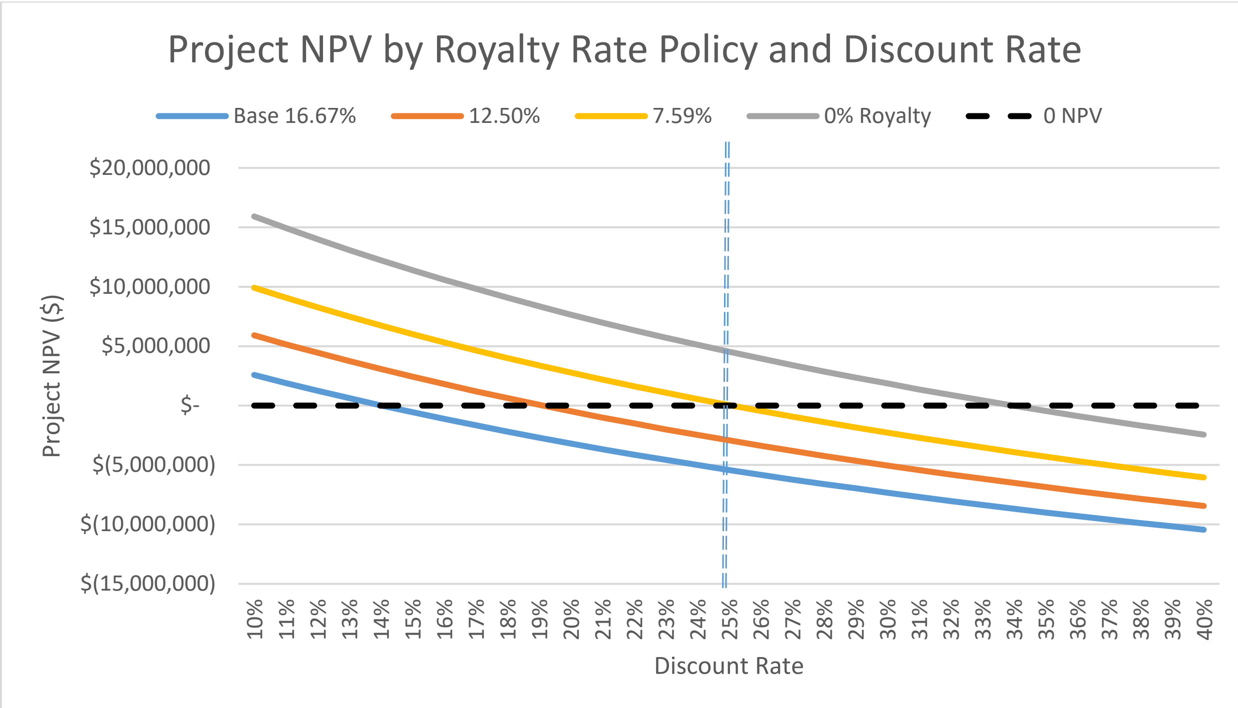


Figure 7 – VSR Required to Reach Zero NPV

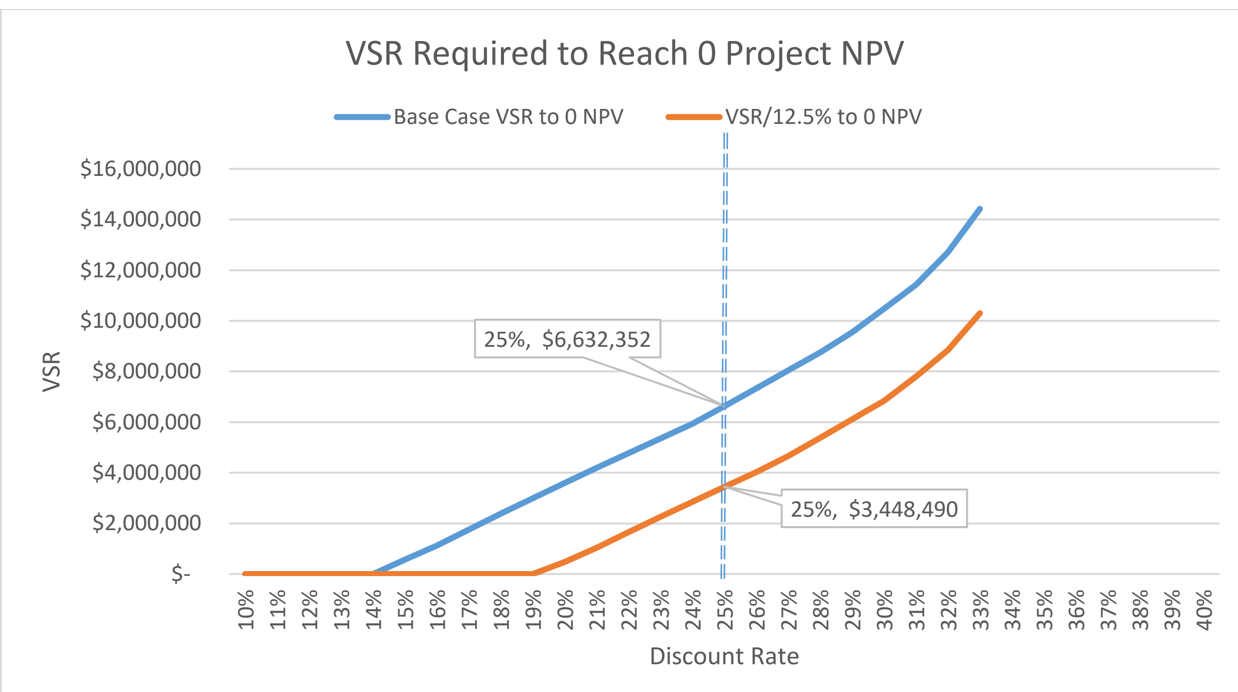


Exhibit A

Table 1 compares the results (NPV and royalties collected) of various policy options to the baseline case of a 16.67% royalty rate and no VSR. The rows of Table 1 represent the following policies and royalty rates:

- A 16.67% royalty rate and no VSR (the baseline).
- A 12.5% royalty rate and no VSR.
- A 7.59% royalty rate and no VSR. Note that 7.59% is the royalty rate at which the project NPV is zero (so no VSR is needed to take NPV to zero). This is also the royalty rate that would be applied using a standard formulation of royalty relief.
- A 16.67% royalty rate and a VSR that would take NPV to zero.
- A 12.5% royalty rate and a VSR that would take NPV to zero.

Table 1 - Royalty Breakdown of VSR Policies

Policy @ 25% Discount Rate	Nominal Royalties Paid	Discounted Royalties Paid	VSR Amount	Nominal Less Royalty Collected	Discounted Less Royalty Collected	NPV
16.67% Royalty	$17,299,744	$9,946,349	$0	$0	$0	-$5,418,591
12.5% Royalty	$12,974,808	$7,459,762	$0	$4,324,936	-$2,486,587	-$2,932,003
7.59% Royalty	$7,875,157	$4,527,759	$0	$9,424,587	-$5,418,591	$0
VSR/16.67% Royalty	$10,667,392	$4,527,759	$6,632,352	$6,632,352	-$5,418,591	$0
VSR/12.5% Royalty	$9,526,318	$4,527,759	$3,448,490	$7,773,426	-$5,418,591	$0

The columns of Table 1 represent the following results (assuming a 25% discount rate):

- Nominal royalties paid: The nominal value of royalties paid over the project lifetime.
- Discounted royalties paid: The value of royalties paid discounted to the initial time period.
- VSR amount: The VSR amount for the particular scenario that takes the NPV to zero.
- Nominal less royalty collected: The nominal amount of lower royalties received under a particular scenario compared to the base scenario of 16.67% royalty and no VSR.
- Discounted less royalty collected: The discounted amount of lower royalties received under a particular scenario compared to the base scenario of 16.67% royalty and no VSR.
- NPV: The lifetime NPV of the project.

One can use the *7.59% Royalty* row and the *VSR/16.67% Royalty* row to compare the results of a standard royalty relief policy to a VSR policy. In particular, a VSR policy provides faster relief to the project operator, meaning that the nominal amount of foregone royalties is lower using a VSR policy than using a standard royalty rate reduction (although the discounted loss of royalties are identical under the two policies).

Exhibit A

Chapter 5: Conclusions

BOEM has examined the available research and data regarding the appropriate discount rates to use in the context of Special Case Royalty Relief applications for shallow water oil and gas projects. When determining its policy recommendations, BOEM needed to account for the numerous factors that determine discount rates, and the fact that shallow water SCRR projects likely entail above-average risks. BOEM recommends that BSEE allow companies to self-report discount rates, but to impose an upper bound of 25% for shallow water leases. This 25% upper bound for shallow water discount rates allows companies to earn appropriate rates of return, and protects the government's right to receive fair amounts of royalty payments.

BOEM has also provided analyses regarding the use of a VSR, and BOEM recommends that BSEE consider applying royalty relief using a VSR formulation. A VSR provides the operator and the government with certainty regarding cash flows, and avoids some problematic features of other forms of royalty relief. A VSR could also simplify the accounting and tracking for both the lessee and the government. Implementing a VSR could raise administrative issues and require certain adjustments by the Office of Natural Resources Revenue. Therefore, if BSEE elects to examine potential future use of a VSR in its royalty relief decision-making, BOEM recommends that BSEE begin coordinating with BOEM and ONRR to ensure that there is sufficient time to work through any needed process changes.

Exhibit A

References

BSEE. 2018. NTL No. 2018-G03. Idle iron decommissioning guidance for wells and platforms.

BOEM. 2019. Royalty relief information. Website: https://www.boem.gov/Royalty-Relief-Information/

Clark, Richard A., Lind, Robert C. and Sweeny, James L. Issues in the choice of discount rates in OCS leasing; CMS Associates 1987.

Corporate Finance Institute. 2019. WACC: What is WACC, its formula, and why it's used in corporate finance. Website: https://corporatefinanceinstitute.com/resources/knowledge/finance/what-is-wacc-formula/. Accessed on April 16, 2019.

Dickens, Ross N. and John Lohrenz. 1996. Evaluating oil and gas assets: option pricing methods prove no panacea. Journal of Financial and Strategic Decisions. Volume 9.

Fama, Eugene F. and Kenneth French. 1993. Common risk factors in the returns on stocks and bonds. Journal of Financial Economics 33 3-56.

Inkpen, Andrew and Michael Moffett. 2011. The global oil and gas industry: management, strategy, and finance.

Oil and Gas Journal. 2018. WoodMac: Upstream industry focused on financial health over growth.

Sharpe, W.F. 1964. Capital asset prices: A theory of market equilibrium under conditions of risk. Journal of Finance, 19 pp 425-442.

Society of Petroleum Evaluation Engineers. 2016. The Society of Petroleum Engineers thirty-fifth annual survey of parameters used in property evaluation. Presentation slides used at the 2016 annual meeting of the Society of Petroleum Evaluation Engineers.

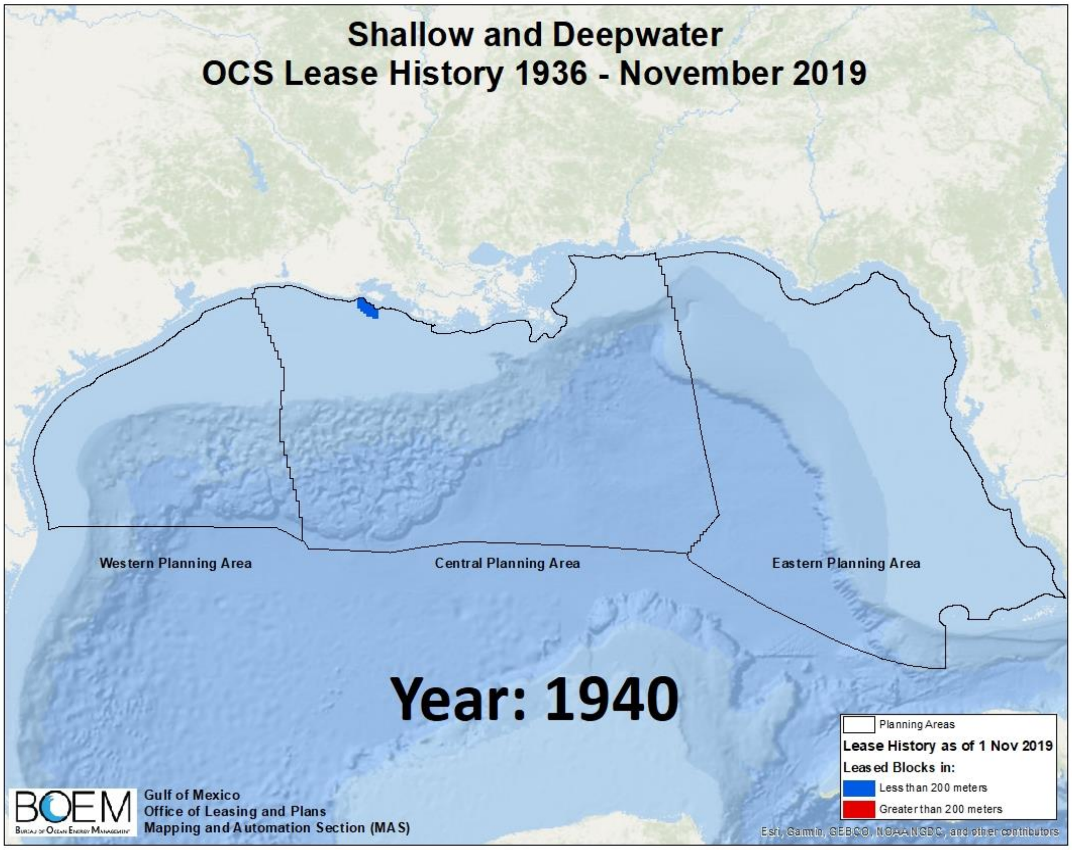
Society of Petroleum Evaluation Engineers. 2017. The Society of Petroleum Engineers thirty-sixth annual survey of parameters used in property evaluation. Presentation slides used at the 2017 annual meeting of the Society of Petroleum Evaluation Engineers.

Society of Petroleum Evaluation Engineers. 2018. The Society of Petroleum Engineers thirty-seventh annual survey of parameters used in property evaluation. Presentation slides used at the 2018 annual meeting of the Society of Petroleum Evaluation Engineers.

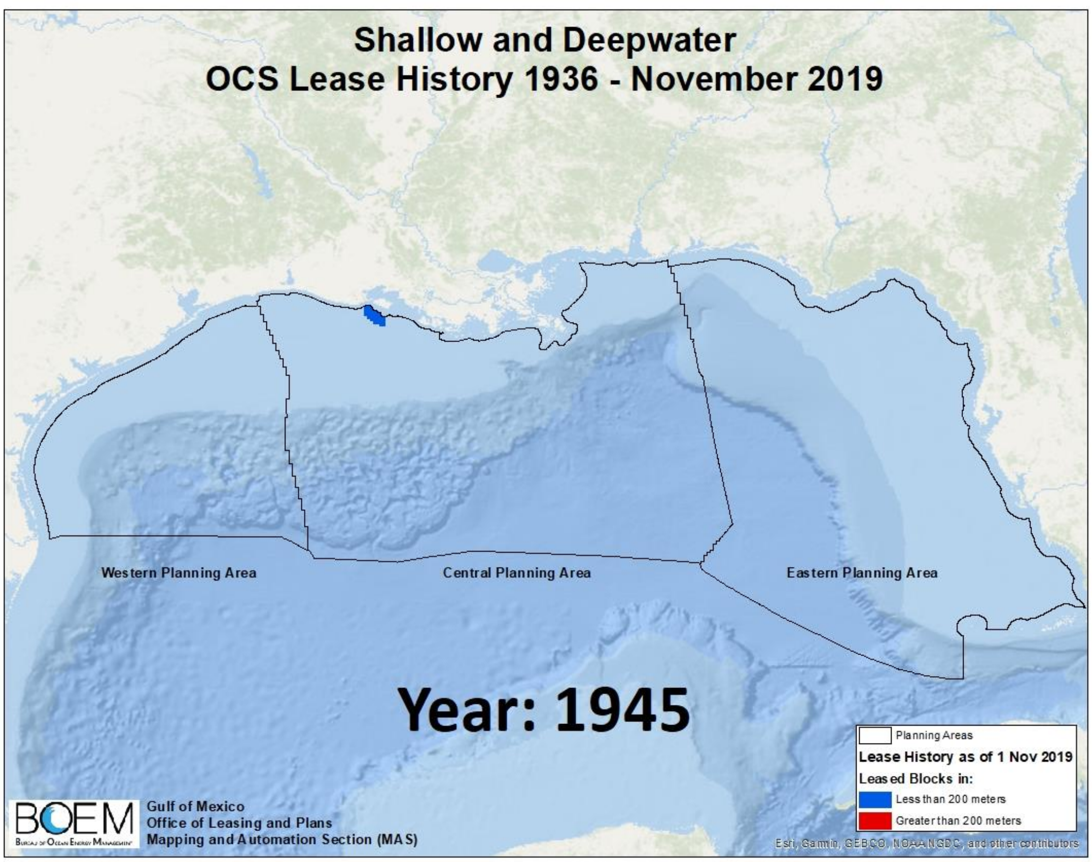
Texas Comptroller of Public Accounts. 2018. 2018 Property value study: Discount rate range for oil and gas properties.

The Oxford Institute for Energy Studies. 2019. Energy transition, uncertainty, and the implications of change in the risk preferences of fossil fuels investors.

Exhibit B

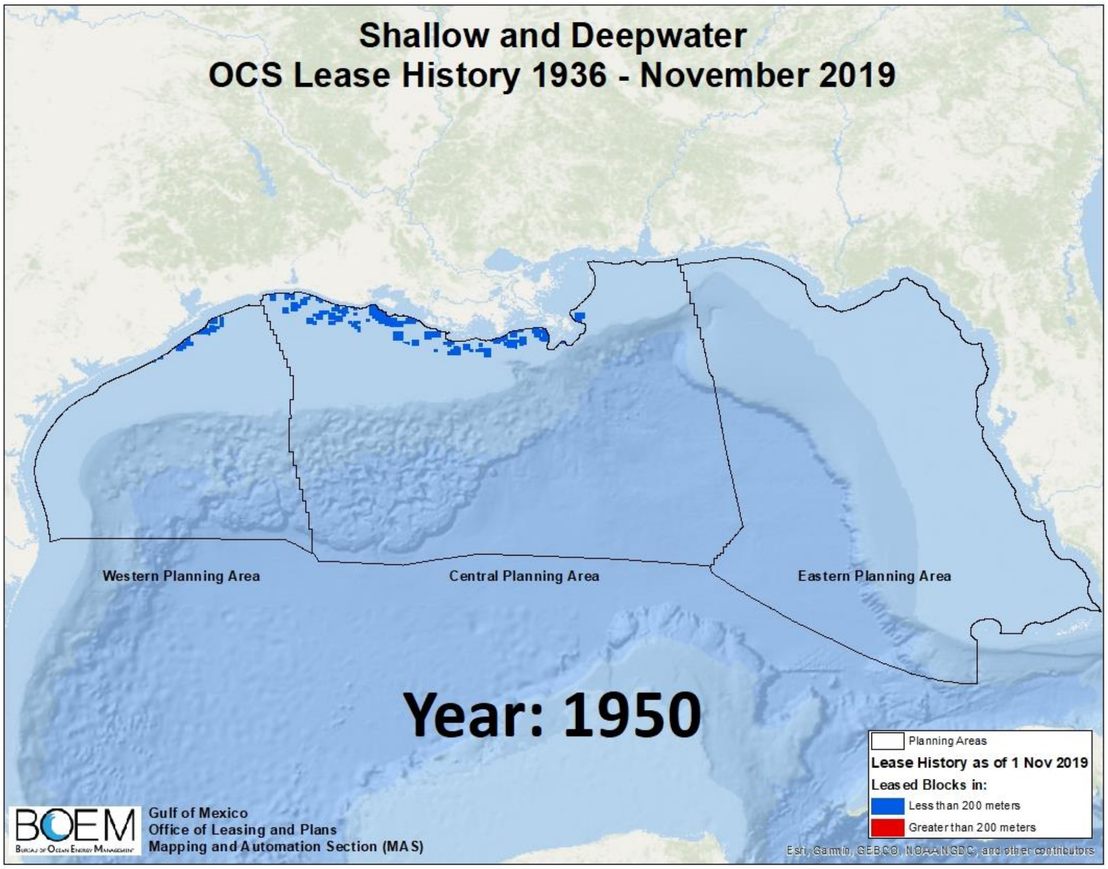


Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 1940
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

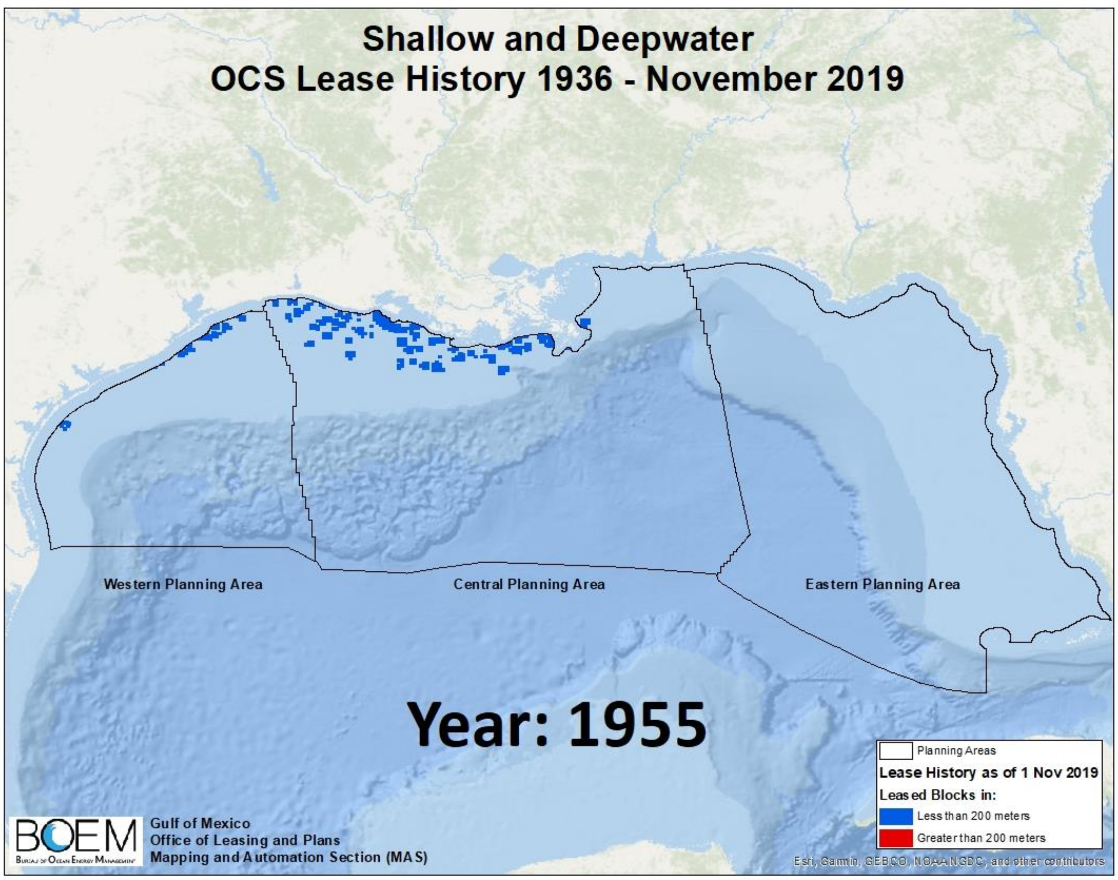


Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 1945
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

Exhibit B

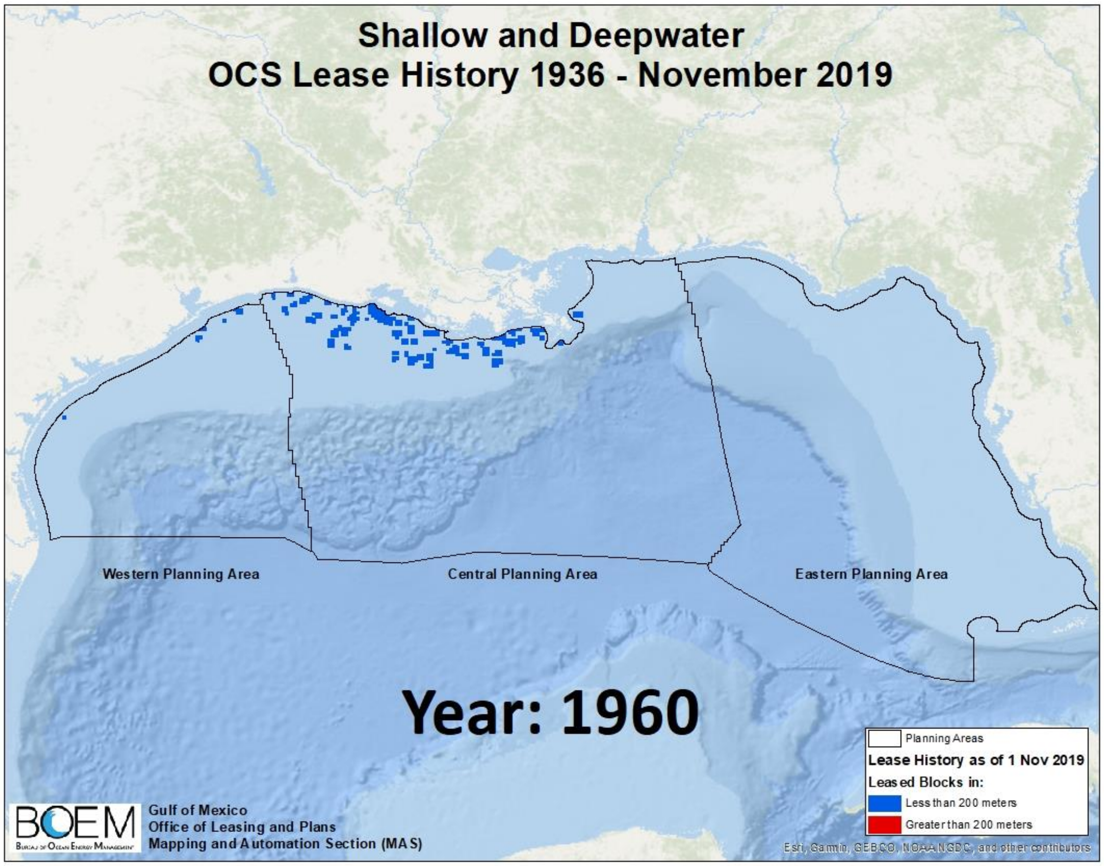


Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 1950
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors



Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 1955
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

Exhibit B


Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 1960
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

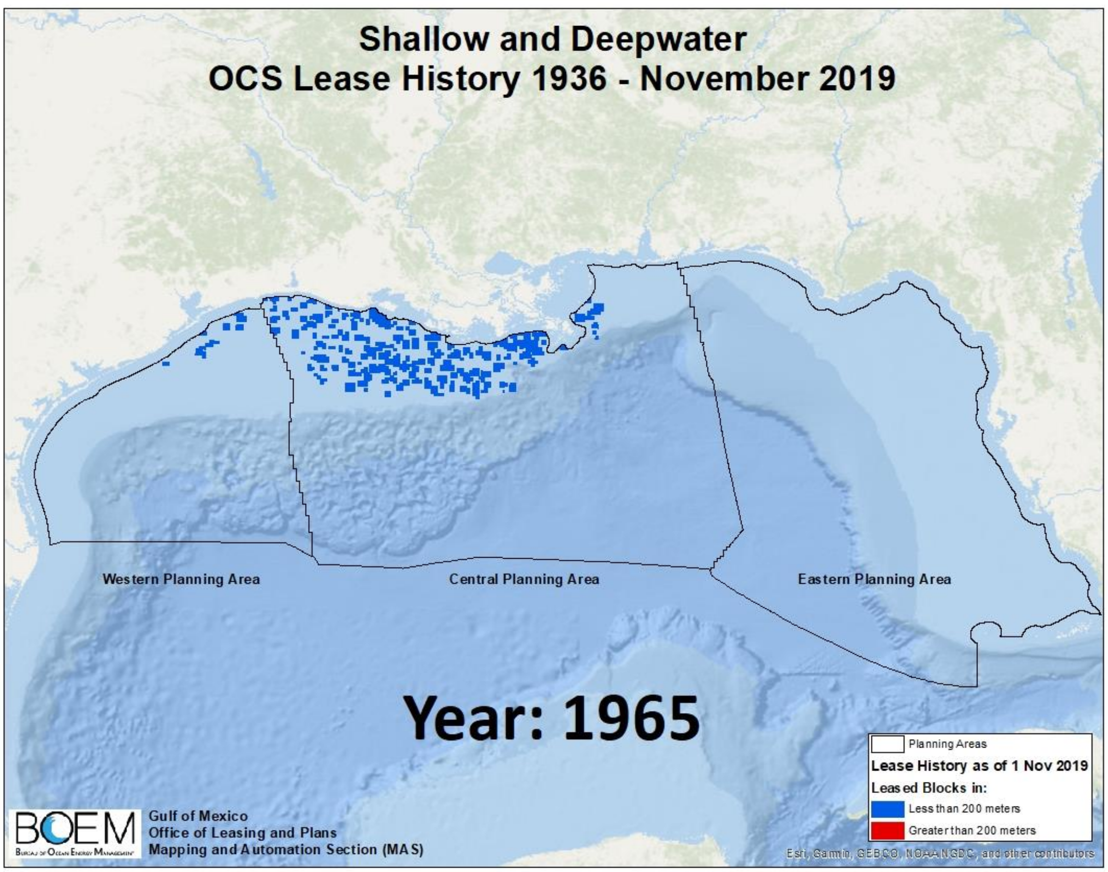
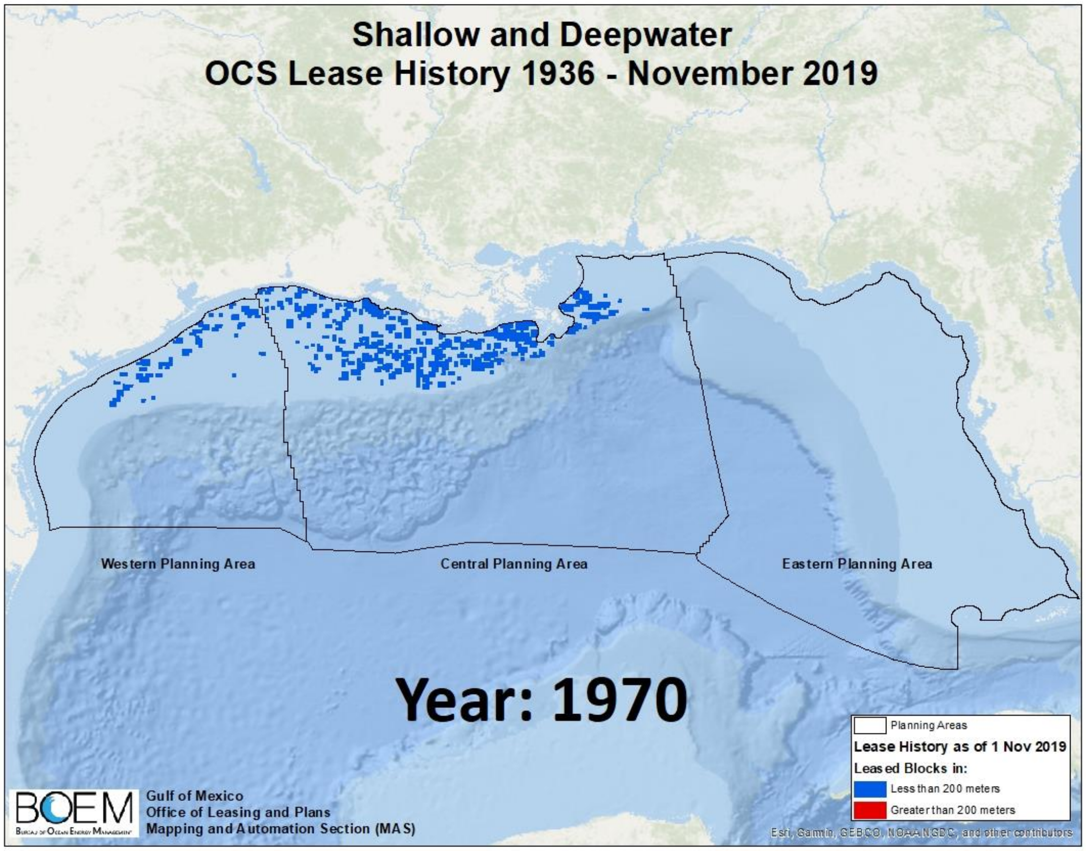

Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 1965
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

Exhibit B


Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 1970
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

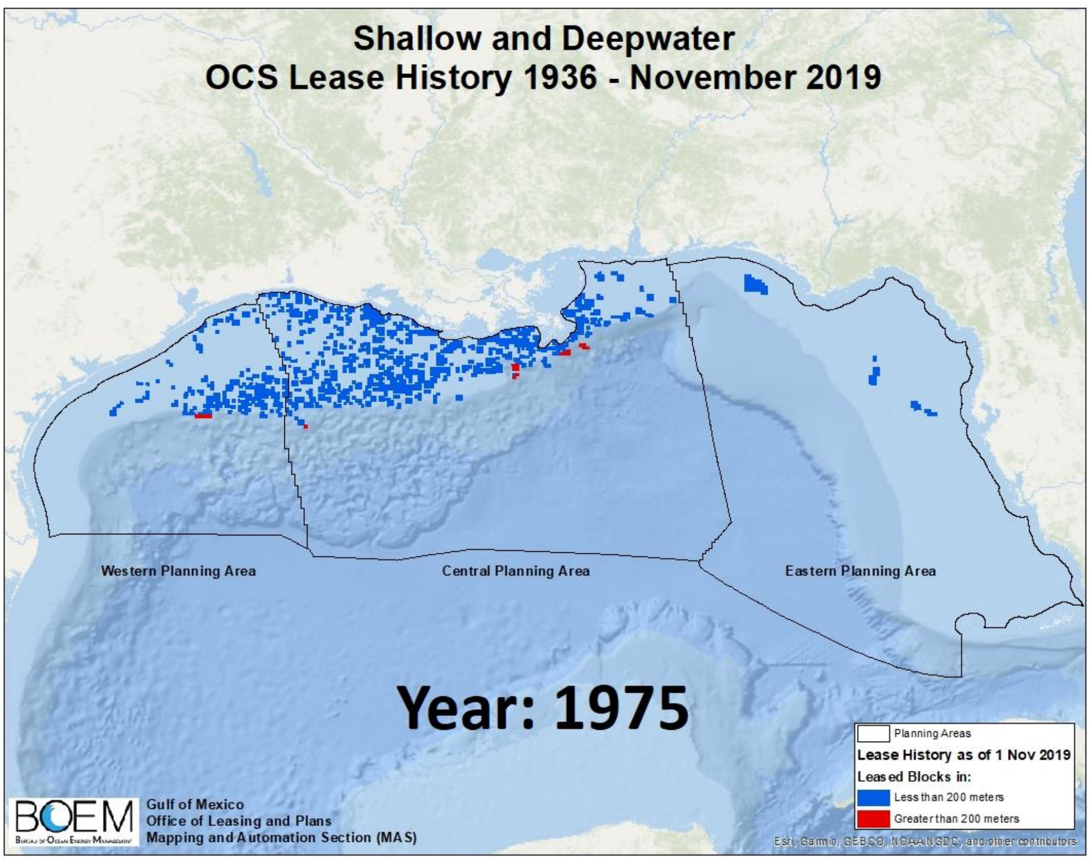
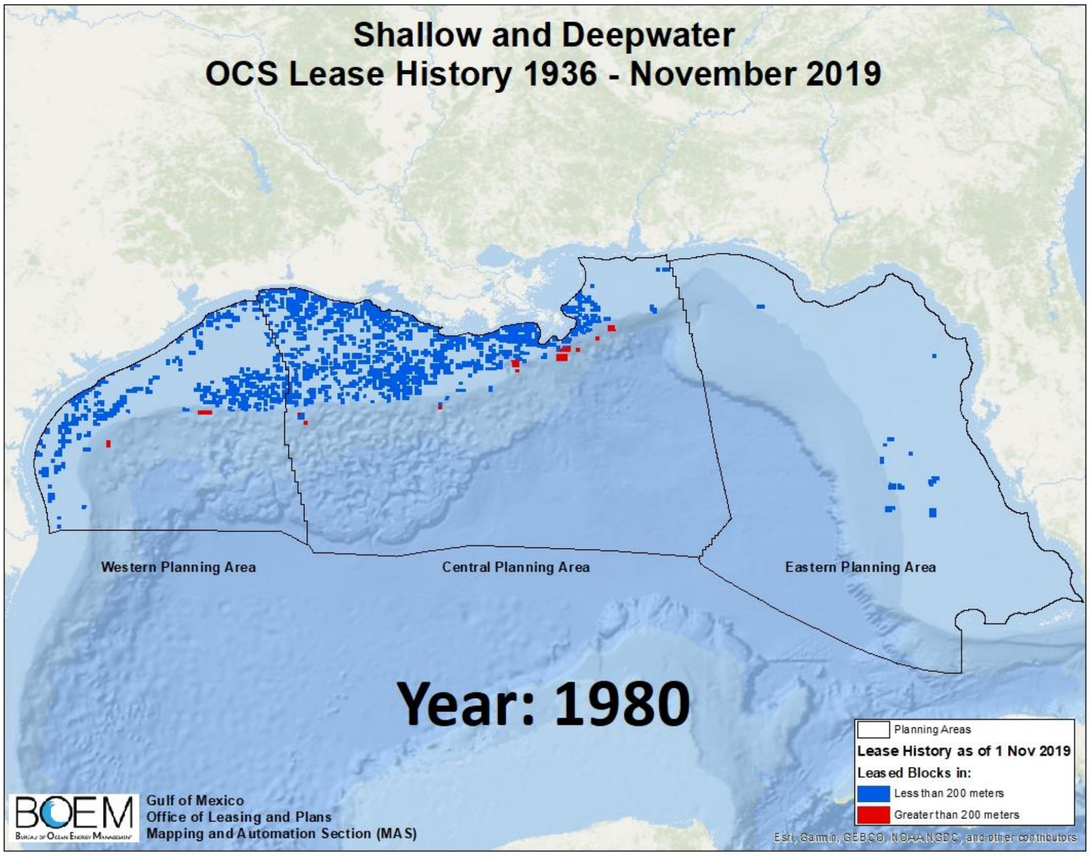

Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 1975
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

Exhibit B


Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 1980
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

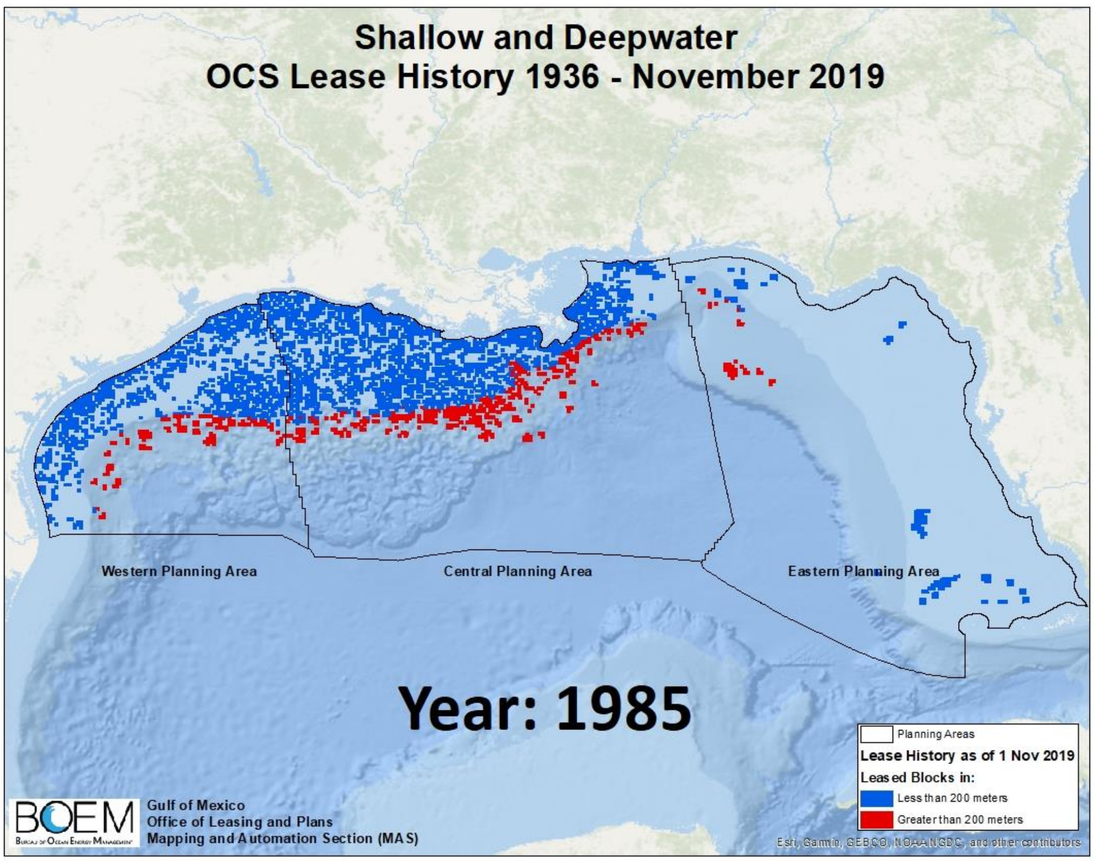
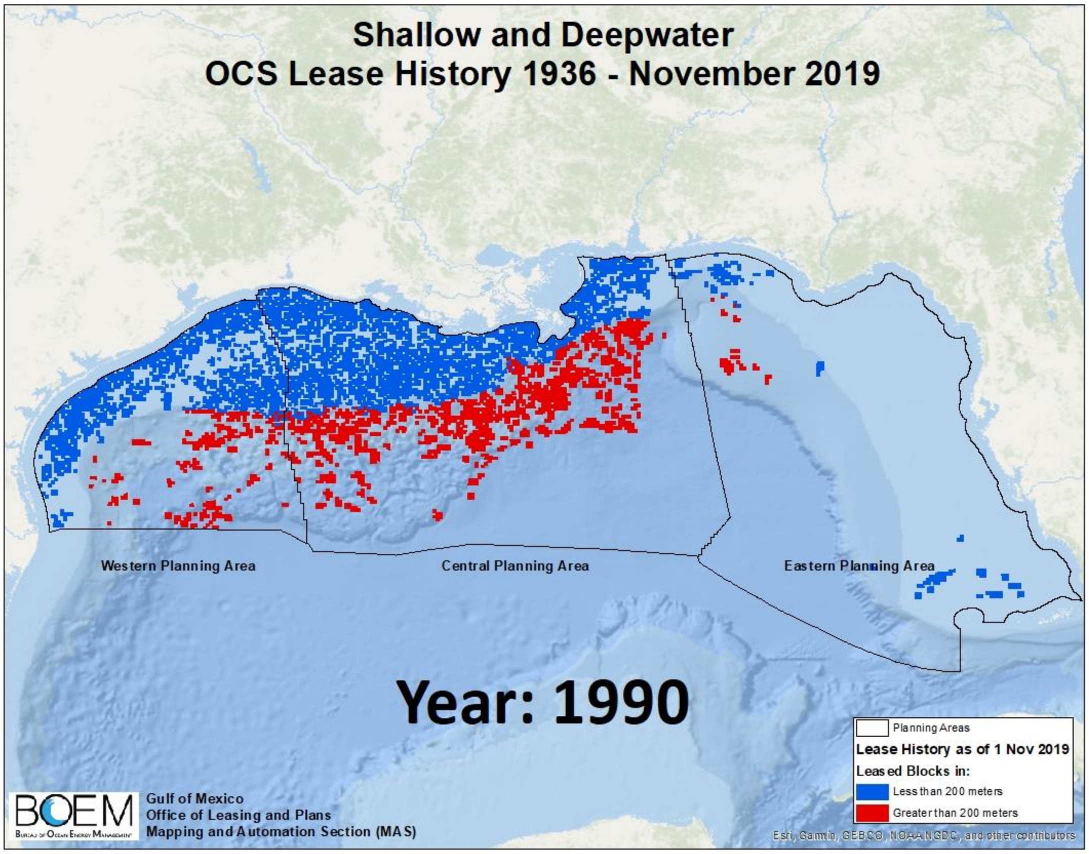
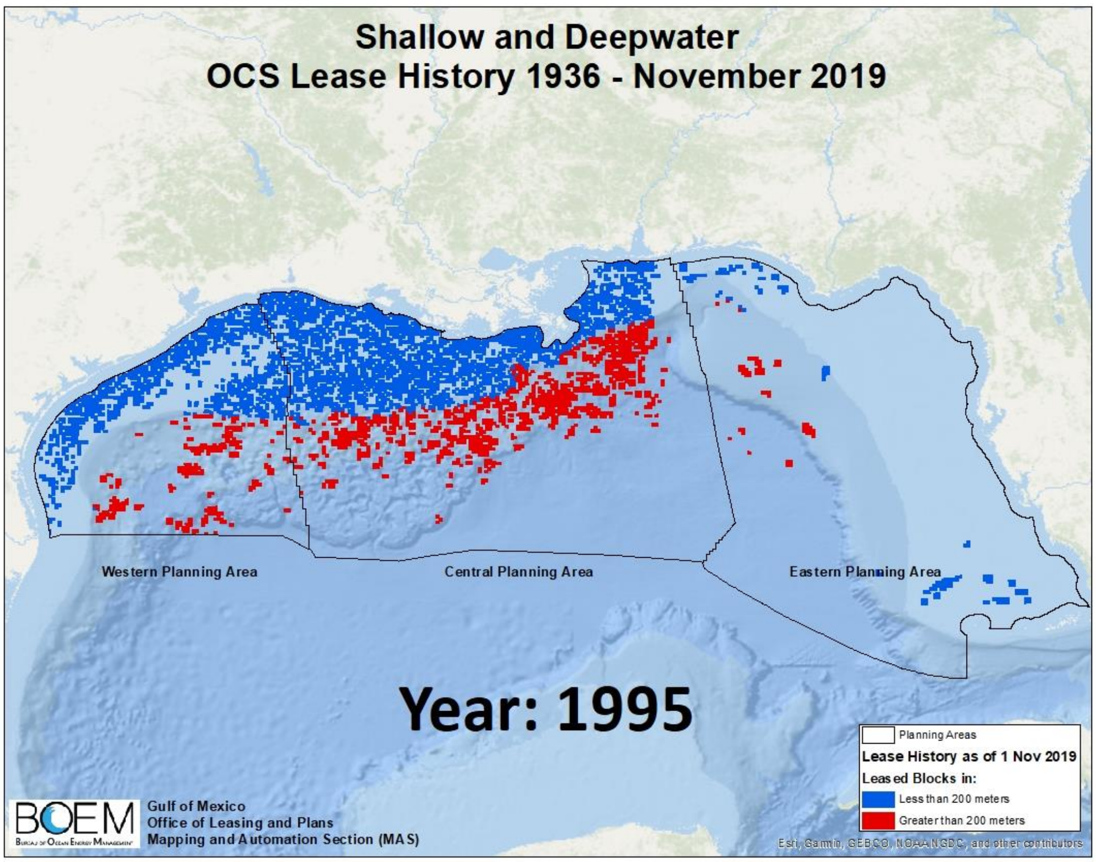

Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 1985
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

Exhibit B

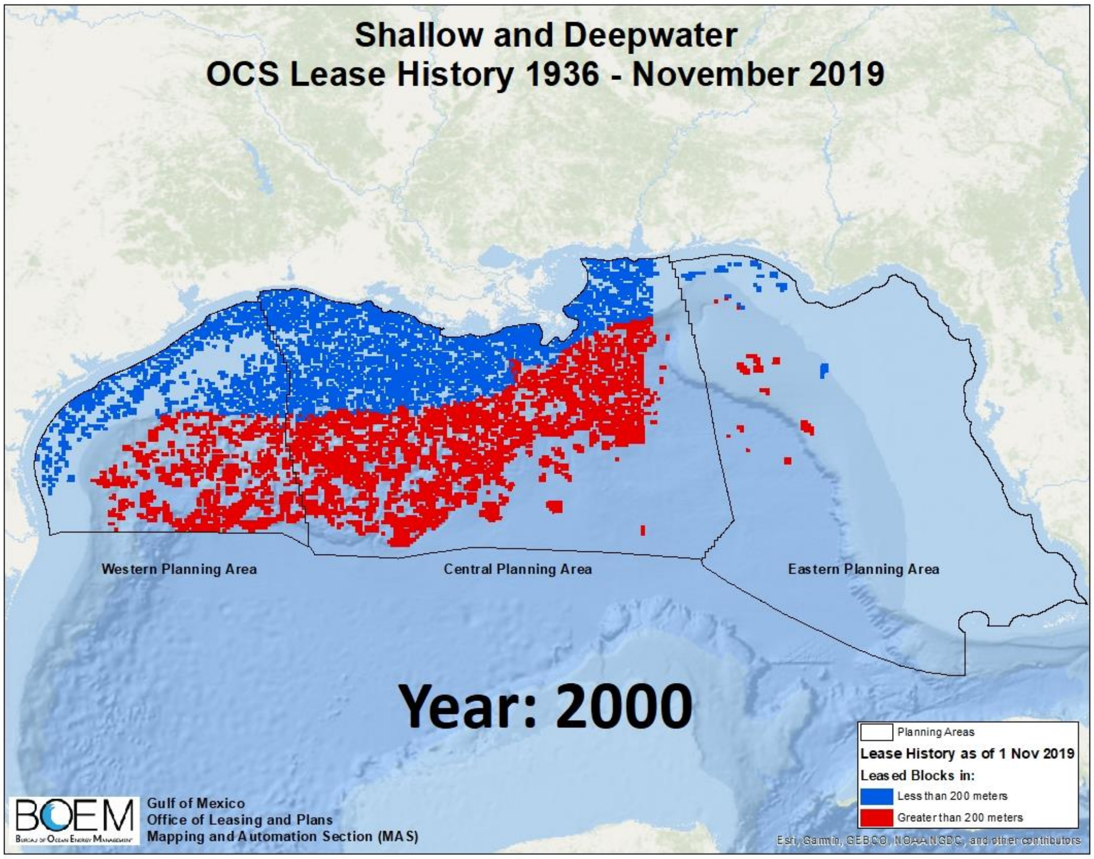


Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 1990
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors



Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 1995
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

Exhibit B


Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 2000
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

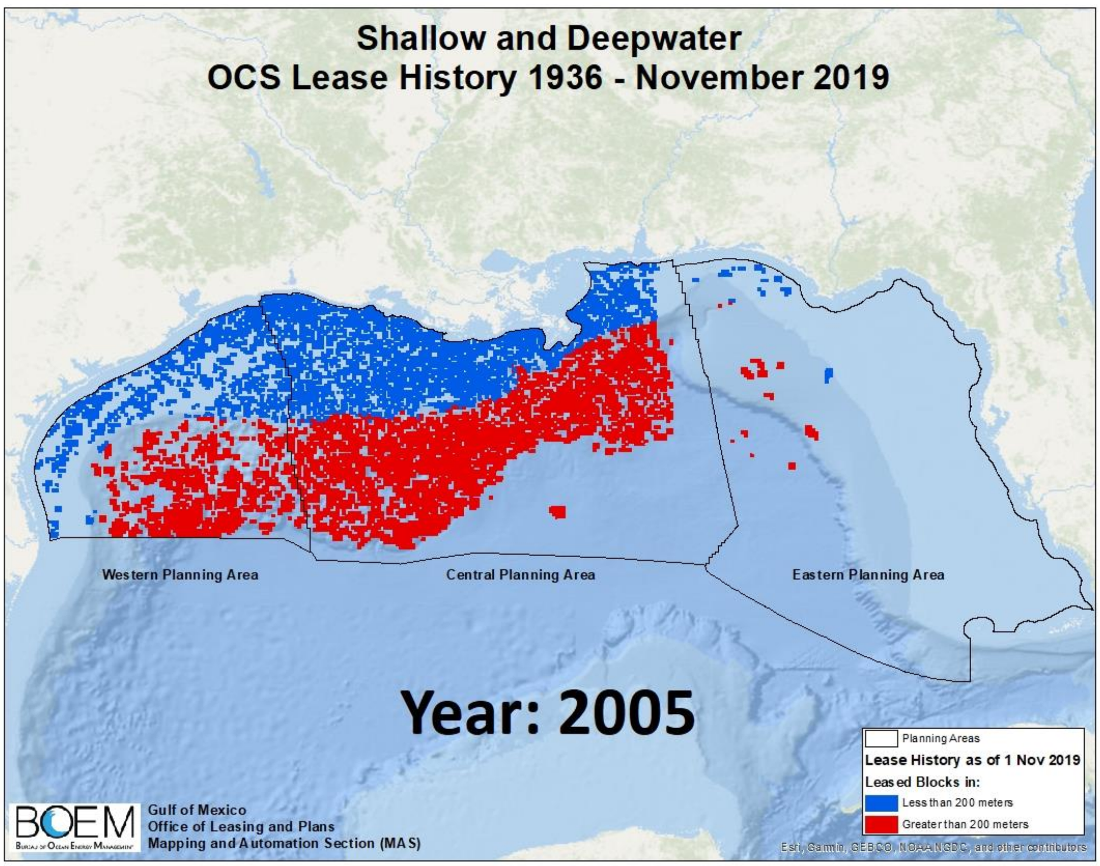
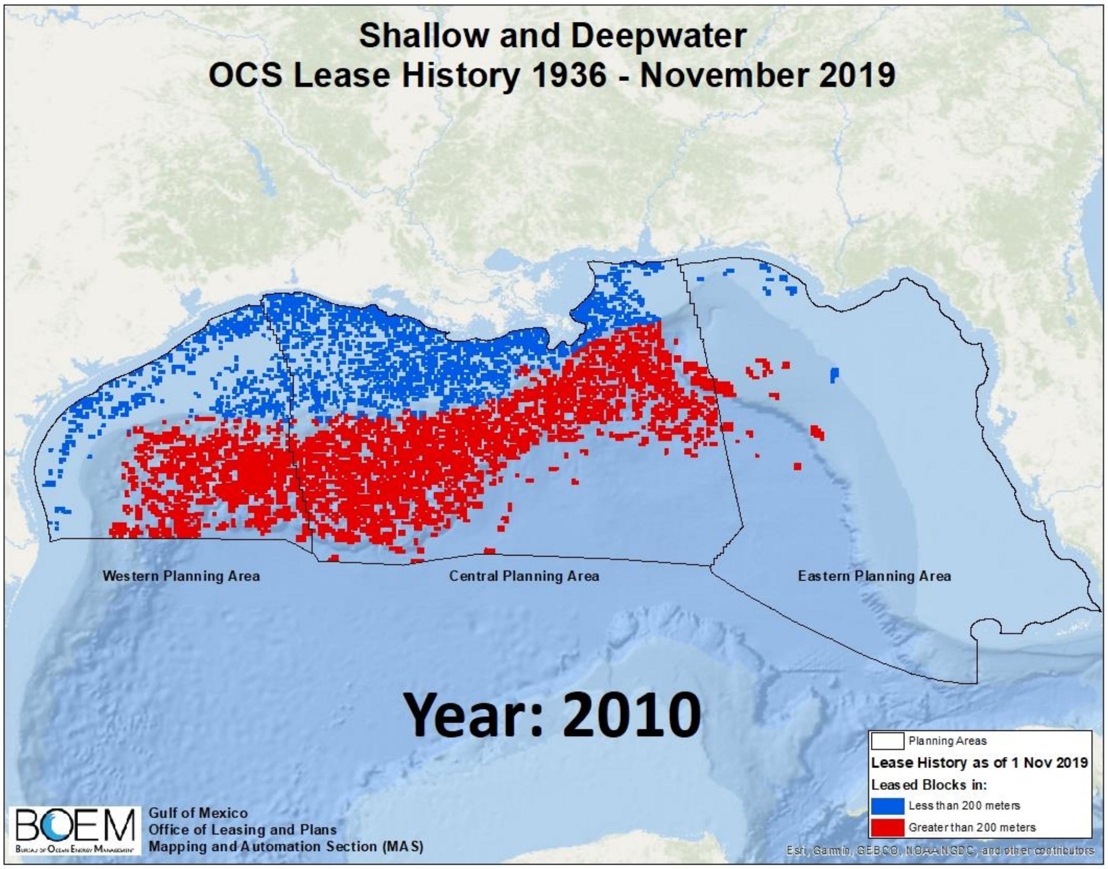

Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 2005
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

Exhibit B


Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 2010
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

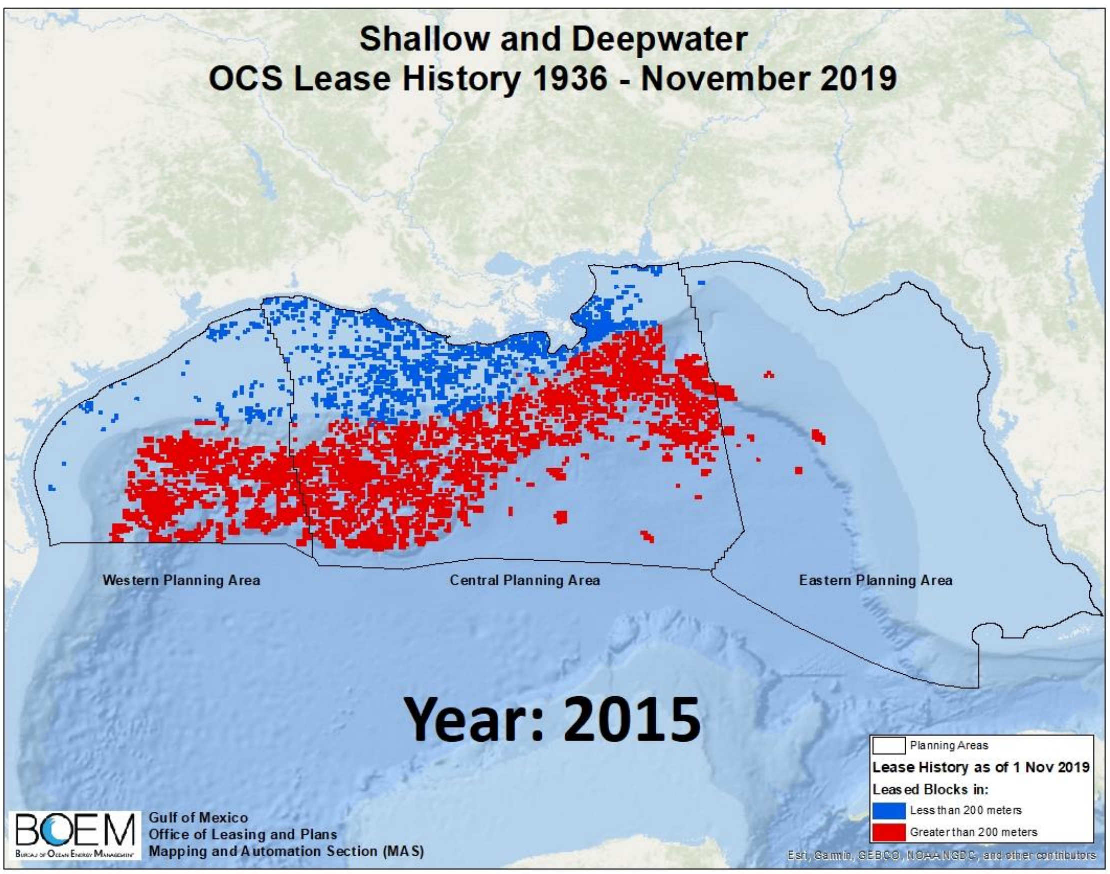
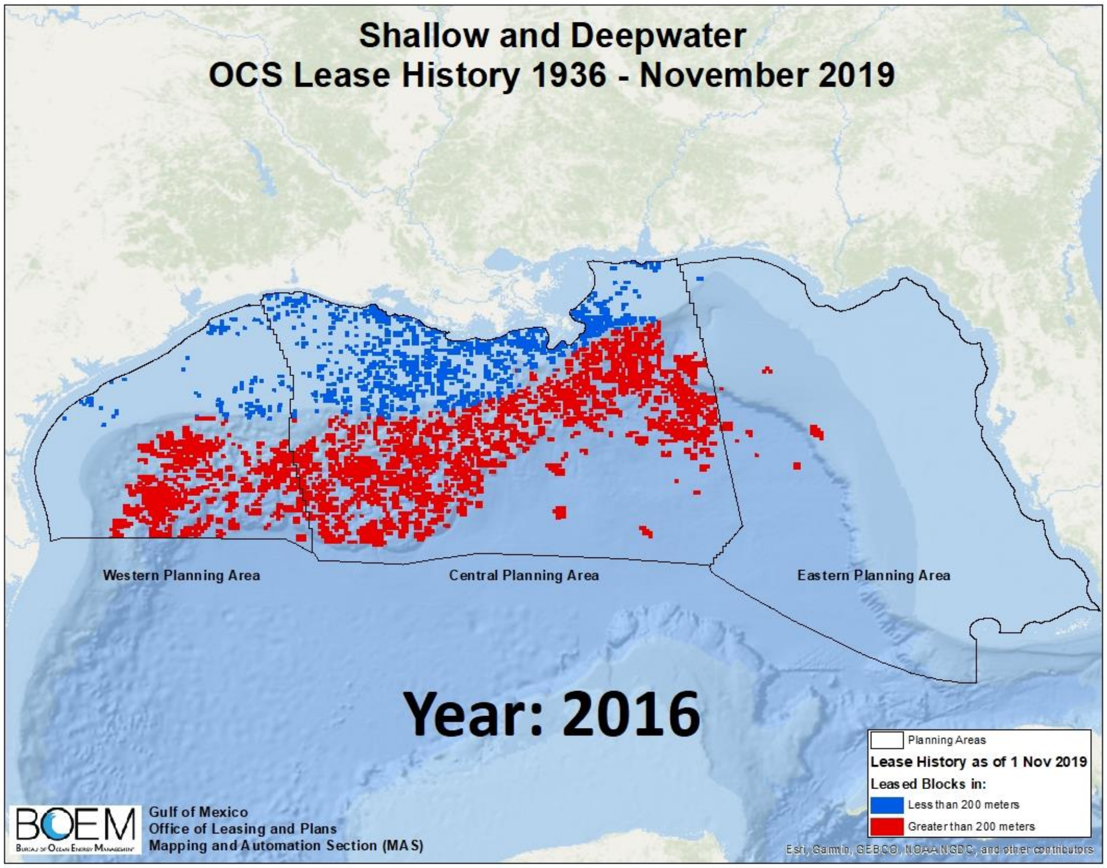

Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 2015
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

Exhibit B


Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 2016
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

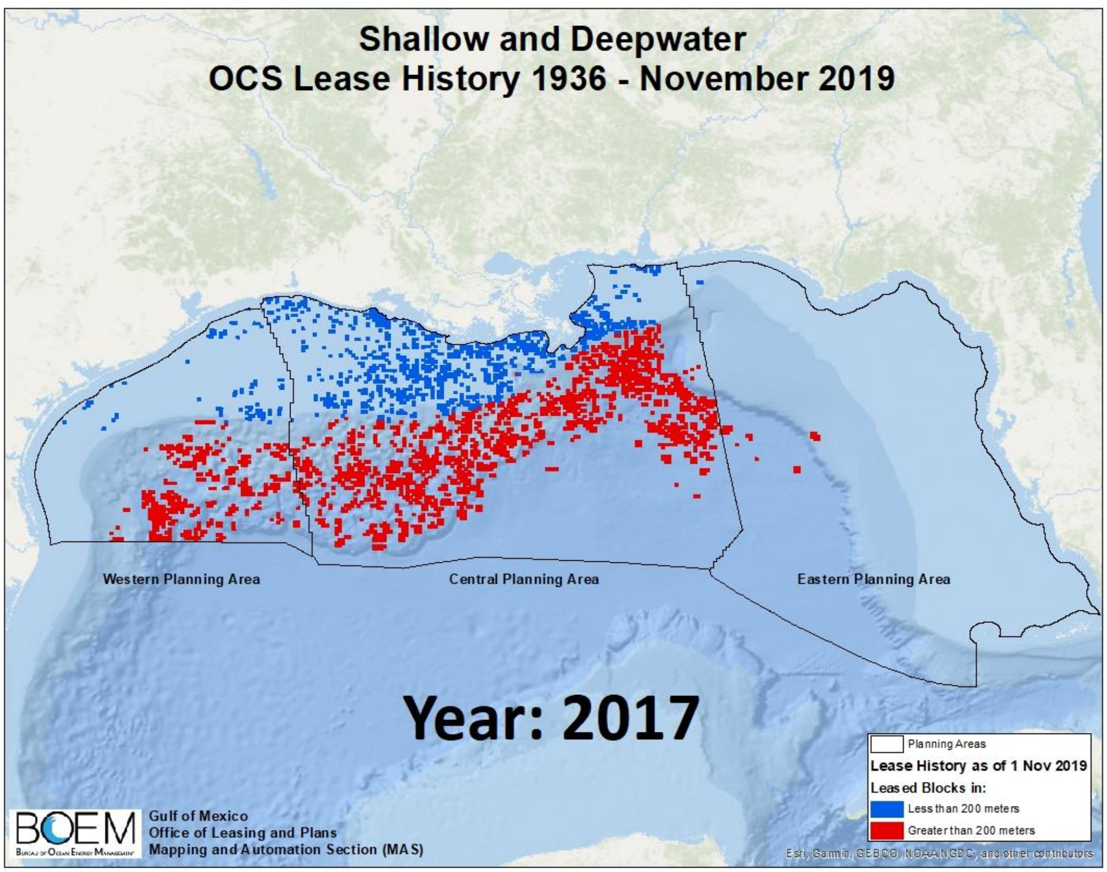
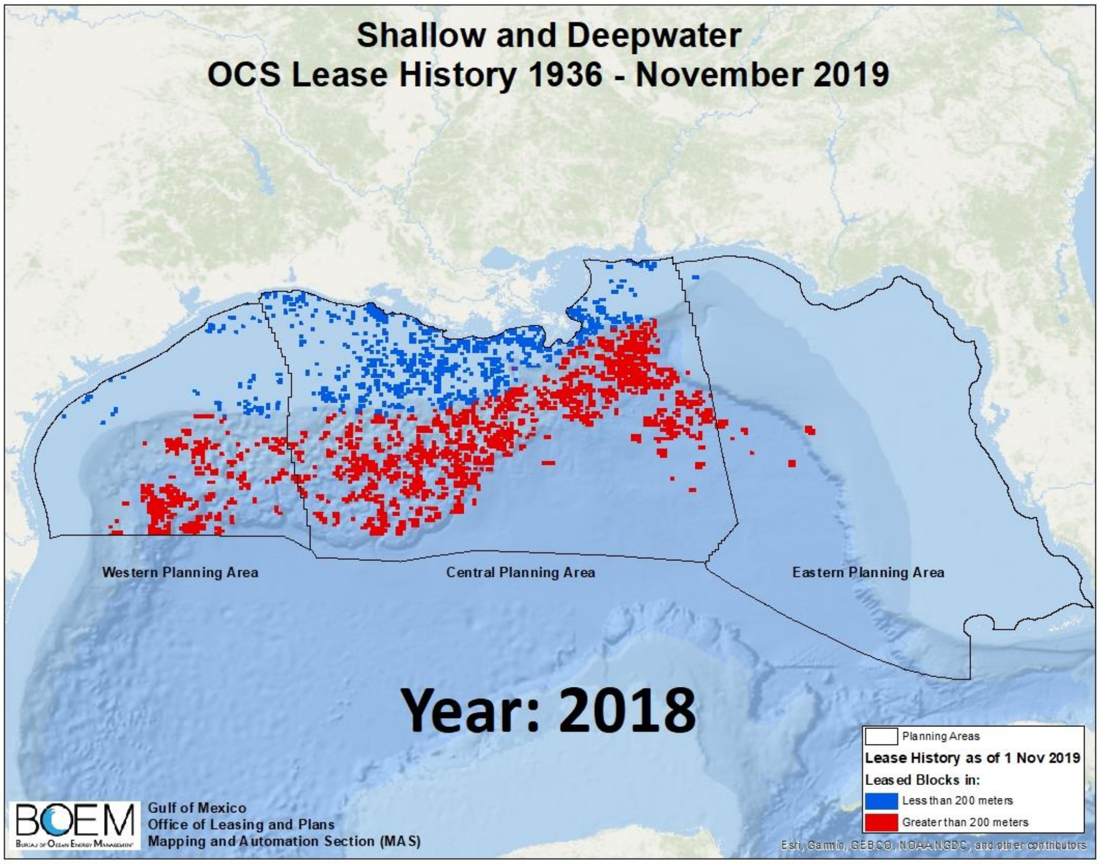

Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 2017
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

Exhibit B


Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 2018
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

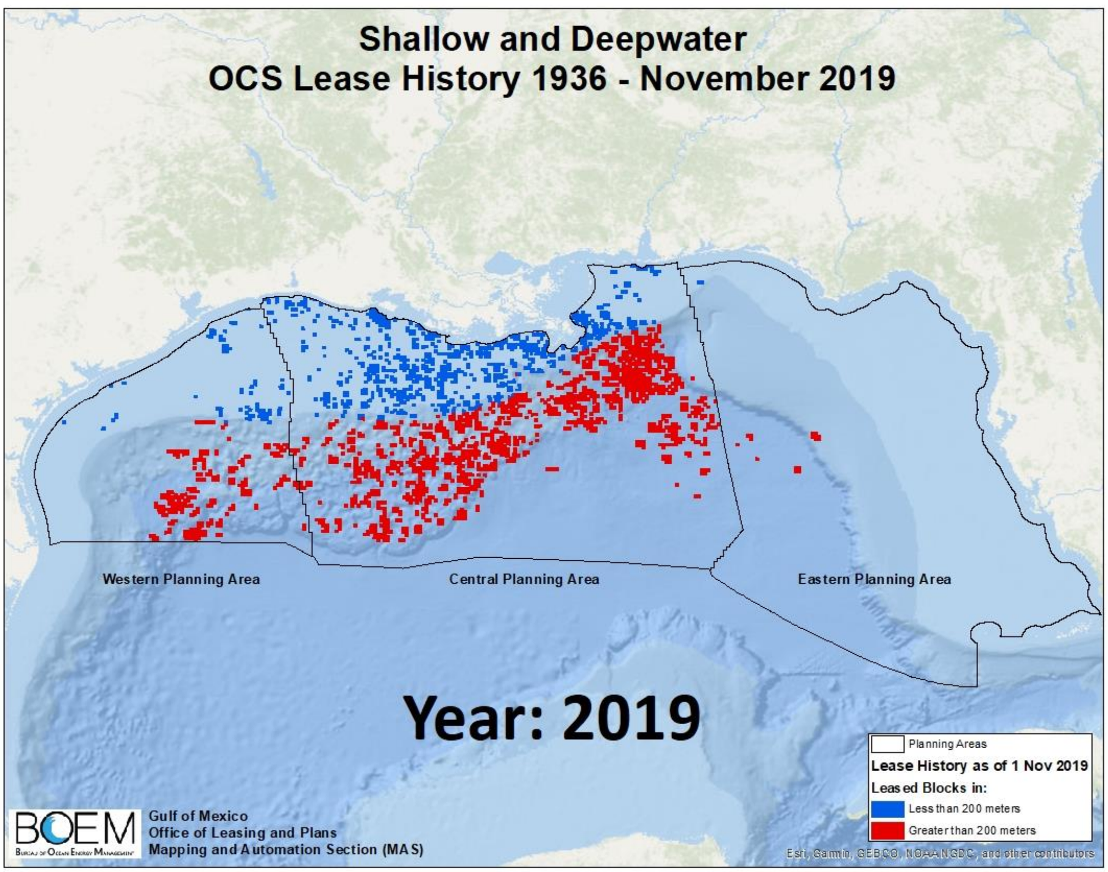
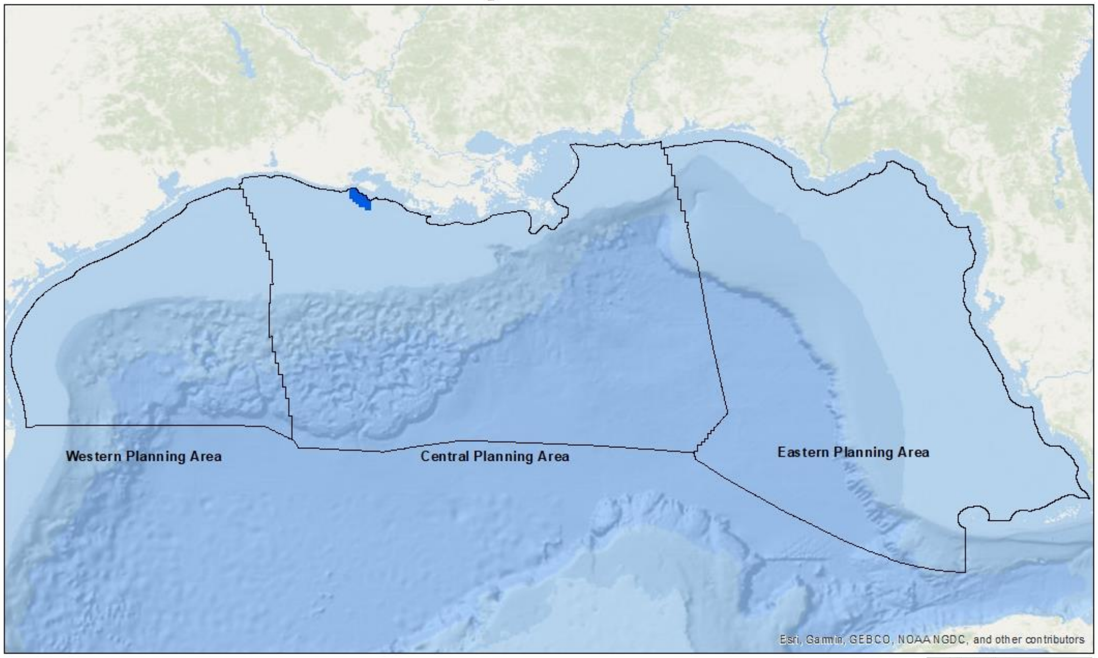

Shallow and Deepwater
OCS Lease History 1936 - November 2019
Western Planning Area
Central Planning Area
Eastern Planning Area
Year: 2019
Planning Areas
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors

Exhibit C

Shallow and Deepwater
OCS Lease History and Production in GOM

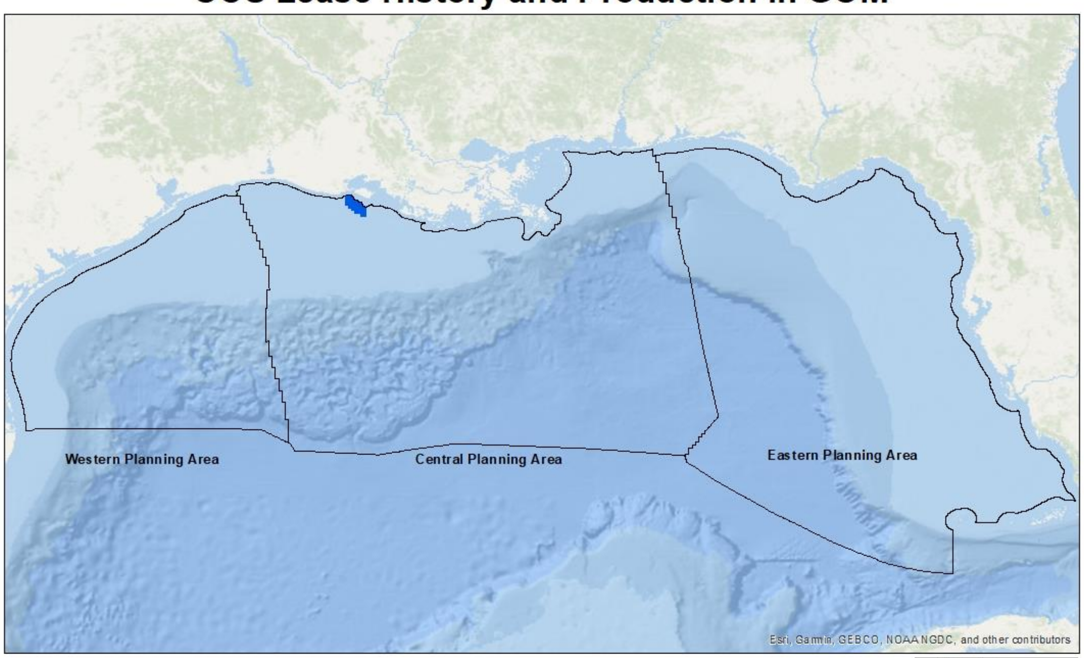


BOEM Bureau of Ocean Energy Management
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)

1940

Planning Areas
Producing Leases
Less than 200 meters
Greater than or equal to 200 meters
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters

Shallow and Deepwater
OCS Lease History and Production in GOM



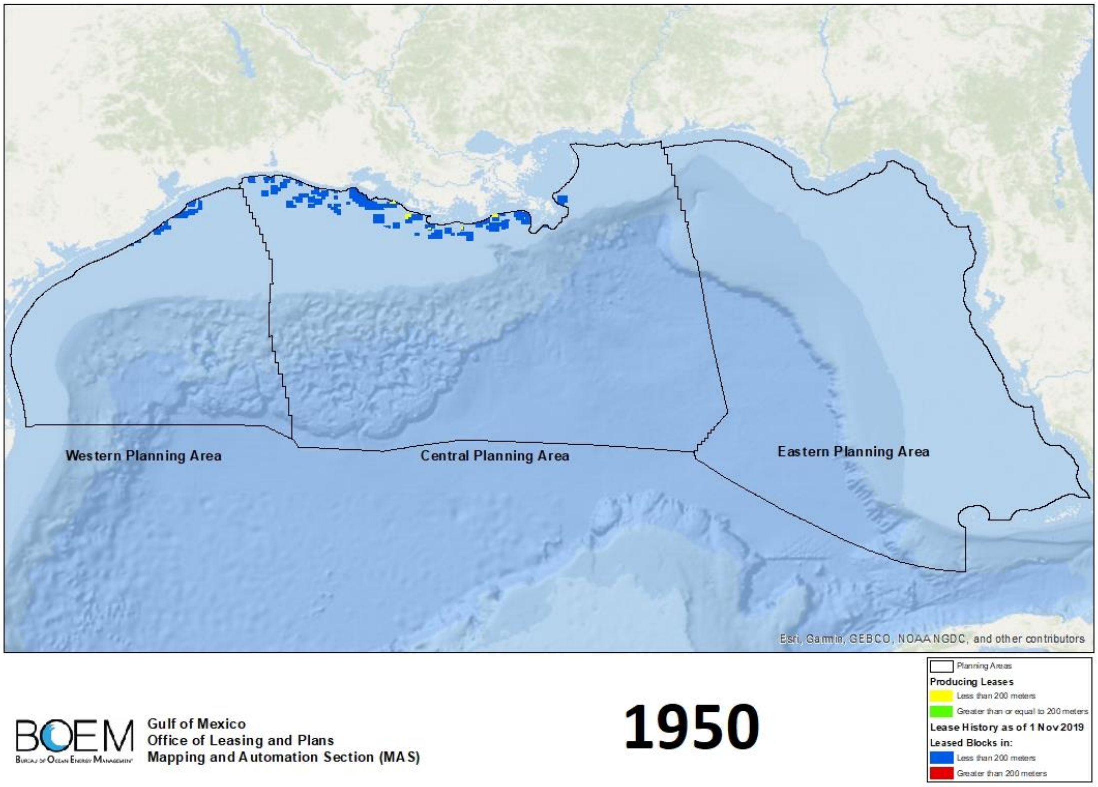
BOEM Bureau of Ocean Energy Management
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)

1945

Planning Areas
Producing Leases
Less than 200 meters
Greater than or equal to 200 meters
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters

Exhibit C

Shallow and Deepwater
OCS Lease History and Production in GOM



Shallow and Deepwater
OCS Lease History and Production in GOM

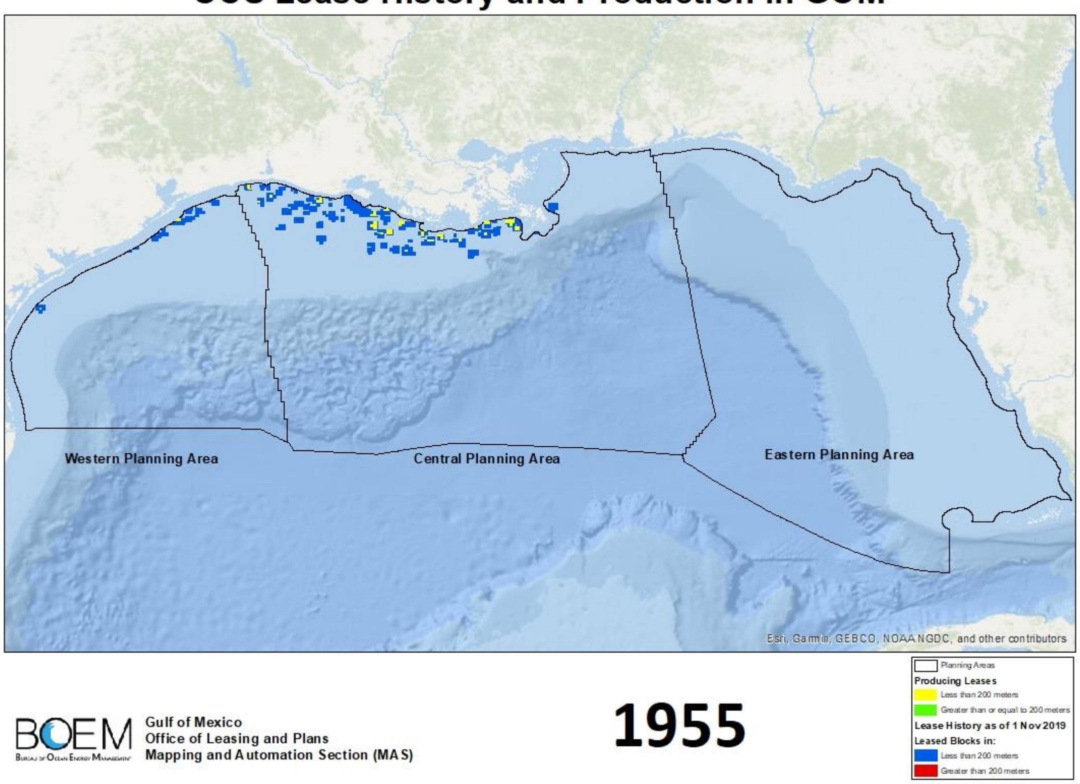
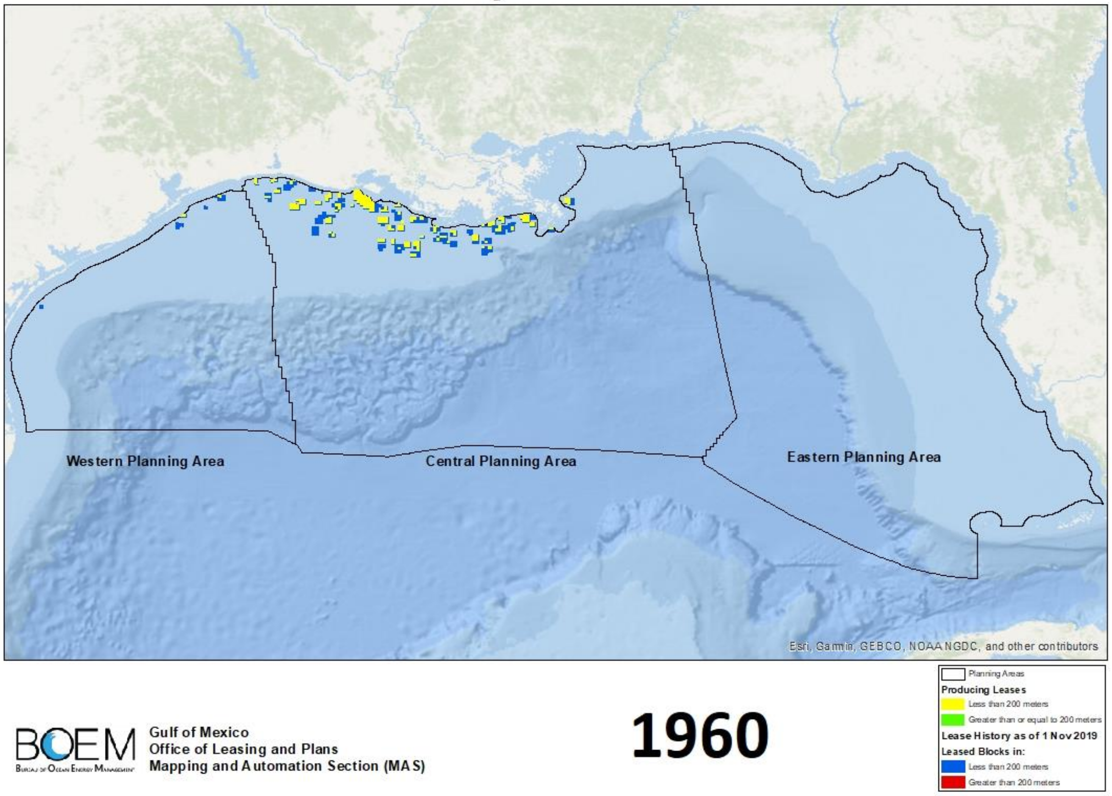


Exhibit C

Shallow and Deepwater
OCS Lease History and Production in GOM



Shallow and Deepwater
OCS Lease History and Production in GOM

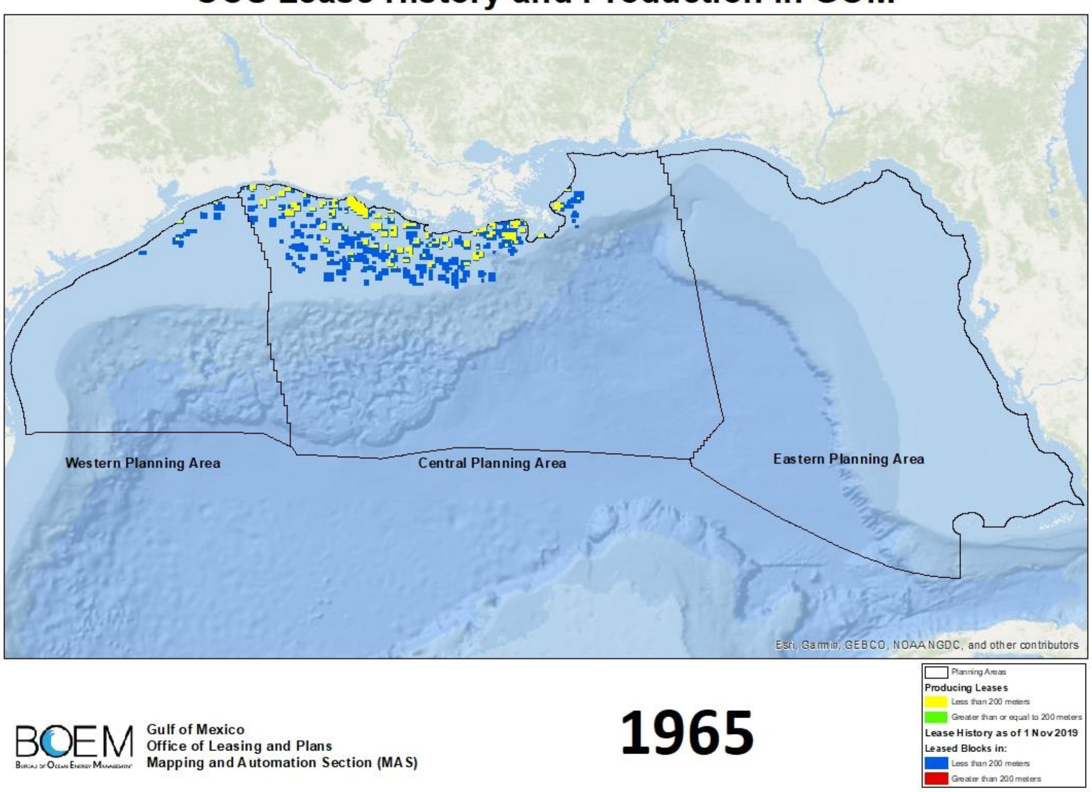
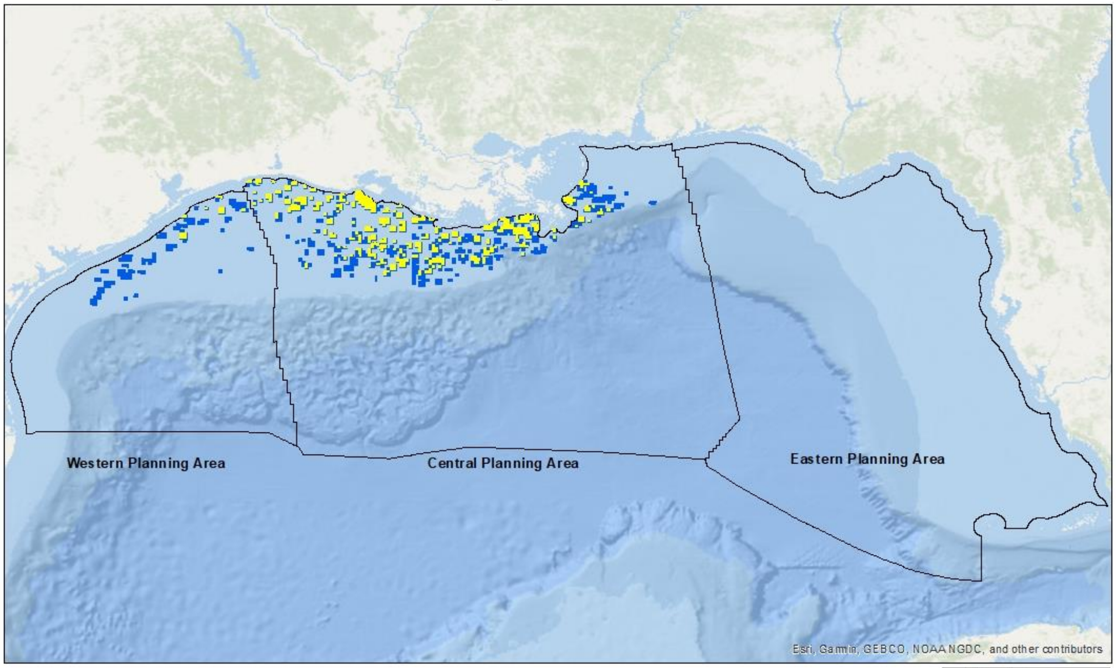


Exhibit C

Shallow and Deepwater
OCS Lease History and Production in GOM

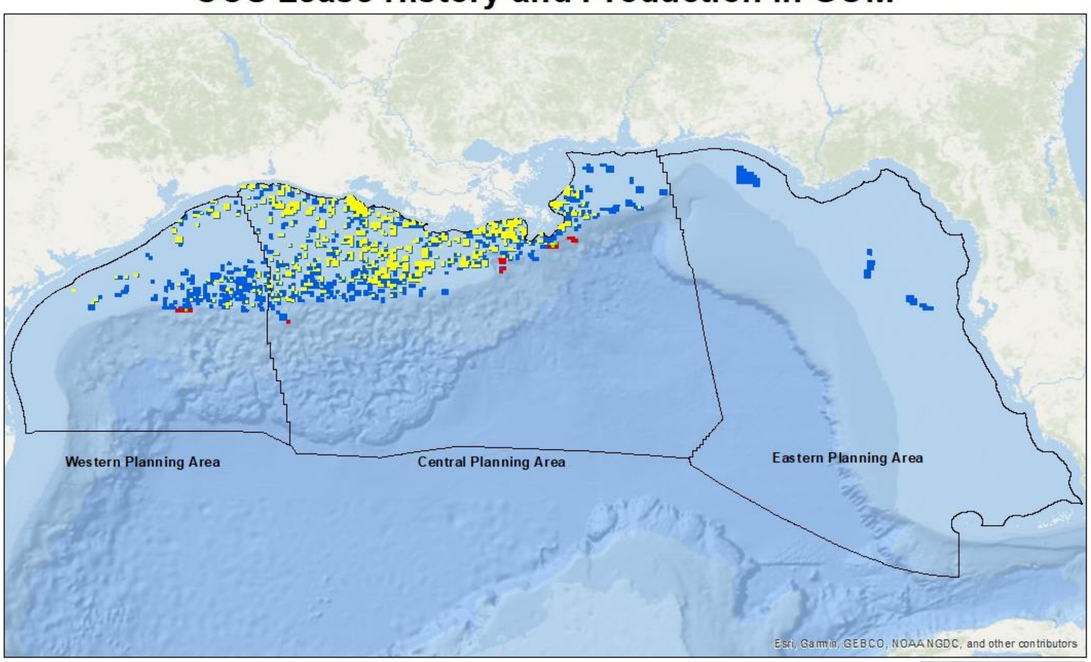


Planning Areas
Producing Leases
Less than 200 meters
Greater than or equal to 200 meters
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters

Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)

1970

Shallow and Deepwater
OCS Lease History and Production in GOM

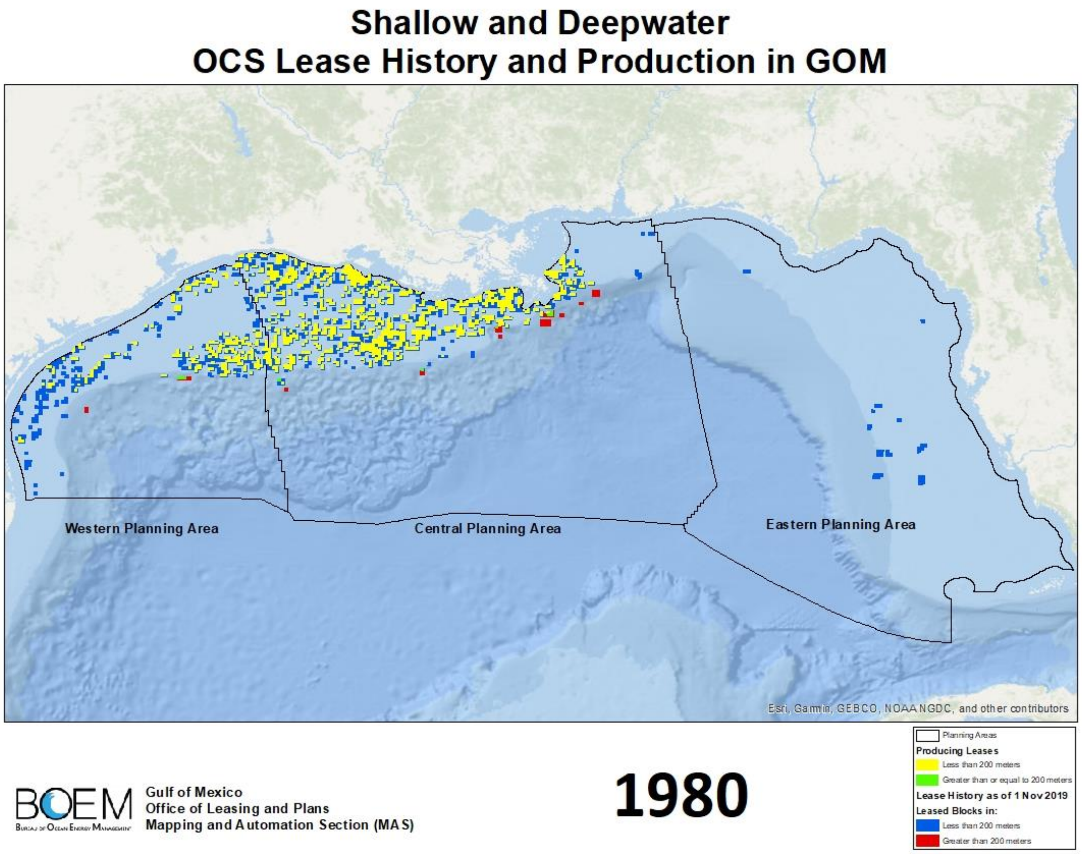


Planning Areas
Producing Leases
Less than 200 meters
Greater than or equal to 200 meters
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters

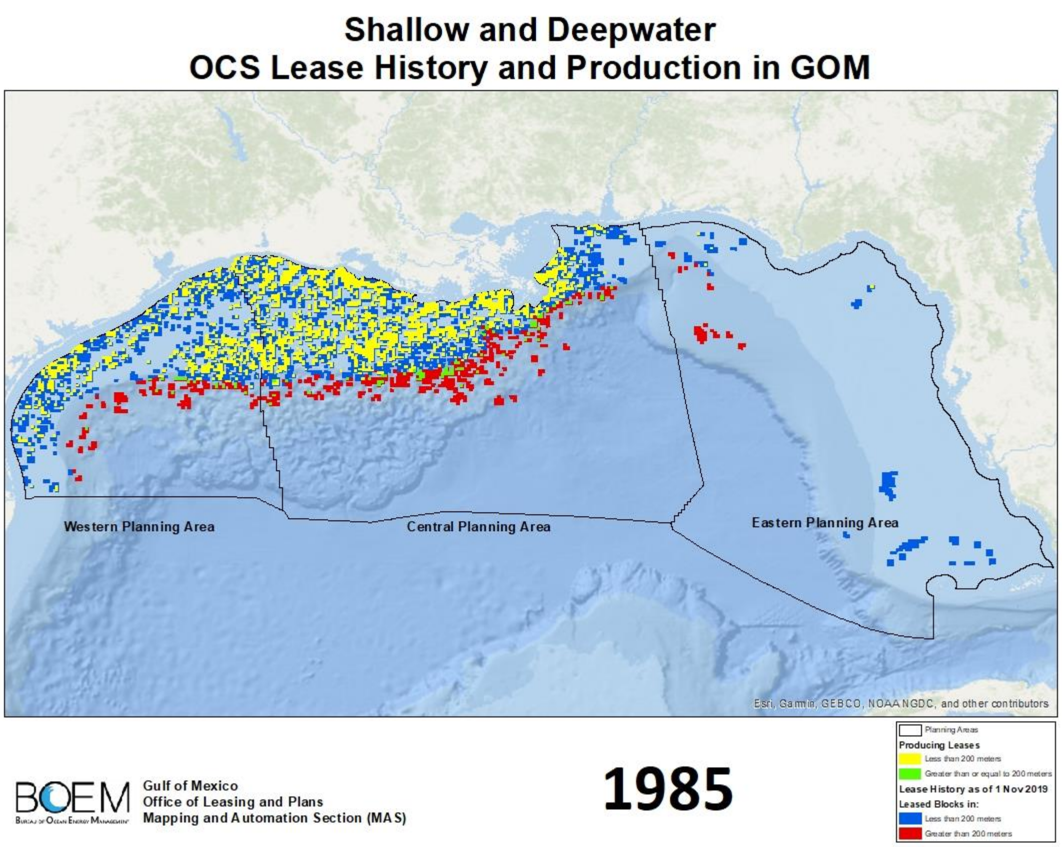
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)

1975

<u>Exhibit C</u>



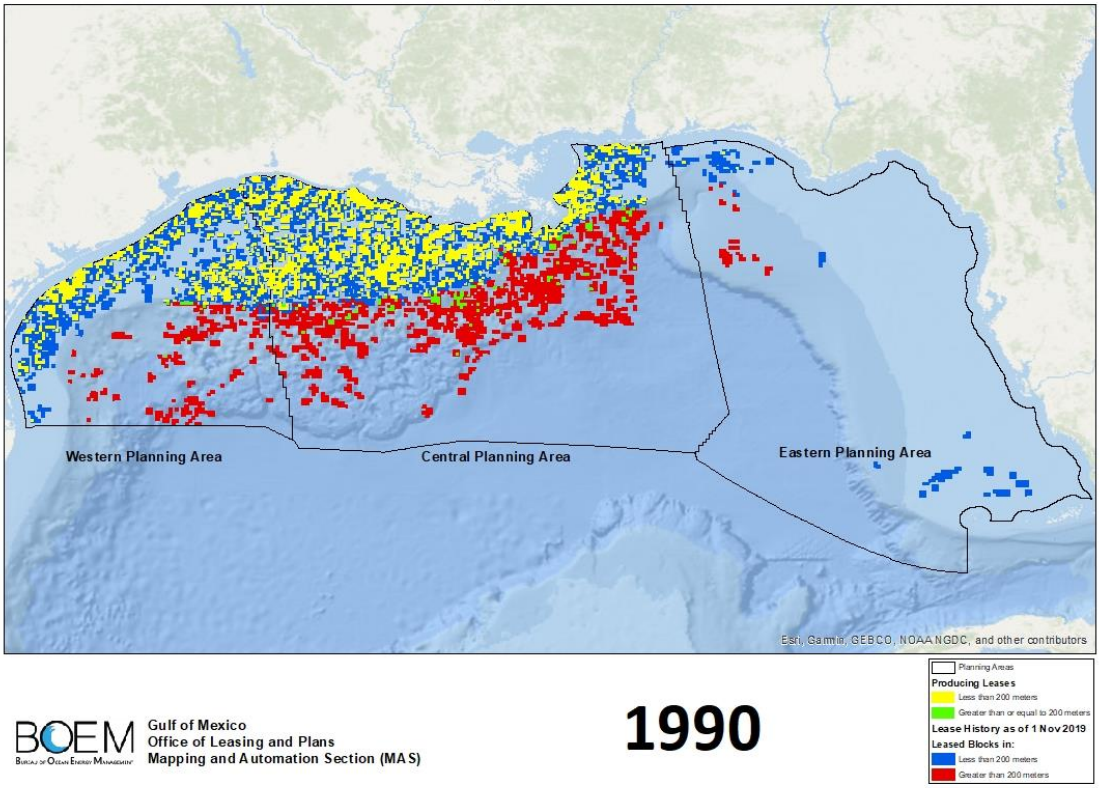
Shallow and Deepwater
OCS Lease History and Production in GOM
Western Planning Area
Central Planning Area
Eastern Planning Area
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors
Planning Areas
Producing Leases
Less than 200 meters
Greater than or equal to 200 meters
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
1980



Shallow and Deepwater
OCS Lease History and Production in GOM
Western Planning Area
Central Planning Area
Eastern Planning Area
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors
Planning Areas
Producing Leases
Less than 200 meters
Greater than or equal to 200 meters
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
1985

Exhibit C

Shallow and Deepwater
OCS Lease History and Production in GOM



Shallow and Deepwater
OCS Lease History and Production in GOM

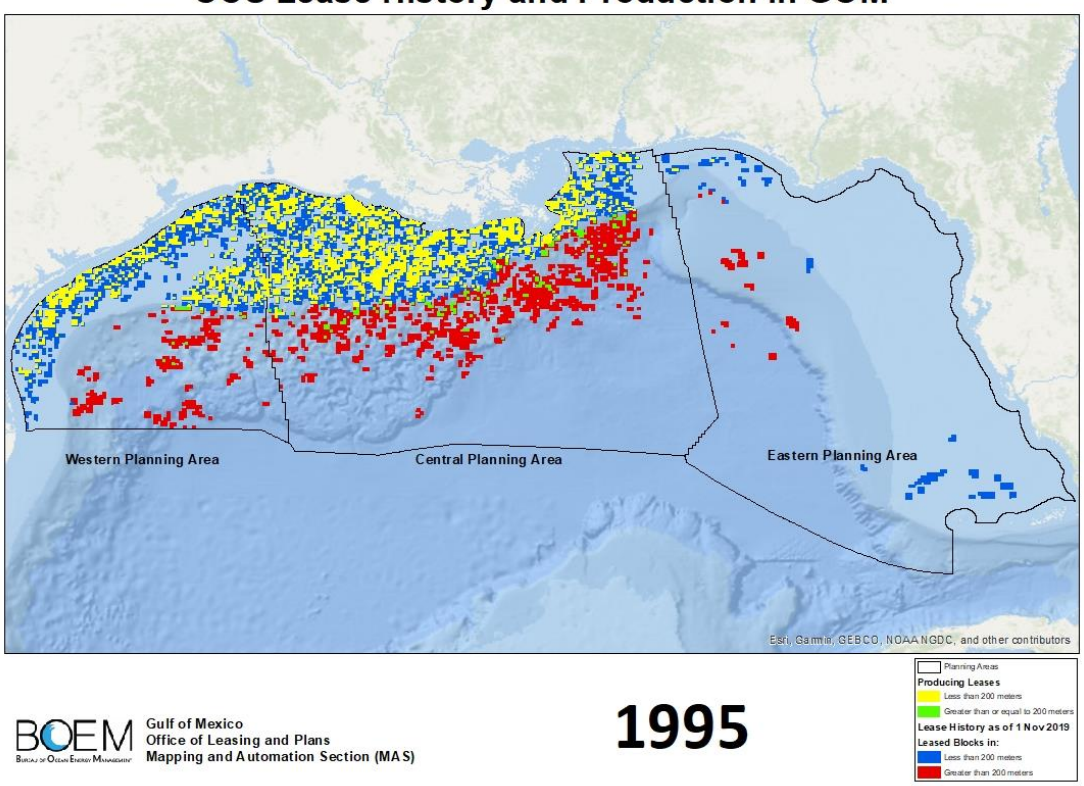
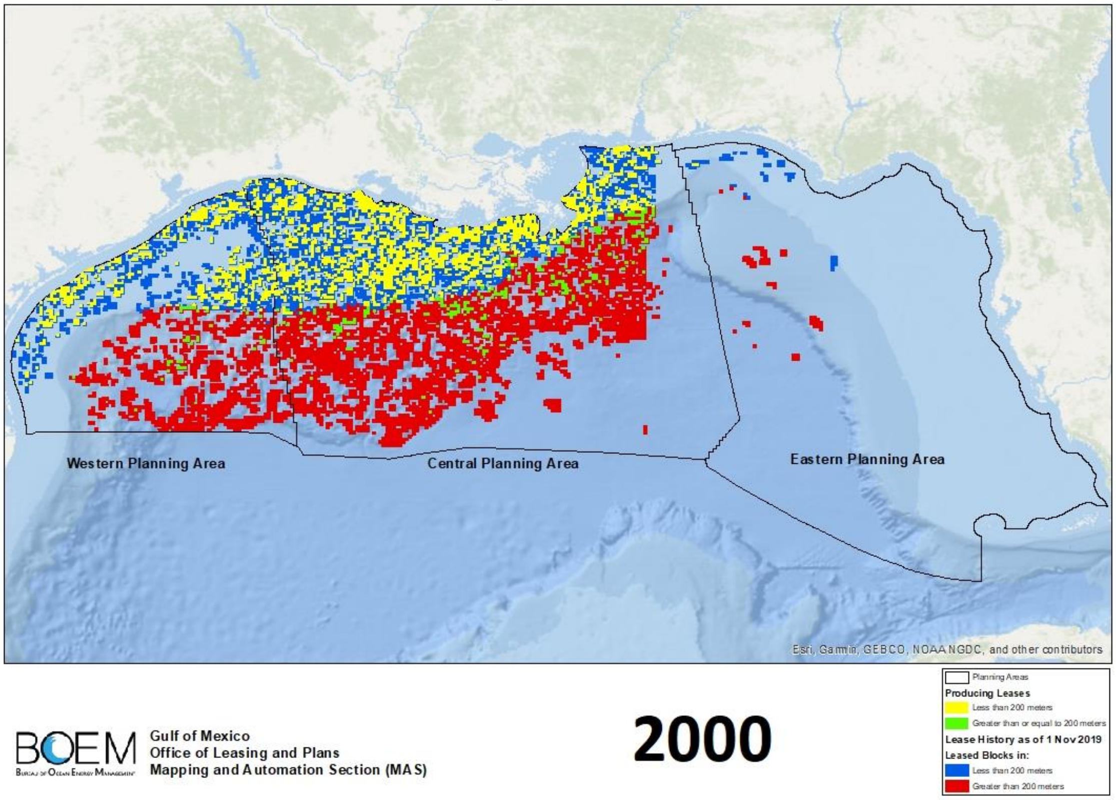


Exhibit C

Shallow and Deepwater
OCS Lease History and Production in GOM



Shallow and Deepwater
OCS Lease History and Production in GOM

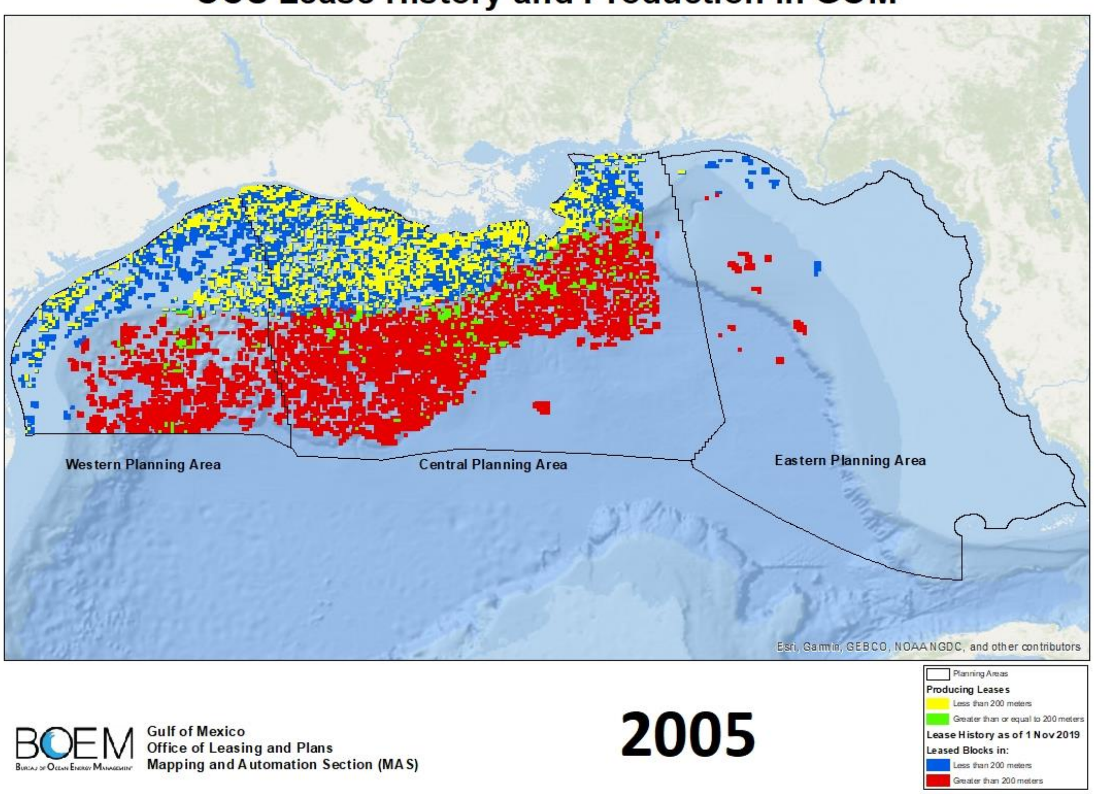
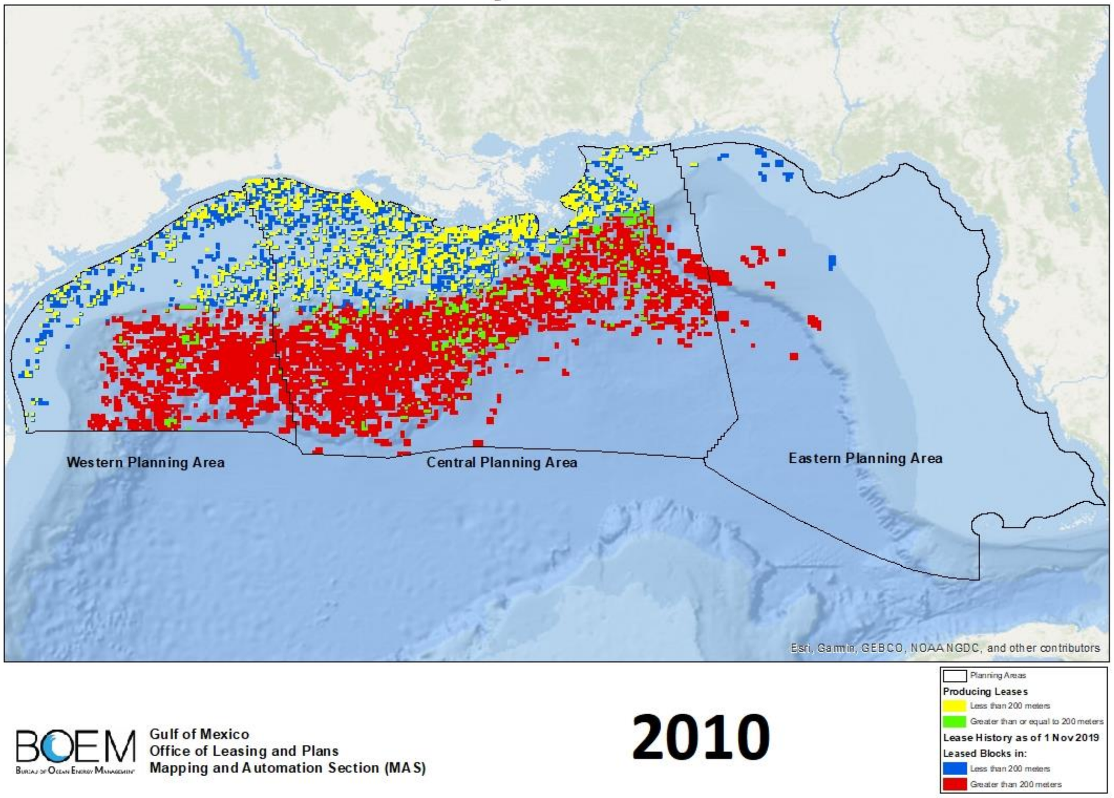


Exhibit C

Shallow and Deepwater
OCS Lease History and Production in GOM



Shallow and Deepwater
OCS Lease History and Production in GOM

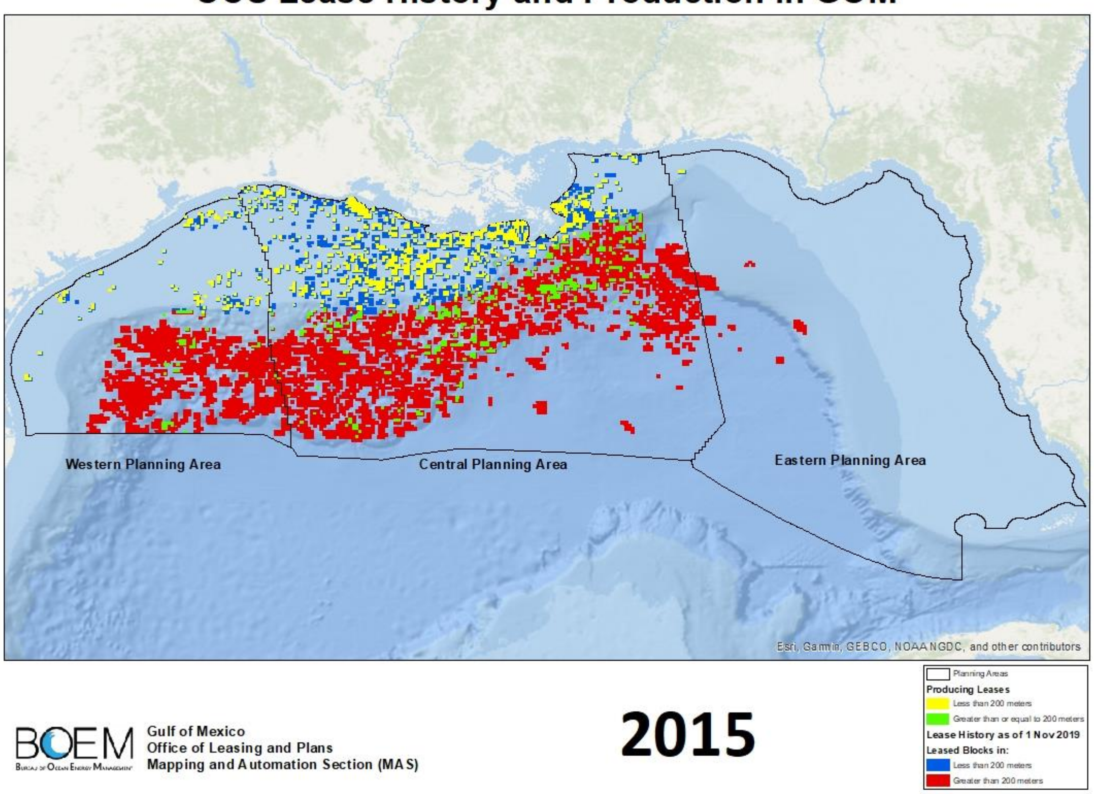
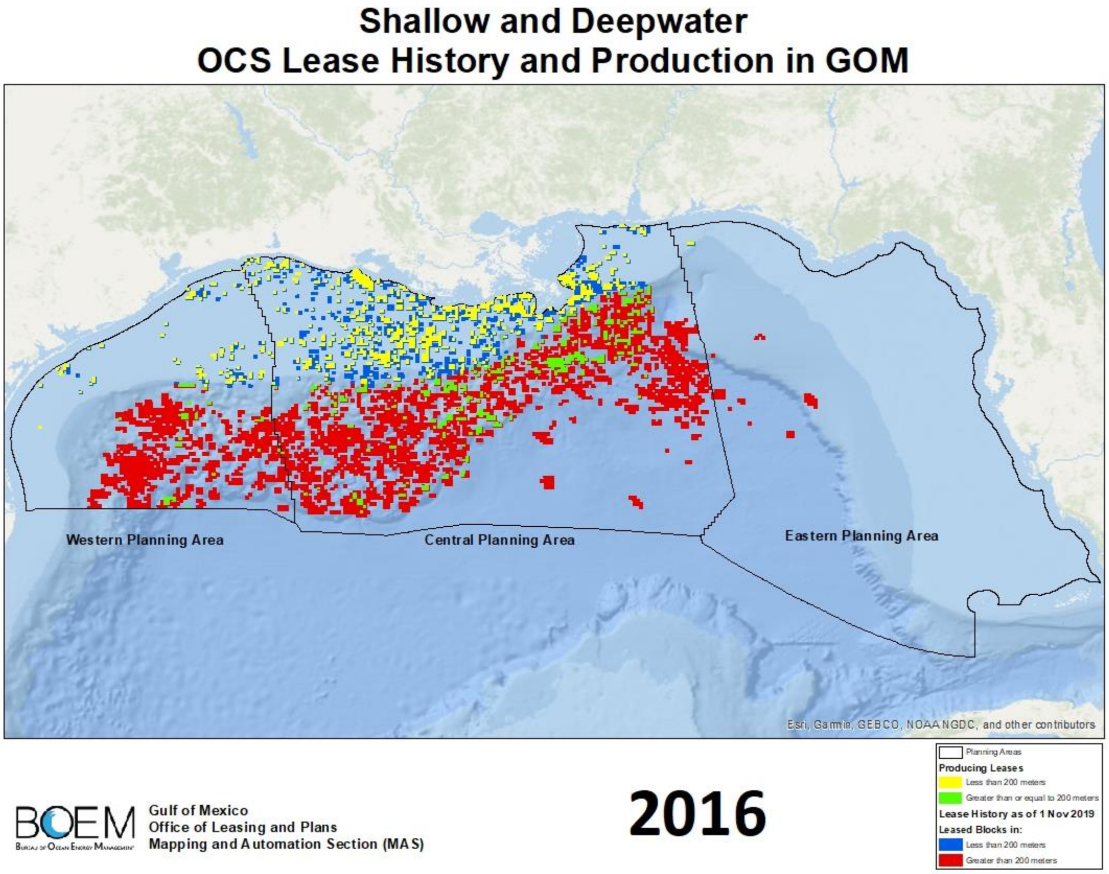


Exhibit C


Shallow and Deepwater
OCS Lease History and Production in GOM
Western Planning Area
Central Planning Area
Eastern Planning Area
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors
Planning Areas
Producing Leases
Less than 200 meters
Greater than or equal to 200 meters
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
2016

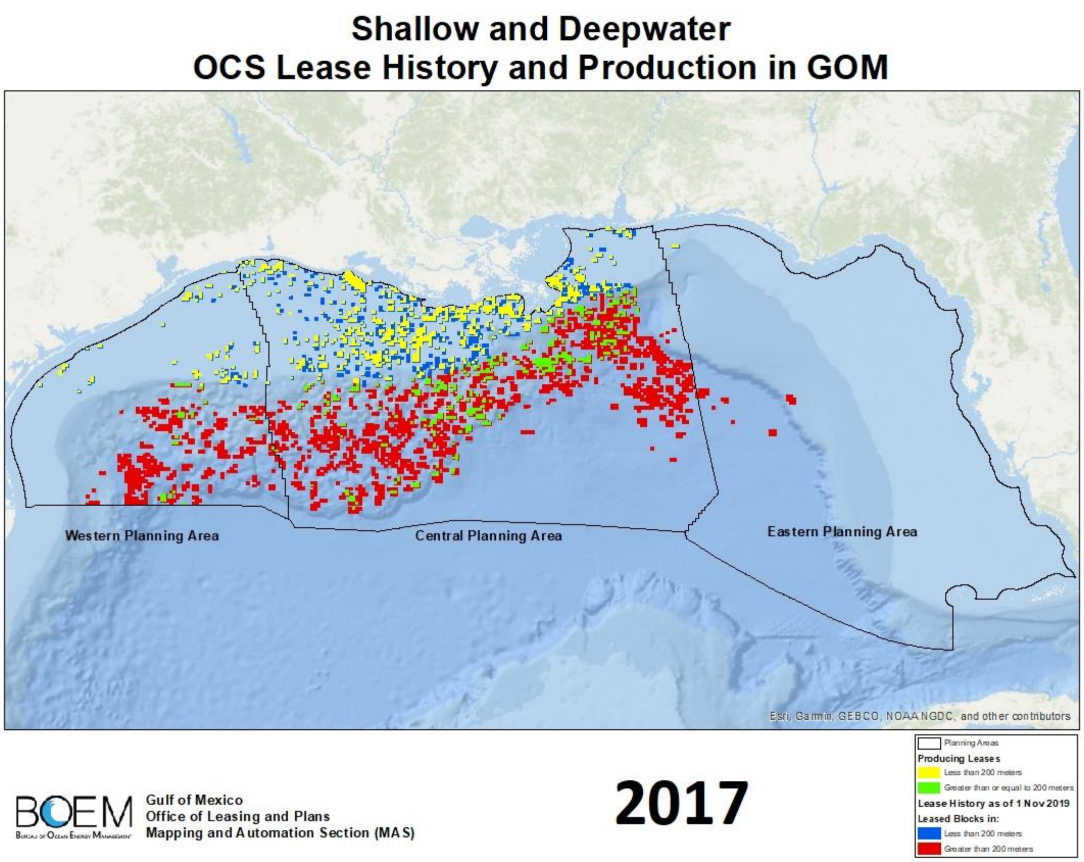
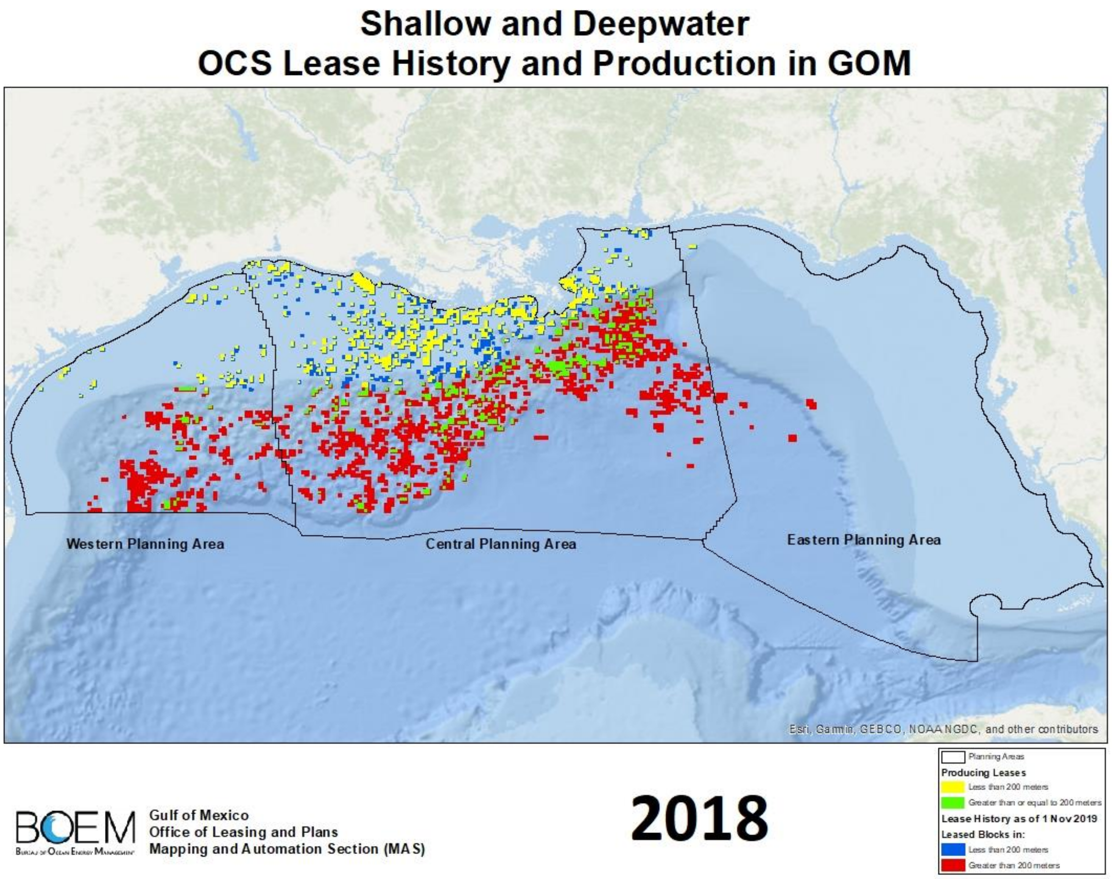

Shallow and Deepwater
OCS Lease History and Production in GOM
Western Planning Area
Central Planning Area
Eastern Planning Area
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors
Planning Areas
Producing Leases
Less than 200 meters
Greater than or equal to 200 meters
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
2017

Exhibit C


Shallow and Deepwater
OCS Lease History and Production in GOM
Western Planning Area
Central Planning Area
Eastern Planning Area
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors
Planning Areas
Producing Leases
Less than 200 meters
Greater than or equal to 200 meters
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Bureau of Ocean Energy Management
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
2018

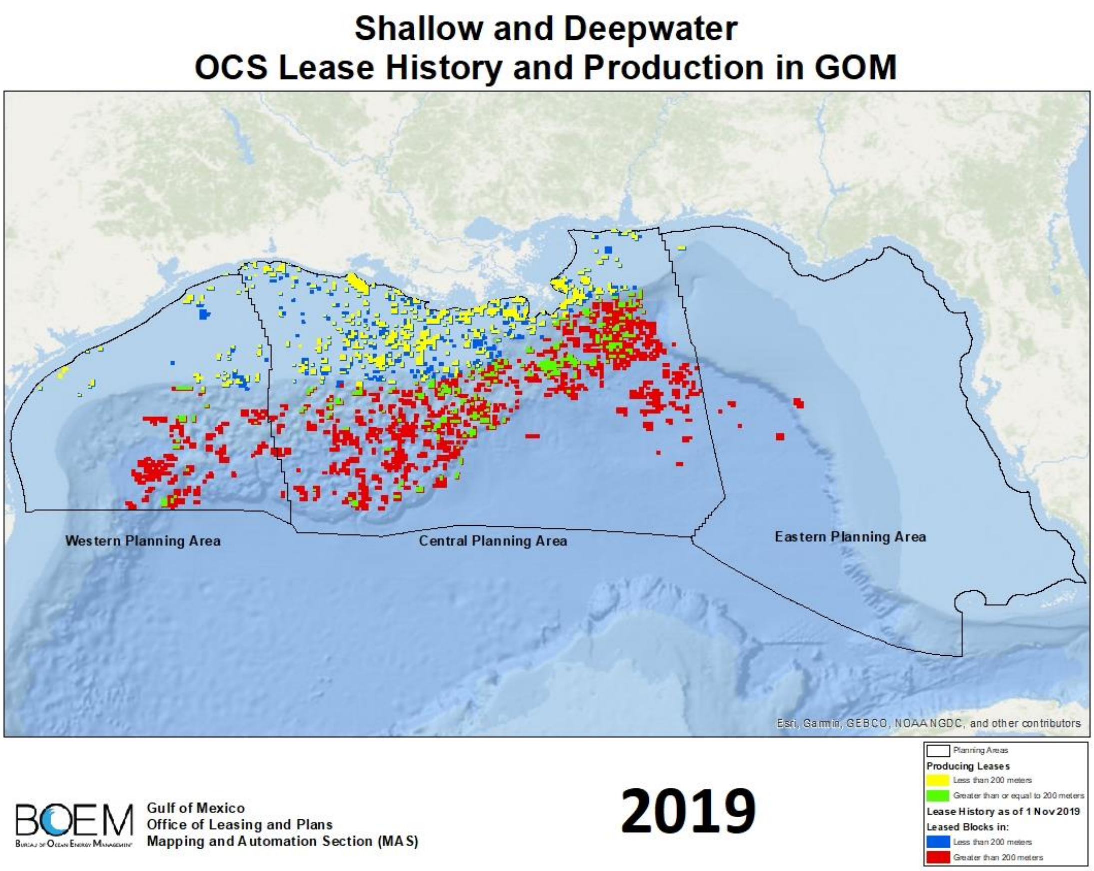
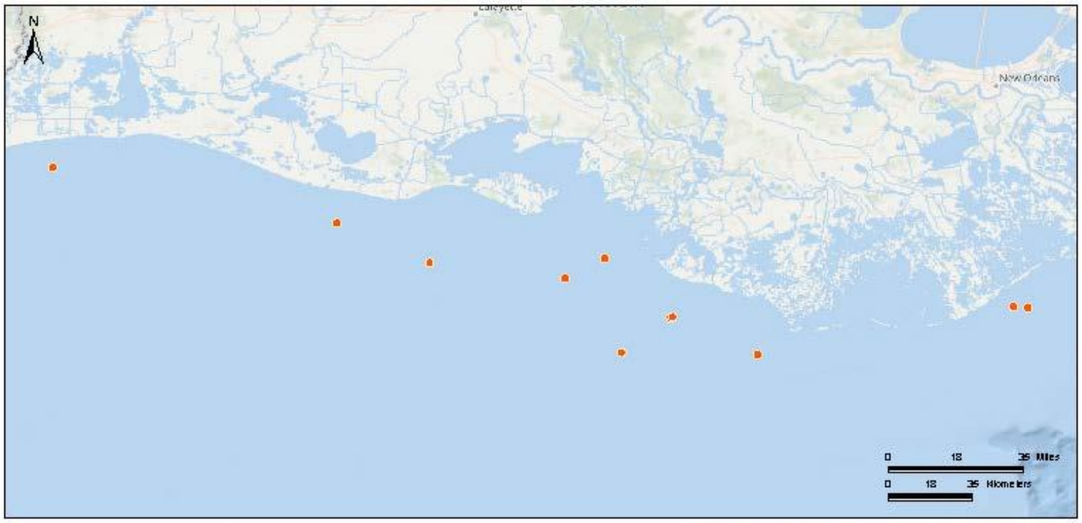

Shallow and Deepwater
OCS Lease History and Production in GOM
Western Planning Area
Central Planning Area
Eastern Planning Area
Esri, Garmin, GEBCO, NOAA NGDC, and other contributors
Planning Areas
Producing Leases
Less than 200 meters
Greater than or equal to 200 meters
Lease History as of 1 Nov 2019
Leased Blocks in:
Less than 200 meters
Greater than 200 meters
BOEM
Bureau of Ocean Energy Management
Gulf of Mexico
Office of Leasing and Plans
Mapping and Automation Section (MAS)
2019

Exhibit D

Structures in the Gulf of Mexico
Shallow and Deep Water



Structure Location
Shallow Water (<200m)

Number of Shallow Water Structures: 16

Number of Deep Water Structures: 0

STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
FIXED	Shallow Water	12
WP	Shallow Water	4

1940 - 1950

Structures in the Gulf of Mexico
Shallow and Deep Water

Structure Location
Shallow Water (<200m)

Number of Shallow Water Structures: 63

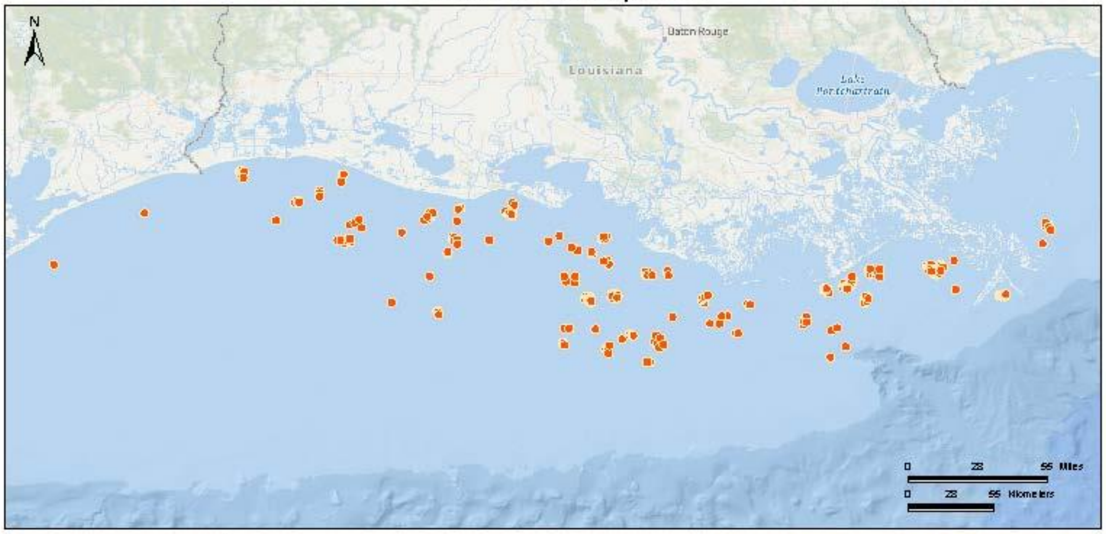
Number of Deep Water Structures: 0

STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
CAIS	Shallow Water	6
FIXED	Shallow Water	47
WP	Shallow Water	10

1950 - 1955

Exhibit D

Structures in the Gulf of Mexico
Shallow and Deep Water



Structure Location
Shallow Water (<200m)

Number of Shallow Water Structures: 352

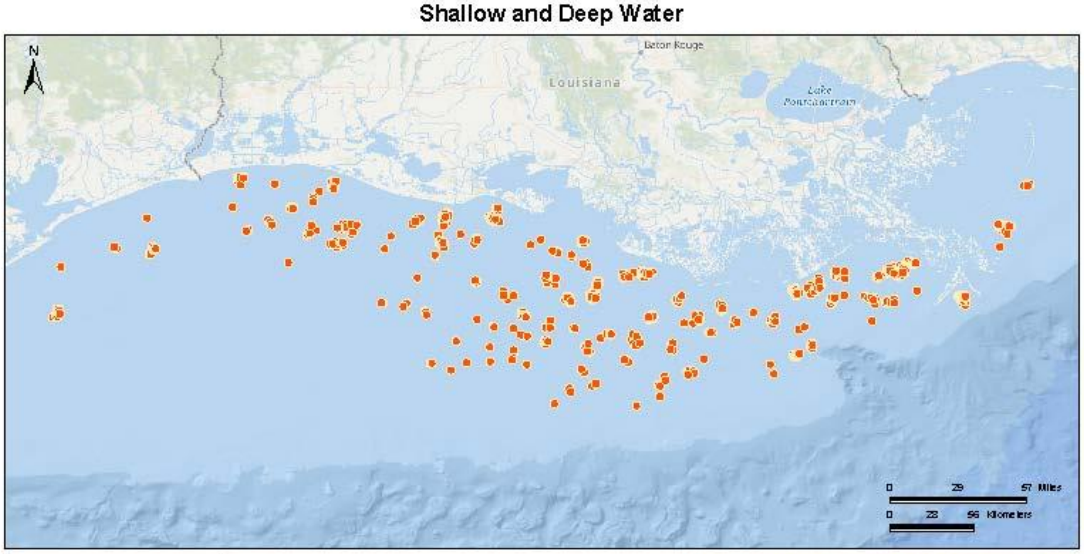
Number of Deep Water Structures: 0

STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
CAIS	Shallow Water	74
FIXED	Shallow Water	214
WP	Shallow Water	64

BSEE

1955 - 1960

Structures in the Gulf of Mexico
Shallow and Deep Water



Structure Location
Shallow Water (<200m)

Number of Shallow Water Structures: 919

Number of Deep Water Structures: 0

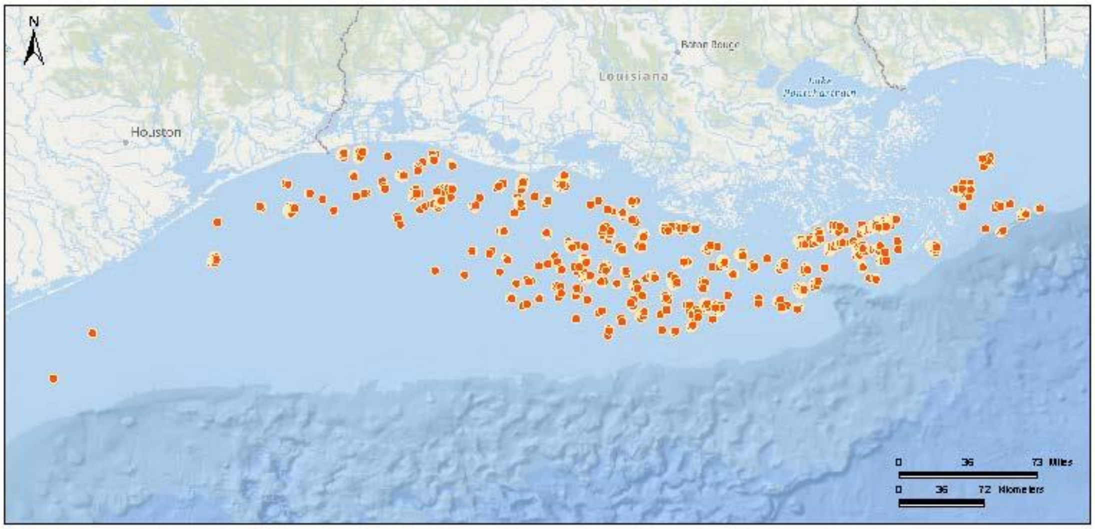
STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
CAIS	Shallow Water	308
FIXED	Shallow Water	457
WP	Shallow Water	154

BSEE

1960 - 1965

Exhibit D

Structures in the Gulf of Mexico
Shallow and Deep Water



Structure Location
Shallow Water (<200m)

Number of Shallow Water Structures: 1,530

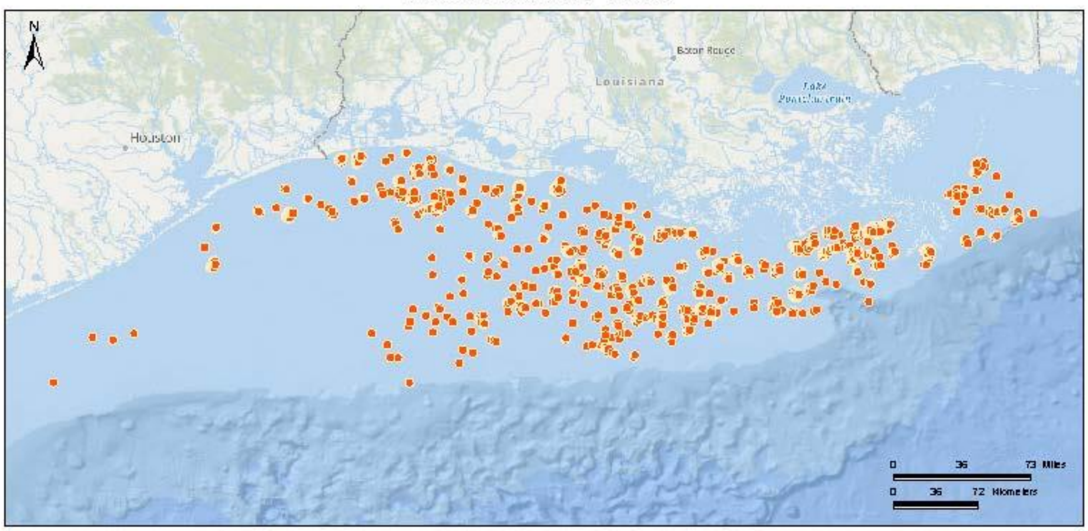
Number of Deep Water Structures: 0

STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
CAIS	Shallow Water	524
FIXED	Shallow Water	773
WP	Shallow Water	233

BSEE

1965 - 1970

Structures in the Gulf of Mexico
Shallow and Deep Water



Structure Location
Shallow Water (<200m)

Number of Shallow Water Structures: 2,042

Number of Deep Water Structures: 0

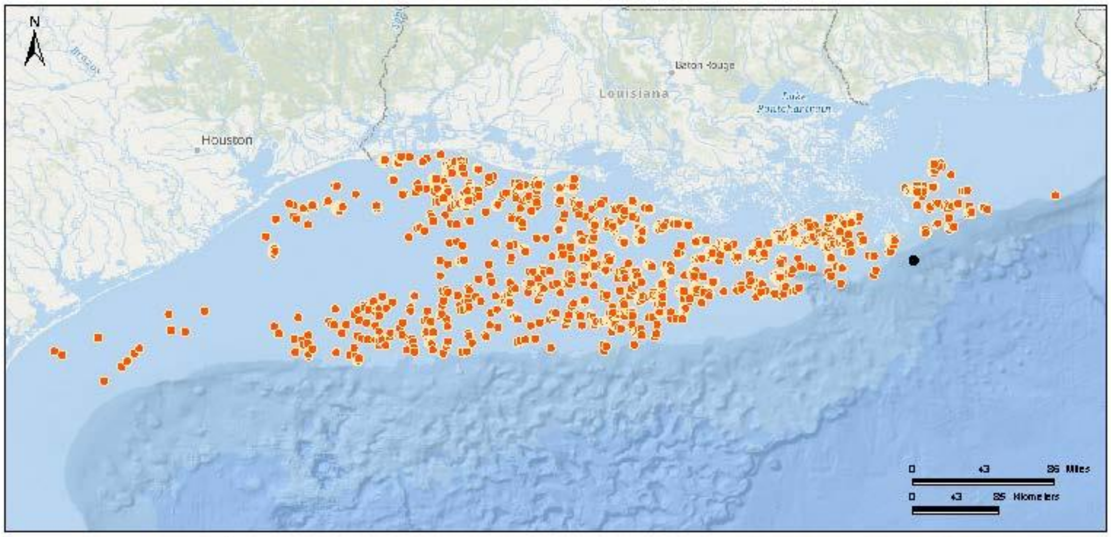
STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
CAIS	Shallow Water	661
FIXED	Shallow Water	1110
WP	Shallow Water	271

BSEE

1970 - 1975

Exhibit D

Structures in the Gulf of Mexico
Shallow and Deep Water



Structure Location
- Deep Water (>=200m)
- Shallow Water (<200m)

Number of Shallow Water Structures: 2,575

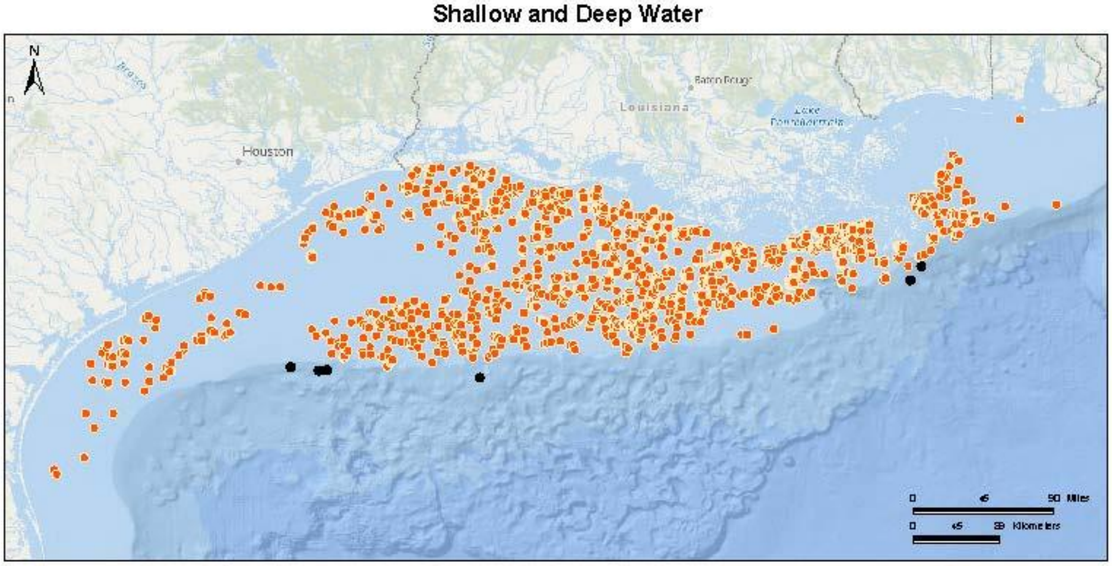
Number of Deep Water Structures: 1

STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
FIXED	Deep Water	1
CAIS	Shallow Water	748
FIXED	Shallow Water	1532
WP	Shallow Water	295

BSEE

1975 - 1980

Structures in the Gulf of Mexico
Shallow and Deep Water



Structure Location
- Deep Water (>=200m)
- Shallow Water (<200m)

Number of Shallow Water Structures: 3,343

Number of Deep Water Structures: 6

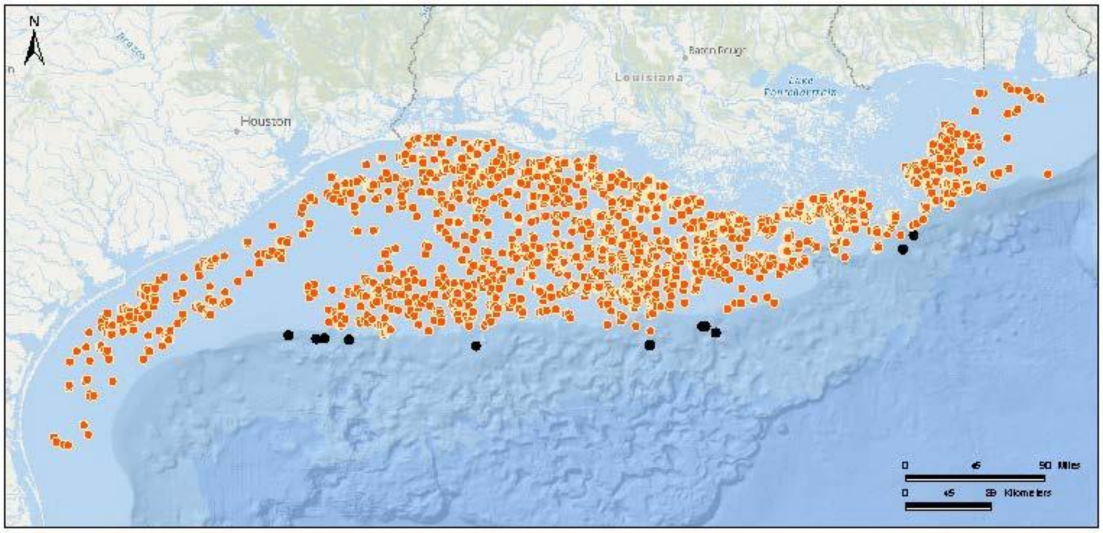
STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
CT	Deep Water	1
FIXED	Deep Water	5
CAIS	Shallow Water	997
FIXED	Shallow Water	1989
WP	Shallow Water	357

BSEE

1980 - 1985

Exhibit D

Structures in the Gulf of Mexico
Shallow and Deep Water



Structure Location
- Deep Water (>=200m)
- Shallow Water (<200m)

Number of Shallow Water Structures: 3,837

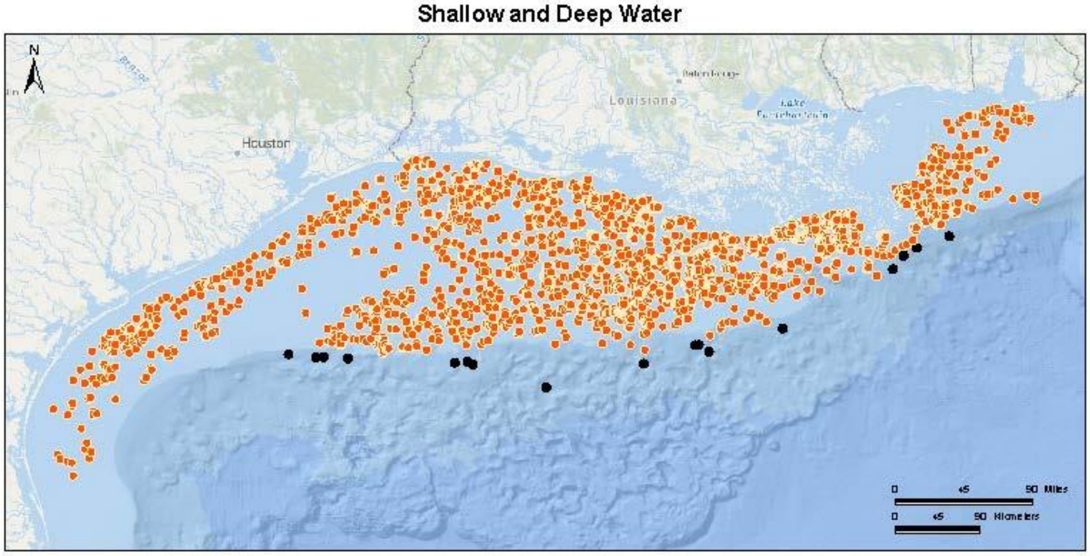
Number of Deep Water Structures: 11

STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
CT	Deep Water	1
FIXED	Deep Water	9
TLP	Deep Water	1
CAIS	Shallow Water	1188
FIXED	Shallow Water	2268
WP	Shallow Water	381

BSEE

1985 - 1990

Structures in the Gulf of Mexico
Shallow and Deep Water



Structure Location
- Deep Water (>=200m)
- Shallow Water (<200m)

Number of Shallow Water Structures: 3,915

Number of Deep Water Structures: 17

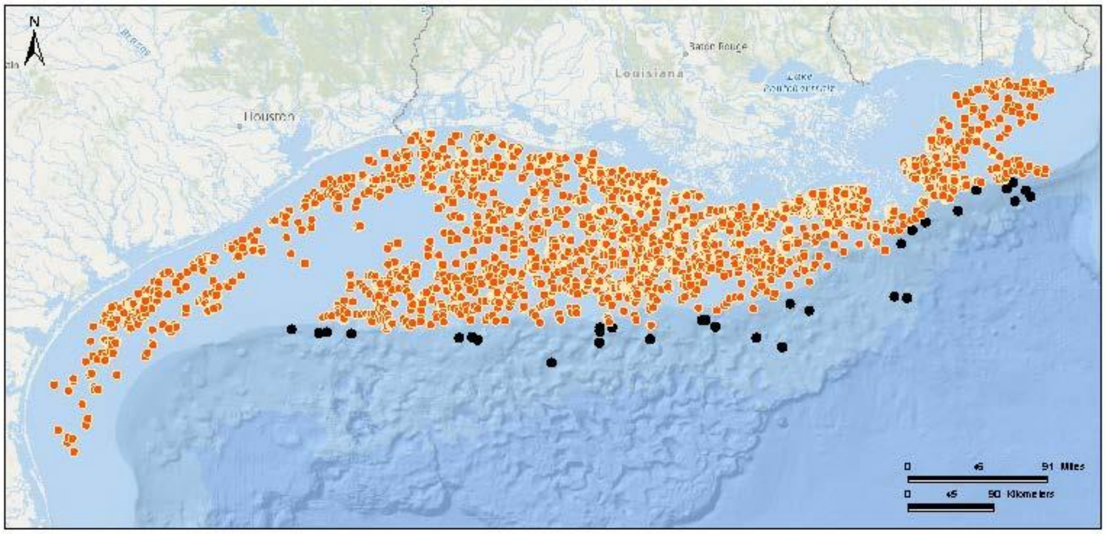
STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
CT	Deep Water	1
FIXED	Deep Water	14
TLP	Deep Water	2
CAIS	Shallow Water	1156
FIXED	Shallow Water	2396
MOPU	Shallow Water	1
WP	Shallow Water	362

BSEE

1990 - 1995

Exhibit D

Structures in the Gulf of Mexico
Shallow and Deep Water



Structure Location
- Deep Water (>=200m)
- Shallow Water (<200m)

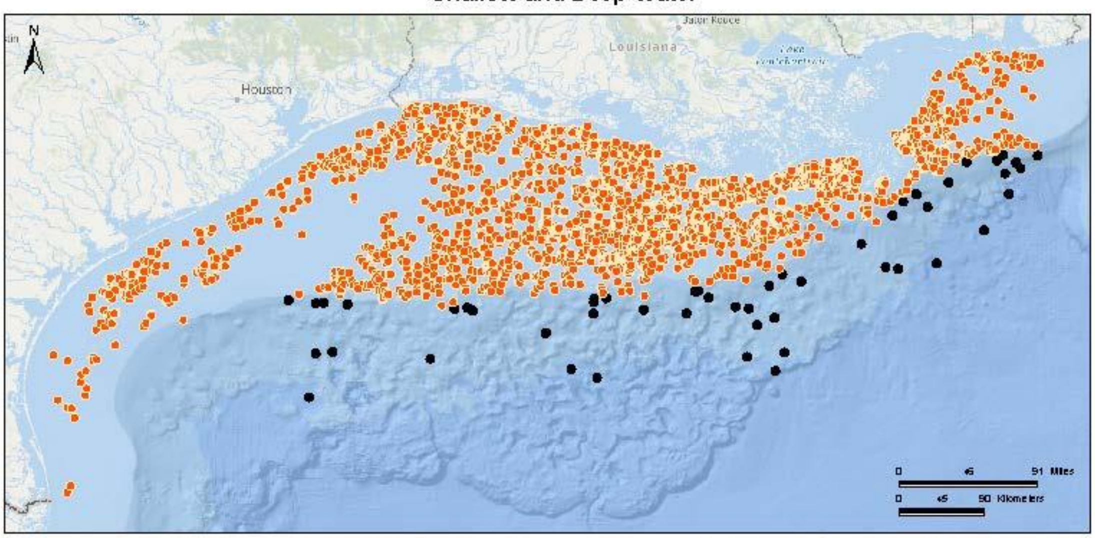
Number of Shallow Water Structures: 3,950

Number of Deep Water Structures: 32

1995 - 2000

STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
CT	Deep Water	2
FIXED	Deep Water	20
MTLP	Deep Water	2
SPAR	Deep Water	2
TLP	Deep Water	6
CAIS	Shallow Water	1096
FIXED	Shallow Water	2525
MOPU	Shallow Water	1
WP	Shallow Water	328

Structures in the Gulf of Mexico
Shallow and Deep Water



Structure Location
- Deep Water (>=200m)
- Shallow Water (<200m)

Number of Shallow Water Structures: 3,846

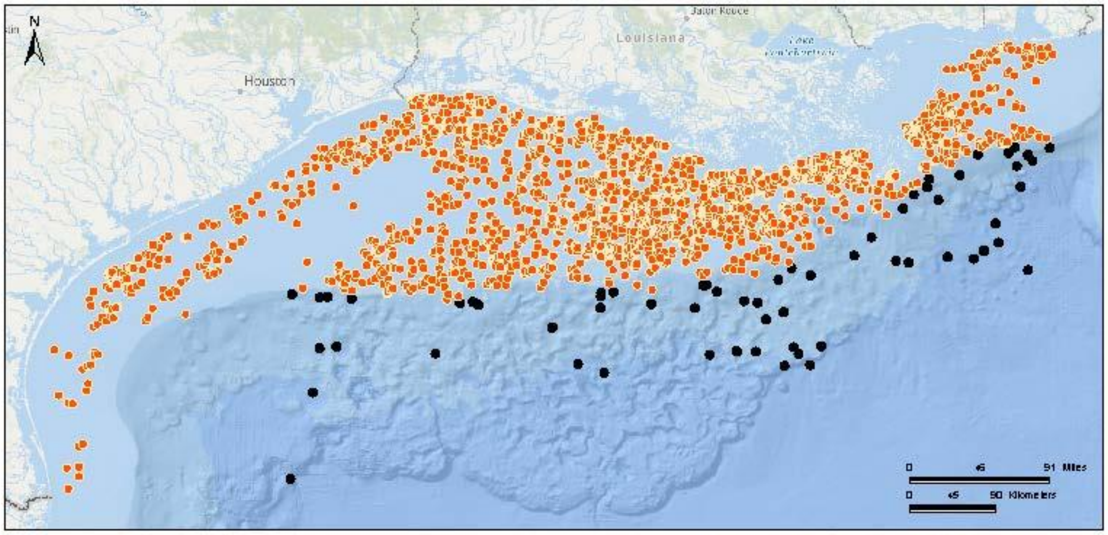
Number of Deep Water Structures: 51

2000 - 2005

STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
CT	Deep Water	3
FIXED	Deep Water	20
MTLP	Deep Water	4
SEMI	Deep Water	1
SPAR	Deep Water	13
TLP	Deep Water	10
CAIS	Shallow Water	1079
FIXED	Shallow Water	2909
MOPU	Shallow Water	2
WP	Shallow Water	296

Exhibit D

Structures in the Gulf of Mexico
Shallow and Deep Water



Structure Location
- Deep Water (>=200m)
- Shallow Water (<200m)

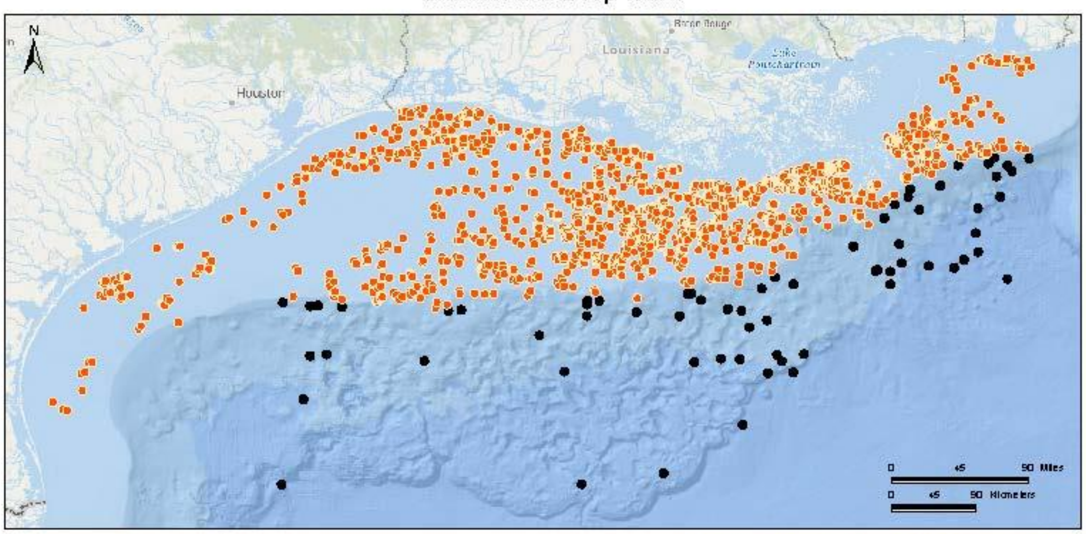
Number of Shallow Water Structures: 3,394

Number of Deep Water Structures: 63

2005 - 2010

STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
CT	Deep Water	3
FIXED	Deep Water	21
MOPU	Deep Water	1
MTLP	Deep Water	4
SEMI	Deep Water	7
SPAR	Deep Water	16
TLP	Deep Water	11
CAIS	Shallow Water	1012
FIXED	Shallow Water	2209
WP	Shallow Water	173

Structures in the Gulf of Mexico
Shallow and Deep Water



Structure Location
- Deep Water (>=200m)
- Shallow Water (<200m)

Number of Shallow Water Structures: 2,342

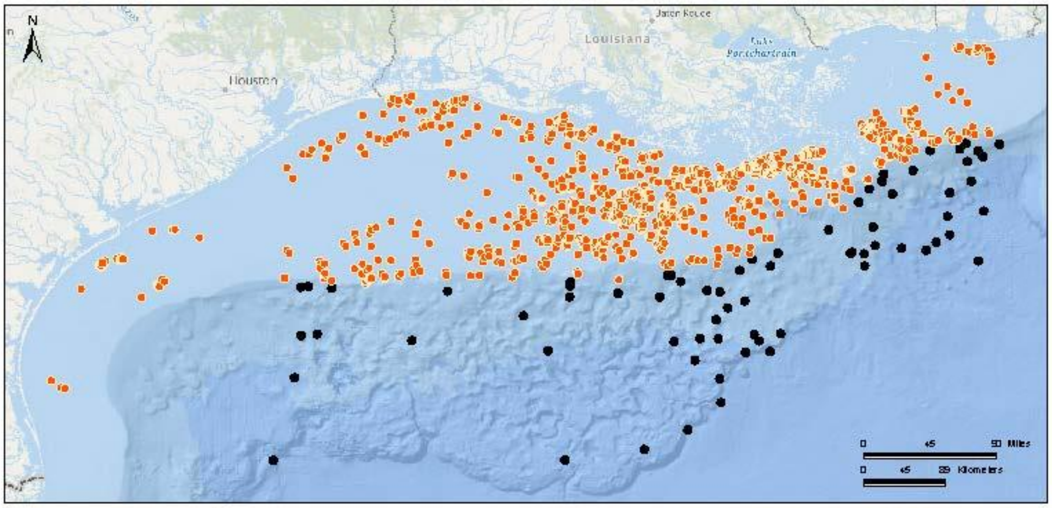
Number of Deep Water Structures: 68

2010 - 2015

STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
CT	Deep Water	3
FIXED	Deep Water	20
FPSO	Deep Water	1
MOPU	Deep Water	1
MTLP	Deep Water	4
SEMI	Deep Water	10
SPAR	Deep Water	17
TLP	Deep Water	12
CAIS	Shallow Water	599
FIXED	Shallow Water	1700
WP	Shallow Water	43

Exhibit D

Structures in the Gulf of Mexico
Shallow and Deep Water



Structure Location
- Deep Water (>=200m)
- Shallow Water (<200m)

Number of Shallow Water Structures: 1,713

Number of Deep Water Structures: 71

STRUCTURE TYPE	LOCATION	NUMBER OF STRUCTURES
CT	Deep Water	3
FIXED	Deep Water	18
FPSO	Deep Water	2
MOPU	Deep Water	1
MTLP	Deep Water	4
SEMI	Deep Water	11
SPAR	Deep Water	18
TLP	Deep Water	14
CAIS	Shallow Water	407
FIXED	Shallow Water	1301
WP	Shallow Water	5

BSEE

2015 - Present