BSEE Proposed Well Control Rule
Cost and Economic Analysis

July 2015

Prepared for:

American Petroleum Institute (API)

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Executive Summary

Introduction

The U.S. DOI Bureau of Safety and Environmental Enforcement (BSEE) recently published new requirements and procedures related to the proposed rule "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" (hereafter, proposed rule). Quest Offshore Resources (hereafter, Quest Offshore or Quest) and Blade Energy Partners (hereafter Blade Energy or Blade) undertook a study to evaluate the potential cost and economic impact effects of the proposed rule (and associated sections and subsections) on oil and gas drilling operations in the US Gulf of Mexico (GOM), and the influence that these effects would have on the broader economy. Although the proposed rule would apply to all US offshore oil and natural gas development, only the impacts to the Gulf of Mexico were considered for this study.

This study examines the proposed rule, determines the estimated cost and impact of the rules, and attributes these costs and impacts to a model of project design, economics and timelines to determine the effects these rules could have on overall GOM oil and gas development. Once the impact on GOM activity was projected, estimates of the related spending and employment were calculated to quantify the overall economic impact of the proposed rule.

Cost of the Proposed Rule

Construction of a detailed analysis for each individual section/requirement of the proposed rule was undertaken by Quest Offshore and Blade Energy. The increased costs resulting from the rules adoption are expected to further increase expenses incurred by industry participants throughout the study period. The cost estimates presented in the study exclude many costs already being spent by the industry prior to the publishing of the proposed rule.

The increased costs associated with the proposed rule are likely to be felt throughout the offshore oil and gas supply chain. Certain operators and contractors, however, are likely to be effected more than others. Cumulative direct costs due to the adoption of the proposed rule as currently written are estimated at over $32 billion for the ten years from 2017 to 2026. The expected impact of the proposed rule will be an increase in the total time and cost required to drill many offshore wells, as well as lead to the replacement of blow out preventers (BOP) and other capital equipment. (Table 1)

Table 1: **10 Year Direct Cost Estimates – Base Development Scenario ($Millions[1])**

Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
BOP Replacement or Modification	$925	$926	$1,336	$1,331	$1,373	$1,465	$1,419	$978	$1,041	$1,052	$11,846
Compliance and Documentation	$11	$12	$11	$12	$13	$13	$14	$13	$12	$15	$127
Containment	$113	$114	$179	$181	$190	$99	$97	$98	$85	$86	$1,241
Rig Requirements	$204	$205	$205	$215	$239	$239	$240	$244	$247	$250	$2,288
Real Time Monitoring (RTM)	$74	$72	$73	$85	$83	$52	$56	$63	$63	$50	$670
Tubing and Wellhead Equipment[2]	$33	$1	$1	$1	$1	$1	$1	$1	$1	$1	$38
Well Design	$1,062	$1,470	$1,597	$1,721	$1,691	$1,739	$1,551	$1,357	$1,601	$1,830	$15,620
Grand Total	$2,421	$2,800	$3,402	$3,547	$3,589	$3,606	$3,378	$2,753	$3,050	$3,284	$31,831

Source: Quest Offshore Resources, Inc.

Impact of Proposed Rule – Gulf of Mexico Oil and Gas Development

If the proposed rule is implemented as written, it would likely reduce the total amount of Gulf of Mexico oil and natural gas activity, including the number of wells drilled and projects developed. The proposed rule will likely negatively influence deepwater development the most, especially high pressure, high temperature, and ultra-deep water wells which may no longer be drillable, and the resources that these wells might have developed may be lost. A significant number of both shallow and deep water wells drilled into depleted reservoirs may also become undrillable, and those resources would also remain undeveloped. These lost reserves would primarily result from the effects of §250.414, "Planned safe drilling margins", though other new regulations may also have a significant effect on the ability to produce from these reserves. Adoption of the proposed rules is expected to lead to a decrease of an average of around 20 exploration wells drilled per year and around 29 development wells per year. Some of these wells are expected to begin drilling, only to be abandoned prior to completion due to the proposed rule.

This study projects that oil and natural gas production in the Gulf of Mexico will be 2.28 million barrels of oil equivalent (BOE) per day in 2017, and grow to 3.10 million BOE per day by 2030. Under the proposed rule, Gulf of Mexico production is forecasted to be nearly 15% or 0.48 million BOE per day lower by 2030.

Total cumulative spending on offshore oil and natural gas development in the Gulf of Mexico OCS is projected at nearly $550 billion between 2017 and 2030 or roughly $39.2 billion per year. If the proposed rule is adopted, cumulative spending is projected at $493 billion; an average reduction of about $4 billion or over 10 percent per year.

Economic Impact of Proposed Rule

The study projects total employment supported from the Gulf of Mexico offshore oil and natural gas industry to rise from approximately 363 thousand in 2015 to over 466 thousand by 2030 under the base development scenario. The adoption of the proposed rule is expected to lead to a reduction in

[1] All costs, spending, GDP Impacts, and government revenues are calculated in constant 2014 dollars.
[2] Tubing and Wellhead Equipment costs associated with Well Design requirements in the proposed rule are included in Well Design Costs (Ex. increased casing costs due to drilling margin requirements.)

industry supported employment levels by over 50,000 by as early as 2027 due to reduced oil and natural gas development. (Table 2)

Table 2: Estimated Total Supported Employment Levels by Scenario – 2010 to 2030 (Thousands)

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	409	409	408	412	421	363	400	419	441	449	449
Proposed Rule	409	409	408	412	421	363	400	412	417	423	413
Difference	-	-	-	-	-	-	-	7	24	26	36

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	434	433	430	434	438	461	469	467	460	467
Proposed Rule	398	399	387	388	403	415	418	411	409	414
Difference	36	34	43	46	35	46	51	56	51	53

Source: Quest Offshore Resources, Inc.

The Gulf of Mexico offshore oil and natural gas industry will contribute an estimated $31.35 billion annually to US GDP in 2015, and is projected to grow to over $40 billion by 2030 (Table 3). The proposed rule, if enacted as written, is projected to lead to a reduction of GDP supported Gulf of Mexico oil and natural gas activities of $4 billion annually by 2030. The 10-year cumulative GDP cost burden of the rule from 2017 to 2026 is estimated at $28.5 billion.

Table 3: Estimated GOM Supported GDP by Scenario – 2010 to 2030 ($Millions)

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	$34,726	$35,098	$35,311	$34,998	$35,946	$31,350	$34,513	$36,077	$38,084	$38,862	$38,699
Proposed Rule	$34,726	$35,098	$35,311	$34,998	$35,946	$31,350	$34,513	$34,726	$36,937	$37,817	$36,857
Difference	$0	$0	$0	$0	$0	$0	$0	($1,351)	($1,147)	($1,045)	($1,841)

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	$37,332	$36,991	$36,661	$36,948	$37,330	$39,618	$40,400	$40,297	$39,641	$40,141
Proposed Rule	$35,099	$34,186	$33,523	$33,819	$34,297	$35,281	$35,900	$36,851	$35,682	$36,133
Difference	($2,233)	($2,805)	($3,138)	($3,130)	($3,034)	($4,337)	($4,500)	($3,445)	($3,960)	($4,007)

Source: Quest Offshore Resources, Inc.

Annual government revenues from Gulf of Mexico lease sales, rents, and royalties is expected to rise from about $5 billion in 2015 to $13 billion by 2030 under the base development scenario. Reduced oil and natural gas development anticipated under the proposed rule is projected to lead to lower overall government revenues, primarily as a result of lower production royalties being collected with lower production volumes. Reduced government revenues could be as high as $1 billion per year as early as 2023, and $2 billion by 2028. The 10-year cumulative lost government revenue burden of the rule from 2017 to 2026 is estimated at $10 billion.

Table 4: Estimated State and Federal Government Revenues from GOM Oil and Natural Gas by Scenario 2010 to 2030 ($Millions)

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	$6,361	$6,177	$7,515	$7,219	$7,079	$5,177	$7,013	$7,625	$8,050	$8,262	$8,828
Proposed Rule	$6,361	$6,177	$7,515	$7,219	$7,079	$5,177	$7,013	$7,389	$7,533	$7,746	$8,110
Difference	$0	$0	$0	$0	$0	($0)	($0)	($236)	($517)	($516)	($719)

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	$9,188	$9,518	$9,953	$10,307	$10,909	$11,247	$11,780	$12,222	$12,777	$13,254
Proposed Rule	$8,267	$8,557	$8,740	$8,889	$9,164	$9,580	$9,865	$10,148	$10,488	$10,870
Difference	($921)	($961)	($1,213)	($1,418)	($1,745)	($1,667)	($1,915)	($2,074)	($2,289)	($2,385)

Source: Quest Offshore Resources, Inc.

Adoption of the proposed "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" rule is expected to significantly increase costs for operators, contractors, and other participants in the Gulf of Mexico offshore oil and natural gas industry. This will likely lead to reduced activity and spending, which is projected to lower production, employment levels, and the growth in GDP and government revenues.

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Section 1 - Introduction

In the Gulf of Mexico, the oil and gas industry has a tremendous influence on the local economies of the Gulf coast and the broader U.S. economy by providing desirable and well-paying employment for hundreds of thousands of Americans, creating revenues for many levels of the U.S. government, and by contributing to the country's energy needs. The industry has grown into the world leader in offshore production, safety, technology, and scientific research. The shallow and mid-water Gulf production areas have been longstanding sources of employment and production, though those areas have been struggling to overcome the economic barriers of production in those now-mature fields, and production has been declining.

Recently, efforts to revitalize mature fields and a shift towards production and activity in deepwater areas of the region have been renewing the strength of the offshore industry, which is poised to reverse the long-standing trend of decline in offshore production volumes that began in the 1980s. Due to the work being done in the deepwater Gulf of Mexico, the industry's global influence has grown steadily, along with the positive economic benefits which it brings. The Gulf has steadily grown into one of the world's most prominent and important oil and natural gas production areas, both in terms of economic value and importance to the global oil and gas industry.

Through an expanded and rigorous set of industry standards put in place over the last five years, the Gulf of Mexico has come to be seen throughout the world as the standard of safety in deepwater and high pressure/high temperature production. Companies operating in the region have not only developed technologies capable of safely and reliably operating in previously impossible-to-reach areas and depths, but have built the region into a center for research and innovation, and a global leader in safety, reliability and technology. As a result of the importance of the industry to the U.S. economy and energy security, any significant changes to regulations should be carefully evaluated.

1.1 Purpose of the Report

Following the announcement of proposed changes to the blowout preventer systems and well control regulations, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf – Blowout Preventer Systems and Well Control", by the Bureau of Safety and Environmental Enforcement (BSEE), Quest Offshore Resources was commissioned by the American Petroleum Institute (API), in collaboration with Blade Energy Partners, to provide an independent evaluation of the potential costs associated with the proposed rule. In addition, potential impacts on Gulf of Mexico oil and natural gas development, supported employment, GDP, and government revenue were also to be projected.

The report seeks to identify the costs associated with additional engineering, regulatory oversight, constrained drilling margins, additional BOP construction and maintenance requirements, changes to the regulations surrounding casings and decommissionings, real time monitoring and well containment regulations, amongst others. Once these costs are established, the report will determine the effect that these additional cost burdens will have on project viability, the broad health of the U.S. oil and gas industry and the US economy as a whole.

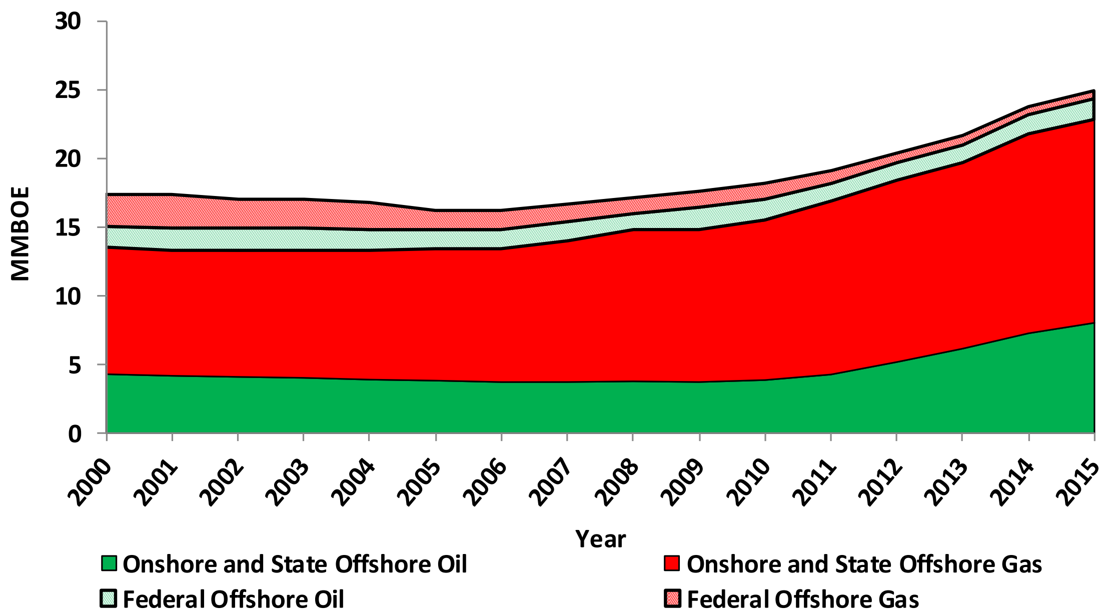
1.2 Report Structure

In this report, Quest will first outline the study methodology in Section 3, followed by a summary of the direct costs associated with the new regulations in Section 4. Following that summary, the study will present forecasts of US offshore oil and gas activity in both the current regulatory environment and under the proposed rule in Section 5. Based on the findings from the activities forecasts, the study them outlines the macroeconomic effects of the proposed regulations on total employment, gross domestic product (GDP) and government revenues in Section 6. Following the findings and conclusions in Section 7, the tables and appendices section contains detailed information on the specific assumptions (Section 8), calculations and findings of the study, as well as a line-by-line analysis of the proposed rule.

1.3 Projected Gulf of Mexico Oil and Natural Gas Development

In recent years, total U.S. oil and natural gas production has increased from approximately 17 million barrels of oil equivalent (MMBOE) in 2006 to over 25 MMBOE in 2015 (Figure 1). This is primarily due to rising production from shale gas and tight oil formations. The dramatic increase in onshore unconventional oil and natural development has been a major contributor in increasing U.S. energy security as well as a significant contributor to the economic recovery in a number of states. U.S. offshore oil and natural gas production, predominately from the Gulf of Mexico, has recently declined. There are, however, a large number of projects under development in the Gulf that are poised to significantly increase output.

Figure 1: **U.S. Oil and Natural Gas Production 2000 to 2015**



Source: Energy Information Administration

As of April 2015, U.S. domestic crude production has grown to 9.7 MMbbl/d (million barrels of oil per day), distributed through:

- 1.51 MMboe/d from the Gulf of Mexico Federal Outer Continental Shelf

- .046 MMboe/d from offshore California
- .51 MMboe/d from onshore and offshore Federal Alaska
- 7.6 MMboe/d from onshore (including shale) and offshore State waters

Natural gas production nationwide has also grown to 75 BCF/d (billion cubic feet of marketed production per day). It is estimated that the oil and gas industry currently supports 9.8 million jobs nationwide[3].

Under the current regulatory structure, growing production from the U.S. offshore areas driven by the Gulf of Mexico OCS is expected both by this study as well as other sources such as the U.S. Energy Information Administration. While this forecast shows a positive outlook for US oil and gas production and energy security, there is the potential for these regulations to impact overall output, and hinder the US return to energy dominance.

1.4 Excluded From This Study

This paper has been limited in scope to the assessment of the effects of the proposed rule, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" on the Gulf of Mexico OCS, though the rule will affect all U.S. OCS offshore oil and natural gas exploration and production areas both current and future. The study also does not attempt to calculate the effects of the proposed rule on mid-stream or down-stream oil and natural gas entities. In addition, the calculated government revenue potential does not include personal income taxes, corporate income taxes or local property taxes.

Given the unpredictable nature of advancements in technology and innovation in the oil and gas industry, the scope of this paper was limited to the effects that new regulations would have on future activity with the assumption that the methods and equipment mentioned in the regulation would still be in use at the end of the study period. It is entirely possible that new designs, methods and target reservoirs would change over time and no longer fall under the umbrella of these regulations, but if that were the case, the effects would be primarily felt toward the end of the forecast period.

In addition to the possibility of new technologies being used in the region, the study has also excluded the effects of activity in other regions inclusive of Alaska, Pacific, and Atlantic OCS regions. It is a very likely possibility that exploration and production activities in the OCS areas will see similar disruptions within the future activity forecast under the proposed regulations.

Overall, given the constraints and assumptions discussed above, it is likely that the costs and economic impacts presented in this study represent a conservative projection of the impact of the proposed rule.

[3] Source PwC – http://www.api.org/~/media/Files/Policy/Jobs/Economic_impacts_Ong_2011.pdf

1.5 About Quest Offshore

Quest Offshore Resources, Inc. is a full-service market research and consulting firm focused on the global offshore oil and natural gas industry. As a function of Quest's core business, the company is engaged daily in the collection and analysis of data as it relates to the offshore oil and natural gas industry. Quest serves the global community of operating oil and natural gas companies, their suppliers, financial firms, and many others by providing detailed data and analysis on capital investment and operational spending undertaken by the offshore industry. Quest collects and develops market data from a variety of sources at the project level for projects throughout the world.

Data is tracked in Quest's proprietary Enhanced Development Database as well as additional proprietary databases related other facets of the global supply chain worldwide. Quest aggregates capital and operating expenditures on a project by project basis for projects worldwide, with detailed information recorded on the supply of the equipment and services necessary to develop individual offshore oil and natural gas projects. Quest Offshore tracks not only existing or historical projects, but also projects that are in all stages of development from the prospect (or undrilled target) stage through to producing and decommissioned projects. For projects without firm development information, Quest utilizes benchmarking based on the proprietary databases mentioned above to forecast development timing and scenarios appropriate to the type of development, the developments' characteristics and region.

1.6 About Blade Energy

Blade Energy Partners is an independent consulting company that focuses on resolving the challenges of complex projects in the energy industry. The company provides leading-edge expertise to solve drilling, completion, production, reservoir and pipeline challenges. Blade works with the sole objective of safely and efficiently maximizing returns on reserves and assets. Since its creation over ten years ago, Blade has collaborated on a wide variety of engineering, research, and development projects in several sectors of the oil and gas and geothermal industries. Blade comprises over 70 engineers, scientists, and project managers. Sixty percent of our staff possess advanced degrees and of those, twenty percent hold doctoral degrees in applied science or engineering. Blade engineers are highly experienced, with, on average, 20+ years in the industry, serving major operating and service companies.

Section 2 - Study Methodology

2.1 Data Development

The authors of this report (Blade Energy and Quest Offshore) have undertaken a detailed engineering and economic analysis of the Bureau of Safety and Environmental Enforcement (BSEE), proposed rule on "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control", as published in the Federal Register Vol. 80 Friday, No. 74 on April 17, 2015 with the purpose of providing a summary of the most impactful areas of these regulations. This study in no way is exhaustive, especially in light of the relatively short period available to develop this analysis and the highly technical nature of these regulations.

This analysis focuses on the likely engineering burdens and operational effects of these regulations and attempts to calculate the cost of overcoming these burdens wherever possible. As such, this analysis is essentially forward looking and potentially subject to significant changes based on the content of the final rule as implemented by BSEE, the way in which it is implemented, and a variety of other factors. However, the report's authors believe that this approach is the best available way to consider this rule, as a backwards looking review based on previous industry activity would likely overstate the effects of these regulations.

Similarly, a more narrow view of the regulations which focuses solely on the narrow cost of implementing individual sections of the proposed rule without taking into account the engineering and operational burdens imposed by the regulations is likely to underestimate the projected costs of their implementation. Due to the limited time available to prepare this report, as well as the significant uncertainties about the way proposed rule would be implemented if enacted, the projected costs, engineering requirements and operational burdens for all proposed regulations are not included in this report. Additionally, the internal costs to BSEE of implementing and administrating the proposed rule are not calculated in this report.

2.2 Engineering Review

The engineering review of the proposed rule was undertaken by a number of by various subject matter experts within Blade.. The review focused on the likely engineering and operational effects of these regulations and attempts to calculate the cost of overcoming these burdens wherever possible, while identifying any burdens imposed by the regulation which could not be overcome by additional engineering or operational means. The engineering review attempted to provide the most reasonable outcome and implications of the proposed regulations, while emphasizing the likely effects of the adoption of the regulations as written. Blade provides its independent view expressly disclaiming any warranty, liability, or responsibility for completeness, accuracy, use, or fitness to any person for any reason.

2.3 Limitations of the Report

The report's authors make no representation as to the effects of proposed regulations not addressed specifically in this report and do not discount the possibility that these proposed changes could impose significant engineering, operational or other burdens on industry or regulators. The report's authors' estimates herein of the effects that BSEE's Proposed Rule will have on current and future engineering, operations and advances in technology are an independent good faith qualitative view arising from considerations by various subject matter experts within Quest Offshore (an independent consulting firm focused on offshore oil and gas operations and economics) and Blade Energy, (an engineering consulting company in well design, engineering and operations). Both Quest Offshore and Blade Energy are providing this independent view expressly disclaiming any warranty, liability, or responsibility for completeness, accuracy, use, or fitness to any person for any reason.

2.4 Cost Calculations

The cost calculations associated with the proposed rule were developed by Quest by calculating the projected engineering and operational burdens by reasonable assumptions of the costs associated with them and the length or scale of these burdens. (ex. $923 for an engineering man day based on the Society of Professional Engineers salary survey and projections of additional employment costs). All costs associated with the regulation were calculated on the most economic method for overcoming the burden imposed by the regulations and any burdens which would overlap with other burdens imposed by the regulations were discounted to avoid double counting. All costs presented in this study are in constant 2014 dollars.

2.5 Scenario Development

The report's scenario development focused on constructing a tiered "bottom-up" model that separates the complete life cycle of offshore operations and subsequent effects into three main categories and five sub categories. The three main categories are as follows; an "Activity" model that assesses potential reserve information in the context of estimating the possible number of projects within the Gulf of Mexico OCS and the currently forecasted projects and trends in exploration and project development in the region; a "Spending" model based on the requirements to develop projects within the "Activity Forecast"; and an "Economic" model focused on the economic impact on employment and government revenue from the "Spending" model. These categories include, leasing activity, drilling, infrastructure & project development, and production & operation.

After the creation of the baseline model, the operational, cost, drilling and development impacts of the report's analysis of the proposed rule, "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control", were applied to the base scenario forecast resulting in the creation of the "Proposed Rule Scenario" which attempts to provide a reasonable projection of oil and natural gas exploration and development activity in the Gulf of Mexico OCS if the proposed rule was enacted as it is currently proposed. After the development of this scenario, the scenario's potential implications for oil and natural gas production, employment, GDP, and government revenues were then calculated.

Section 3 - Summary of Potential Costs

The proposed rule “Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control” is expected to have significant direct costs to entities developing oil and natural gas resources in the US OCS such as the Gulf of Mexico. In addition to direct costs, the proposed rule is likely to impose additional costs to the US economy due to slower or reduced OCS development. While the increased costs of the rule are likely to be felt by all participants in Gulf of Mexico OCS oil and natural gas exploration activities, the effects are most likely to disproportionately affect certain operators and contractors.

The authors of this report (Blade Energy and Quest Offshore) have undertaken a detailed engineering and economic analysis of the proposed rule with the purpose of projecting the total cost of the proposed rule if implemented as currently written. This analysis is in no way is exhaustive, especially in light of the relatively short period available to develop this analysis, and the highly technical nature of these regulations. This analysis focuses on the likely engineering and operational effects of these regulations and wherever possible attempts to calculate the cost of overcoming these burdens.

The following table, prepared by Quest Offshore Resources, presents summary of the estimated direct costs of the proposed rule (Table 5).

Table 5: Estimated 10 Year Costs by Rule by Subsection – 2017 to 2026 ($Millions)

30 CFR Proposed Regulation Reference	Subsection	10 Year Cumulative Cost (2017 to 2026) Base Development Scenario	Average Annual Cost Base Development Scenario	Line
§ 250.107 (a)	Compliance and Documentation	$65.2	$6.5	1
§ 250.107 (e)	Compliance and Documentation	$61.7	$6.2	2
§ 250.1703 (b)	Well Design	Contributes to Packers and bridge plugs inventory loss	See line 86	3
§ 250.1703 (f)	Well Design	Not currently calculated[4]		4
§ 250.413 (g)	Well Design	$6.9	$0.69	5
§ 250.414 (c)	Well Design	$10,689	$1,069	6
§ 250.414 (j)	Well Design	$6.9	$0.69	7
§ 250.414 (k)	Well Design	$1,126	$113	8
§ 250.415 (a)	Well Design	$26	$2.6	9
§ 250.418 (g)	Well Design	$3.5	$0.346	10
§ 250.420 (a)(6)	Well Design	$1,126	$113	11
§ 250.420 (b)(4)	Well Design	$1.7	$0.173	12
§ 250.420 (c)(2)	Well Design	$983	$98	13
§ 250.421 (b)	Well Design	$441	$44	14
§ 250.427 (b)	Well Design	Large dead weight loss of wells / projects from forecast	See line 6	15
§ 250.428 (b)	Well Design	$195	$19.5	16
§ 250.428 (c)	Well Design	Not currently calculated		17
§ 250.428 (k)	Well Design	$1.7	$0.173	18
§ 250.462	Containment	$1,240	$124	19
§ 250.462 (b)	Containment	Contributes to containment	See line 19	20
§ 250.462 (c)	Containment	$1.1	$0.11	21
§ 250.462 (d)	Well Design	$195	$19.5	22
§ 250.462 (e)	Containment	Contributes to containment	See line 19	23
§ 250.518 (New e)	Tubing and wellhead equipment	Contributes to Packers and bridge plugs inventory loss	See line 86	24
§ 250.518 (e)(2)	Tubing and wellhead equipment	$1.1	$0.113	25
§ 250.518 (e)(4)	Tubing and wellhead equipment	$1.7	$0.173	26
§ 250.518 (New f)	Tubing and wellhead equipment	$1.7	$0.173	27
§ 250.619 (f)	Tubing and wellhead equipment	$1.7	$0.173	28
§ 250.710	Rig Requirements	$2,288	$229	29
§ 250.712	Rig Requirements	Not currently calculated		30
§ 250.712 (a)	Rig Requirements	Not currently calculated		31
§ 250.712 (e)	Rig Requirements	Not currently calculated		32
§ 250.712 (f)	Rig Requirements	Not currently calculated		33
§ 250.720	Well Design	Not currently calculated		34
§ 250.721 (a)	Well Design	Not currently calculated		35
§ 250.721 (e)	Well Design	$327	$33	36
§ 250.721 (f)	Well Design	$12.2	$1.2	37
§ 250.721 (g)	Well Design	$478	$48	38
§ 250.722	Well Design	$0.346	$0.03	39
§ 250.723	Well Design	Not currently calculated		40
§ 250.724	RTM	$670	$67	41
§ 250.730	BOP	Contributes to BOP replacement	See line 85	42
§ 250.730 (a)(3)	BOP	Not currently calculated		43
§ 250.730 (a)(4)	BOP	Not currently calculated		44

[4] Sections of the proposed rule marked as not currently calculated denote sections with some expected cost and/or operational burden that was unable to be calculated due to the time limitations associated with this study.

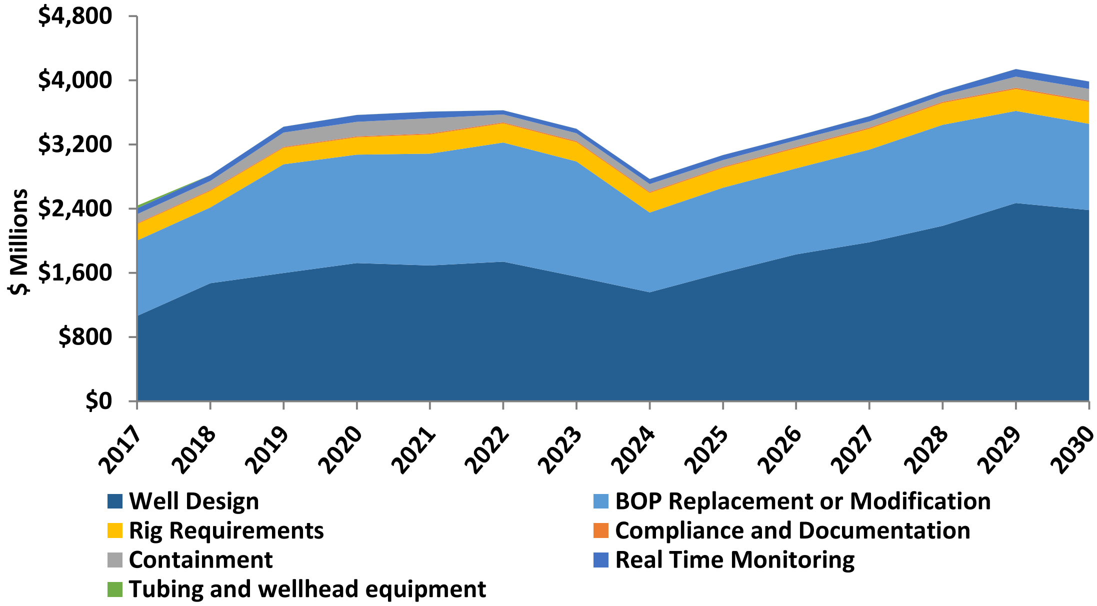
30 CFR Proposed Regulation Reference	Subsection	10 Year Cumulative Cost (2017 to 2026) Base Development Scenario	Average Annual Cost Base Development Scenario	Line
§ 250.730 (d)	BOP	Contributes to BOP replacement	See line 85	45
§ 250.731 (a & b)	BOP	$3.3	$0.33	46
§ 250.731 (c)	BOP	BSEE Approved Verification Organization[5]	See Footnote	47
§ 250.731 (d)	BOP	BSEE Approved Verification Organization	See Footnote 5	48
§ 250.731 (e)	BOP	$3.3	$0.331	49
§ 250.731 (f)	BOP	BSEE Approved Verification Organization	See Footnote 5	50
§ 250.732	BOP	$231	$23	51
§ 250.732 (a)	BOP	BSEE Approved Verification Organization	See Footnote 5	52
§ 250.732 (b)	BOP	$45	$4.5	53
§ 250.732 (c)	BOP	BSEE Approved Verification Organization	See Footnote 5	54
§ 250.732 (d)	BOP	$1.3	$0.13	55
§ 250.732 (e)	BOP	BSEE Approved Verification Organization	See Footnote 5	56
§ 250.733	BOP	BSEE Approved Verification Organization	See Footnote 5	57
§ 250.733 (b)	BOP	Not currently calculated		58
§ 250.733 (e)	BOP	$5.5	$0.6	59
§ 250.733 (f)	BOP	Not currently calculated		60
§ 250.734	BOP	Contributes to BOP replacement	See line 85	61
§ 250.734 (a)(1)	BOP	Contributes to BOP replacement	See line 85	62
§ 250.734 (a)(3)	BOP	Contributes to BOP replacement	See line 85	63
§ 250.734 (a)(4)	BOP	Contributes to BOP replacement	See line 85	64
§ 250.734 (a)(5)	BOP	Not currently calculated	See line 85	65
§ 250.734 (a)(6)	BOP	Contributes to BOP replacement	See line 85	66
§ 250.734 (a)(15)	BOP	Contributes to BOP replacement	See line 85	67
§ 250.734 (a)(16)	BOP	Contributes to BOP replacement	See line 85	68
§ 250.734 (b)	BOP	$48	$4.8	69
§ 250.734 (c)	BOP	$3.3	$0.33	70
§ 250.735 (a)	BOP	$48	$4.8	71
§ 250.737 (d)	BOP	$237	$23.7	72
§ 250.737 (d)(5)	BOP	Cost is included in Parent Rule	See line 72	73
§ 250.737 (d)(12)	BOP	Cost is included in Parent Rule	See line 72	74
§ 250.737 (d)(13)	BOP	Not currently calculated		75
§ 250.738 (b)	BOP	Not currently calculated		76
§ 250.738 (j)	BOP	Not currently calculated		77
§ 250.738 (o)	BOP	$48	$4.8	78
§ 250.738 (p)	BOP	Not currently calculated		79
§ 250.739 (b)	BOP	$8,968	$897	80
§ 250.743 (c)	Well Design	$0.433	$0.043	81
§ 250.746 (e)	BOP	$123.8	$12.4	82
Safe Drilling Practices	RTM	Real Time Monitoring	See line 41	83
Shearing Requirements	BOP	Contributes to BOP replacement	See line 85	84
BOP Replacement (Result of Multiple Regulations)	BOP	$2,080	$208	85
Packer and Bridge Plug Inventory Loss (Result of Multiple Regulations)	Tubing and wellhead equipment	$32.1	$3.2	86
BSEE Approved Verification Organization	BAVO	BSEE Approved Verification Organization	See Footnote 5	87
Total		**$31,830.5**	**$3,183.1**	88

[5] BSEE Approved Verification Organizations (BAVO) are not defined by the regulations and do not currently exist as proposed by the rule. As such it is not possible to calculate the cost that the involvement of these organizations will entail or other possible effect.

Estimated costs are identified by rule section, subsection, or, when necessary, individual line item where multiple regulations cumulatively contributed to an effect. For more specific explanations and analysis of the regulations cited in this table please see section 8, BSEE Rules and Regulations Appendix. The cost of regulations is calculated based on Quest's "Base Development Scenario" for the Gulf of Mexico and is the projected activity levels for various offshore oil and natural gas related activities based on current regulations without the proposed rule. Actual direct costs are likely to be lower due to wells not drilled due to the rule. This is discussed in section 5, Impact on Development.

The average annual costs to industry participants of the proposed rule are projected at around $3.2 billion per year from 2017 to 2026. Cumulative 10-year costs are estimated at over $32 billion. (Figure 2)

Figure 2: **Estimated Annual Cost Rule by Category – 2017 to 2030 ($Millions)**



Source: Quest Offshore Resources, Inc.

Costs are projected to rise rapidly in the early years of adoption due to implementation costs and the required replacement of equipment through years 5-7, before falling beginning in 2022 as implementations costs and the replacement of equipment slows. Costs begin to rise again in 2025 as those costs that are closely tied to activity levels (especially well costs) increase with activity levels. Additionally, certain areas of operations are expected to carry higher costs than others. For example, costs associated with well design regulations are projected at over $1.6 billion per year from 2017 to 2026 a total of over $15.6 billion over the same period, while costs associated with changes to BOP regulations are projected at just over $1.2 billion a year from 2017 to 2026 for a total of $12 billion over the same period. (Table 6)

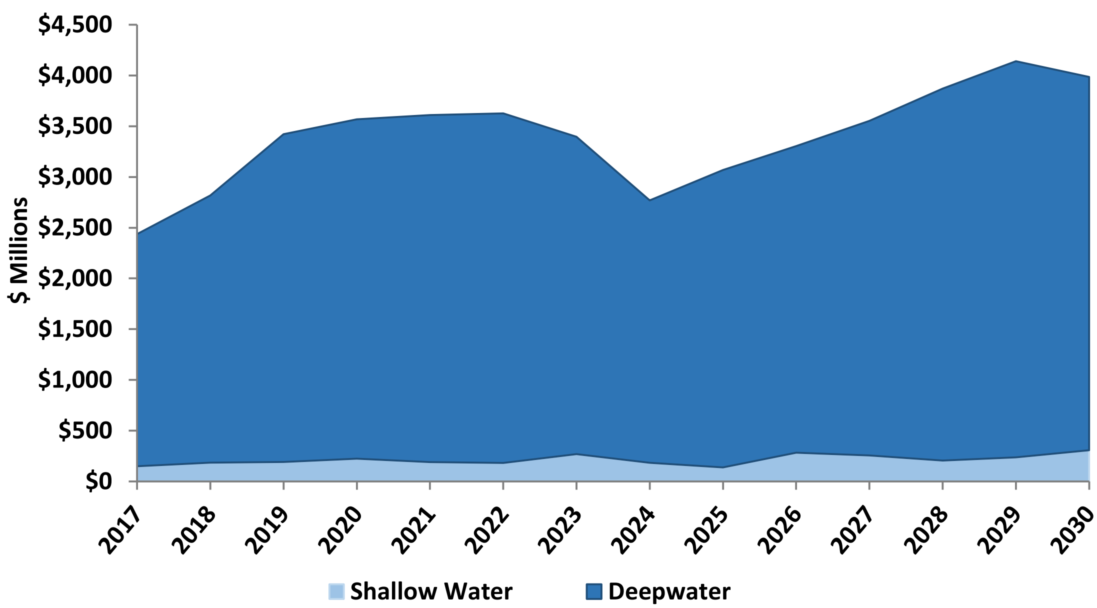
Table 6: Ten Year Direct Cost Estimates – Base Development Case ($Millions)

Category	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
BOP Replacement or Modification	$925	$926	$1,336	$1,331	$1,373	$1,465	$1,419	$978	$1,041	$1,052	$11,846
Compliance and Documentation	$11	$12	$11	$12	$13	$13	$14	$13	$12	$15	$127
Containment	$113	$114	$179	$181	$190	$99	$97	$98	$85	$86	$1,241
Rig Requirements	$204	$205	$205	$215	$239	$239	$240	$244	$247	$250	$2,288
Real Time Monitoring (RTM)	$74	$72	$73	$85	$83	$52	$56	$63	$63	$50	$670
Tubing and Wellhead Equipment	$33	$1	$1	$1	$1	$1	$1	$1	$1	$1	$38
Well Design	$1,062	$1,470	$1,597	$1,721	$1,691	$1,739	$1,551	$1,357	$1,601	$1,830	$15,620
Grand Total	$2,421	$2,800	$3,402	$3,547	$3,589	$3,606	$3,378	$2,753	$3,050	$3,284	$31,831

Source: Quest Offshore Resources, Inc.

Although the proposed rule is expected to increase costs for wells and projects in all water depths in the Gulf of Mexico, the effect is expected to be felt disproportionately in deep and ultra-deep water depths, areas which carry a disproportionally higher operating cost and are projected to account for the majority of activity in the region. (Figure 3) Under the base development scenario, average annual costs for deepwater activity are projected to increase by over $3 billion a year from 2017 to 2026, with total cumulative costs of $30 billion from 2017 to 2026. Increased costs for shallow water activity are projected to be around $200 million dollars annually, with cumulative costs from 2017 to 2026 projected at nearly $2 billion.

Figure 3: Estimated Annual Costs Deepwater vs. Shallow Water – Base Development Scenario ($Millions)



Source: Quest Offshore Resources, Inc.

Increased costs, coupled with wells and projects not able to be developed, are expected to have a significant effect on Gulf of Mexico OCS activity levels in the forecasted period, with effects from this reduced activity level felt in employment, GDP, and other indicators. These effects are described in the following sections of the study, section 5, Impact on Development and section 6, Macro-Economic Impact Conclusions.

3.1 Ten Year Cost Comparison – Study Estimates vs. BSEE

Although the cost impacts associated with the proposed rule "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" developed by this study were developed independently and without reference to additional studies analyzing the proposed regulatory changes and effects, the following table provides a ten year cost comparison to BSEE's own cost impact study for reference. It is important to note that due to the time limitations associated with this study, both additional costs and possible cost savings calculated by BSEE, are not included in this study. Additionally, as this study projects that costs associated with this study will begin to be required in 2017, the reference year (year 1) for this cost comparison is 2017 for this study compared to 2015 for the BSEE analysis. It is also important to note that both the BSEE cost analysis and that provided by this study take into account the varied implementation timelines of the proposed regulations and both studies do not address the costs associated with the proposed rule. (Table 7)

Table 7: BSEE Ten Year Cost Comparison Table ($Millions)

Year	BSEE Estimates	Study Estimates
Year 1	$165	$2,421
Year 2	$77	$2,800
Year 3	$77	$3,402
Year 4	$77	$3,547
Year 5	$77	$3,589
Year 6	$99	$3,606
Year 7	$77	$3,378
Year 8	$77	$2,753
Year 9	$77	$3,050
Year 10	$77	$3,284

Source: Quest Offshore Resources, Inc.

The overall industry-incurred cost due to the proposed rule change within the first ten years of implementation of the studies displays significant divergence, under which Quest has predicted an average of around $3.2 billion per year while BSEE foresees $120 million per year. Furthermore, Quest also projects additional industry effects throughout the supply chain due to the inability to develop numerous projects, which are then removed from the forecast.

Allocation of Costs

This study does not attempt to allocate the projected costs associated with the adoption of the proposed rule to specific industry participants due to the difficulty of that process. Each of the individual rules' effects are likely to be felt by numerous groups of industry participants and the specific allocation of these costs is unlikely to be accurately predicted. However, the vast majority of the costs associated with the proposed rule are expected to affect certain groups disproportionately. As an example, the costs associated with rules affecting subsea blow out preventers are expected to be borne primarily by drilling contractors operating floating drilling rigs and the limited number of original equipment manufacturer who manufacture these pieces of equipment. In comparison, the costs associated with rules which are focused on well construction are expected to be borne mostly by oil and natural gas operators with the majority of the cost borne by the limited operators active in deep and ultra-deep waters. Implementation of the proposed rule as currently written would likely also lead to a change in the operators and contractors active in the Gulf of Mexico OCS, as smaller companies may reduce participation in the area due to the increased costs. Therefore while this study does not specifically allocate costs to specific industry participants it is important to emphasize that the costs of the regulations will be primarily borne by those industry participants engaged in the types of activity most affected by the proposed rule.

Containment Costs Already Borne by Industry

The increased costs resulting from the adoption of the proposed rule, calculated above, exclude many costs already borne by the industry which would not be required prior to the implementation of the proposed rule. The largest single investment by oil and natural gas operators and contractors has been on containment equipment including subsea capping stacks, storage equipment, and vessels to deploy this equipment and process contained fluids. Neither this investment, nor the impacts of that spending are included in the costs above nor are the employment or GDP impacts, as they were not required prior to the proposed rule. However, the study includes an estimate of this spending for reference. The industry has invested in two separate containment systems, organized as the Marine Well Containment Company (MWCC) and the Helix Well Containment Group (HWCG). Both of these systems have required significant upfront investment as well as ongoing spending. MWCC and its member companies have spent an nearly $1.5 billion since its founding, with investment in two tankers designed to process oil and gas, multiple capping stacks and a variety of other equipment. HWCG, which has utilized some existing equipment such as the Helix Q4000 and the Helix Producer 1 has, with its member companies, invested approximately $780 million into well containment preparation since its founding. Beyond equipment, the costs associated with these containment organizations range from shorebases, to preposition equipment, to training for the utilization of the equipment and continued maintenance.

Effect on Other U.S. OCS Areas

Although the costs and other impacts associated with the proposed rule are calculated solely as it effects Gulf of Mexico OCS activity, the rule will affect all U.S. Federal OCS areas including Alaska, existing production on the Pacific coast and any future activity in areas where oil and natural gas exploration activity is not currently taking place. These areas include the Atlantic coast (where there is a currently proposed lease sale expected to take place in 2021 in limited areas of the central and southern Atlantic coast), the Eastern Gulf of Mexico, and areas of the Pacific coast which are currently closed to new oil and natural gas activity. Although many of the costs associated with the proposed rule would be similar to those stemming from the rule in the Gulf of Mexico, other costs would likely be higher, especially on a per-well or per-project basis. The section of regulation most likely to see higher costs in new areas (such as the Atlantic coast) is projected to be containment, as the prepositioning of materials, capping stacks and vessels for operations in the Atlantic would likely be spread over far fewer wells and projects, especially initially.

Cost Effects of Proposed Regulations

The detailed technical and economic analysis of the projected costs of the proposed rule "developed in this study indicate that the effects of the adoption of this proposed rule would likely impose a significant burden on participants in the Gulf of Mexico OCS oil and gas industry. In addition, these costs and requirements are likely to reduce overall OCS oil and natural gas development relative to what is projected to occur with current regulations. The lost activity is due to increased costs which may make some wells or projects uneconomic, delays reducing the number of wells drilled per year, and the inability to drill certain wells or develop certain projects and meet new technical requirements of the rule. The projected impact of the proposed rule on Gulf of Mexico oil and natural gas development and the subsequent impacts on spending by the industry, oil and natural gas production, employment, GDP and government revenues are discussed in the next section.

Section 4 - Impact on Development

Natural gas and crude oil exploration and production activities offshore of the US provide large contributions to employment, gross domestic product and state and federal government revenues. To quantify the effects of the proposed rule, the study forecasted activity levels for Gulf of Mexico OCS oil and gas activity with and without the proposed rule. The forecasted activity levels include the number of wells drilled, projects executed, total production, and spending. These activity forecast drive the spending projections from which GDP, employment and government revenue effects are estimated.

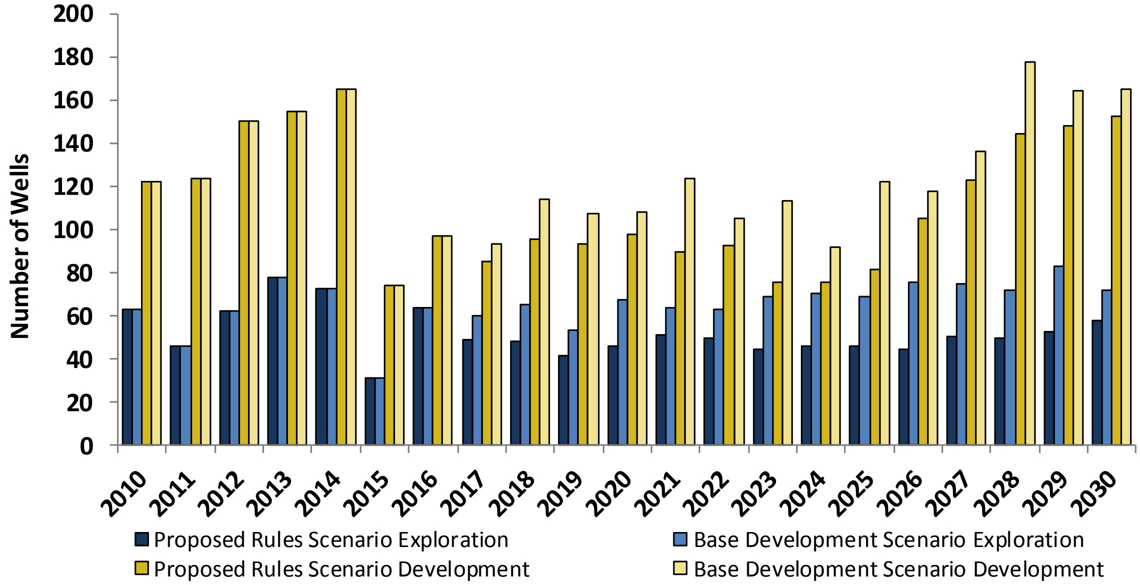
4.1 Wells Drilled

Exploration appraisal and development drilling is used to identify, confirm, delineate, and produce oil and natural gas, making it one of the most important offshore oil and natural gas activities. Drilling is a very capital intensive process employing drilling rigs that require large crews as well as significant quantities of consumables ranging from food and fuel to drill pipe and fluids. Drilling rigs (mobile offshore drilling units – MODU's) and platform rigs must constantly be resupplied and crewed, and thus lead to high levels of activity in the areas and ports that support offshore drilling activity.

Drilling activity in the US Gulf of Mexico is projected to continue to be robust throughout the forecast period as exploration of new geologic areas continues and development of the known production areas progresses. The region is projected to see around 960 exploration wells drilled and around 1740 development wells drilled between 2017 and 2030 under the current regulatory environment, and around 670 exploration wells and around 1335 development wells under the proposed rule scenario. This represents a 26 percent decrease in drilling activity over the study period.

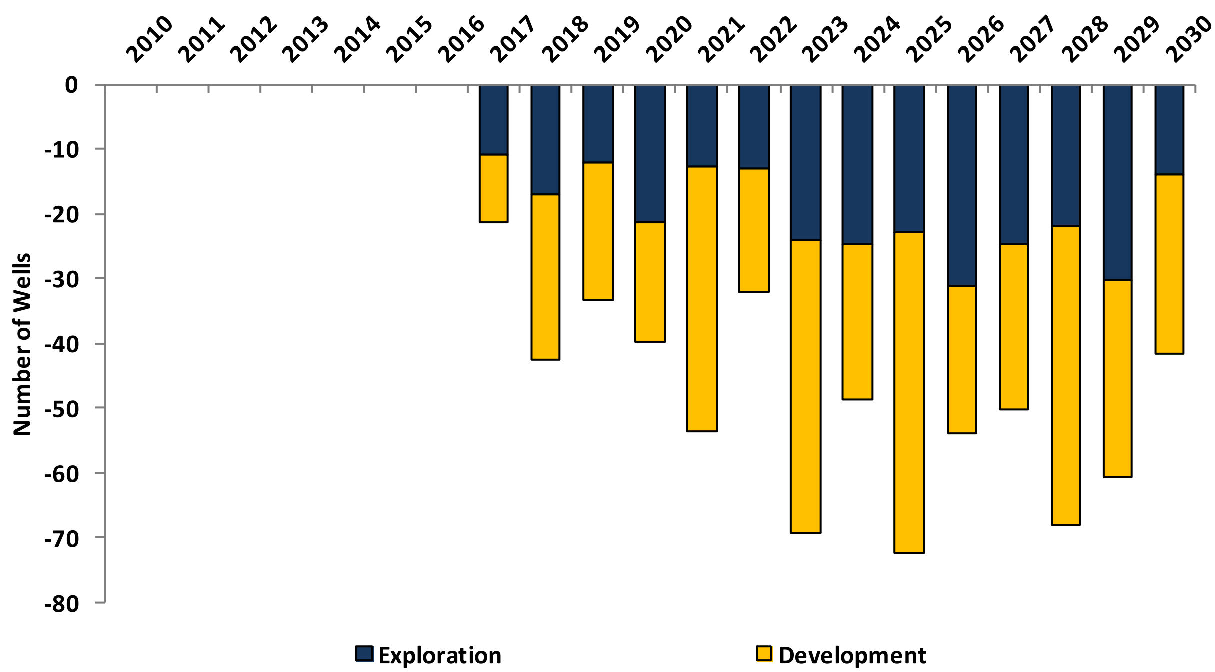
The decrease in drilling under the new regulations, as mentioned in the regulation section, is primarily due to the effects of §250.414, "Planned safe drilling margins" as well as higher costs associated with the regulations. Since many of the wells that are projected to be drilled in the Gulf are in particularly deep water, and located in high pressure, high temperature reservoirs, or are being drilled in depleted reservoirs, some of these wells are expected to be no longer technically possible to drill or complete under the new regulations, and others, particularly development wells, may become economically non-viable. The effects of the regulations, as written, are projected to have a significant influence on overall drilling levels (Figure 4). The proposed rule scenario results in an average of around 20 less exploration wells drilled per year and around 29 less development wells per year. (Figure 5)

Figure 4: Number of Wells Drilled by Well Type and Scenario - Exploration and Development



Source: Quest Offshore Resources, Inc.

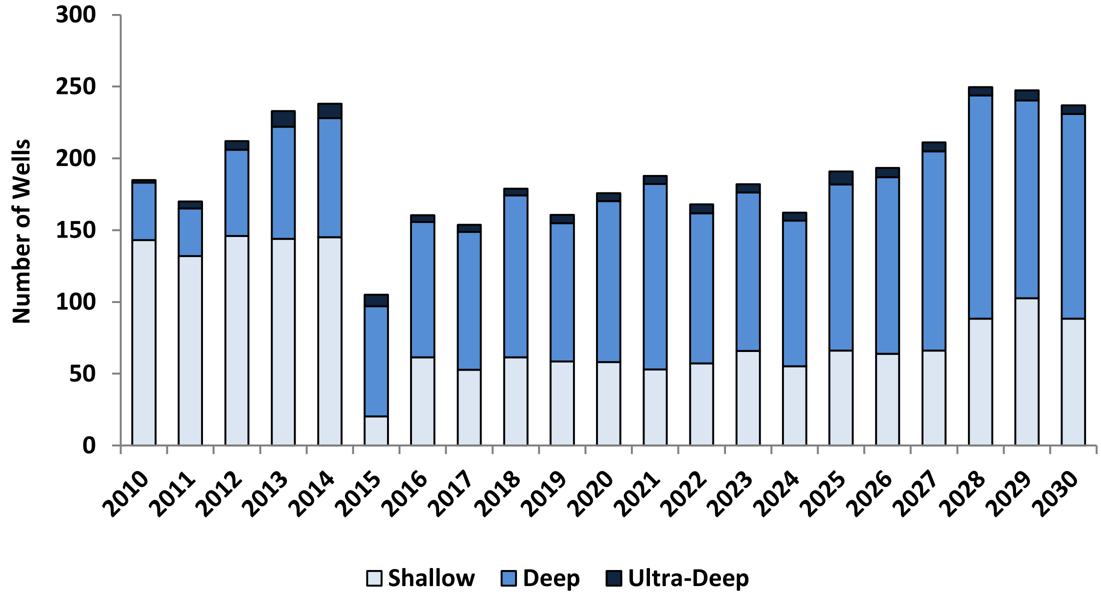
Figure 5: Difference between Number of Wells Drilled in Base Development and Proposed Rule Scenarios



Source: Quest Offshore Resources, Inc.

Drilling activity as a whole has shifted from primarily shallow water areas into progressively deeper and higher pressure areas, as the reservoirs in shallower areas mature and new fields are discovered. (Figure 6)

Figure 6: Number of Wells Drilled by Water Depth and Year – Base Development Scenario



Source: Quest Offshore Resources, Inc.

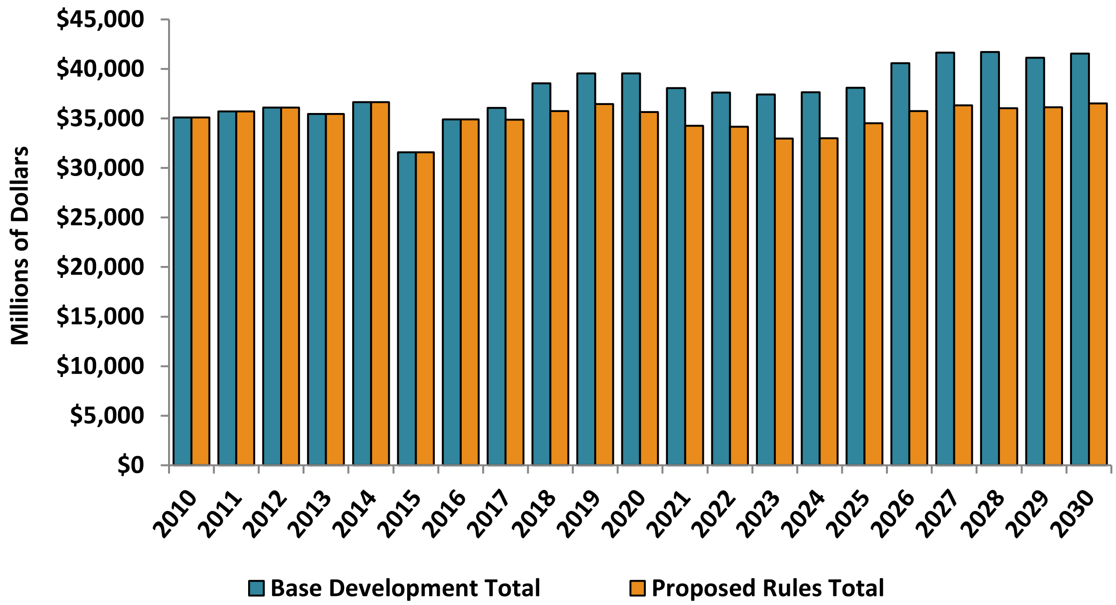
Under the base development scenario, a total of around 2,700 wells are projected to be drilled from 2017 to 2030, with three percent of wells projected to be located in ultra-deep water, 62 percent of the wells projected in deep water and 35 percent projected in shallow water. Under the new regulations, approximately around 690 fewer wells are projected to be drilled from 2017 to 2030, a 26 percent decline, with similar water depth distributions. Over the 10-year 2017 to 2026 period the projected number of wells projected not to be drilled equals around 470, with an average of 20 fewer exploration wells per year and 29 fewer development wells.

4.2 Projects Executed

Developing an offshore project is a complex process that requires a significant amount of time, planning and high levels of capital investment. Project executions and their respective timelines are the best indicator of overall market health, as they can be viewed as representative of total trends in production, employment and revenue for the broad market.

Over the forecasted period of this study (2017-2030), 15 standalone floating production projects and 49 fixed platform-based oil and natural gas projects are projected to begin production under the base development scenario. These projects and other additions to the existing projects in the Gulf collectively represent $549 billion in capital and operational spending over the course of the forecast period. As a result of the burdens placed on project and drilling economics by the proposed rule scenario, the total number of floating production units developed is projected to decrease by 20% and fixed platforms are projected to decrease by nearly 33% under the new regulations. Collectively, this reduction in activity is projected to lead to a decrease in total spending of nearly 30 percent, which would be worth around $52 billion. (Figure 7)

Figure 7: Total Yearly Project Spending by Scenario



Source: Quest Offshore Resources, Inc.

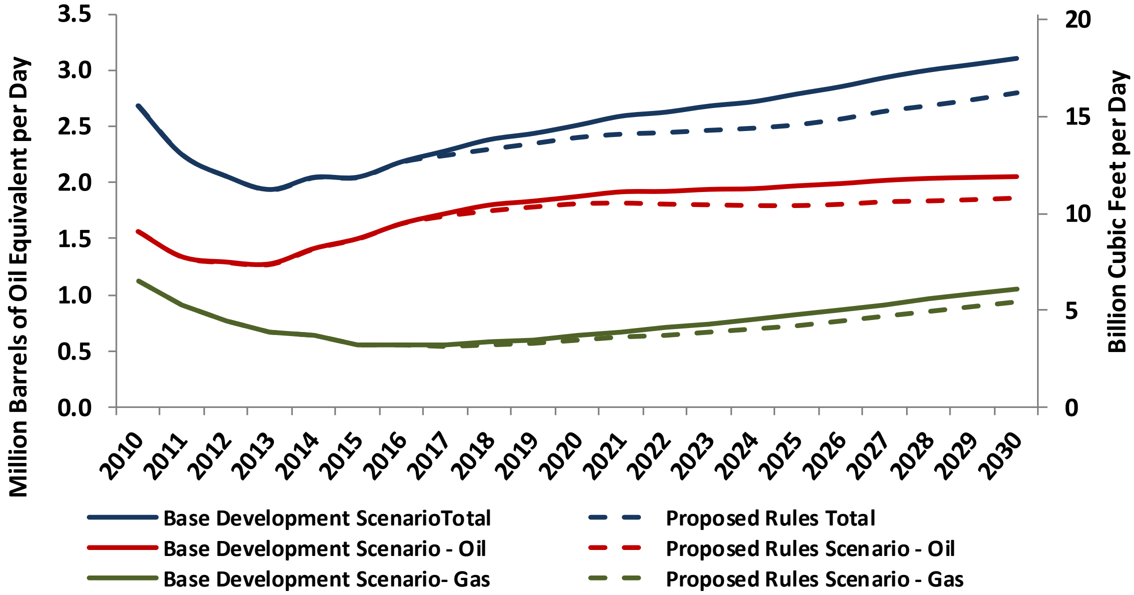
Total project spending is primarily driven by overall activity levels, and partially driven by the project design and size of the projects executed. Apart from water depth, project size is typically defined by reservoir characteristics, hydrocarbon volumes and expected production, which define the timeline and capital investment required to develop the project. Larger projects typically require more wells and a longer development period, in addition to requiring increased material resources and larger equipment such as platforms, production trees and pipelines. Smaller projects, on the other hand, often rely on larger projects for certain types of infrastructure such as pipelines or processing facilities. This leads to the spending, production and other effects on a per project basis to be highly variable.

4.3 Production

The number of projects developed, coupled with reservoir size and reservoir productivity, is the main determinant of oil and natural gas production levels. Most oil and natural gas reservoirs contain a combination of oil, natural gas, water, and other native substances such as sand, sulphur, CO2, and salt, though some reservoirs may contain nearly all oil or all natural gas. In order to forecast aggregate production, each project was modeled based on production curves for similar developments, taking into account the start-up, ramp-up, peak, and decline timing, as well as the expected hydrocarbon mix.

This study projects that production in the Gulf of Mexico will be around 2.28 million barrels of oil equivalent (BOE) per day in 2017 and is projected to grow relatively consistently throughout the period, at a compound annual growth rate of roughly 2.5 percent per year from 2017 to 2030. Production is projected to reach 3.10 million BOE per day by 2030, with approximately 66 percent of production oil (2.05 million BOE per day), and 34 percent of the production natural gas (1.05 million BOE per day). Under the proposed rule, Gulf of Mexico production is forecasted to be reduced by nearly 15% and 0.48 million BOEPD by 2030, with approximately 67 percent of production being oil (1.74 million BOE per day), and 33 percent of the production being natural gas (739 thousand BOE) under the proposed regulations. (Figure 8)

Figure 8: **Production by Type by Scenario – MMBOED 2010 to 2030**



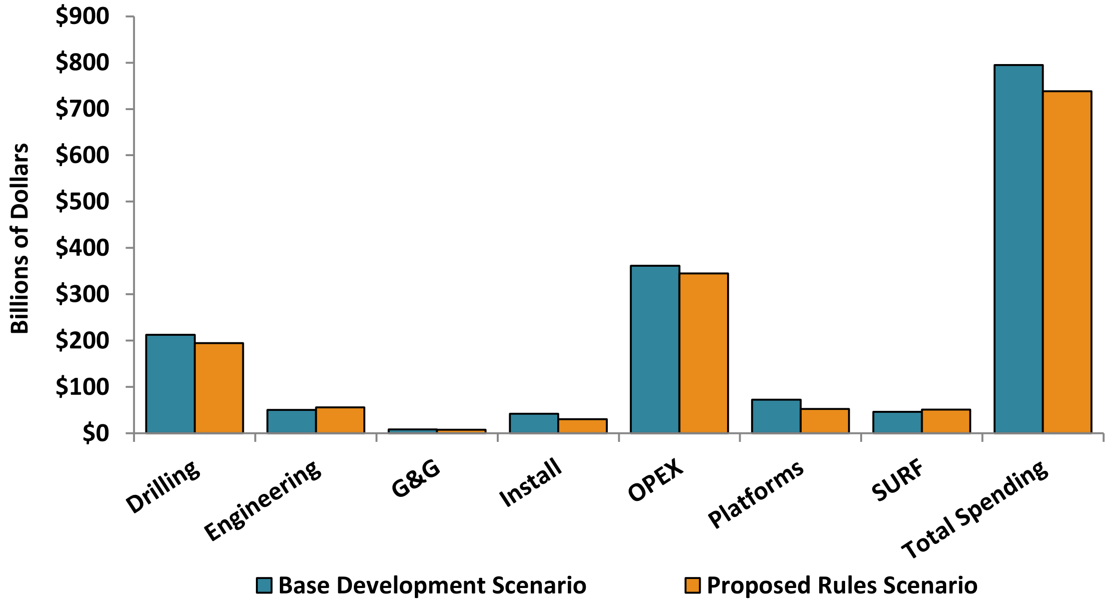
Source: Quest Offshore Resources, Inc.

4.4 Total Spending

Offshore oil and natural gas exploration and development is a capital intensive process. Offshore projects require exploratory seismic surveys, drilling, production equipment, engineering, operational expenditures including the ongoing supply of consumables, and maintenance as well as other spending to be found and developed. The total cumulative spending from offshore oil and natural gas development is projected to be nearly $550 billion between 2017 and 2030 under the base case scenario and $493 billion under the proposed rule, a yearly average of $39.2 and $35.2 billion respectively, which equals an average decline of $4 billion per year. This represents a 10.3 percent decrease in total spending as a result of the proposed rule changes.

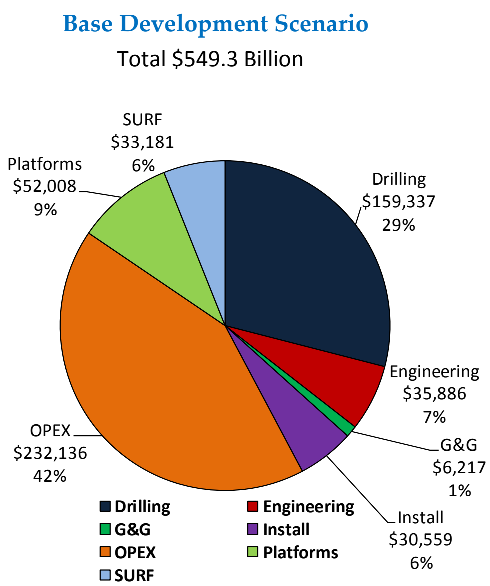
For the purposes of this report, spending is divided into seven main categories: Drilling, Engineering, G&G, Installation, OPEX, Platforms, and Subsea Umbilicals, Risers and Flowlines (SURF). Each category encompasses a major type of exploration and production activity and has a significant influence on overall spending. Both development scenarios estimate total spending amounts that rise slightly through the end of the decade, decline briefly, then recover due to normal project development cycles. Under the proposed rule case, very little spending growth is projected during the forecast period. (Figures 9 & 10)

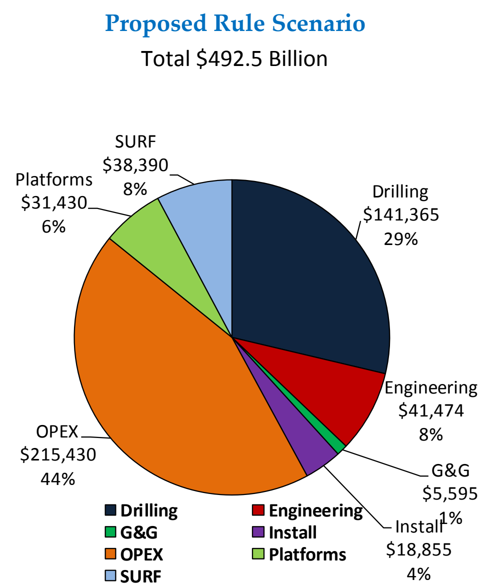
Figure 9: Cumulative Spending by Category and Scenario – 2017 to 2030



Source: Quest Offshore Resources, Inc.

Figure 10: Share of Total Spending by Category and Case – 2017 to 2030 ($Billions)



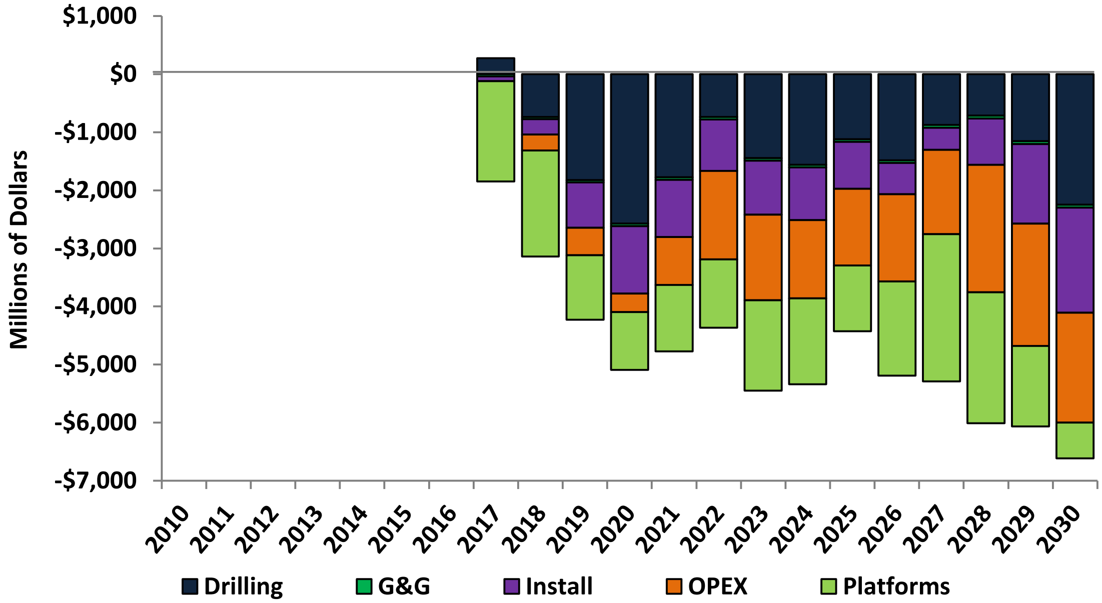


Source: Quest Offshore Resources, Inc.

The proposed rule is anticipated to increase some types of spending for Gulf of Mexico oil and natural gas development. However, increased spending due to compliance with the proposed rule is anticipated to be more than offset by reduced spending in areas that are impacted from fewer wells drilled and projects developed. Therefore, as a result of the proposed rule overall spending for Gulf of Mexico oil and natural gas activity is projected to decline.

The platform CAPEX, drilling, OPEX, installation, and G&G markets are all projected to see decreased spending under the proposed rule scenario, with average yearly spending decreases of $1.47 billion, $1.28 billion, $1.19 billion, $836 million and $44 million respectively (Figure 11)

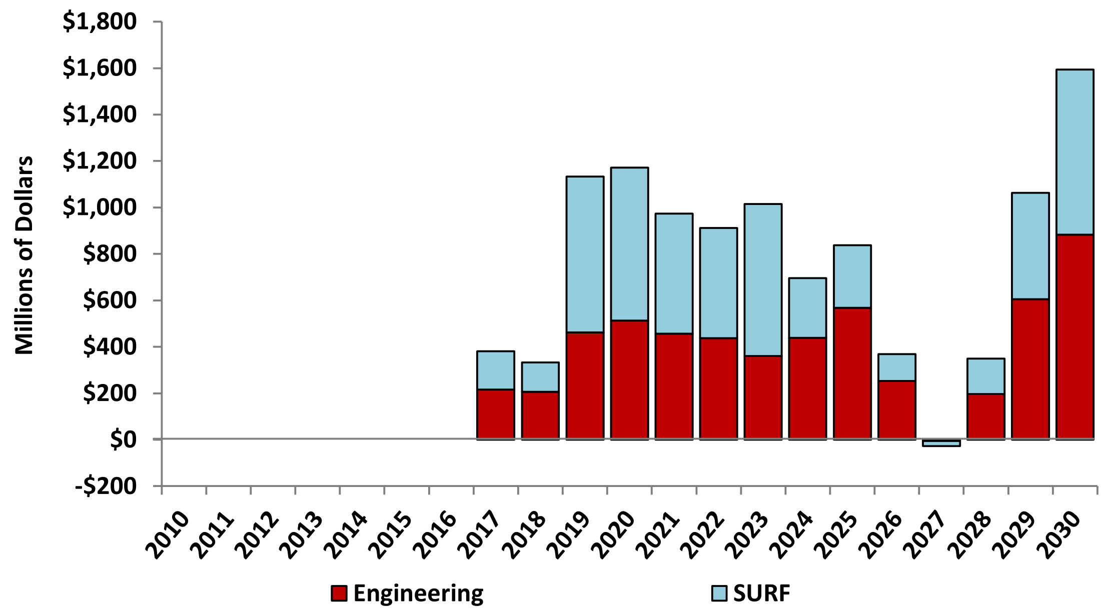
Figure 11: Projected Spending Decreases under Proposed Rule Scenario Spending by Category



Source: Quest Offshore Resources, Inc.

The platform Engineering and SURF markets are both projected to see increased spending under the proposed rule scenario, with average yearly spending increases of $399 million and $372 million respectively. A more detailed look at these market segments may be found below (Figure 12 & Table 8).

Figure 12: Projected Spending Increases under the Proposed Rule Scenario Spending by Category



Source: Quest Offshore Resources, Inc.

Table 8: Base Development and Proposed Rules Scenario Spending Comparison 2017 to 2030 ($Millions)

Category	Annual Base Development Scenario ($ Millions)	Annual Proposed Rules Scenario ($ Millions)	Annual Net change in Spending ($ Millions)	% Change in Spending
Drilling	$11,381	$10,097	-$1,284	-11%
Engineering	$2,563	$2,962	$399	16%
G&G	$444	$400	-$44	-10%
Installation	$2,183	$1,347	-$836	-38%
OPEX	$16,581	$15,388	-$1,193	-7%
Platforms	$3,715	$2,245	-$1,470	-40%
SURF	$2,370	$2,742	$372	16%
Total	**$39,237**	**$35,181**	**-$4,056**	**-10%**

Source: Quest Offshore Resources, Inc.

G&G

Seismic (G&G) spending is normally associated with imaging of possible reservoirs prior to exploration drilling and thus takes place primarily at the early stages of a project's lifecycle. Although critically important to long-term development, seismic spending is a relatively low percent of overall spending at an average of $444 million per year, or roughly one percent of overall spending from 2017 to 2030 in our base development case, and $399.6 million and around one percent per year in our proposed rule case.

Drilling

Given the expense and logistics requirements of offshore drilling, where rigs command significant day rates and operational costs, drilling expenditures represent one of the largest sources of spending for any offshore project. Total drilling costs from 2017 to 2030 for exploration and development drilling combined are projected to average nearly $11.4 billion per year in the base development scenario and $10.1 billion in the proposed rule scenario, indicating a $1.3 billion decrease in activity due to a drop in well demand partially offset as a result of the increased costs of the proposed rule. Drilling accounts for 29 and 26 percent of each case's total spending respectively.

Engineering

Engineering spending takes place at all stages of an offshore project's lifecycle, including exploration, project development and the operational phase. These activities vary from overall project-focused engineering to the engineering of very specific equipment and components. Engineering spending is projected to average $2.5 billion per year from 2017 to 2030 in the base development scenario. In the proposed rule scenario due to the engineering burdens necessitated by the regulation, engineering spending is projected to average $3.0 billion per year. These spending categories account for around seven and eight percent of total spending in their respective cases.

Platforms & SURF

The majority of equipment utilized in developing offshore oil and natural gas fields can be found on either the platform (both fixed and floating) or subsea, as a part of the SURF (subsea equipment, umbilicals, risers and flowlines) category. This equipment is purchased and constructed prior to production of oil and natural gas, though more can be added to a project after first production. The types of equipment include complicated structures like floating platforms that weigh tens of thousands of tons, complex subsea trees that control wells at the ocean floor and miles of pipeline that transport the produced oil and gas back to shore. In addition to these large, expensive pieces of equipment, some of the components required for offshore production are less complex (e.g. offshore accommodation modules, metal mats placed on the seafloor to hold other equipment, or stairwells).

Due to the varying timelines for procurement of equipment, spending for platforms and SURF equipment is more variable year to year than most other offshore exploration and development spending. Platform spending is projected to average over $3.7 billion per year from 2017 to 2030 in the base development scenario and $2.2 billion per year under the new regulations, due to decreased project activity. SURF spending is projected to rise under the new regulations due to increased per-well spending on the associated systems. Due to these effects, in the base case forecast $2.4 billion are projected to be spent each year from 2017 to 2030, and in the proposed regulation case an average of $2.7 billion of spending are projected to be attributable to SURF hardware and associated activity. These costs represent 6.0 and 7.0 percent of total spending in their cases respectively.

Installation Activity

The Installation of platforms and SURF equipment is normally carried out by multiple vessels, each with specialized functions such as pipe-lay or heavy-lift. Some vessels might lay large diameter pipelines (14 inch+), while other vessels lay smaller diameter infield lines (2-10 inches) or lift equipment, and install hardware. Other specialized vessels supply drill-pipe, fuel and other fluids, and food. Nearly everything installed offshore must first be prepared onshore at specialized bases in the region prior to installation. Equipment is sometimes transported to the field on the installation vessels themselves, and at other times is brought to the field on specialized barges or transportation vessels. Installing offshore equipment often requires complex connection or integration operations and uses vessels that can command day rates of over $1 million.

Due to lower project development activity in the proposed rule scenario, a significant decrease in installation activity is expected between the two cases for this subsection of the market. Between the 2017 and 2030 period, average annual installation spending is projected to be $2.2 billion per year under the current regulatory environment and over $1.3 billion under the proposed regulations, representing around six percent and just over three percent of total spending in each of the cases.

OPEX

Once the initial wells have been drilled and the necessary equipment installed, a field enters the operational phase, which requires manning and operating facilities and equipment, continuously supplying essential fluids and constant general maintenance. Due to the maturity of the market and the large amount of existing infrastructure, these operational expenditures (OPEX) are a significant source of ongoing spending by oil and gas companies within the region. However, much of the aging infrastructure in the Gulf is being removed, allowing expenditures on many assets to be rolled back or even stopped. In the base development scenario, operational expenditures are projected to decrease from over $17.6 billion in 2017 to $16.2 billion by 2030, mostly driven by a decrease in shallow water OPEX, which is offset by increasing deepwater OPEX. In the proposed rule scenario, there is less new activity to offset the decline, and the trend is even more pronounced. OPEX spending under the new rules is projected to decline from $17.6 billion to $14.2 billion per year, averaging $15.4 billion over the forecast period.

Section 5 - Macro-Economic Impact Conclusions

In order to further quantify the effects of the proposed rule, Quest constructed an economic analysis model to estimate changes in jobs, GDP, and governmental revenue. The estimates created throughout this section closely parallel spending and activity trends. Employment and GDP effects are calculated using the most recent Bureau of Economic Analysis' (BEA) RIMS II models in order to quantify the effects of domestic spending.

This analysis further underscores that the economic benefit of increased spending due to the adoption of the proposed rule as written will likely be outweighed by overall reductions in oil and natural gas exploration and development. The net economic analysis anticipated from the proposed rule is projected to result in significant declines in employment, GDP, and federal revenue from 2017 forward.

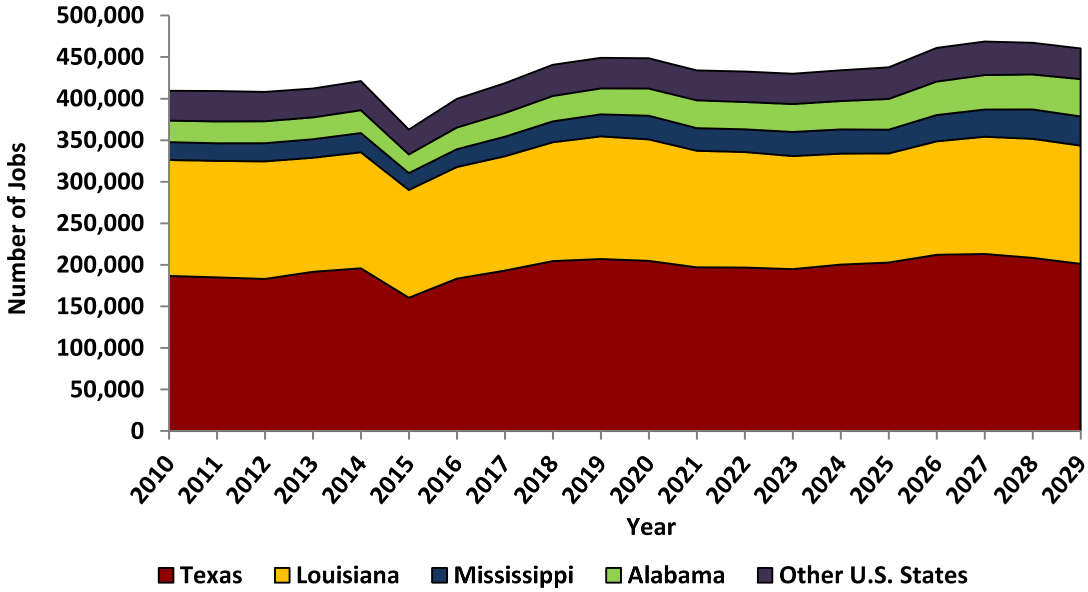
5.1 Employment

The offshore oil and gas industry has a long history of significant employment throughout the nation and in particular in the Gulf Coast states. Continued investment in offshore infrastructure has built a buoyant and diverse supply chain that has historically provided high wages to significant numbers of white and blue collar laborers. Most recent estimates through Quest's application of the BEA economic models have suggested that total employment supported by industry spending is approximately 363 thousand in 2015 with nearly 142 thousand direct industry jobs and an additional 220 thousand jobs provided from indirect and induced industry spending[6].

Employment is expected to grow throughout the forecast, as continued project investment, particularly in deep and ultra-deep waters is projected to lead to employment growth throughout the region. Gulf of Mexico OCS activity-driven employment within the U.S. is likely to grow from 363 thousand jobs in 2015 to more than 466 thousand by 2030, which equals an additional 104 thousand jobs and represents 29 percent growth. No major shifts are expected within the state employment distribution, as Texas and Louisiana are expected to continue to be the most significant beneficiaries of offshore oil and gas with 160 thousand and 130 thousand jobs in 2015 respectively, and 202 thousand and 145 thousand jobs projected by 2030. (Figure 13)

[6] Indirect jobs are those related to the oil and natural gas supply chain. Induced jobs are created from more income that is spent throughout the economy.

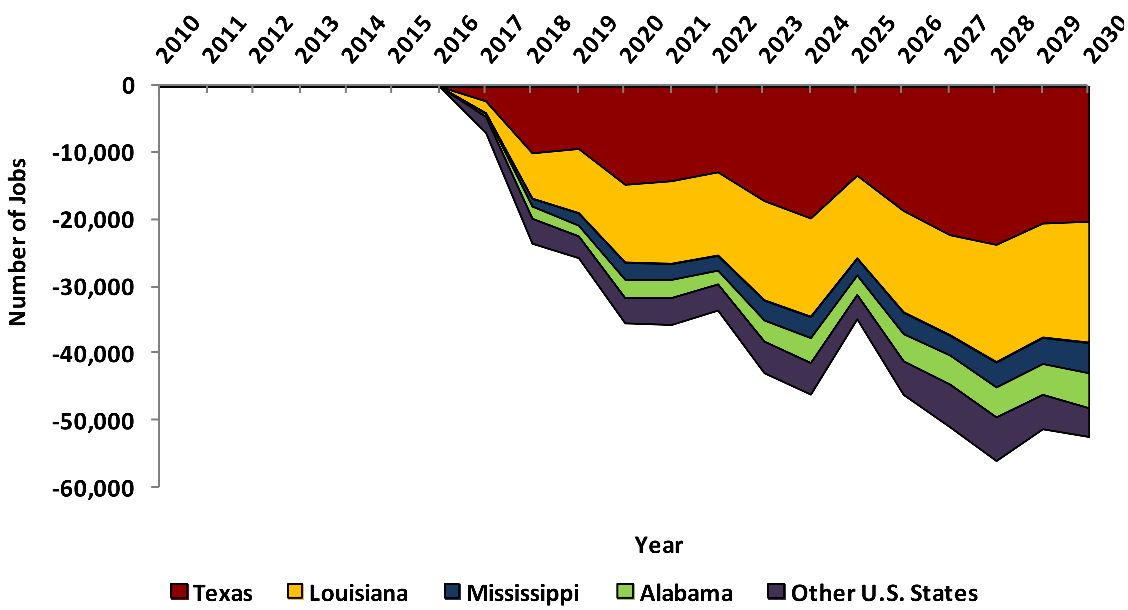
Figure 13: **Jobs by State - Base Development Scenario**



Source: Quest Offshore Resources, Inc.

With the proposed rule, yearly employment supported is projected to diverge from the base forecast, continuing to widen in the later years with over 50 thousand yearly jobs displaced through lost offshore activity by 2030. Gulf of Mexico oil and natural gas development is projected to support fewer jobs with the proposed rule despite increases in spending by the industry to meet the rule's requirements. This is due to fewer wells drilled and lower overall spending. (Figure 14)

Figure 14: **Jobs by State - Proposed Rule Scenario Difference**



Source: Quest Offshore Resources, Inc.

This lower employment level is likely to primarily affect the Gulf Coast, with Texas and Louisiana expected to see employment levels of 20 thousand and 18 thousand jobs lower by 2030. This represents ten percent and 12 percent lower projected Gulf of Mexico OCS oil and natural gas production employment respectively. (Table 9)

Table 9: Estimated Total Supported Employment Levels by Scenario – 2010 to 2030

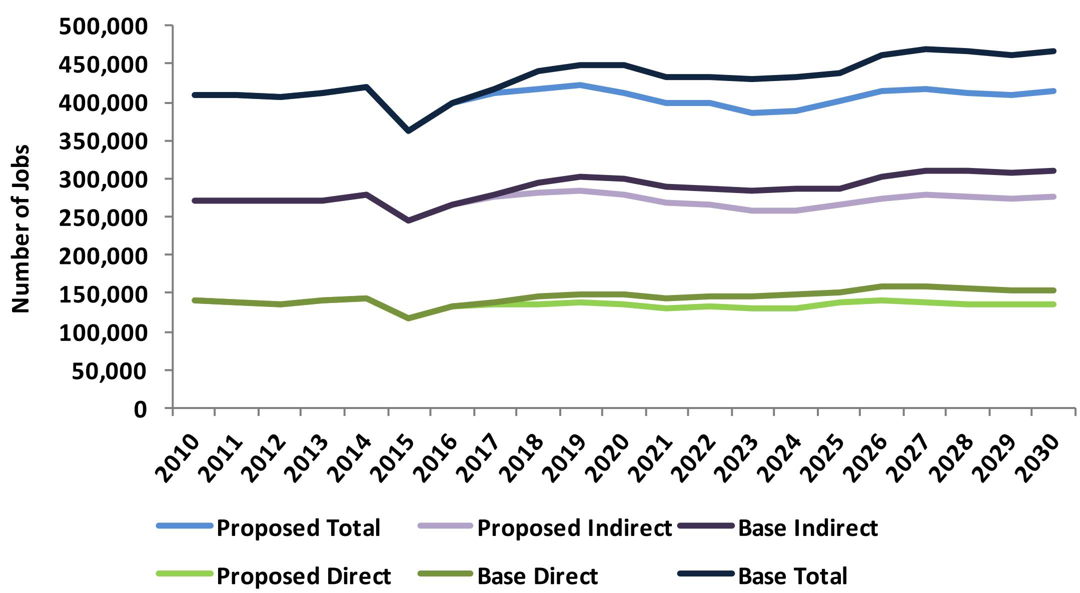
Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	409,484	409,165	408,102	412,231	421,157	362,797	399,745	418,592	440,788	449,152	448,591
Proposed Rule	409,484	409,165	408,102	412,231	421,157	362,797	399,745	411,674	417,244	423,443	413,102
Difference	-	-	-	-	-	-	-	(6,918)	(23,544)	(25,709)	(35,488)

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	433,987	432,658	429,997	434,125	437,702	461,102	468,727	467,236	460,408	466,541
Proposed Rule	398,256	399,091	387,026	387,946	402,826	414,877	417,656	411,089	409,033	414,002
Difference	(35,731)	(33,567)	(42,972)	(46,179)	(34,875)	(46,225)	(51,071)	(56,147)	(51,376)	(52,539)

Source: Quest Offshore Resources, Inc.

The BEA's RIMS II model allows the calculation of employment estimates for both direct jobs, (employment for those that work within the industry) and indirect and induced jobs (those created through the network of oil and gas operations as well as ancillary spending from the industry and its employees). Estimates for direct job numbers are expected to grow from 118 thousand to 154 thousand between 2015 and 2030, a 31 percent growth, while indirect jobs are expected to grow from 244 thousand to 311 thousand, a 27 percent growth. (Figure 15)

Figure 15: Direct vs. Indirect/Induced, and Total Employment – Base Development Scenario vs. Proposed Rule Scenario

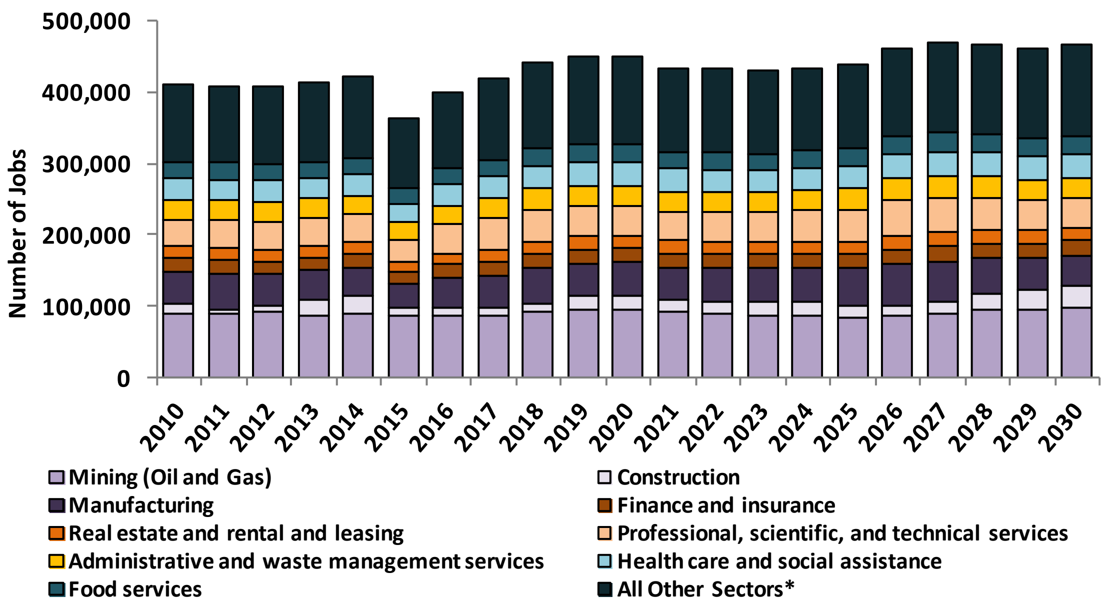


Source: Quest Offshore Resources, Inc.

The impacts of the proposed rule are expected to have the largest numeric effect on indirect jobs, with an expected net loss of 34 thousand jobs or a 12 percent reduction to the base case, while direct jobs are expected to see a smaller, net loss of 18 thousand jobs or 14 percent of projected employment in 2030.

The current offshore oil and gas supply chain has grown to include suppliers throughout the country and world and a multitude of companies. Development of offshore oil and natural gas projects involves a larger number of industries, which include, but are not limited to: mining (of natural resources including oil and natural gas production), manufacturing, professional, scientific, and technical services (engineering), manufacturing, and construction (installation). Combined, these industries are expected to see additional employment of around 50 thousand jobs by 2030, with employment growing from 162 thousand to 212 thousand jobs. Additional industrial sectors that benefit indirectly through induced employment are likely to see continued benefits throughout the study period due to Gulf of Mexico oil and natural gas development. These industries include among others, retail, finance and insurance, food services, and health care and social assistance. Employment in these industry sectors alone due to Gulf of Mexico oil and natural gas activities account for 25 thousand jobs on average in 2015 and is projected to reach 30 thousand jobs on average in 2030 under current regulations. (Figure 16)

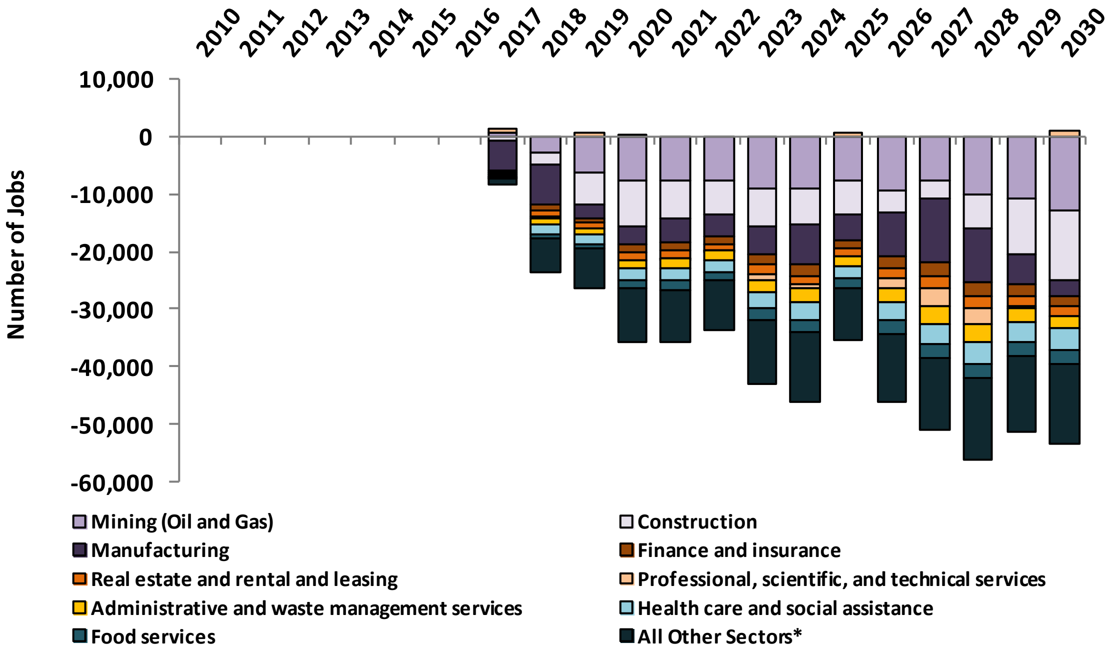
Figure 16: **Jobs by Profession – Base Development Scenario**



Source: Quest Offshore Resources, Inc.

The proposed regulations will have far reaching effects throughout the Gulf Coast economies as employment levels due to Gulf of Mexico oil and natural gas activities are projected to be 50 thousand lower as early as 2027 relative to employment projections under current regulations. These jobs are expected to be numerically focused within mining (oil and gas) and manufacturing, with both sectors seeing lower employment of around 12 thousand jobs in 2030. The construction (installation) sector has the largest employment impact proportionately over the study period, with a 44 percent decline in projected employment as the costs of the proposed rule slow new project development activity. Numerous other industries are likely to see declines in projected employment of around 10 percent within their professions while professional, scientific, and technical services (engineering) are expected to see slightly higher employment in certain years due to the increased engineering burden of the proposed rule. (Figure 17)

Figure 17: Jobs by Profession – Delta Proposed Rule Scenario Difference



Source: Quest Offshore Resources, Inc.

5.2 GDP (Gross Domestic Product)

Potential gross domestic product (GDP) effects were calculated as a multiplier on spending within the U.S., further utilizing the BEA's RIM II model. The estimated effects of proposed rule changes are therefore likely to be strongly correlated to any shifts within spending, with international spending (mainly on platform fabrication) excluded, and should mirror the shifts throughout employment.

The current GDP impact of the Gulf of Mexico offshore oil and natural gas industry in the U.S. is estimated at $34.5 billion annually, and is projected to continue to grow to around $40 billion over the forecast period by 2030 – representing around 16 percent growth. The proposed rule, if enacted as written, is projected to lead to the GDP impact from Gulf of Mexico oil and natural gas activities being $4 billion lower in 2030. The cumulative 10-year loss of GDP from 2017 to 2026 is estimated at $27 billion (Table 10).

Table 10: Estimated GOM Supported GDP by Scenario – 2010 to 2030 ($Millions)

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	$34,726	$35,098	$35,311	$34,998	$35,946	$31,350	$34,513	$36,077	$38,084	$38,862	$38,699
Proposed Rule	$34,726	$35,098	$35,311	$34,998	$35,946	$31,350	$34,513	$34,726	$36,937	$37,817	$36,857
Difference	$0	$0	$0	$0	$0	$0	$0	($1,351)	($1,147)	($1,045)	($1,841)

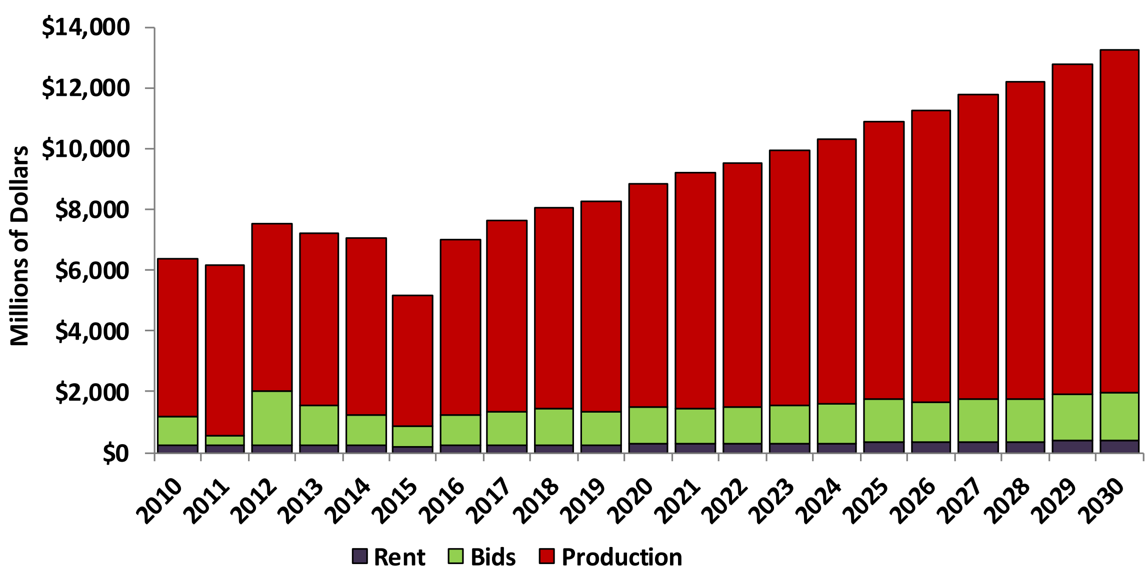
Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	$37,332	$36,991	$36,661	$36,948	$37,330	$39,618	$40,400	$40,297	$39,641	$40,141
Proposed Rule	$35,099	$34,186	$33,523	$33,819	$34,297	$35,281	$35,900	$36,851	$35,682	$36,133
Difference	($2,233)	($2,805)	($3,138)	($3,130)	($3,034)	($4,337)	($4,500)	($3,445)	($3,960)	($4,007)

Source: Quest Offshore Resources, Inc.

5.3 Government Revenue

Government revenues due to Gulf of Mexico offshore oil and gas operations are currently collected through three main revenue streams; revenue from lease sales, lease rental rates, and production royalties. The distribution of these revenues streams is heavily skewed towards production royalties, which account for around 80 percent of revenues from offshore oil and natural gas activities. Total government revenues from Gulf of Mexico offshore oil and gas royalties have been between $5 and $8 billion in recent years, lease sale revenues have been between $300 million and $1.5 billion, lease rental revenues have been approximately $200 million per year, and production revenues have provided $5 billion per year. (Figure 18)

Figure 18: Projected Governmental Revenues – Base Development Scenario



Source: Quest Offshore Resources, Inc.

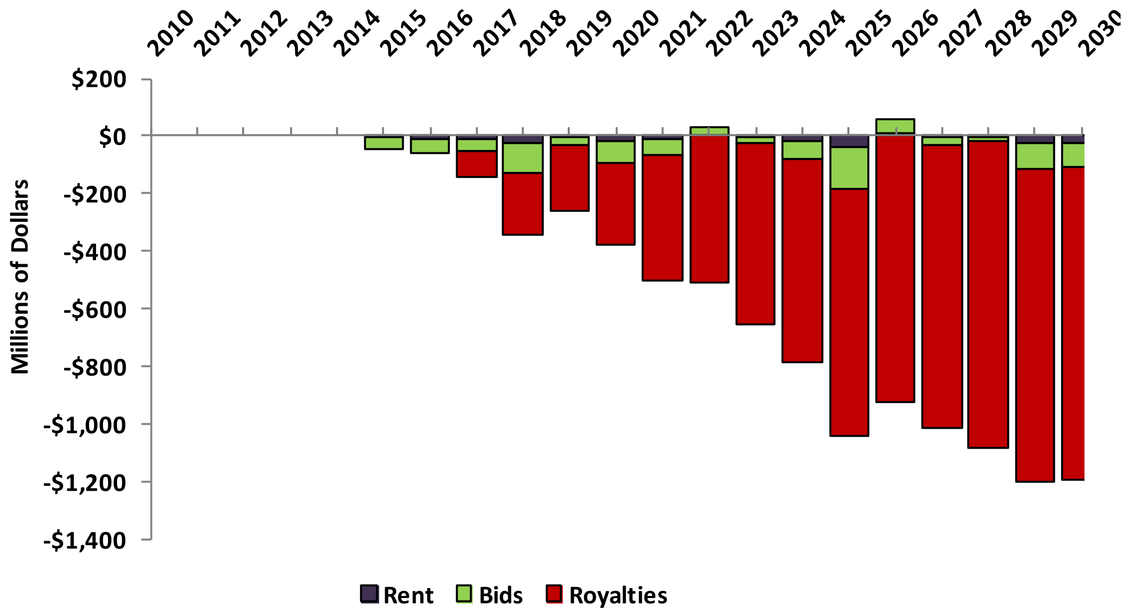
Under the base development scenario, future lease sale levels are expected to remain in line with recent lease sale levels in the region. A minor decrease in the uptake rate due to decreasing lease availability and expected recoverable reserves is projected to leave lease sales relatively flat, ranging from $1 to $1.5 billion each year over the forecast period. Block rentals account for the smallest portion of government revenue and are projected to fluctuate between $200 and $400 million per year over the forecast. Production royalties, calculated using the EIA long term oil and gas price forecast, continue to grow over the forecast due to increasing production, growing from a recent low of $4.2 billion in 2015, driven by low oil prices, to more than $11 billion in 2030. Production royalties will likely increase as projects with royalty rates on more recent leases with high tax rates come on stream throughout the forecast.

State and Federal governments share in the revenue from the GOM oil and natural gas development. Under GOMESA[7] regulations instituted in 2007, state and federal regulators proposed a splitting of offshore revenues between state and federal governments. The second phase of the GOMESA rule will take effect in 2017 which will lead to an approximately a 62.5% to 37.5% split between state and federal governments with revenue capping provisions at $500 million for states.

In parallel with previous section, the effects of the proposed rule are estimated to lead to lower government revenues of around $18.5 billion from 2017 to 2030. Increased costs and lower recovery rates are expected to drive lower lease sales through the period, though growth within leases is expected, with the value of leases sold rising from $650 million in 2015 to $1.5 billion in 2030, while rental rates rise from $180 million to $350 million. The total estimated decline in combined rental and bid revenue due to the proposed rule is approximately $1 billion over the life of the study. Production revenues are expected to rise from 2017 levels even under the proposed rule scenario, especially due to higher oil prices, though the growth is limited in comparison to the base development scenario. Under the proposed rule, revenues rise from $4.3 billion in 2015 to $9 billion in 2030, which is more than $2 billion less than the base case total and represents a drop of nearly 15%. The estimated lost revenue from production royalties will provide the largest portion of potential lost revenues, estimated at around $17.7 billion from 2017 to 2030. The cumulative 10-year loss of government revenue from 2017 to 2026 is estimated at $9.9 billion (Figure 19).

[7] Gulf of Mexico Energy Security Act of 2006 (Pub. Law 109-432) – was instituted to update the visibility on leasing activities as well as revenue sharing between state and federal governments.

Figure 19: Governmental Revenues – Proposed Rule Scenario Difference



Source: Quest Offshore Resources, Inc.

The revenue effects at the state level are expected to be minimal as GOMESA limits of $500 million per year are reached under both revenue scenarios under Quest's interpretation of the law. (Table 11)

Table 11: Estimated State and Federal Government Revenues from GOM Oil and Natural Gas by Scenario 2010 to 2030 ($Millions)

Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Case	$6,361	$6,177	$7,515	$7,219	$7,079	$5,177	$7,013	$7,625	$8,050	$8,262	$8,828
Proposed Rule	$6,361	$6,177	$7,515	$7,219	$7,079	$5,177	$7,013	$7,389	$7,533	$7,746	$8,110
Difference	$0	$0	$0	$0	$0	($0)	($0)	($236)	($517)	($516)	($719)

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Case	$9,188	$9,518	$9,953	$10,307	$10,909	$11,247	$11,780	$12,222	$12,777	$13,254
Proposed Rule	$8,267	$8,557	$8,740	$8,889	$9,164	$9,580	$9,865	$10,148	$10,488	$10,870
Difference	($921)	($961)	($1,213)	($1,418)	($1,745)	($1,667)	($1,915)	($2,074)	($2,289)	($2,385)

Source: Quest Offshore Resources, Inc.

Section 6 - Conclusions

The oil and gas industry in the Gulf of Mexico has a tremendous influence on the local economies of the Gulf coast and the broader U.S. economy by supporting well-paying employment for hundreds of thousands of Americans, by providing revenues to many levels of the U.S. government and by contributing to the country's energy needs. The industry has grown into the world leader in offshore safety, technology, and scientific research. The shallow and mid-water Gulf production areas have been longstanding sources of employment and production, though those areas have been struggling to overcome the economic barriers of production in now-mature fields, and production has been in decline. Recently, efforts to revitalize mature fields and a shift towards production and activity in deepwater areas of the region have led to renewed activity in the Gulf of Mexico OCS, which is poised to reverse the long-standing trend of decline in offshore production volumes that began in the 1980s. Due to the work being done in the deepwater Gulf of Mexico, the industry's global influence has grown steadily, along with the economic benefits which it brings. The health of the industry is not, however, guaranteed. A lingering low-price environment and the steadily increasing difficulty and cost of producing oil and gas assets in the Gulf of Mexico have strained project economics and threatened the health of the industry.

While some part of the proposed rule, “Oil and Gas and Sulphur Operations in the Outer Continental Shelf – Blowout Preventer Systems and Well Control”, are expected to have little or no negative affect on the industry, others will, in their current forms, seriously limit the ability of operators, drilling contractors, and service providers to safely, effectively, and economically operate in U.S. offshore areas, and may make the cost of producing currently economic wells prohibitively high or technically impossible. This decrease in activity and increase in cost will further damage an important industry that is already dealing with the repercussions of a volatile and challenging commodity price environment and may seriously impact the overall U.S. economy.

After analyzing the operational and economic impacts of the regulations, as proposed by BSEE, this study has projected that the following effects will result from their implementation:

- The 10-year costs estimates for the proposed rule from 2017 to 2026 are estimated to be over $32 billion compared to a BSEE estimate of $882 million. Most of these costs are attributable to well design requirements and BOP spending.

- When compared to the Base Development Scenario, the decreases in activity caused by these regulations are projected to reduce employment by over 50 thousand jobs as early as 2027 relative to jobs supported under current regulations. This is an estimated decrease of 11% of the projected employment due to the Gulf of Mexico oil and natural gas industry.

- If the proposed rule were to be enacted as currently written, annual capital investment and other spending directly related to offshore oil and natural gas development in the Gulf of Mexico OCS is projected to decrease from $41.5 billion per year in 2030 to $36.5 billion per year in 2030.

Cumulative capital investments and other spending from 2017 to 2030 are projected to decrease by nearly $57 billion, a more than 10% drop.

- Between 2017 and 2030, the proposed rule is expected to decrease overall activity significantly in the Gulf, including:
    - A reduction in oil and natural gas production of 0.5 Million Barrels per day or 15.5% (from an average production of 3.10 Million BOE per day to 2.62 Million BOE per day),
    - A 26% decline in the number of wells drilled (from roughly 2,700 to 2,000),
    - 4% fewer leases (Dropping from 6350 to 6100), and
    - 13% less government revenue decreasing from $144 billion to $125 billion (The cumulative 10-year loss of government revenue from 2017 to 2026 is estimated at $9.9 billion).
- The effect that domestic offshore oil and gas exploration and production are expected to have on US Gross Domestic Product is expected to be $44 billion lower under the proposed regulations, which is 9% lower than the previous effect. The ten year GDP cost burden of the proposed rule from 2017 to 2026 is estimated at $27 billion.
- It is clear that the proposed rule as currently written will have a significant effect on US employment, GDP, government revenues and domestic energy security due to increased costs borne by industry participants and reduced activity levels.

Section 7 - BSEE Rules & Regulations Appendix

This Report provides an independent high-level review and evaluation of the United States Department of Interior Bureau of Safety and Environmental Enforcement ("BSEE"), proposed rule on "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" as published in the Federal Register Vol. 80 Friday, No. 74 on April 17, 2015 (the "Proposed Rule"). The purpose of this Report was to provide a summary of the most impactful sections and subsections of the Proposed Rule. This study is in no way exhaustive - especially in light of the quite short period available to review the Proposed Rule, the highly technical nature of these regulations, and time to develop this analysis with comments.

This Report reviewed key technical effects expected by the Proposed Rule on industry operations, and included those key technical effects within a larger evaluated economic analysis of the Proposed Rule on offshore resource development. The larger economic analysis viewed across stakeholders, including the industry operators, industry support providers (i.e. engineers, designers, manufacturers, service, and equipment suppliers), government revenue losses, and resultant employment effects. The key technical effects were reviewed by Blade Energy Partners, and the economic analyses and evaluation was provided by Quest Offshore Resources.

The analysis in this Report focuses on the likely engineering and operational effects of these regulations, and wherever possible attempts to calculate the cost of overcoming these burdens. As such, this analysis is essentially forward looking, and therefore subject to significant changes based on the final rules as implemented by BSEE, the way in which the final rules are implemented, and a variety of other factors. However, this Report's authors believe that this approach is the best available way to consider this rule (as more a backwards looking review based on previous industry activity would likely overstate the effects of these regulations). Similarly, a more narrow view of the regulations which focuses solely on the narrow cost of implementing individual rules without taking into account the engineering and operational burdens imposed by the regulations is likely to underestimate the projected costs of their implementation. Due to the limited time available to prepare this Report, as well as significant uncertainties about the way the Proposed Rule would be implemented if enacted, the projected costs and engineering and operational burdens for all proposed regulations are not included in this Report. Additionally, the internal costs to BSEE of implementing and administrating the proposed rule are not calculated in this Report. Due to the conservative approach and the time limitations associated with this study it is likely that the full costs and economic impacts presented in this report underestimate the overall impacts of the proposed rule.

The Report's authors make no representation as to the effects of proposed regulations not addressed specifically in this report, and do not discount the possibility that these proposed changes could impose additional significant engineering, operational or other burdens on industry, regulators or others. The Report's authors' estimates herein of the effects that BSEE's Proposed Rule will have on current and future engineering and operations and technology advances are an independent good faith qualitative view arising from unfortunately short considerations by various subject matter persons within Quest Offshore (an independent consulting firm focused on offshore oil and gas operations and economics) and Blade Energy, (a consulting company in well design, engineering and operations. If BSEE extends the comment period for the Proposed Rule, then further consideration of the effects the Proposed Rule will have on industry resource development may be requested. The future effects of these Proposed Rule on new, emerging, and likely technologies and methods cannot be evaluated properly within the time frame of this Report effort.

As this was an independent review, industry and others (operators, original equipment manufacturers, support and service providers) may, and surely will have differences of opinion with all or part of this analysis. This analysis was not in any way prepared to contradict or supersede any other view. Both Quest Offshore and Blade Energy are providing this independent view expressly disclaiming any warranty, liability, or responsibility for completeness, accuracy, use, or fitness to any person for any reason.

7.1 General Comments

In general, it is understood that BSEE's Proposed Regulations are attempting to address upstream industry well design and operations perceived gaps or inadequacies. The industry continues to quickly address these topics on its own. Industry well technology is complex, taking time to engineer, develop, and apply for all stakeholders. Even small changes can result in significant ramifications, additional complexities, and costs immediately and in the future. This review strives to identify how BSEE's Proposed Rule will add immediate and future ramifications and added complexities to oil and gas operations on the continental shelf.

Considering the very complex nature of the Gulf of Mexico oil and gas industry, any single Proposed Rule change and the combination of all changes require evaluation by many stakeholders and technology providers.

BSEE's Proposed Rule is expected to have significant current and future effects on well engineering and operations. Industry's ongoing research and development on these topics is continuing, which includes new technologies being deployed currently and in the near to medium future. Much of industry’s research and development efforts are focused on the challenges of deepwater drilling in the Gulf of Mexico water with a focus on life of the well, integrity and increasing resource development efficiencies. Research and development also continues in U.S. Government labs and U.S. Government funded projects with universities and others. The fruits of this R&D work will continue to be seen across industry now and beyond - and many are referenced herein. However, it is the opinion of this Report’s authors that while some of these proposed regulations will lead to more industry research and development to overcome the burden imposed by these regulations; the prescriptive nature of the proposed rule will likely lead to some current and developing technologies being excluded from offshore oil and gas operations in the Gulf of Mexico.

This Report's authors believe it is positive for all stakeholders that BSEE references recognized developed standards (API, etc.) - as such references are accessible to all stakeholders - whether for U.S. application or globally. However, consideration must be taken as to the evolving nature of industry standards and this should be taken into consideration when writing existing or developing industry standards into proposed rules as this may preclude industry participants from adopting updated industry standards.

Additionally, BSEE needs to review the amount of time that industry and BSEE itself requires to staff and train sufficient numbers of competent personnel to monitor, review, and provide efficient approval feedback for many of these Proposed Rules. These include well designs and operations, resource development plans, real time monitoring, and 'BSEE approved verification organizations'. Additionally, the effects of the Proposed Rule requirements needs to be considered if proposed and existing rules are extended to all 'rig' types (including coiled tubing and wireline).

7.2 Analysis of the Proposed Rule

Under the main section: § 250.107 What must I do to protect health, safety, property, and the environment?

Proposed Rule: § 250.107 (a) Lists various compliance and documentation requirements and service fees.

Proposed Regulation Effect on Current Practices: Change will significantly impact well engineering and well operations by adding compliance time to document risk reducing efforts and well construction efforts.

Projected Operational Burden: For well planning, the change will impact well engineering by adding compliance time to document risk reducing efforts and well construction efforts. Including initially, significant compliance cost of around 2 months, including setting up to comply. Once compliance incorporated within a well operator's procedures, the burden should be no more than 2 man-days per individual well plan.

For well operations: The proposed rule adds to the rig management requirements. Initially, these effects could be significant, but once incorporated, the burden should be around 8 man-days per month of operation.

Projected Cost of Proposed Rule: The total cost for from 2017 to 2026 under the base development scenario developed for this report is projected at $65.2 million, and an average annual cost $6.5 million from 2017 to 2026.[8]

[8] Cost estimates for each proposed rule subsection are provided based on projected activity levels prior to the adoption of the proposed rule (base case scenario, see Section 2 – Study Methodology for scenario development. Each cost estimate is provided as a 2017 to 2026 total and average annual additional cost to the Gulf Of Mexico OCS oil and natural gas industry as a whole.

Under the main section: § 250.107 What must I do to protect health, safety, property, and the environment?

Proposed Rule: § 250.107 (e) The BSEE may issue orders to ensure compliance with this part, including but not limited to, orders to produce and submit records and to inspect, repair, and or replace equipment. The BSEE may also issue orders to shut-in operations of a component or facility because of a threat of serious, irreparable, or immediate harm to health, safety, property, or the environment posed by those operations or because the operations violate law, including a regulation, order, or provision of a lease, plan, or permit.

Proposed Regulation Effect on Current Practices: Said "issued orders" seem to be targeted at operations.

Projected Operational Burden: None; unless the "issued orders" impose a compliance burden, expected to be around 8 man-days per month of operation per facility; or, if an operation is shut down, the burden could be extremely disruptive and costly to the operator.

Projected Cost of Proposed Rule: The total cost for from 2017 to 2026 under the base development scenario developed for this report is projected at $61.7 million, and an average annual cost $6.2 million from 2017 to 2026.

Under the main section: § 250.1703 What are the general requirements for decommissioning?

Proposed Rule: § 250.1703 (b) Permanently plug all wells. All packers and bridge plugs must comply with API Spec. 11D1 (as incorporated by reference in § 250.198)

Proposed Regulation Effect on Current Practices: New requirement that all packers and bridge plugs would have to comply with API Spec. 11D1

Projected Operational Burden: The proposed rule would lead to the loss/scrapping of inventory packers and bridge plugs which do not conform to API Spec. 11D1 manufactured prior to adoption of the rule. It is suggested that the rule adopts a grandfather clause for packers and bridge plugs manufactured prior to the adoption of the rule.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules effect the loss/scrapping of inventory packers and bridge plugs. See section 8.3, Other Cost Items – Packer and Bridge Plug Inventory Loss.

Under the main section: § 250.1703 What are the general requirements for decommissioning?

Proposed Rule: § 250.1703 (f) Follow all applicable requirements of subpart G; and;

Proposed Regulation Effect on Current Practices: Revised to add reference to the requirements of new Subpart G. This would make Subpart G applicable to decommissioning. The new regulations applying to "all drilling, completion, workover, and decommissioning operations…" The burden for the strict application of these regulations to decommissioning operations needs to be considered. These effects are difficult to estimate.

Projected Operational Burden: Well abandonments are normally considered as part of the plan only for exploration programs and not development programs. At the minimum the burden, applied to development wells, can be estimated at 3 man-days per individual employed in the operation who may be expected to operate the BOP plus 3 additional days of operating time plus services, needed to comply with the specified well control regulations.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.413 What must my description of well drilling design criteria address?

Proposed Rule: § 250.413 (g) A single plot containing curves for estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, maximum equivalent circulating density, and casing setting depths in true vertical measurements;

Proposed Regulation Effect on Current Practices: This rule would require maximum ECD to the PP/FG/ MW & shoe plot. Additional engineering time will be required.

Projected Operational Burden: This rule would require operators to include fluid modeling and temperature to well planning. The burden should not exceed 4 man-days per individual well plan.

Projected Cost of Proposed Rule: The total cost for from 2017 to 2026 under the base development scenario developed for this report is projected at $6.9 million, and an average annual cost $690 thousand from 2017 to 2026.

Under the main section: § 250.414 What must my drilling prognosis include?

Proposed Rule: § 250.414 (c) Planned safe drilling margins between proposed drilling fluid weights and the estimated pore pressures, and proposed drilling fluid weights and the lesser of estimated fracture gradients or casing shoe pressure integrity test. Your safe drilling margins must meet the following conditions:

Proposed Regulation Effect on Current Practices: The safe drilling margins would also have to meet the following conditions (and was not previously defined): Static downhole mud weight must be greater than estimated pore pressure; Static downhole mud weight must be a minimum of one-half pound per gallon below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient; The ECD must be below the lesser of the casing shoe pressure integrity test or the lowest estimated fracture gradient; When determining the pore pressure and lowest estimated fracture gradient for a specific interval, related hole behavior must be considered (e.g., pressures, influx/loss of fluids, and fluid types). The proposed changes seem to preclude the use of underbalanced drilling and managed pressure drilling by ignoring the use of applied surface pressure. This section defines mud as the only primary operational barrier allowable. It then goes further to require MW 0.5 ppg below FG and further require ECD to be below FG. This requires mud to be the primary barrier during drilling operations. Precluding the use of MPD, and drilling narrow margin PP/FG wells which is especially relevant in deepwater and ultra-deepwater wells, depleted reservoirs both on the shelf and in deepwater as well in areas with shallow hazards which require casing to be set at relatively shallow depths.

Projected Operational Burden: This proposed rule would likely have a very significant impact on Gulf of Mexico oil and gas activities. Today in the GOM, wells are being designed and operationally planned with BSEE review to use forms of Managed Pressure Drilling (MPD technologies). Globally, wells in shallow water, deepwater, and onshore are and have been drilled successfully using MPD technologies and methods. Existing and new deepwater rigs are being retrofitted or designed as 'MPD' ready rigs. The proposed rule may eliminate drilling narrow margin wells from being drilled. The proposed changes seem to preclude the use of underbalanced drilling and managed pressure drilling by ignoring the use of applied surface pressure. It also does not allow for alternate technologies to replace mud weight as the primary drilling barrier. There are many drilling technologies that allow for a barrier other than drilling fluid during operations. These technologies are employed both onshore and offshore throughout the world. If MPD and drilling with mud weights below .5 PPG is not allowed, many wells in the GOM could not be drilled. If these wells cannot be drilled & completed, then huge deepwater, depleted and other reserves will be undeveloped.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $10.7 billion, and an average annual cost $1.1 billion from 2017 to 2026. This cost was calculated based on estimation of 30 percent of wells requiring additional casing strings, as well around 35 percent of wells lost due to this rule being abandoned while drilling.

Under the main section: § 250.414 What must my drilling prognosis include?

Proposed Rule: § 250.414 (j) The type of wellhead system and liner hanger system to be installed and a descriptive schematic, which includes but is not limited to pressure ratings, dimensions, valves, load shoulders, and locking mechanisms, if applicable; and

Proposed Regulation Effect on Current Practices: The rule would require operators to include wellhead and liner hanger specifications in the APD.

Projected Operational Burden: Additional information to be provided in the permitting process. The proposed additional requirement will add an engineering burden, estimated at 4-10 man-days per individual well plan regarding well design.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $6.9 million, an average annual cost from 2017 to 2026 of $690 thousand.

Under the main section: § 250.414 What must my drilling prognosis include?

Proposed Rule: § 250.414 (k) Any additional information required by the District Manager.

Proposed Regulation Effect on Current Practices: New paragraph (k) would be added to require submittal of any additional information required by the District Manager. The proposed additional requirement could add a significant engineering burden.

Projected Operational Burden: Will allow for requests of additional information not specified in the CFR. The burden could be as minor as one rig-day per request or as severe as preventing the project from moving forward altogether. A provision for additional information is needed, but there must be a provision for justification (provided by BSEE) and a means for due process appeal (by the Operator). As currently written the rule essentially gives the District Supervisor the power to make requests without limit or justification.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario based on developed for this report is projected at $1.2 billion, an average annual cost from 2017 to 2026 of $113 million based on one request per well and one rig day per request.

Under the main section: § 250.415 What must my casing and cementing programs include?

Proposed Rule: § 250.415 (a) What must my casing and cementing programs include?

(a) The following well design information: (1) Hole sizes; (2) Bit depths (including measured and true vertical depth (TVD)); (3) Casing information including sizes, weights, grades, collapse and burst values, types of connection, and setting depths (measured and TVD) for all sections of each casing interval; and (4) Locations of any installed rupture disks (indicate if burst or collapse and rating);

Proposed Regulation Effect on Current Practices: The rule would require the rupture disc information for each casing string (if any).

Projected Operational Burden: The rule would require operators to modify drawings to this information include information, additional engineering time will be required. The burden should not exceed 15 man-days per individual well plan.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $25.9 million, an average annual cost from 2017 to 2027 of $2.6 million.

Under the main section: § 250.418 What additional information must I submit with my APD?

Proposed Rule: § 250.418 (g) A request for approval if you plan to wash out or displace cement to facilitate casing removal upon well abandonment. Your request must include a description of how far below the mudline you propose to displace cement and how you will visually monitor returns;

Proposed Regulation Effect on Current Practices: The proposed rule would likely require a separate approval for well abandonment. The approval would require plan details included in the APD.

Projected Operational Burden: The proposed rule would likely require a more detailed well abandonment plans for casing removal. Additional engineering time will be required. The burden should not exceed 2 man-days per individual well plan.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $3.5 million, and an average annual cost of $345 thousand from 2017 to 2026.

Under the main section: § 250.420 What well casing and cementing requirements must I meet?

Proposed Rule: § 250.420 (a) (6) Provide adequate centralization to ensure proper cementation; and

Proposed Regulation Effect on Current Practices: Include comments for centralizers and require "adequate centralization".

Projected Operational Burden: Additional time to run the required centralization, when centralizers may not have normally been run. Non Productive Time (NPT) associated with centralizer failures. Together, these can range from no additional time, to a likely estimate of one rig-day per individual well, to weeks of rig time plus services spent fishing centralizers and casing in the event of a catastrophic failure (unlikely). Additional engineering time will be required. The burden should not exceed 3 man-days per individual well plan. Would require documentation that the proposed centralizer program would provide adequate centralization (assumed to be 70% across and above production zones). Would have to attach and perhaps document and/or verify that centralizers are attached to casing.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.1 billion, an average annual cost $113 million from 2017 to 2026 based on an average of one additional rig day per well drilled.

Under the main section: § 250.420 What well casing and cementing requirements must I meet?

Proposed Rule: § 250.420 (b)(4) If you need to substitute a different size, grade, or weight of casing than what was approved in your APD, you must contact the District Manager for approval prior to installing the casing.

Proposed Regulation Effect on Current Practices: Minor time requirement to report the needed change. Approval needed for changes to casing design.

Projected Operational Burden: A potential for delay while waiting on a decision from the District Manager. The delay should not exceed 3 rig-days per incident (a full weekend plus one day for review). The impact is expected not to exceed 1 man-day per incident. Changes require approval by District Manager. PE certification is required with submission.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.7 million, an average annual cost $173 thousand from 2017 to 2026.

Under the main section: § 250.420 What well casing and cementing requirements must I meet?

Proposed Rule: § 250.420 (c)(2) You must use a weighted fluid to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections.

Proposed Regulation Effect on Current Practices: Would require the use of a weighted fluid to maintain an overbalanced hydrostatic pressure during the cement setting time, except when cementing casings or liners in riserless hole sections. Weighted spacers, designed to avoid going underbalanced during cement placement are a common practice offshore. If the intent is to provide enough hydrostatic pressure in the fluid, above the top of cement, to control the well without the pressure exerted by the cement column, then placement of this very heavy fluid column could be extraordinarily difficult, requiring a good deal of planning.

Projected Operational Burden: If the intent is to provide enough hydrostatic pressure in the fluid, above the top of cement, to control the well without the pressure exerted by the cement column, then placement of this very heavy fluid column could be extraordinarily difficult and prone to incurring Non Productive Time (NPT) due to lost circulation. Estimates range from no lost time to the loss of the hole section or entire well, in the event of a serious lost circulation event. An estimate of the additional planning for such a cement job is likely to range between 2 and 10 days per individual well. May affect the cementing operational design but wording in document only requires greater than seawater density of fluid to enhance well bore stability. Operator would have to do proper calculation to insure that this is followed. Would require review during certification process.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $983 million, an average annual cost $98 million from 2017 to 2026 based on an average of six engineering days and one rig day per well.

Under the main section: § 250.421 What are the casing and cementing requirements by type of casing string?

Proposed Rule: § 250.421 (b) Conductor ... Design casing and select setting depths based on relevant engineering and geologic factors. These factors include the presence or absence of hydrocarbons, potential hazards, and water depths. Set casing immediately before drilling into formations known to contain oil or gas. If you encounter oil or gas or unexpected formation pressure before the planned casing point, you must set casing immediately and set it above the encountered zone. Use enough cement to fill the calculated annular space back to the mudline. Verify annular fill by observing cement returns. If you cannot observe cement returns, use additional cement to ensure fill-back to the mudline. For drilling on an artificial island or when using a well cellar, you must discuss the cement fill level with the District Manager

Proposed Regulation Effect on Current Practices: Revised to specify that if oil, gas, or unexpected formation pressure is encountered, the operator would have to set conductor casing immediately and set it above the encountered zone, even if it is before the planned casing point.

Projected Operational Burden: Change to well design and requires permitting and PE certification of design change. Time to secure the well bore and execute the contingency casing option may range between 2 and 7 days of rig time, depending on how much trouble is encountered. The engineering time required to provide a shallow contingency option would add an estimated 2 days to the well engineering process.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $440 million, an average annual cost $44 million from 2017 to 2026 based on an assumption of ten percent of wells on average requiring four and a half rig days and two engineering days requiring execution of a contingency casing option after encountering unexpected formation pressure, oil, or gas.

Under the main section: § 250.427 What are the requirements for pressure integrity tests?

Proposed Rule: § 250.427 (b) While drilling, you must maintain the safe drilling margins identified in § 250.414. When you cannot maintain the safe margins, you must suspend drilling operations and remedy the situation.

Proposed Regulation Effect on Current Practices: As was the case with § 250.414, the proposed changes seem to preclude the use of underbalanced drilling and managed pressure drilling by ignoring the use of applied surface pressure.

Projected Operational Burden: If MPD is not allowed, many wells in the GOM could not be drilled. Refer to comments for § 250.414 (c)

Projected Cost of Proposed Rule: Refer to comments for § 250.414 (c)

Under the main section: § 250.428 What must I do in certain cementing and casing situations?

Proposed Rule: § 250.428 (b) Need to change casing setting depths or hole interval drilling depth (for a BHA with an under-reamer, this means bit depth) more than 100 feet true vertical depth (TVD) from the approved APD due to conditions encountered during drilling operations. Submit those changes to the District Manager for approval and include a certification by a professional engineer (PE) that he or she reviewed and approved the proposed changes.

Proposed Regulation Effect on Current Practices: District Manager approval is now required if the casing setting depth change is more 100 feet regardless of whether it is deeper or shallower. Require submittal of a professional engineer (PE) certification, certifying that the PE reviewed and approved the proposed changes.

Projected Operational Burden: Statistically speaking, setting pipe shallower than planned is more common than deeper. As such, add an average of 1 day of rig time for waiting per individual well for this occurrence. An additional requirement for PE certification of the change has been added at an expected 3 man-days per well.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $195 million, an average annual cost $19.5 million from 2017 to 2026 based on 20 percent of wells requiring a rig day and a 3 man days to receive approval to submit and receive approval to set casing more than 100 feet TVD from the approved APD.

Under the main section: § 250.428 What must I do in certain cementing and casing situations?

Proposed Rule: § 250.428 (c) Have indication of inadequate cement job (such as lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment). (1) Locate the top of cement by: (i) Running a temperature survey; (ii) Running a cement evaluation log; or (iii) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.

Proposed Regulation Effect on Current Practices: Additional engineering time due to the NPT is expected to be disproportionately higher as depth increases. Revised to clarify requirements concerning what actions must be taken if there is an indication of an inadequate cement job. There are many indicators of an inadequate cement job. These include lost returns, no returns to the mudline or failure to reach the expected height for the specific cement job, cement channeling, abnormal pressures, or failure of equipment. If any of these indicators, or others, are encountered during the cement job, then action must be taken to ensure the cement job is adequate. Such actions may include running a temperature survey, running a cement evaluation log (such as an ultrasonic or equivalent bond log), or a combination of these or other techniques to check cement integrity by verifying the top of cement, density, condition, bond, etc. If the cement job is determined to be adequate, the results of the cement job determination would be submitted to the District Manager in the WAR. Paragraph (c) of the table in this section would be revised to clarify requirements concerning what actions must be taken if there is an indication of an inadequate cement job.

Projected Operational Burden: The change may cause additional NPT due to the new definition for a failed cement job and that the NPT is expected to be disproportionately higher as depth increases. The estimated operational burden is 1 day of rig time per unit of depth squared (measured in thousands of feet) plus the cost of the investigative services. The estimated burden is 1 man-day per unit of depth squared (measured in thousands of feet). Operators would have the burden to review the multiple potential causes for potential inadequate cement job, take action to try to evaluate potential problem, and then make recommendations for and take corrective action.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.428 What must I do in certain cementing and casing situations?

Proposed Rule: § 250.428 (k) Plan to use a valve on the drive pipe during cementing operations for the conductor casing, surface casing, or liner. Include a description of the plan in your APD. Your description must include a schematic of the valve and height above the water line. The valve must be remotely operated and full opening with visual observation while taking returns. The person in charge of observing returns must be in communication with the drill floor. You must record in your daily report and in the WAR if cement returns were observed. If cement returns are not observed, you must contact the District Manager and obtain approval of proposed plans to locate the top of cement before continuing with operations.

Proposed Regulation Effect on Current Practices: New § 250.428 (k) New requirement for the use of valves while cementing shallow strings. Add clarification concerning the use of valves on drive pipes during cementing operations for the conductor casing, surface casing, or liner, and require the following to assist BSEE in assessing the structural integrity of the well:

—The operator would include a description in the APD of the plan to use a valve that includes a schematic of the valve and height above the water line.

—The valve would be remotely operated and full opening with visual observation while taking returns.

—The person in charge of observing returns would be in communication with the drill floor.

—The operator would record in the daily report and in the WAR if cement returns were observed; and

—If cement returns were not observed, the operator would have to contact the District Manager and obtain approval of proposed plans to locate the top of cement, before continuing with operations.

Projected Operational Burden: The engineering burden is expected to be 1 man-day per well to include the necessary details in the APD or APM.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.7 million, an average annual cost $173 thousand from 2017 to 2026.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 What are the source control and containment requirements?

Proposed Regulation Effect on Current Practices: See below.

Projected Operational Burden: See below.

Projected Cost of Proposed Rule: This entry is used for containment system costs, membership, fees and other containment related items not itemized in the following containment related subsection subsections and excludes existing containment equipment. The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.2 billion, an average annual cost $124 million from 2017 to 2026.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 (b) You must have access to and ability to deploy Source Control and Containment Equipment (SCCE) necessary to regain control of the well. SCCE means the capping stack, cap and flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels whose collective purpose is to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. This equipment must include, but is not limited to, the following: (1) Subsea containment and capture equipment, including containment domes and capping stacks; (2) Subsea utility equipment, including hydraulic power, hydrate control, and dispersant injection equipment; (3) Riser systems; (4) Remotely operated vehicles (ROVs); (5) Capture vessels; (6) Support vessels; and (7) Storage facilities.

Proposed Regulation Effect on Current Practices: Requires operators to have access to and ability to deploy Source Control and Containment Equipment (SCCE) as above.

Projected Operational Burden: This is a very costly endeavor and will require a long term industry-wide effort to achieve. In the meantime, operators will need to survey the capabilities of the service community to develop a plan that satisfies the District Manager. Maintain contracts and maintain a fleet of equipment for emergency/ contingency use.

Projected Cost of Proposed Rule: See entry for § 250.462.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 (c) You must submit a description of your source control and containment capabilities to the Regional Supervisor and receive approval before BSEE will approve your APD, Form BSEE–0123. The description of your containment capabilities must contain the following: (1) Your source control and containment capabilities for controlling and containing a blowout event at the seafloor, (2) A discussion of the determination required in paragraph (a) of this section, and (3) Information showing that you have access to and ability to deploy all equipment required by paragraph (b) of this section.

Proposed Regulation Effect on Current Practices: Requires submittal of a description of the source control and containment capabilities before BSEE would approve an APD. The submittal to the Regional Supervisor would need to include the following: The source control and containment capabilities for controlling and containing a blowout event at the seafloor, and a discussion of the determination required by paragraph (a), and information showing that the operator has access to, and the ability to deploy, all equipment necessary to regain control of the well.

Projected Operational Burden: Once the equipment and capability survey is complete to the satisfaction of the District Manager, then it should only add 1 man-day per individual well.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.1 million, an average annual cost $110 thousand from 2017 to 2026.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 (d) You must contact the District Manager and Regional Supervisor for reevaluation of your source control and containment capabilities if your: (1) Well design changes, or (2) Approved source control and containment equipment is out of service.

Proposed Regulation Effect on Current Practices: District Manager and Regional Supervisor approval is now required for any well design changes or if any of the approved SCCE is out of service.

Projected Operational Burden: The potential for waiting on approval exists and is estimated at 1 rig-day per event. An engineering effort of 2 man-days per event is estimated.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $195 million, an average annual cost $19.5 million from 2017 to 2026 based on 20 percent of wells facing one rig day and 2 man days of non-productive time while waiting on approval of the district manager due to well designs changes.

Under the main section: § 250.462 What are the source control and containment requirements?

Proposed Rule: § 250.462 (e) You must maintain, test, and inspect the source control and containment equipment identified in the following table according to these requirements: Equipment Requirements, you must: Additional information (1) Capping stacks .... (i) Function test all pressure holding critical components on a quarterly frequency (not to exceed 104 days between tests). Pressure holding critical components are those components that will experience wellbore pressure during a shut-in after being functioned. (ii) Pressure test pressure holding critical components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE and a BSEE-approved verification organization. Pressure holding critical components are those components that will experience wellbore pressure during a shut-in. These components include, but are not limited to: All blind rams, wellhead connectors, and outlet valves. (iii) Notify BSEE at least 21 days prior to commencing any pressure testing. (2) Production Safety Systems used for flow and capture operations. (i) Meet or exceed the requirements set forth in 30 CFR 50.800–250.808, Subpart H. (ii) Have all equipment unique to containment operations available for inspection at all times. (3) Subsea utility equipment Have all equipment unique to containment operations available for inspection at all times. Subsea utility equipment includes, but is not limited to: Hydraulic power sources, debris removal, hydrate control equipment, and dispersant injection equipment.

Proposed Regulation Effect on Current Practices: New inspection and testing requirements.

Projected Operational Burden: (1) Capping Stacks: Estimated at 80 man-days per year per system. (2) Prod. Safety Systems: Estimated at 80 man-days per year per system. (3) SS Utility equip.: No burden expected

Projected Cost of Proposed Rule: See entry for § 250.462.

Under the main section: § 250.518 Tubing and wellhead equipment

Proposed Rule: § 250.518 (New e) New paragraph (e) would add packer and bridge plug requirements including: Adherence to newly incorporated API Spec. 11D1, Packers and Bridge Plugs; Production packer setting depth t allow for a sufficient column of weighted fluid for hydrostatic control of the well; and Production packer setting depth criteria.

Proposed Regulation Effect on Current Practices: Completions fluids, including gas lifted wells, have clean brine in the A annulus. This rule will preclude gas lift completions because gas lift requires gas filling the A annulus above the operating gas lift valves. The rule should allow a phase-in application of API Spec. 11D1, so existing inventory of supplier and operator to be grandfathered and not rendered immediately scrap.

Projected Operational Burden: The rule should allow a phase-in application of API Spec. 11D1, so existing inventory of supplier and operator to be grandfathered and not rendered immediately scrap. The production tieback casing choices become limited or non-existent with the requirement for kill weight packer fluids hydrostatic control of the well in the A annulus or tubing annulus. Additionally, HPHT wells require very dense fluids to control the well. These fluids are very corrosive at high temperatures.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules effect the loss/scrapping of inventory packers and bridge plugs. See section 8.3, Other Cost Items – Packer and Bridge Plug Inventory Loss.

Under the main section: § 250.518 Tubing and wellhead equipment

Proposed Rule: § 250.518 (e)(2) During well completion operations, the production packer must be set at a depth that will allow for a column of weighted fluids to be placed above the packer that will exert a hydrostatic force greater than or equal to the force created by the reservoir pressure below the packer;

Proposed Regulation Effect on Current Practices: It may not be possible to set a packer deep enough to have a column of kill weight fluid at the packer.

Projected Operational Burden: If the casing design is suitable for the packer to casing loads, it should not matter if the casing is cemented or not. For those that aren't, additional engineering time will be required. The burden should not exceed 1 man-day per individual well plan.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.1 million, an average annual cost $113 thousand. Although the effects of this rule under the proposed rule scenario were not calculated due to the time limitations associated with the study, in cases where it is not possible to set a packer deep enough to have a column of kill weight fluid at the packer the regulation as written would likely lead to the abandonment of otherwise safe and commercial wells.

Under the main section: § 250.518 Tubing and wellhead equipment

Proposed Rule: § 250.518 (e)(4) The production packer must be set at a depth that is within the cemented interval of the selected casing section.

Proposed Regulation Effect on Current Practices: Additional engineering time will be required. Sometimes it is not possible to get cement at the packer depth. For instance, where a production packer is set above a production liner top and the well is perforated inside the liner.

Projected Operational Burden: The burden should not exceed 1 man-day per individual well plan. In some cases a well could not completed due to this rule or if a block squeeze job is required to meet the proposed rule requirements.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.7 million, an average annual cost of $173 thousand.

Note: The above costs exclude the costs which would be encountered if a well could not be completed due to this rule. These costs were unable to be calculated under the time limitations for this report but would be significantly larger than the calculated engineering costs if even minimal wells were required to be abandoned due to this rule.

Under the main section: § 250.518 Tubing and wellhead equipment

Proposed Rule: § 250.518 (New f) Would require, in your APM, a description and calculations of how the production packer setting depth was determined.

Proposed Regulation Effect on Current Practices: Operators would be required to calculate the hydrostatic head of a column of fluid to the packer.

Projected Operational Burden: Depending on wellbore dimensions this rule can make it impossible to complete a well that may otherwise be commercial. For those that aren't, additional engineering time will be required. The burden should not exceed 1 man-day per individual well plan. It is not uncommon to use a lower density packer fluid that does not exceed reservoir pressure hydrostatic.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.7 million, an average annual cost of $173 thousand.

Note: The above costs exclude the costs which would be encountered if a well could not completed due to this rule. These costs were unable to be calculated under the time limitations for this report but would be significantly larger than the calculated engineering costs if even minimal wells were required to be abandoned due to this rule.

Under the main section: § 250.619 Tubing and wellhead equipment

Proposed Rule: § 250.619 (f) Your APM must include a description and calculations for how you determined the production packer setting depth

Proposed Regulation Effect on Current Practices: See comments as § 250.518 (New f)

Projected Operational Burden: Depending on wellbore dimensions this rule can make it impossible to complete a well that may otherwise be commercial. For those that aren't, additional engineering time will be required. The burden should not exceed 1 man-day per individual well plan. It is not too uncommon to use a lower density packer fluid that does not exceed reservoir pressure hydrostatic. The additional engineering time should not exceed 1 man-day per individual APM.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.7 million, an average annual cost of $173 thousand.

Under the main section: § 250.710 What instructions must be given to personnel engaged in well operations?

Proposed Rule: § 250.710 Prior to engaging in well operations, personnel must be instructed in: (a) Date and time of safety meetings. The safety requirements for the operations to be performed, possible hazards to be encountered, and general safety considerations to protect personnel, equipment, and the environment as required by subpart S of this part. Date and time of safety meetings must be recorded and available at the facility for review by BSEE representatives. (b) Well control. You must prepare a well-control plan for each well. Each well-control plan must contain instructions for personnel about the use of each well-control component of your BOP, procedures that describe how personnel will seal the wellbore and shear pipe before maximum anticipated surface pressure (MASP) conditions are exceeded, assignments for each crew member, and a schedule for completion of each assignment. You must keep a copy of your well-control plan on the rig at all times, and make it available to BSEE upon request. You must post a copy of the well-control plan on the rig floor.

Proposed Regulation Effect on Current Practices: Additional offshore drills will be required during well operations in critical hole sections (i.e., BHST > 300˚F or MASP > 10,000 psi at the point of control or where H2S or hydrocarbons are flowing at the surface.

Projected Operational Burden: The burden is estimated at one-half hour per rig-day of operation when applicable. The burden is estimated at 3 man-days per individual employed in the operation who may be expected to operate the BOP.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $2.3 billion, an average annual cost $230 million based on one half a rig day per month of non-productive time and around 5 additional engineering days required to meet the increased training requirements.

Under the main section: § 250.712 What rig unit movements must I report?

Proposed Rule: § 250.712 What rig unit movements must I report?

Proposed Regulation Effect on Current Practices: This additional regulation will add the time needed to make the required application and it applies to all, but routine, well interventions, regardless of the type.

Projected Operational Burden: Wireline units are included in this regulation as a 'rig movement'. The burden could be estimated by surveying the service industry to get an idea of how many interventions are performed and multiply that number by 1 man-day of operator time plus the application fee, if applicable, needed to make the application. (Presently, Form BSEE-0144 is not listed in the fee schedule but this this study foresees that the increased burden on BSEE to process this additional information will require some cost.)

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.712 What rig unit movements must I report?

Proposed Rule: § 250.712 (a) You must report the movement of all rig units on and off locations to the District Manager using Form BSEE– 0144, Rig Movement Notification Report. Rig units include MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. You must inform the District Manager 72 hours before: (1) The arrival of a rig unit on location; (2) The movement of a rig unit to another slot. For movements that will occur less than 72 hours after initially moving onto location (e.g., coiled tubing and batch operations), you may include your anticipated movement schedule on Form BSEE–0144; or (3) The departure of a rig unit from the location.

Proposed Regulation Effect on Current Practices: All equipment movement reported notification time from 24 hrs to 72 hrs. May submit permitting for short operations at the same time for move on/ move off.

Projected Operational Burden: This is cumbersome and expensive for wireline and coiled tubing units. Advance notice of wireline movements or coiled tubing movements could impose an operations burden on operators of these units depending on implementation.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.712: What rig unit movements must I report?

Proposed Rule: § 250.712 (e) If a drilling rig is entering OCS waters, you must inform the District Manager where the drilling rig is coming from.

Proposed Regulation Effect on Current Practices: Movement of rig prior to arriving in OCS waters.

Projected Operational Burden: Requires an update form based on change in equipment movement by more than 24 hours. This is not limited to rig movement but any equipment movement onto or off of a well.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.712 What rig unit movements must I report?

Proposed Rule: § 250.712 (f) If you change your anticipated date for initially moving on or off location by more than 24 hours, you must submit an updated Form BSEE–0144, Rig Movement Notification Report.

Proposed Regulation Effect on Current Practices: A new movement form required if the move on/ off location changes by more than 24 hours.

Projected Operational Burden: If reporting requirement leads to a movement delay, costs are increased.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.720 When and how must I secure a well?

Proposed Rule: § 250.720 When and how must I secure a well?

Proposed Regulation Effect on Current Practices: This is related to emergency or contingency operations. While the occurrence of compromised casing integrity can vary widely between operators and well types, a reasonable rate of occurrence for the purpose of this calculation is that one "critical" string in 50 can be expected to become compromised. (A critical string can be defined as one where the BHST > 300˚F or MASP > 10,000 psi at the point of control or where H_2S is flowing at the surface.)

Projected Operational Burden: While the mitigation efforts associated with a breach of casing integrity do vary widely, a reasonable estimate of the operational time required mitigate such a breach is 5 rig days per event. In these events, the time needed for the development of a mitigation strategy, then PE review and certification is estimated at 4 man-days per event. None, except for cases where prolonged operations have actually compromised well bore integrity.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.721 What are the requirements for pressure testing casing and liners?

Proposed Rule: § 250.721 (a)**:** You must test each casing string that extends to the wellhead according to the following table…

Proposed Regulation Effect on Current Practices: Changes the requirements for pressure testing casing and liners, increase conductor test pressure from 200 psi to 250 psi., test surface, intermediate, and production to 70% of Minimum Internal Yield, test each drilling liner and liner lap before continuing operations. Requires testing each production liner and liner lap, DM may approve or require additional casing test pressures. If a well would be fully cased and cemented, the operator would have to pressure test the well to the maximum anticipated shut-in tubing pressure before perforating the casing or liner. If a well would be an open-hole completion, the operator would have to pressure test the entire well to the maximum anticipated shut-in tubing pressure before drilling the open-hole section of the well. Requires for a PE certification of proposed plans to provide a proper seal if there is an unsatisfactory pressure test. Requires a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems and outline the requirements for those tests.

Projected Operational Burden: Will require minor changes to pressure testing of BOPs. Presumably, the new requirement for District Manager notification in the event of an interruption of operations will be by telephone call. If a written notification must be made, assume 1/2 man-day per incident as the burden to the operator. Also requires time to pressure test. As well as possible safety risks associated with high pressure testing equipment at surface. Excess internal pressure causes tensile cracks and leak paths in the cement sheath. Inconsistent, and conflicting wording in this rule (requirement to test production casing to 70% test and testing maximum anticipated SITP).

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.721 What are the requirements for pressure testing casing and liners?

Proposed Rule: § 250.721 (e) If you plan to produce a well, you must: (1) For a well that is fully cased and cemented, pressure test the entire well to maximum anticipated shut-in tubing pressure before perforating the casing or liner; or (2) For an open-hole completion, pressure test the entire well to maximum anticipated shut-in tubing pressure before you drill the open-hole section.

Proposed Regulation Effect on Current Practices: Requires pressure testing the well to maximum anticipated shut in tubing pressure which is excessive.

Projected Operational Burden: Requires additional time to perform these tests is expected to be 1/2 rig-day of operating time per producing well to pressure test. There are risks associated with high surface pressure testing equipment.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $327 million, an average annual cost $33 million based on one half a day of additional rig time for production wells.

Under the main section: § 250.721 What are the requirements for pressure testing casing and liners?

Proposed Rule: § 250.721 (f) You may not resume operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test, or if there is another indication of a leak, you must submit to the District Manager for approval your proposed plans to replacement, repair the casing or liner, or run additional casing/liner to provide a proper seal. Your submittal must include a PE certification of your proposed plans.

Proposed Regulation Effect on Current Practices: PE certification of proposed plans to provide a proper seal if there is an unsatisfactory pressure test.

Projected Operational Burden: The estimated burden is one man-day per failed pressure test. A reasonable rate of occurrence for the purpose of this calculation is that one test in 40 can be expected to fail. The rig time spent waiting on orders following a failed pressure test, plus the time needed to mitigate and re-test are already being absorbed by the operator. The new requirement for certification is expected to add to this waiting time and is estimated at 1/2 rig-day per event.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $12.2 million, an average annual cost $1.2 million based on one half a day of additional rig time for production wells.

Under the main section: § 250.721 What are the requirements for pressure testing casing and liners?

Proposed Rule: § 250.721 (g) You must perform a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems.

Proposed Regulation Effect on Current Practices: Requires operators to perform a negative pressure test.

Projected Operational Burden: Additional rig time will be required during well operations to perform the tests. The burden is estimated at 0.5 rig-days per test.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $478 million, an average annual cost $48 million.

Under the main section: § 250.722 What are the requirements for prolonged operations in a well?

Proposed Rule: § 250.722 What are the requirements for prolonged operations in a well? If wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test of the well’s casing or liner, you must:…

Proposed Regulation Effect on Current Practices: Requires operators to perform certain actions if wellbore operations continue within a casing or liner for more than 30 days from the previous pressure test of the well's casing or liner.

Projected Operational Burden: PE certification required if testing shows well below safety factors. Burden is estimated as 1 man-day.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $346 thousand, an average annual cost $35 thousand.

Under the main section: § 250.723 What additional safety measures must I take when I conduct operations on a platform that has producing wells or has other hydrocarbon flow?

Proposed Rule: § 250.723 What additional safety measures must I take when I conduct operations on a platform that has producing wells or has other hydrocarbon flow? You must take the following safety measures when you conduct operations with a rig unit or lift boat on or jacked up over a platform with producing wells or that has other hydrocarbon flow:

Proposed Regulation Effect on Current Practices: Would require the installation of emergency shutdown stations on rig units tied into the production system.

Projected Operational Burden: This will take design and engineering time and new emergency shutdown procedure training for both the rig and platform crews.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.724 What are the real-time monitoring requirements??

Proposed Rule: § 250.724 What are the real-time monitoring requirements?

Proposed Regulation Effect on Current Practices: Presently, only a few of the super-major oil and gas operators have onshore real-time monitoring capability. Under these provisions, the rest of the operators would have to establish a monitoring facility and staff it 24/7, in order to comply. Requires a RTOC for monitoring BOPs, fluid handling and downhole conditions, requires onshore personnel to assist rig crew in monitoring, requires BSEE access upon request, and requires operators to notify DM if monitoring capability is lost.

Additionally, BSEE is considering extend this requirement beyond subsea BOPs, surface BOPs, floating facilities or BOPs operating in an HPHT environment

Projected Operational Burden: This will be a very costly addition to the regulations for most operators. Furthermore, the option for smaller operators to share a common monitoring facility is unlikely due to the sensitive nature of the data. Real Time Monitoring on all well operations, including shallow water shelf operations, will result in significant addition to the sensor, data integration, data telemetry band width, data reception and storage, and data monitoring & interpretation burden for all operators. There is significant uncertainty on the implementation and ongoing cost of these efforts due to the previously limited scale of these types of operations.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $670 million, an average annual cost $67 million.

Under the main section: § 250.730 What are the general requirements for BOP systems and system components?

Proposed Rule: § 250.730 What are the general requirements for BOP systems and system components?

Proposed Regulation Effect on Current Practices: The proposed additions will serve to limit the number of vendors whose equipment can be used in operations under the regulation of BSEE. There will certainly be a cost associated with the increased consideration given to the design, testing and maintenance of the BOP and its associated systems.

Projected Operational Burden: This regulation should exclude components above the uppermost ram preventer (e.g.. annular and LMRP or riser connect.) Annular preventer does not meet MASP, annulars are available up to 10,000 psi at this time and are not available for 15K, 20K or 25K stacks. Even with this change this may limit the number of contract rigs available to support operations in BSEE regulated waters. There will certainly be a cost associated with the increased consideration given to the operation and testing of the BOP and its associated systems while in service. There also exists the very real possibility that an operation will have to be suspended if a BOP fails to meet the standard and an alternative is not available.

Projected Cost of Proposed Rule: The total effects of this rule as written are impossible to calculate, as written this rule would preclude drilling wells with pressures greater than 10 thousand psi with available technology, these wells account for a significant portion of US OCS activity.

The total cost of the effects of this rule if modified are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.730 What are the general requirements for BOP systems and system components?

Proposed Rule: § 250.730 (a)(3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing in the hole under MASP, as defined for the operation, with the proposed regulator settings of the BOP control system.

Proposed Regulation Effect on Current Practices: Would require that pipe and variable bore rams be capable of closing and sealing on drill pipe, workstrings, or tubing under MASP with the proposed regulator settings of the BOP control system.

Projected Operational Burden: The intent of this regulation is unclear. The BOP pressure test indicates if the BOP will seal for MASP or RWP as required. A shear test for on the actual run-in-hole tubing final completion tubing systems cannot be completed, because testing the final completion system will shear and destroy safety valve (SCSSV) and chemical injection or intelligent completion control lines and/or electrical submersible pump (ESP) or downhole sensor or intelligent completion electric cables. Nevertheless, these lines and/or cables are easy to shear (compared to the tubing), and a sample shop stump test tubing w/ lines-cables proves it all.

Projected Cost of Proposed Rule: The costs of this regulation have not been calculated as the shear tests as described in this regulation would be impossible to complete without damaging important well equipment and tubing effecting both the commercial viability and safety of a well. If the suggestion to allow performance of this testing at a test shop is enacted the effects will be minimal.

Under the main section: § 250.730 What are the general requirements for BOP systems and system components?

Proposed Rule: § 250.730 (a) (4) The current set of approved schematic drawings must be available on the rig and at an onshore location. If you make any modifications to the BOP or control system that will change your BSEE approved schematic drawings, you must suspend operations until you obtain approval from the District Manager.

Proposed Regulation Effect on Current Practices: Paragraph (a) (4) would require a current set of approved schematics to be on the rig and at an onshore location. It would also require that if there are any modifications to the BOP or control system that will change your schematics, operations would be suspended until the operator obtains approval of the new schematics from the District Manager.

Projected Operational Burden: This section seems to imply that the operator would specify, own and maintain BOP system. Also could lead to delays while waiting approval of new BOP schematics.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.730 What are the general requirements for BOP systems and system components?

Proposed Rule: § 250.730 (d) If you plan to use a BOP stack manufactured after the effective date of this regulation, you must use one manufactured pursuant to an API Spec. Q1 (as incorporated by reference in § 250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO 17011.

Proposed Regulation Effect on Current Practices: Would require that if an operator plans to use a BOP stack manufactured after the effective date of the final rule, the operator must use one manufactured pursuant to API Spec. Q1.

Projected Operational Burden: Compliance effective date set in the Proposed Rule must allow industry time to engineer and design new API Spec. Q1 equipment - and allow time for existing inventory, work in process, and already ordered but not yet manufactured non Spec. Q1 equipment to be grandfathered and worked through.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (a & b) A complete description of the BOP system and system components, (1) Pressure ratings of BOP equipment; (2) Proposed BOP test pressures (for subsea BOPs, include both surface and corresponding subsea pressures); (3) Rated capacities for liquid and gas for the fluid-gas separator system; (4) Control fluid volumes needed to close, seal, and open each component; You must submit: Including: (5) Control system pressure and regulator settings needed to achieve an effective seal of each ram BOP under MASP as defined for the operation; (6) Number and volume of accumulator bottles and bottle banks (for subsea BOP, include both surface and subsea bottles); (7) Accumulator pre-charge calculations (for subsea BOP, include both surface and subsea calculations); (8) All locking devices; and (9) Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes). (b) Schematic drawings, (1) The inside diameter of the BOP stack, (2) Number and type of preventers (including blade type for shear ram(s)), (3) All locking devices, (4) Size range for variable bore ram(s), (5) Size of fixed ram(s), (6) All control systems with all alarms and set points labeled, including pods, (7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP), (8) Associated valves of the BOP system, (9) Control station locations, and (10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP.

Proposed Regulation Effect on Current Practices: What information must I submit for BOP systems and system components? The introductory text would reflect that the requirements of BOP description submittals would apply to APDs, APMs, and other required submittals. This introductory text would also clarify that if the operator is not required to resubmit the BOP information in subsequent applications, then the operator must document why the submittal is not required — in other words, the operator would need to reference the previously approved or accepted application or submittal and state that no changes have been made. New requirements for BOP description, new requirement for BOP drawings and labeling on drawings.

Projected Operational Burden: Testing required for BOP operation at specific water depth. An estimated 3 man-days per individual well to prepare the location-specific calculations for submittal.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $3.3 million, an average annual cost $330 thousand.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (c) Certification by a BSEE approved verification organization, Verification that: (1) Test data clearly demonstrates the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform at the most extreme anticipated conditions; and (3) The accumulator system has sufficient fluid to function the BOP system without assistance from the charging system.

Proposed Regulation Effect on Current Practices: New requirement for BOP to shear at water depth, meets the extreme environment conditions and accumulator have sufficient fluid to function without assistance from the charging system.

Projected Operational Burden:

Changes to permitting documents. No indication in the Proposed Rule what a 'BSEE approved verification organization' may be or what is needed to qualify as one, or the current and future availability of sufficient verification organizations and personnel to properly staff these verification organizations at the effective date of the Proposed Rule and into the future.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (d) Additional certification by a BSEE approved verification organization, if you use a subsea BOP, a BOP in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility, Verification that: (1) The BOP stack is designed for the specific equipment on the rig and for the specific well design; (2) The BOP stack has not been compromised or damaged from previous service; and (3) The BOP stack will operate in the conditions in which it will be used without assistance from the charging system.

Proposed Regulation Effect on Current Practices: New requirement for additional certification if an operator uses: a subsea BOP, a BOP in an HPHT environment, or a surface BOP on a floating facility. The certification would include verification of the following, the BOP stack is designed for the specific equipment on the rig and for the specific well design, the BOP stack has not been compromised or damaged from previous service; and the BOP stack will operate in the conditions in which it will be used.

Projected Operational Burden: In the short term, there may be limits to the number of qualifying and certifiable BOP systems available for service. BSEE does not want to limit the new requirements only to deepwater or HPHT wells. Additional certification is estimated at 3 man-days to accumulate the documentation plus 1 man-days for the actual certification. No indication in the Proposed Rule what a 'BSEE approved verification organization' may be or what is needed to qualify as one, or the current and future availability of sufficient verification organizations and personnel to properly staff these verification organizations at the effective date of the Proposed Rule and into the future.

Projected Cost of Proposed Rule: The expected documentation and verification cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Other costs of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (e) If you are using a subsea BOP, descriptions of autoshear, deadman, and emergency disconnect sequence (EDS) systems, A listing of the functions with their sequences and timing.

Proposed Regulation Effect on Current Practices: This paragraph would require a listing of the functions with sequences and timing of autoshear, deadman, and emergency disconnect sequence (EDS) systems.

Projected Operational Burden: Additional information provided to the BSEE for BOP certification. Additional time will be required to prepare the documents for submission. The burden is estimated at 3 man-days per individual well.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $3.3 million, an average annual cost $331 thousand.

Additionally: The BSEE is considering expanding the requirements of this paragraph to all BOPs. The BSEE is specifically soliciting comments on whether this certification requirement should be applied to all well operations, including shallow water shelf operations and operations with surface BOPs.

Proposed Regulation Effect on Current Practices: For some well operations (coiled tubing, and wireline specially) this will be an expensive new requirement. BSEE needs to review the amount of time that industry and BSEE itself requires to staff and train sufficient numbers of competent personnel to monitor, review, and provide efficient approval feedback for many of these Proposed Rules. These include well designs and operations, resource development plans, real time monitoring, and 'BSEE approved verification organizations'. Also, the effects of the Proposed Rule requirements need to consider the personnel necessary to cover BSEE's proposed extension to all 'rig' types (including coiled tubing and wireline), and to all shallow water and shelf operations.

Projected Operational Burden: BSEE needs to review the amount of time that industry and BSEE itself requires to staff and train sufficient numbers of competent personnel to monitor, review, and provide efficient approval feedback for many of these Proposed Rules. These include well designs and operations, resource development plans, real time monitoring, and 'BSEE approved verification organizations'. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.731 What information must I submit for BOP systems and system components?

Proposed Rule: § 250.731 (f) Certification stating that the Mechanical Integrity Assessment Report required in § 250.732 (d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility.

Proposed Regulation Effect on Current Practices: Adds a certification requirement stating that the Mechanical Integrity Assessment Report required in proposed § 250.732 (d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. The items covered under this section have not been routinely submitted to BSEE or obtained by the operators charged with responsibility to maintain well control.

Projected Operational Burden: 'BSEE approved verification organizations' required. Additionally life cycle monitoring of the BOP. This may be possible for new BOPs but difficult for existing BOPs with limited records of well life loads.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 General Overview

Proposed Regulation Effect on Current Practices: In reference to the third-party verification and documentation by a BSEE approved verification organization: The objective is to have this equipment monitored during its entire lifecycle by an independent third-party to verify compliance with BSEE requirements, OEM recommendations, and recognized engineering practices. The list of approved verification organizations would be limited to those that can clearly demonstrate the capability to perform this comprehensive detailed technical analysis.

Projected Operational Burden: BSEE has not yet established criteria of organizations and will need to maintain a list of approved suppliers.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $231 million, an average annual cost $23 million based on each operating rig requiring 30 man days per month of additional engineering time to comply with the sections requirements.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (a) The BSEE will maintain a list of BSEE approved verification organizations that you may use. For an organization to become a BSEE approved verification organization, it must submit the following information to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia, 20166, for BSEE review and approval:

1) Previous experience in verification or in the design, fabrication, installation, repair, or major modification of BOPs and related systems and equipment;
2) Technical capabilities;
3) Size and type of organization;
4) In-house availability of, or access to, appropriate technology. This should include computer programs, hardware, and testing materials and equipment;
5) Ability to perform the verification functions for projects considering current commitments;
6) Previous experience with BSEE requirements and procedures; and
7) Any additional information that may be relevant to BSEE's review.

Proposed Regulation Effect on Current Practices: None, if companies can be grandfathered. Otherwise, there will be some time required to apply to be an approved verification company. BSEE will maintain a list of BSEE approved verification organizations, and also outline criteria to become a BSEE approved verification organization.

Projected Operational Burden: The effective date of new regulations requiring a BSEE approved verification organization is too short to have sufficient numbers or verification organizations available for all GOM OCS drilling well operations.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (b) Prior to beginning any operation requiring the use of any BOP, you must submit verification by a BSEE approved verification organization and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor. You must submit verification and documentation related to:

1) Shear Testing that:
   i) Demonstrates that the BOP will shear the drill pipe and any electric-,wire-, and slick-line to be used in the well;
   ii) Demonstrates the use of test protocols and analysis that represent recognized engineering practices for ensuring the repeatability and reproducibility of the tests, and that the testing was performed by a facility that meets generally accepted quality assurance standards;
   iii) Provides a reasonable representation of field applications, taking into consideration the physical and mechanical properties of the drill pipe;
   iv) Ensures testing was performed on the outermost edges of the shearing blades of the positioning mechanism as required in § 250.734(a)(16);
   v) Demonstrates the shearing capacity of the BOP equipment to the physical and mechanical properties of the drill pipe; and
   vi) Includes all testing results
2) Pressure integrity testing that:
   i) Shows that testing is conducted immediately after the shearing tests;
   ii) Demonstrates that the equipment will seal at the rated working pressure of the BOP for 30 minutes; and
   iii) Includes all test results.
3) Calculations that
   i) Include shearing and sealing pressures for all pipe to be used in the well including corrections for MASP

Proposed Regulation Effect on Current Practices: - This rule is applicable to any operation that requires any type of BOP, and would require verification of shear testing, pressure integrity testing, and calculations for shearing and sealing pressures for all pipe to be used. Each of these verifications must demonstrate the outlined specific requirements.

Projected Operational Burden: This requirement is vague related to HPHT environment and what existing standards are being exceeded. This indicates that the operator, not the equipment owner carries the burden for demonstrating reliability. Added time to perform a shear test is estimated at 20 man-days per ram plus an additional 5 man-days per size, weight & grade of pipe.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $45 million, an average annual cost $4.5 million.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (c) For wells in an HPHT environment, as defined by § 250.807(b), you must submit verification by a BSEE approved verification organization that the verification organization conducted a comprehensive review of the BOP system and related equipment you propose to use. You must provide the BSEE approved verification organization access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph to the appropriate District Manager and Regional Supervisor before you begin any operations in an HPHT environment with the proposed equipment. The required submissions are:

1) Verification that the verification organization conducted a detailed review of the design package to ensure that all critical components and systems meet recognized engineering practices,
2) Verification that the designs of individual components and the overall system have been proven in a testing process that demonstrates the performance and reliability of the equipment in a manner that is repeatable and reproducible, including:
   i) Identification of all reasonable potential modes of failure, and
   ii) Evaluation of the design verification tests. The design verification tests must assess the equipment for the identified potential modes of failure.
3) Verification that the BOP equipment will perform as designed in the temperature, pressure, and environment that will be encountered, and
4) Verification that the fabrication, manufacture, and assembly of individual components and the overall system uses recognized engineering practices and quality control and assurance mechanisms.
   i) For the quality control and assurance mechanisms, complete material and quality controls over all contractors, subcontractors, distributors, and suppliers at every stage in the fabrication, manufacture, and assembly process.

Proposed Regulation Effect on Current Practices: This regulation would require a comprehensive review by a BSEE approved verification organization of BOP and related equipment being proposed for use in HPHT service. This would require a special verification process for BOP and related equipment being used in HPHT environments because the design conditions required for an HPHT environment exceed the limits of existing engineering standards. Additionally, the use of a BSEE approved verification body would provide BSEE with an additional layer of review and verification at all steps in the development process.

The paragraph makes it clear that the operator has the burden of clearly demonstrating the reliability of the equipment through a comprehensive review of the design, testing, and fabrication process.

Projected Operational Burden: This rule is related to § 250.731 (f), but explains what is required in the report. This will require added time to perform the additional verifications. The reviewer defers estimating this requirement to a BOP expert.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (d) Once every 12 months, you must submit a Mechanical Integrity Assessment Report for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. This report must be completed by a BSEE approved verification organization. You must submit this report to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia, 20166. This report must include:

1) A determination that the BOP stack and system meets or exceeds all BSEE regulatory requirements, industry standards incorporated into this subpart, and recognized engineering practices.
2) Verification that complete documentation of the equipment's service life exists that demonstrates that the BOP stack has not been compromised or damaged during previous service.
3) A description of all inspection, repair and maintenance records reviewed, and verification that all repairs, replacement parts, and maintenance meet regulatory requirements, recognized engineering practices, and OEM specifications.
4) A description of records reviewed related to any modifications to the equipment and verification that any such changes do not adversely affect the equipment's capability to perform as designed or invalidate test results.
5) A description of the Safety and Environmental Management Systems (SEMS) plans reviewed related to assurance of quality and mechanical integrity of critical equipment and verification that the plans are comprehensive and fully implemented.
6) Verification that the qualification and training of inspection, repair, and maintenance personnel for the BOP systems meet recognized engineering practices and OEM requirements.
7) A description of all records reviewed covering OEM safety alerts, all failure reports, and verification that any design or maintenance issues have been completely identified and corrected.
8) A comprehensive assessment of the overall system and verification that all components (including mechanical, hydraulic, electrical, and software) are compatible.

9) Verification that documentation exists concerning the traceability of the fabrication, repair, and maintenance of all critical components.
10) Verification of use of a formal maintenance tracking system to ensure that corrective maintenance and scheduled maintenance is implemented in a timely manner.
11) Identification of gaps or deficiencies related to inspection and maintenance procedures and documentation, documentation of any deferred maintenance, and verification of the completion of corrective action plans.
12) Verification that any inspection, maintenance, or repair work meets the manufacturer's design and material specifications.
13) Verification of written procedures for operating the BOP stack and LMRP (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components.
14) Recommendations, if any, for how to improve the fabrication, installation, operation, maintenance, inspection, and repair of the equipment.

Proposed Regulation Effect on Current Practices: The rule would include new requirements on the submission of a Mechanical Integrity Assessment Report on the BOP stack and systems. New paragraph (d) would outline the requirements for this report, which must be completed by a BSEE approved verification organization and submitted by the operator for operations that would require the use of a subsea BOP, a surface BOP on a floating facility, or a BOP that is being used in HPHT operations.

This rule specifically requires an annual submittal of a Mechanical Integrity Assessment Report for a subsea BOP, a BOP used in HPHT environment, or a surface BOP on a floating facility. This paragraph would outline the requirements of a Mechanical Integrity Assessment report.

Projected Operational Burden: This rule will result in added time to submit the annual assessment. The estimated time required to generate and submit the report is 3 man-days per stack per year.

Projected Cost of Proposed Rule[9]: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $1.3 million, an average annual cost $130 thousand.

Under the main section: § 250.732 What are the BSEE approved verification organization requirements for BOP systems and system components?

Proposed Rule: § 250.732 (e) You must make all documentation that supports the requirements of this section available to BSEE upon request.

[9] The projected cost of 250.732 (d) is based solely on the preparing of the verification reports, the cost associated with various inspections and procedures which are required to be verified are listed in the appropriate subsections. The removal or rewriting of those subsections without subsequent modification of the verification requirements could lead to significant increases in the projected cost of this subsection.

Proposed Regulation Effect on Current Practices: This rule will require operators to make all documentation that supports the requirements of this section available to BSEE upon request, and by extension, will require that a third party verify the testing and qualification of BOP equipment to ensure consistent results and provide a reasonable assurance of the performance of this equipment.

The BSEE requests comments on the following issues associated with this section:

- On the issue of standardized test protocols and whether there are any specific procedures that should be considered for adoption.
- On the importance of applying forces in tension or compression during the actual shearing tests.
- On what criteria should be used to qualify a BSEE approved verification organization and whether OEMs should be considered for the program.
- On the issue of updating test protocols and criteria used by verification organizations, given the likelihood of future improvements to BOP technology.

Projected Operational Burden: BSSE requested comments for the section (e) will take a longer than the current comment period to formulate.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.733 What are the requirements for a surface BOP stack?

Proposed Rule: § 250.733 General Overview

Proposed Regulation Effect on Current Practices: This regulations would contain revisions clarifying its applicability to all operations covered under Subpart G. It also adds specific requirements for a surface BOP used in HPHT environments if operations are suspended to make repairs to any part of the BOP system.

The BSEE is requesting comments on requiring dual shear rams for BOPs used in HPHT environments, and how long it would take to comply with the dual shear requirement for BOPs used in HPHT environments."

Projected Operational Burden: Request for comments only.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study as well as the lack of available information on BSEE approved verification organizations. See section 8.3, Other Cost Items – BSEE Approved Verification Organizations.

Under the main section: § 250.733 What are the requirements for a surface BOP stack?

Proposed Rule: § 250.733 (b) If you plan to use a surface BOP on a floating production facility you must: (1) Follow the BOP requirements in § 250.734 (a)

1) You must comply with this requirement within 5 years from the publication of the final rule.
2) Use a dual bore riser configuration, for risers installed after the effective date of this rule, before drilling or operating in any hole section or interval where hydrocarbons are, or may be, exposed to the well. The dual bore riser must meet the design requirements of API RP 2RD (as incorporated by reference in § 250.198) including appropriate design for the most extreme anticipated operating and environmental conditions.
   i) For a dual bore riser configuration, the annulus between the risers must be monitored during operations. You must describe in your APD or APM your annulus monitoring plan and how you will secure the well in the event a leak is detected.
   ii) The inner riser for a dual riser configuration is subject to the requirements for testing the casing or liner at § 250.721.

Proposed Regulation Effect on Current Practices: This regulation would codify BSEE policy and would:

—Clarify that when using a surface BOP on a floating production facility:

a) the same BOP requirements apply as in § 250.734 (a)(1), and
b) a dual bore riser configuration would be required for risers installed after the effective date of this rule before drilling or operating in any hole section or interval where hydrocarbons may be exposed to the well;

—Require risers to meet the design requirements of API RP 2RD;

—Clarify that the annulus between the risers must be monitored during operations;

—Require a description of the monitoring plan in the APD or APM, including how you would secure the well if a leak is detected; and

—Clarify that the inner riser for a dual riser configuration is subject to the requirements for testing the casing or liner.

Additionally, API Standard 53 does not impose dual shear requirements for surface BOPs on floating facilities; however, this proposed rule would require dual shears.

Projected Operational Burden: The dual riser requirement may require additional engineering time going forward. Existing production floating facilities must have the room to accept dual bore risers or dual shear BOPs. If not, retrofitting may not be possible. This rule should allow existing and under construction units to be grandfathered in, otherwise the projected cost of the proposed rule would likely be much higher.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated in total, however, while some engineering and construction costs would be expected to design and manufacture new units to comply with these rules the effect on existing units would likely be orders of magnitude greater if a provision to grandfather in existing units is not inserted. As an example, newly installed or soon to be installed dry tree floating production units for some multi-billion dollar projects may be unable to drill and complete new wells if they could not be modified to meet the new requirement. This would likely lead to a 10 to 20 year reduction in the life of these fields and a loss of a majority of the investment into these projects.

Under the main section: § 250.733 What are the requirements for a surface BOP stack?

Proposed Rule: § 250.733 (e) You must install hydraulically operated locks.

Proposed Regulation Effect on Current Practices: This regulation would require the replacement of manual locks with hydraulically operated locks for surface BOPs.

Projected Operational Burden: Depending on the implementation timing of the requirement manufacturing, deliver, and installation of this equipment could lead to out of service time for drilling rigs with surface BOPs. Additionally, this requirement is unnecessary as manual locks on surface BOPS are always accessible.

Projected Cost of Proposed Rule: The projected cost of this rule under the base development scenario from 2017 to 2026 is $5.5 million or $550 thousand a year on average based on average replacement cost per surface BOP of around $250 thousand.

Under the main section: § 250.733 What are the requirements for a surface BOP stack?

Proposed Rule: § 250.733 (f) For a surface BOP used in HPHT environments, if operations are suspended to make repairs to any part of the BOP system, you must stop operations at a safe downhole location. Before resuming operations you must:

1) Submit a revised APD or APM including documentation of the repairs and a certification from a BSEE approved verification organization stating that they reviewed the repairs, and that the BOP is fit for service; and
2) Receive approval from the District Manager.

Proposed Regulation Effect on Current Practices: The dual shear requirement could present an issue for rigs where stack space is already limited.

Projected Operational Burden: Repair conditions will impact operations, requiring the rig to stand by until the repairs are complete or a replacement stack can be acquired. In either event, an estimate of 5 to 10 rig-days seems appropriate, per failure that requires a repair.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a) (1) When operating with a subsea BOP system, you must have at least five remote-controlled, hydraulically operated BOPs. You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. For the two shear ram requirement, you must comply with this requirement within 5 years from the publication of the final rule. Additionally:

(i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.

Proposed Regulation Effect on Current Practices: The dual shear ram requirement is a very challenging requirement, with the need to be able to cut pipe and coiled tubing and wire while still being able to seal. If put into effect, it will

- Require operators to install a gas bleed line with two valves for the annular preventer.

- Necessitate that each annular has a gas bleed line if annulars were installed on both the LMRP and lower BOP stack

- Demand that the two valves would be able to hold pressure from both directions.

- Require a new device for centering drill pipe that is not one of the BOPs

Projected Operational Burden: The expected time needed to meet this requirement could be lengthy. The added requirements for accumulator capacity & redundancy, ROV intervention, emergency shut down, the use of acoustics, side outlet requirements, gas bleed capability below annulars, pipe positioning requirements, pipe compression mitigation and sub-sea battery monitoring will all contribute to significant amounts of engineering effort for new sub-sea BOP stacks.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(1)(ii) The proposed rule requires that both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that includes heavy-weight pipe or collars), workstring, tubing, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole under MASP.

Proposed Regulation Effect on Current Practices: The proposed rule requires that both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that includes heavy-weight pipe or collars), workstring, tubing, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire- , slick-line in the hole under MASP.

Projected Operational Burden: The expected time needed to meet this requirement could be lengthy. Adoption of this requirement will require development of new rams that can shear tubing, wireline, etc.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(3) When operating with a subsea BOP system, you must have the accumulator capacity located subsea, to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface. Additionally, the accumulator capacity must:

(i) Function each required shear ram, choke and kill side outlet valves, one pipe ram, and disconnect the LMRP.

(ii) Have the capability of delivering fluid to each ROV function i.e., flying leads.

(iii) Have dedicated independent bottles for the autoshear, deadman, and EDS systems.

(iv) Perform under MASP conditions as defined for the operation

Proposed Regulation Effect on Current Practices: Generally conforms with API 53.

Projected Operational Burden: Minor modifications to hydraulic system and accumulators.

Projected Cost of Proposed Rule: The estimated cost of modifying BOPs is around $150 thousand per BOP, this cost is excluded from the cumulative analysis to prevent double counting. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(4) When operating with a subsea BOP system, you must have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability. Additionally, the ROV must be capable of performing critical functions, including opening and closing each shear ram, choke and kill side outlet valves, all pipe rams, and LMRP disconnect under MASP conditions as defined for the operation. The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in § 250.198).

Proposed Regulation Effect on Current Practices: The proposed rule will increase potential leak paths by requiring an increased requirement for ROV stabs and require minor modification of existing BOP units.

Projected Operational Burden: As written the rule will lead to increased maintenance costs and time, as well as increasing the difficulty of other BOP maintenance. Will also require modifications to existing BOPs including addition of high flow stabs and valves.

Projected Cost of Proposed Rule: The estimated cost of modifying existing BOPs is around $350 thousand per BOP, this cost is excluded from the cumulative analysis to prevent double counting. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(5) When operating with a subsea BOP system, you must maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The crew must examine all ROV related well-control equipment (both surface and subsea) to ensure that it is properly maintained and capable of shutting in the well during emergency operations. Additionally, the crew must be trained in the operation of the ROV. The training must include simulator training on stabbing into an ROV intervention panel on a subsea BOP stack. The ROV crew must be in communication with designated rig personnel who are knowledgeable about the BOP's capabilities.

Proposed Regulation Effect on Current Practices: This rule will require communication between the ROV crew and the rig personnel familiar with the BOP.

Projected Operational Burden: Will require additional training and ROV operations.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.734: What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(6) When operating with a subsea BOP system, you must provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs. Additionally, in reference to the above rule:

(i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the LMRP. This is considered a rapid discharge system.

(ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system.

(iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system.

(iv) Each emergency function must close at a minimum, two shear rams in sequence and be capable of performing their expected shearing and sealing action under MASP conditions as defined for the operation.

(v) Your sequencing must allow a sufficient delay for closing the upper shear ram after beginning closure of the lower shear ram to provide for maximum shearing efficiency.

(vi) The control system for the emergency functions must be a fail-safe design, and the logic must provide for the subsequent step to be independent from the previous step having to be completed.

Proposed Regulation Effect on Current Practices: This paragraph would require each emergency function to include both shear rams closing under MASP. The sequencing of each emergency function would have to provide for the lower shear ram beginning closure before the upper shear ram would begin closure. The control system for the emergency functions would be required to be a failsafe design, and each step in the logic would have to be independent of the previous step being completed.

Projected Operational Burden: Will require modifications to the control systems of BOP For safety reasons emergency disconnect sequences must disconnect in the shortest possible time, the sequencing of the shear rams will delay disconnect.

Projected Cost of Proposed Rule: Although the cost effects of this rule are not included in the total estimated cost of the rule to prevent double counting the addition of timing circuits is estimated at $100 thousand per BOP excluding additional hydraulic tubing and engineering which will be dependent on the specific design of a BOP.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(15) When operating with a subsea BOP system, you must install a gas bleed line with two valves for the annular preventer with the following requirements:

(i) The valves must hold pressure from both directions;
(ii) If you have dual annulars, where one annular is on the LMRP and one annular is on the lower BOP stack, you must install a gas bleed line on each annular

Proposed Regulation Effect on Current Practices: The proposed rule requires operators to install a gas bleed line with two valves for the second annular preventer if one is in the LMRP and one in the lower BOP stack.

Projected Operational Burden: This regulation would lead to a significant requirement to modify the stack framework and to purchase suitable annular BOPs to allow the installation of a lower gas bleed line. Immediate implementation of this rule would likely lead to a significant slowdown in drilling from rigs with subsea BOPs due to the time required to manufacture and install components that comply with this rule.

Projected Cost of Proposed Rule: Although the cost effects of this rule are not included in the total estimated cost of the rule to prevent double counting the addition suitable annular is estimated at $2 million per BOP.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (a)(16) When operating with a subsea BOP system, you must use a BOP system that has the following mechanisms and capabilities:

(i) A mechanism coupled with each shear ram to position the entire pipe, including connection, completely within the area of the shearing blade and ensure shearing will occur any time the shear rams are activated. This mechanism cannot be another ram BOP or annular preventer, but you may use those during a planned shear. You must install this mechanism within 7 years from the publication of the final rule;

(ii) The ability to mitigate compression of the pipe stub between the shearing rams when both shear rams are closed;

(iii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of charge of the subsea electronic module batteries in the BOP control pods.

Proposed Regulation Effect on Current Practices: This regulation requires the installation of a vertical positioning system to position the entire pipe within in the shearing blade. These positioning systems are currently not available. The requirement will also require the installation of a position indicator for each ram BOP, wellhead connector, and LMRP connector that is viewable by the ROV. This would require sensing and displaying pressure within the BOP that is viewable by the ROV.

Projected Operational Burden: Addition of positioning system will likely require significant modification of BOPs, the extent of which is difficult to ascertain prior to the development of these systems. Additional costs associated with modification of control systems are likely.

Projected Cost of Proposed Rule: The total cost of the effects of this rule are presented in a summary effect section at the end of this subsection to prevent double counting as multiple rules are expected to affect the replacement of BOPs for use in the US OCS. See section 8.3, Other Cost Items – BOP Replacement.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (b) If operations are suspended to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations you must:

1. Submit a revised permit with a verification report from a BSEE approved verification organization documenting the repairs and that the BOP is fit for service;
2. Perform a new BOP test in accordance with § 250.737 and § 250.738 upon relatch including deadman and ROV intervention; and
3. Receive approval from the District Manager.

Proposed Regulation Effect on Current Practices: Require that if operations are suspended to make repairs to the BOP, operations would have to be stopped at a safe downhole location, submit a revised permit with a report from a BSEE approved verification organization documenting the repairs and that the BOP is fit for service, perform a new BOP test upon relatch and receive approval from the District Manager.

Projected Operational Burden: This rule would require a minimum of 1 rig day to report and get permission to continue operations.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $48 million, an average annual cost $4.7 million based on five percent of wells requiring submission of the required information and waiting on approval.

Under the main section: § 250.734 What are the requirements for a subsea BOP system?

Proposed Rule: § 250.734 (c) If you plan to drill a new well with a subsea BOP, you do not need to submit with your APD the verifications required by this subpart for the open water drilling operation. Before drilling out the surface casing, you must submit for approval a revised APD, including the verifications required in this subpart.

Proposed Regulation Effect on Current Practices: Additions to this section would provide that if an operator plans to drill a new well with a subsea BOP, the operator does not need to submit with its APD the verifications required by this subpart for the open water drilling operation. However, before drilling out the surface casing, the operator would be required to submit for approval a revised APD, including the third-party verifications required in this subpart.

Projected Operational Burden: This rule would require a minimum of one (1) man-day to report and get permission to continue operations.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $3.3 million, an average annual cost $330,000.

Under the main section: § 250.735 What associated systems and related equipment must all BOP systems include?

Proposed Rule: § 250.735 (a) A BOP system must include a surface accumulator system that provides 1.5 times the volume of fluid capacity necessary to close and hold closed all BOP components against MASP. The system must operate under MASP conditions as defined for the operation. You must be able to operate all BOP functions without assistance from a charging system, with the blind shear ram being the last in the sequence, and still have enough pressure to shear pipe and seal the well with a minimum pressure of 200 psi remaining on the bottles above the precharge pressure. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost.

Proposed Regulation Effect on Current Practices: This rule clarifies that the requirements are for a surface accumulator system, that the system would have to operate all BOP functions, including shearing pipe and sealing the well against MASP without assistance from a charging system; and that these provisions would apply to all BOP systems, not just surface BOP stacks.

Projected Operational Burden: This would require additional tanks, accumulators and pumps to be installed on affected drilling rigs. The ease of the addition of this equipment will be highly affected by the availability of usable deck space in appropriate areas on a given drilling rig.

Projected Cost of Proposed Rule: Cost is estimated at a minimum of $500 thousand per drilling rig if no major structural modification are needed. If major structural modifications are needed costs would be expected to be significantly higher. Due to the time limits associated with this study the costs excluding possible modifications to rig structures under the base development scenario are projected at $48 million total from 2017 to 2026, an annual average of around $4.8 million.

Under the main section: § 250.737 What are the BOP system testing requirements?

Proposed Rule: § 250.737 (d) Additional test requirements. You must meet the following additional BOP testing requirements: [§ 250.737 (d)(1)-(12)]

Proposed Regulation Effect on Current Practices: This list of additional rules will lead to new ROV requirements which will mean an extra effort for the ROV service provider until the fleet is wholly compatible. The expanded function testing requirements for the auto-shear, deadman and EDS will add considerable time to the APD & APM submittal effort for subsea operations.

Projected Operational Burden: The reviewer has deferred an estimate for this effort to the ROV service provider, but the expanded function testing requirements for the auto-shear, deadman and EDS are expected to add 0.5 rig-days to the sub-surface BOP test procedures.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $237 million, an average annual cost $23.7 million.

Under the main section: § 250.737 What are the BOP system testing requirements?

Proposed Rule: § 250.737 (d)(5) You must alternate tests between control stations and pods. Additionally:

i) For two complete BOP control stations:
   a) You must designate a primary and secondary station, and both stations must be function-tested weekly,
   b) The control station used for the pressure test must be alternated between pressure tests, and
   c) For a subsea BOP, the pods must be rotated between control stations during weekly function testing, and the pod used for pressure testing must be alternated between pressure tests.

ii) Any additional control stations must be function tested every 14 days.

Proposed Regulation Effect on Current Practices: This rule expands testing requirements for two BOP control stations. The operator would be required to designate the control stations as primary and secondary and function-test each station weekly. The control station used to perform the pressure test would be required to be alternated between each pressure test. For a subsea BOP, the operator would be required to rotate the pods between each control station during the weekly function tests and alternate the pod used for pressure testing between each pressure test. If additional control stations are installed, they would have to be tested every 14 days.

Projected Operational Burden: This rule requires at least 15 min per function test for each additional control station. If additional control stations (beyond the minimum of two) are installed, they would have to be tested every 14 days.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was included in the parent level cost of rule § 250.737 (d) to avoid double counting.

Under the main section: § 250.737 What are the BOP system testing requirements?

Proposed Rule: § 250.737 (d)(12) You must test and verify closure capability of all ROV intervention functions on your subsea BOP. In addition:

(i) Each ROV must be fully compatible with the BOP stack ROV intervention panels.

(ii) You must submit test procedures, including how you will test each ROV intervention function, with your APD or APM for District Manager approval.

(iii) You must document all your test results and make them available to BSEE upon request.

Proposed Regulation Effect on Current Practices: These new provisions include requirements that:

—Each ROV must be fully compatible with the BOP stack ROV intervention panels;

—Operators must submit test procedures, including how they will test each ROV intervention function;

—Operators must document all test results and make them available to BSEE upon request.

Projected Operational Burden: These regulations will require additional documentation which will take 15 minutes of engineer time per ROV testing.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was included in the parent level cost of rule § 250.737 (d) to avoid double counting.

Under the main section: § 250.737 What are the BOP system testing requirements?

Proposed Rule: § 250.737 (d)(13) You must function test the autoshear, deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system and verify closure of the shearing rams during the initial test on the seafloor. Additionally:

(i) You must submit test procedures with your APD or APM for District Manager approval. The procedures for these function tests must include the schematics of the actual controls and circuitry of the system that will be used during an actual autoshear or deadman event.

(ii) The procedures must also include the actions and sequence of events that take place on the approved schematics of the BOP control system and describe specifically how the ROV will be utilized during this operation.

(iii) When you conduct the initial deadman system test on the seafloor, you must ensure the well is secure and, if hydrocarbons have been present, appropriate barriers are in place to isolate hydrocarbons from the wellhead. You must also have an ROV on bottom during the test.

(iv) The testing of the deadman system on the seafloor must indicate the discharge pressure of the subsea accumulator system throughout the test.

(v) For the function test of the deadman system during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures.

Proposed Regulation Effect on Current Practices: The test procedures must be submitted for District Manager approval and the proposed rule would require that the procedures include:

—Schematics of the circuitry of the system that would be used during an autoshear or deadman event;

—The approved schematics of the BOP control system with the actions and sequence of events that would take place; and

—How the ROV would be used during the well-control operations.

During the initial test of the deadman system, the operator would need to have the ability to quickly disconnect the LMRP. The operators would also have to submit the quick-disconnect procedures with the deadman test procedures in the APD or APM. The operator would have to include in its procedure a description of how it plans to verify closure of a casing shear ram if installed. All test results would have to be documented and submitted to BSEE upon request.

Projected Operational Burden: If the rule allows simulated testing of the deadman switch the operational burden is expected to be minimal.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the unclear intent of the proposed rule as noted above.

Under the main section: § 250.738 What must I do in certain situations involving BOP equipment or systems?

Proposed Rule: § 250.738 (b) If you need to repair, replace, or reconfigure a surface or subsea BOP system; (1) First place the well in a safe, controlled condition as approved by the District Manager (e.g., before drilling out a casing shoe or after setting a cement plug, bridge plug, or a packer). (2) Any repair or replacement parts must be manufactured under a quality assurance program and must meet or exceed the performance of the original part produced by the OEM. (3) You must receive approval from the District Manager prior to resuming operations with the new, repaired, or reconfigured BOP. You must submit a report from a BSEE approved verification organization to the District Manager certifying that the BOP is fit for service.

Proposed Regulation Effect on Current Practices: This regulation requires that the operator receive approval from the District Manager prior to resuming operations after replacing, repairing, or reconfiguring the BOP system. To obtain approval, the operator would have to submit a report from a BSEE approved verification organization attesting that the BOP system is fit for service. Any repair or replacement parts would have to be manufactured under a quality assurance program and would have to meet or exceed the performance of the original part produced by the OEM.

Projected Operational Burden: The expected rig down-time associated with the BOP repairs should be fully captured under § 250.733 (f).

Projected Cost of Proposed Rule: Not currently calculated [See § 250.733(f)]

Under the main section: § 250.738 What must I do in certain situations involving BOP equipment or systems?

Proposed Rule: § 250.738 (j) If you encounter a situation where the need to remove the BOP stack arises, you must have a minimum of two barriers in place prior to BOP removal. You must obtain approval from the District Manager of the two barriers prior to removal and the District Manager may require additional barriers.

Proposed Regulation Effect on Current Practices: This regulation will require that, after pipe or casing is sheared either intentionally or unintentionally, the operator would have to retrieve, inspect, and test the BOP as well as submit a report to the District Manager from a BSEE approved verification body, stating that the BOP is fit to return to service. Additionally, the subsea stack must be pulled and inspected by a BSEE approved verification company who then must submit a report stating that the BOP is fit to be returned to service following any shearing event. The report should be able to be prepared while the stack is being re-run, assuming the inspection was satisfactory.

Projected Operational Burden: None, as the rig time associated with pulling, inspecting, re-running and testing the sub-surface BOP stack is already a requirement.

Projected Cost of Proposed Rule: Due to the lack of expected operational burdens, there has not been an associated cost calculated for this regulation.

Under the main section: § 250.738: What must I do in certain situations involving BOP equipment or systems?

Proposed Rule: § 250.738 (o) If you install redundant components for well control in your BOP system that are in addition to the required components of this subpart (e.g., pipe/variable bore rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines), you must comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from a BSEE approved verification organization that describes the failure, and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require additional information.

Proposed Regulation Effect on Current Practices: This rule adds new requirements applicable to redundant well-control components in BOP systems that are in addition to components required in Subpart G. If any redundant component fails a test, you must submit a report from a BSEE approved verification organization that describes the failure and confirms that there is no impact on the BOP that will make it unfit for well-control purposes.

Projected Operational Burden: The associated time burden of waiting on approval following the failure of a redundant BOP system is estimated at 1 rig-day per event. Failure of a redundant component will require a report to be submitted to the District Manager, estimated to be one man-day's effort per failed BOP test.

Projected Cost of Proposed Rule: The total cost for from 2017 to 2026 under the base development scenario developed for this report is projected at $48 million, an average annual cost $4.8 million based on five percent of wells encountering a failure of a redundant BOP system.

Under the main section: § 250.738 What must I do in certain situations involving BOP equipment or systems?

Proposed Rule: § 250.738 (p) If you need to position the bottom hole assembly, including heavy-weight pipe or collars, and bottom-hole tools across the BOP for tripping or any other operations, you must ensure that the well has been stable for a minimum of 30 minutes prior to positioning the bottom hole assembly across the BOP. You must have, as part of your well-control plan required by § 250.710, procedures that enable the immediate removal of the bottom hole assembly from across the BOP in the event of a well control or emergency situation (for dynamically positioned rigs, your plan must also include steps for when the EDS must be activated) before MASP conditions are reached as defined for the operation.

Proposed Regulation Effect on Current Practices: This rule will result in new requirements that operators would have to meet if they need to position the bottom hole assembly across the BOP for tripping or any other operations, including:

—Ensuring that the well is stable at least 30 minutes before positioning the bottom hole assembly across the BOP, and

—Including in the well-control plan (required by proposed § 250.710(b)) procedures for immediately removing the bottom hole assembly from across the BOP in the event of a well control or emergency situation before exceeding MASP conditions.

Projected Operational Burden: If this situation arises, the rig must wait at least 30 minutes to prove well stability.

Projected Cost of Proposed Rule: The expected cost of this proposed rule was not calculated due to the time limitations associated with this study.

Under the main section: § 250.739 What are the BOP maintenance and inspection requirements?

Proposed Rule: § 250.739 (b) A complete breakdown and detailed physical inspection of the BOP and every associated system and component must be performed every 5 years. This complete breakdown and inspection may not be performed in phased intervals. A BSEE approved verification organization is required to be present during the inspection and must compile a detailed report documenting the inspection, including descriptions of any problems and how they were corrected. You must make this report available to BSEE upon request.

Proposed Regulation Effect on Current Practices: This new requirement details the procedures for a complete breakdown and inspection of the BOP and every associated component (which is undefined) which rig owners would be required to undertake every 5 years. This paragraph would also clarify that the complete breakdown and inspection may not be performed in phased intervals. BSEE approved verification organization would have to be present documenting the inspection and any problems encountered and produce a detailed report. The requirement for a complete tear-down & inspection every five years will require considerable manpower on the part of the manufacturer and the BSEE approved verification organization.

Projected Operational Burden: The rig time required to swap BOP stacks is estimated at 80 rig-days every five years, plus the cost to remove tear-down, rebuilt, retest, and reinspect the BOP. This would be based on rig owners purchasing additional rig specific BOPs prior to the five year inspection which can then be reused to reduce downtime. Additional burdens associated with this rule are likely due to the limited infrastructure associated with this type of inspection including a lack of shore based OEM facilities, cranes to remove BOPs at US shipyards, and appropriate testing equipment.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $8.9 billion, an average annual cost $895 million. This is cost is based on $40 million per additional BOP as a one off cost, and $15 million of inspection and yard costs and 80 days of downtime every five years for each active rig utilizing a subsea BOP.

Under the main section: § 250.743 What are the well activity reporting requirements?

Proposed Rule: § 250.743 (c) The Well Activity Report (WAR) must include a description of the operations conducted, any abnormal or significant events that affect the permitted operation each day within the report from the time you begin operations to the time you end operations, any verbal approval received, the well’s as-built drawings, casing, fluid weights, shoe tests, test pressures at surface conditions, and any other information required by the District Manager. For casing cementing operations, indicate type of returns (i.e., full, partial, or none). If partial or no returns are observed, you must indicate how you determined the top of cement. For each report, indicate the operation status for the well at the end of the reporting period. On the final WAR, indicate the status of the well (completed, temporarily abandoned, permanently abandoned, or drilling suspended) and the date you finished such operations.

Proposed Regulation Effect on Current Practices: This regulation will require a report describing the operations conducted, any abnormal or significant events that affect the permitted operation, verbal approvals, the wells as-built drawings, casing fluid weights, shoe tests, test pressures at surface conditions, and status of the well at the end of the reporting period. The final WAR would include the date operations finished.

Projected Operational Burden: Properly completing these forms is estimated to require two hours of time from each engineer working on each well.

Projected Cost of Proposed Rule: The total cost for the studied period under the base development scenario developed for this report is projected at $443 thousand, an average annual cost $43 thousand.

Under the main section: § 250.746 What are the recordkeeping requirements for casing, liner, and BOP tests, and inspections of BOP systems and marine risers?

Proposed Rule: 250.746 (e) Requires that the company identify on the daily report any problems or irregularities observed during BOP system testing and record actions taken to remedy the problems or irregularities. Any leaks associated with the BOP or control system during testing are considered problems or irregularities and must be reported immediately to the District Manager, and documented in the WAR. If any problems or irregularities are observed during testing, operations must be suspended until the District Manager determines that you may continue.

Proposed Regulation Effect on Current Practices: Clarifies that any irregularity that is identified during BOP system testing must be identified on the daily report, any leaks observed during testing or observed from the control station are considered irregularities and would have to be reported to BSEE. Operations would have to be suspended until BSEE grants approval to continue after irregularities.

Projected Operational Burden: One rig day per irregularity of any type, though possibly longer if irregularities are serious. Some irregularities are very minor and should not have to be reported or await approval to continue.

Projected Cost of Proposed Rule: The total cost from 2017 to 2026 under the base development scenario developed for this report is projected at $123.8 million, an average annual cost $12.4 million based on the assumption that ten percent of wells on average may encounter an irregularity requiring one day of non-productive time while waiting on the district manager.

7.3 Other Cost Items

Packer and Bridge Plug Inventory Loss

The following regulations [§ 250.1703 (b), § 250.518 (New e)] are expected to lead to a loss of already manufactured and held in inventory packers and bridge plugs that fail to meet the specifications required by the new rule. The cost of this inventory was calculated by estimating the number of packers and bridge plugs required on a per well basis and under the assumption that one and a half years' worth of inventory is held by various suppliers and operators. The introduction of a grandfathering provision for packers and bridge plugs manufacturer prior to the adoption of this rule would remove this expected cost of the proposed rule. The total cost for replacement of inventory packers and bridge plugs under the base development scenario developed for this report is projected at $32 million, an average annual cost $3.2 million.

BOP Replacement

The following regulations [§ 250.730, § 250.730 (d), § 250.734 (a)(1), § 250.734 (a)(1)(ii), § 250.734 (a)(3), § 250.734 (a)(4), § 250.734 (a)(6), § 250.734 (a)(15), § 250.734 (a)(16)] are expected to lead to the replacement of subsea blow out preventers in the US OCS. The accumulation of these regulations is projected to lead to the inability to economically modify existing subsea blow out preventers for use in the US OCS, leading to the replacement of these BOPs. Any modification costs listed above are solely for indicative purposes in the event of a limited adoption of the proposed rule as written and are not included in the cumulative costs in this study. The total projected cost of replacing subsea BOPs for use in the Gulf of Mexico OCS is projected at around $2.1 billion from 2017 to 2026 and annual average of around $210 million over the same period.

BSEE Approved Verification Organizations

BSEE Approved Verification Organizations (BAVO) are not defined by the regulations [§ 250.731 (c), § 250.731 (d), § 250.732 (a), § 250.732 (c), § 250.732 (e), § 250.733] and do not currently exist as proposed by the rule. As such it is not possible to calculate the cost that the involvement of these organizations will entail or the possible effects that delays in defining and approving these organizations may impose.

Section 8 - Extended Methodology Appendix

8.1 General Methodology

Quest's methodology focused on constructing a tiered "bottom-up" model that separated the complete life cycle of offshore operations and subsequent effects into four main categories – these categories are further developed into cases and presented as the Base Development scenario and Proposed Rule scenario within the paper. The four main categories are as follows;

- A "Rule" model that independently assesses the individual or combined effects of the proposed rules within "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control"
- An "Activity Forecast" model assessing Quest's project database and project modeling information under which the number of expected projects is developed
- A "Spending" model based on the requirements of developing projects within the "Activity Forecast"
- An "Economic" model focusing on the economic impact on employment and government revenue from the "Spending" model.

Three (Activity Forecast, Spending, and Economic models) of the four individual subsections were further split into five additional criteria that create an individual "Project" model. These categories include; seismic, leasing activity, drilling, infrastructure & project development, and production & operation. (Table 12)

Table 12: Oil and Gas Project Development Model – Aspects of Additional Criteria Included by Model

	Activity Forecast	Spending Model	Economic Model
Seismic	• Pre-Lease Seismic • Leased Block Seismic • Shoot Type	• Cost per acre	• Economic Activity due to seismic spending within states
Leasing	• Yearly lease sales for individual regions	• Bonus bid prices • Rental rate	• Federal and state revenues created through lease sales • Economic activity due to increased state/personal spending
Drilling	• Number of wells drilled • Water depth of wells drilled • Number of drilling rigs required	• Cost per well	• Economic activity due to activity within states
Project Development & Operation	• Project size • Project development time	• Spending per project • Per project spending timeline	• Division of state spending • Economic activity due to project development within states vicinity
Production	• Production type and amount	• Oil and gas price forecast	• Federal and state revenues created by royalty sharing • Economic activity due to increased states/personal spending

Source: Quest Offshore Resources, Inc.

In order to estimate the economic effects and project activity losses through the "Project" model, additional analysis was undertaken to understand which projects would be disrupted through the inability to discover and develop the reserves. This was presented through additional analysis of the Base Development scenario and is provided as the Proposed Rule scenario.

8.2 Rule Costing Methodology

The analysis of spending related to proposed "Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control" was undertaken through the individual analysis of each rule, while also considering the accretive effects of multiple rules placed upon similar equipment, tasks, and future opportunities. The cost of the proposed rule changes were analyzed on either the basis of time required to complete each activity or the replacement cost of equipment where applicable. Equipment costs were calculated using actual or estimated replacement costs depending on the availably of information. All costs are attempted to be calculated on the basis of the most economic reasonable method to overcome the burden imposed by the regulation. General assumptions used within the modeling are as followed:

- Engineering rate (daily) : $923[10]
- Drilling rate (daily) including spread costs[11]: $800 thousand for deepwater drilling, $250 thousand for shallow water drilling.

The determination of any further costs incurred through the loss of productivity within the region was undertaken through the application of the calculated costs and burdens of rules onto Quest's project and well forecast developed for this study from Quest's proprietary databases. The total cost of the rule was calculated through the combination of reanalyzing Quest's "Project", "Activity", "Spending", and "Economic" forecasts with the additional cost of the rule changes. The difference between the two cases, from a spending, economic, and regulatory perspective provide the total estimated "cost" of the rule.

8.3 Project Development Methodology

In order to account for both currently active projects within the Gulf of Mexico and longer-term prospects that will be developed towards the end of the forecast period into the study's project development activity, Quest incorporated two models into the project development forecast. The near-term activity was developed on known projects or prospects currently under consideration for development, while a longer term forecast was developed on top of the near-term forecast through the analysis of oil prices, leasing trends, development trends, historic project sizes and other relevant factors

The forecast of near term projects utilized Quest's Gulf of Mexico project database that encompasses all major portions of offshore field development (e.g. exploration, number of wells, length of pipelines, size of FPS unit, installation vessels, etc.). In addition to that information, lead times for project development, sanctioning trends and additional spending information led to the expected timeline

[10] Based on the most recent Society of Petroleum Engineers Salary Survey and estimates of total compensation costs.
[11] Based on current day rate and spread (additional drilling) costs from Quest Offshore Data.

and development costs of individual projects. The summation of these costs and timelines over all of the forecasted individual projects provided the total cost of near term projects.

Longer term projects were developed under a less independent methodology for individual projects. In the place of the project-specific spending model, Quest applied historical and current trends within the region to future developments (e.g. a greater focus on deep water oil projects as well as infield drilling and subsea infrastructure) in order to apply the proper costs and timelines to the expected activity. Projects were still delineated by individual timelines and the development scenarios that may be expected of future activity within the region, but were calculated using assumptions on industry trends in production methods instead of on confirmed aspects of the specific projects.

With regards to the Proposed Rule scenario, projects were examined for potential hurdles that would be encountered under the new regulations through several criteria identified from Quest and Blade's research. These topics were focused on emerging trends such as HPHT reservoirs, ultra-deep wells, projects developing already depleted reservoirs, as well as increased project costs. These identified factors drove the forecasted possibility of delays or lost activity due to project economics, technology-driven hurdles, or regulatory impasses. Furthermore, where necessary, additional costs were administered to subsections of projects where increased costs were to be expected for calculations in the economic model.

8.4 Project Spending Methodology

This spending analysis accounts for all capital investment and operational spending through the entire "life cycle" of operations. Every offshore oil or natural gas project must go through a series of steps in order to be developed. Initial expenditures necessary to identify targets and estimate the potential recoverable resources in place include seismic surveys (G&G) and the drilling and evaluation of exploration & appraisal (E&A) wells. For projects that are commercially viable, the full range of above-surface and below-water (subsea) equipment must be designed and purchased. Offshore equipment includes production platforms and on-site processing facilities, as well as below-water equipment generally referred to as SURF (Subsea, Umbilicals, Risers and Flowlines). Finally, the equipment must be installed and additional development wells must be drilled. Once under production, further operational expenditures (OPEX) are required to perform ongoing maintenance, production operations and other life extension activities as necessary for continued field production and optimization.

Spending for individual projects was subdivided into sixteen categories covering the complete life cycle of a single offshore project, as well as two additional groups for natural gas processing and operation. Timing and cost for individual categories were assigned based on the previously mentioned project types where prices are scaled according to the complexity and size of the project. (Table 13)

Table 13: Oil and Gas Project Spending Model

	Activity Model	Spending Model	Economic Model
Seismic (G&G)	• Number of leases • 2D vs. 3D	• Cost per acre	• Operation requirements
SURF	• Trees, manifolds, and other subsea equipment • Umbilicals • Pipelines, flowlines, and risers	• Cost per item • Cost per mile	• Fabrication locations
Platforms	• Fixed Platforms • Floating Production System	• Unit size	• Fabrication locations
Installation	• Surf Installation • Platform Installation	• Number of vessels • Type of vessels • Vessel dayrate	• Operation requirements • Shorebase locations
Drilling	• Exploration drilling • Development drilling	• Rig type • Rig dayrate	• Operating requirements • Shorebase locations
Engineering	• FEED	• CAPEX • OPEX	• Technological centers
Operating Expenditures (OPEX)	• Supply and personnel requirements • Project maintenance • Project reconfiguration	• Type of project and associated infrastructure	• Shorebase locations

Source: Quest Offshore Resources, Inc.

Upon compiling the scenario of overall spending estimates, Quest deconstructed the "local content" of oil and gas operations within the studied region. Individual tasks were analyzed on a component-by-component basis to provide an estimate of the percentage of regional, national, and international construction required by offshore operations. Additionally, delineations were made at the regional level in order to project spending for individual states. Considerations were based on current oil and gas development, the proximity to reserves and production, strategic locations such as shore bases and ports, as well as Bureau of Economic Analysis (BEA) data pertaining to each state's present economic distribution.

8.5 Economic Methodology

The study's GDP and job data were calculated using the BEA's RIMs II Model providing an input-output multiplier on spending at the industry and state levels for each defined category. Model outputs considered from spending effects include number of jobs and GDP multiplier effects. Further delineation is presented in the form of direct and indirect and induced job numbers, which encompass the number of jobs relating to the spending in that category versus indirect and induced jobs that are created from pass-through spending. For states considered within the study that contained no RIMs II multipliers for specific sectors, state multiplier from economies that most closely paralleled those in question were replicated.

Rims Categories used:

- Architectural, Engineering, and Related Services
- Construction
- Drilling Oil and Gas Wells
- Fabricated Metal Product Manufacturing

- Mining and Oil and Gas Field Machinery Manufacturing
- Oil and Gas Extraction
- Steel Product Manufacturing from Purchased Steel
- Support Activities for Oil and Gas Operations

8.6 Governmental Revenue Development

Governmental revenue data is presented in three categories; bonus bids from lease sales, rents from purchased but not yet developed leases, and royalty payments from producing leases. The projected revenue was calculated under the assumption that the current operating structure of the Gulf of Mexico would remain in place where applicable. Lease sales and rental rates were calculated through the simulation of yearly lease sales within each individual area, while the number of leases acquired was modeled on oil price forecasts, historical rates, and on the estimated amount of reserves in the western and central OCS regions.

The federal / state government revenue split of leases, rents and royalties were modeled under the application of GOMESA (Gulf of Mexico Energy Security Act). As Quest understands the rule and phase II beginning in 2017, GOMESA regulations would effectively split 37.5 percent of OCS bonus bid, rent, and royalty income between the appropriate states. GOMESA has an annual revenue cap of $500 million for the Gulf States.

Production pricing were calculated using the EIA estimates for both West Texas Intermediate (WTI) spot and Henry Hub natural gas prices[12]. Additional governmental revenues such as income and corporate taxes were considered outside of the scope of this study, and are likely to provide additional government revenues throughout the studied period.

[12] United States. Energy Information Administration. *Annual Energy Outlook 2015*. Energy Information Administration, 14 April 2015.

Section 9 – Additional Tables Appendix

Table 14: Annual Compliance Costs by Affected Activity or Equipment – Proposed Rule Scenario ($Millions)

Category	2017	2018	2019	2020	2021	2022	2023
BOP Replacement or Modification	$822	$856	$1,246	$1,223	$1,184	$1,225	$1,163
Compliance and Documentation	$9	$11	$10	$10	$11	$10	$10
Containment	$112	$113	$177	$177	$186	$83	$82
Rig Requirements	$175	$186	$181	$185	$186	$176	$171
Real Time Monitoring (RTM)	$69	$69	$71	$63	$55	$50	$46
Tubing and Wellhead Equipment	$33	$0	$1	$1	$1	$0	$0
Well Design	$1,441	$1,205	$1,312	$1,395	$1,380	$1,387	$1,243
Grand Total	**$2,661**	**$2,441**	**$2,997**	**$3,055**	**$3,003**	**$2,931**	**$2,715**

Category	2024	2025	2026	2027	2028	2029	2030
BOP Replacement or Modification	$712	$752	$823	$918	$1,038	$914	$851
Compliance and Documentation	$10	$9	$12	$11	$13	$12	$14
Containment	$82	$83	$83	$74	$77	$78	$79
Rig Requirements	$171	$171	$191	$205	$225	$224	$225
Real Time Monitoring (RTM)	$47	$48	$47	$40	$54	$83	$61
Tubing and Wellhead Equipment	$0	$0	$1	$1	$1	$1	$1
Well Design	$1,112	$1,253	$1,427	$1,547	$1,741	$1,901	$1,943
Grand Total	**$2,135**	**$2,317**	**$2,584**	**$2,795**	**$3,148**	**$3,212**	**$3,175**

Source: Quest Offshore Resources, Inc.

Table 15: Annual Compliance Costs by Affected Activity or Equipment – Base Development Scenario ($Millions)

Category	2017	2018	2019	2020	2021	2022	2023
BOP Replacement or Modification	$925	$926	$1,336	$1,331	$1,373	$1,465	$1,419
Compliance and Documentation	$11	$12	$11	$12	$13	$13	$14
Containment	$113	$114	$179	$181	$190	$99	$97
Rig Requirements	$204	$205	$205	$215	$239	$239	$240
Real Time Monitoring (RTM)	$74	$72	$73	$85	$83	$52	$56
Tubing and Wellhead Equipment	$33	$1	$1	$1	$1	$1	$1
Well Design	$1,062	$1,470	$1,597	$1,721	$1,691	$1,739	$1,551
Grand Total	**$2,421**	**$2,800**	**$3,402**	**$3,547**	**$3,589**	**$3,606**	**$3,378**

Category	2024	2025	2026	2027	2028	2029	2030
BOP Replacement or Modification	$978	$1,041	$1,052	$1,133	$1,233	$1,120	$1,047
Compliance and Documentation	$13	$12	$15	$15	$14	$15	$16
Containment	$98	$85	$86	$76	$80	$139	$146
Rig Requirements	$244	$247	$250	$259	$272	$273	$274
Real Time Monitoring (RTM)	$63	$63	$50	$66	$59	$95	$92
Tubing and Wellhead Equipment	$1	$1	$1	$1	$1	$1	$1
Well Design	$1,357	$1,601	$1,830	$1,981	$2,186	$2,470	$2,382
Grand Total	**$2,753**	**$3,050**	**$3,284**	**$3,531**	**$3,845**	**$4,113**	**$3,957**

Source: Quest Offshore Resources, Inc.

Table 16: US Gulf of Mexico Production by Type – Proposed Rule Scenario (Thousands)[13]

Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Oil - BOE/D	1,563	1,338	1,292	1,275	1,411	1,499	1,634	1,693	1,724	1,745	1,760
Gas - BOE/D	1,119	909	765	662	634	548	550	541	544	555	574
Total	**2,682**	**2,248**	**2,056**	**1,937**	**2,045**	**2,047**	**2,183**	**2,234**	**2,268**	**2,299**	**2,334**

Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil - BOE/D	1,758	1,742	1,730	1,718	1,712	1,717	1,730	1,733	1,740	1,748
Gas - BOE/D	593	613	635	656	683	718	760	796	834	876
Total	**2,351**	**2,355**	**2,364**	**2,374**	**2,396**	**2,435**	**2,490**	**2,529**	**2,573**	**2,623**

Source: Quest Offshore Resources, Inc.

Table 17: US Gulf of Mexico Production by Type – Base Development Scenario (Thousands)

Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Oil - BOE/D	1,563	1,338	1,292	1,275	1,411	1,499	1,634	1,722	1,799	1,833	1,874
Gas - BOE/D	1,119	909	765	662	634	548	550	558	583	602	634
Total	**2,682**	**2,248**	**2,056**	**1,937**	**2,045**	**2,047**	**2,183**	**2,280**	**2,381**	**2,435**	**2,508**

Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Oil - BOE/D	1,916	1,920	1,938	1,944	1,969	1,990	2,018	2,035	2,044	2,051
Gas - BOE/D	674	704	742	774	817	863	915	963	1,006	1,052
Total	**2,590**	**2,624**	**2,679**	**2,718**	**2,787**	**2,852**	**2,933**	**2,999**	**3,050**	**3,104**

Source: Quest Offshore Resources, Inc.

Table 18: Government Revenues by Source – Proposed Rule Scenario ($Millions)

Revenue Source	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rent	$238	$218	$218	$236	$232	$182	$217	$236	$237	$241	$263
Bids	$920	$325	$1,815	$1,299	$976	$707	$1,041	$1,041	$1,051	$1,039	$1,161
Royalties	$5,203	$5,635	$5,481	$5,684	$5,870	$4,288	$5,755	$6,112	$6,245	$6,466	$6,685
Total	**$6,361**	**$6,177**	**$7,515**	**$7,219**	**$7,079**	**$5,177**	**$7,013**	**$7,389**	**$7,533**	**$7,746**	**$8,110**

Revenue Source	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rent	$263	$291	$294	$290	$306	$333	$331	$338	$350	$370
Bids	$1,135	$1,249	$1,252	$1,231	$1,286	$1,389	$1,373	$1,392	$1,432	$1,502
Royalties	$6,869	$7,017	$7,195	$7,368	$7,573	$7,859	$8,160	$8,418	$8,706	$8,998
Total	**$8,267**	**$8,557**	**$8,740**	**$8,889**	**$9,164**	**$9,580**	**$9,865**	**$10,148**	**$10,488**	**$10,870**

Source: Quest Offshore Resources, Inc.

[13] 2010 to 2014 Production is actual production.

Table 19: Government Revenues by Source – Base Development Scenario ($Millions)

Revenue Source	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rent	$238	$218	$218	$236	$232	$182	$217	$245	$261	$247	$281
Bids	$920	$325	$1,815	$1,299	$976	$707	$1,041	$1,084	$1,158	$1,067	$1,237
Royalties	$5,203	$5,635	$5,481	$5,684	$5,870	$4,288	$5,755	$6,296	$6,631	$6,948	$7,311
Total	**$6,361**	**$6,177**	**$7,515**	**$7,219**	**$7,079**	**$5,177**	**$7,013**	**$7,625**	**$8,050**	**$8,262**	**$8,828**

Revenue Source	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Rent	$275	$285	$298	$305	$342	$322	$337	$341	$373	$391
Bids	$1,188	$1,222	$1,270	$1,294	$1,437	$1,344	$1,397	$1,404	$1,525	$1,590
Royalties	$7,725	$8,012	$8,385	$8,708	$9,130	$9,582	$10,046	$10,477	$10,879	$11,273
Total	**$9,188**	**$9,518**	**$9,953**	**$10,307**	**$10,909**	**$11,247**	**$11,780**	**$12,222**	**$12,777**	**$13,254**

Source: Quest Offshore Resources, Inc.

Table 20: Project Development Spending by Component – Proposed Rule Scenario ($Millions)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Drilling	$6,069	$6,270	$8,188	$7,610	$9,411	$7,862	$8,069	$8,547	$9,611	$10,611	$10,404
Engineering	$2,098	$2,517	$2,206	$2,022	$1,940	$1,297	$2,463	$3,065	$2,981	$2,632	$2,522
G&G	$183	$163	$348	$368	$439	$319	$372	$321	$305	$354	$383
Install	$1,918	$631	$762	$2,791	$2,995	$1,442	$1,084	$837	$1,152	$1,401	$1,377
OPEX	$19,533	$19,466	$18,920	$18,355	$17,836	$17,845	$17,766	$17,629	$17,052	$16,791	$16,351
Platforms	$3,215	$4,150	$3,620	$2,715	$2,530	$1,700	$2,960	$1,717	$2,105	$2,025	$1,922
SURF	$2,098	$2,513	$2,051	$1,613	$1,503	$1,144	$2,213	$2,781	$2,545	$2,640	$2,686
Total	**$35,114**	**$35,710**	**$36,095**	**$35,473**	**$36,653**	**$31,609**	**$34,927**	**$34,897**	**$35,750**	**$36,454**	**$35,643**

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Drilling	$9,329	$8,487	$7,827	$7,714	$8,034	$9,061	$11,381	$13,610	$13,692	$13,057
Engineering	$2,583	$2,809	$2,809	$3,123	$3,814	$4,066	$3,412	$2,591	$2,482	$2,585
G&G	$413	$414	$403	$392	$391	$399	$423	$451	$473	$475
Install	$1,069	$1,051	$1,325	$1,522	$1,134	$851	$1,364	$1,966	$1,958	$1,849
OPEX	$15,983	$15,866	$15,379	$15,153	$14,655	$14,485	$14,471	$13,797	$13,566	$14,253
Platforms	$2,100	$2,666	$2,383	$2,453	$3,223	$3,418	$2,253	$1,312	$1,795	$2,058
SURF	$2,800	$2,870	$2,862	$2,651	$3,272	$3,491	$3,031	$2,334	$2,170	$2,257
Total	**$34,276**	**$34,163**	**$32,987**	**$33,007**	**$34,523**	**$35,771**	**$36,336**	**$36,061**	**$36,136**	**$36,534**

Source: Quest Offshore Resources, Inc.

Table 21: Project Development Spending by Component – Base Development Scenario ($Millions)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Drilling	$6,069	$6,270	$8,188	$7,610	$9,411	$7,862	$8,069	$8,271	$10,350	$12,436	$12,977
Engineering	$2,098	$2,517	$2,206	$2,022	$1,940	$1,297	$2,463	$2,849	$2,775	$2,171	$2,008
G&G	$183	$163	$348	$368	$439	$319	$372	$357	$339	$393	$426
Install	$1,918	$631	$762	$2,791	$2,995	$1,442	$1,084	$924	$1,416	$2,182	$2,539
OPEX	$19,533	$19,466	$18,920	$18,355	$17,836	$17,845	$17,766	$17,629	$17,326	$17,263	$16,671
Platforms	$3,215	$4,150	$3,620	$2,715	$2,530	$1,700	$2,960	$3,443	$3,933	$3,134	$2,914
SURF	$2,098	$2,513	$2,051	$1,613	$1,503	$1,144	$2,213	$2,617	$2,418	$1,968	$2,027
Total	**$35,114**	**$35,710**	**$36,095**	**$35,473**	**$36,653**	**$31,609**	**$34,927**	**$36,089**	**$38,557**	**$39,548**	**$39,563**

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Drilling	$11,106	$9,223	$9,272	$9,274	$9,156	$10,543	$12,255	$14,324	$14,845	$15,305
Engineering	$2,127	$2,373	$2,448	$2,684	$3,246	$3,813	$3,417	$2,395	$1,877	$1,703
G&G	$459	$460	$448	$435	$435	$443	$470	$501	$526	$527
Install	$2,051	$1,936	$2,253	$2,433	$1,943	$1,393	$1,745	$2,764	$3,325	$3,655
OPEX	$16,810	$17,390	$16,854	$16,500	$15,973	$15,983	$15,924	$15,990	$15,676	$16,148
Platforms	$3,245	$3,844	$3,942	$3,932	$4,355	$5,045	$4,792	$3,572	$3,182	$2,674
SURF	$2,282	$2,396	$2,207	$2,394	$3,003	$3,376	$3,055	$2,181	$1,712	$1,546
Total	**$38,080**	**$37,620**	**$37,424**	**$37,652**	**$38,111**	**$40,596**	**$41,657**	**$41,726**	**$41,142**	**$41,557**

Source: Quest Offshore Resources, Inc.

Table 22: Government Revenues by Recipient – Proposed Rule Scenario ($Millions)

Revenue	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Federal Share	$6,359	$6,176	$7,515	$7,219	$7,075	$5,172	$7,008	$6,889	$7,033	$7,246	$7,610
State Totals	$3	$1	$0	$0	$4	$5	$5	$500	$500	$500	$500
Texas	$0	$0	$0	$0	$0	$1	$1	$150	$150	$150	$150
Louisiana	$1	$0	$0	$0	$1	$2	$2	$150	$150	$150	$150
Mississippi	$1	$0	$0	$0	$1	$1	$1	$125	$125	$125	$125
Alabama	$1	$0	$0	$0	$1	$1	$1	$75	$75	$75	$75

Revenue	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Federal Share	$7,767	$8,057	$8,240	$8,389	$8,664	$9,080	$9,365	$9,648	$9,988	$10,370
State Totals	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
Texas	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150
Louisiana	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150
Mississippi	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125
Alabama	$75	$75	$75	$75	$75	$75	$75	$75	$75	$75

Source: Quest Offshore Resources, Inc.

Table 23: Government Revenues by Recipient – Base Development Scenario ($Millions)

Revenue	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Federal Share	$6,359	$6,176	$7,515	$7,219	$7,075	$5,172	$7,008	$7,125	$7,550	$7,762	$8,328
State Totals	$3	$1	$0	$0	$4	$5	$5	$500	$500	$500	$500
Texas	$0	$0	$0	$0	$0	$1	$1	$150	$150	$150	$150
Louisiana	$1	$0	$0	$0	$1	$2	$2	$150	$150	$150	$150
Mississippi	$1	$0	$0	$0	$1	$1	$1	$125	$125	$125	$125
Alabama	$1	$0	$0	$0	$1	$1	$1	$75	$75	$75	$75

Revenue	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Federal Share	$8,688	$9,018	$9,453	$9,807	$10,409	$10,747	$11,280	$11,722	$12,277	$12,754
State Totals	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
Texas	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150
Louisiana	$150	$150	$150	$150	$150	$150	$150	$150	$150	$150
Mississippi	$125	$125	$125	$125	$125	$125	$125	$125	$125	$125
Alabama	$75	$75	$75	$75	$75	$75	$75	$75	$75	$75

Source: Quest Offshore Resources, Inc.

Table 24: Total Employment – Base Development and Proposed Rule Scenarios in Thousands

Scenario	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Base Direct	139	139	136	140	142	118	134	139	146	148	148
Base Indirect	270	271	272	272	279	245	266	280	294	301	300
Proposed Direct	139	139	136	140	142	118	134	134	136	138	135
Proposed Indirect	270	271	272	272	279	245	266	277	281	285	278
Base Total	**409**	**409**	**408**	**412**	**421**	**363**	**400**	**419**	**441**	**449**	**449**
Proposed Total	**409**	**409**	**408**	**412**	**421**	**363**	**400**	**412**	**417**	**423**	**413**

Scenario	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base Direct	144	145	145	148	150	158	159	156	154	155
Base Indirect	290	287	285	286	288	303	309	311	307	312
Proposed Direct	131	133	130	131	137	141	139	135	135	136
Proposed Indirect	267	266	257	257	266	274	278	276	275	278
Base Total	**434**	**433**	**430**	**434**	**438**	**461**	**469**	**467**	**460**	**467**
Proposed Total	**398**	**399**	**387**	**388**	**403**	**415**	**418**	**411**	**409**	**414**

Source: Quest Offshore Resources, Inc.

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