Final Regulatory Impact Analysis for the Final Rule on Increased Safety Measures for Energy Development on the Outer Continental Shelf

RIN 1014-AA02

Bureau of Safety and Environmental Enforcement

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EXECUTIVE SUMMARY

This document describes the regulatory impact analysis (RIA) conducted for the final rule, RIN 1014-AA02, Increased Safety Measures, Drilling Operations on the Outer Continental Shelf (OCS). On October 14, 2010 BSEE' predecessor agency published an Interim Final Rule (75 FR 63346) as RIN 1010 AD68 addressing certain recommendations from the Safety Measures Report, and soliciting public comment on the Interim Final Rule. The Interim Final Rule was effective immediately, with a 60-day comment period. The Final Rule will modify, in part, provisions of the Interim Final Rule based on comments received, however many of the provisions adopted October 14, 2010, are retained without change. The resulting changes from the draft benefit cost analysis published with the interim final rule (IFR) are minor and are mostly found in the compliance cost estimates for the final rulemaking. Because of regulatory changes in the final rule, revised cost assumptions and estimated drilling activity, the estimated annual compliance costs is reduced to $131 million from $183 million in the IFR.

Various events around the world as well as the US over the years demonstrate that catastrophic oil spills can and do occur. The costs associated with such spills can be enormous. As a matter of policy, BSEE has decided that any reasonable measures to reduce the risks of another catastrophic spill occurring on the OCS should be put in place and enforced. The requirements included in this rulemaking are such measures. They were identified in the May 27, 2010 report, Increased Safety Measures for Energy Development on the Outer Continental Shelf, for which the recommendations were peer-reviewed by seven experts identified by the National Academy of Engineering, or identified by industry or academic experts in materials presented to BSEE as part of the public forums and information gathering. Also on September 14, 2011 BSEE's predecessor agency published the final joint investigation report on the causes of the Deepwater Horizon incident, which included multiple regulatory recommendations. Upon review of the report recommendations, BSEE decided to include in the interim final rule only those recommendations that are appropriate for change without public comment (i.e. updating definitions and clarifications). The remainder of the report recommendations will be addressed through future rulemakings subject to public comment procedures.

While the estimated costs of this rulemaking, as reflected in the compliance costs of the enumerated requirements of approximately $131 million per year are based on updated BSEE estimates from surveys of public and industry sources, quantification of the benefits is uncertain. The benefits are represented by the avoided costs of a catastrophic spill, which are estimated under the stipulated scenario as being $16.3 billion per spill avoided. These regulations will reduce the likelihood of another blowout and associated spill, but the risk reduction associated with the specific provisions of this rulemaking cannot be quantified because there are many complex factors that affect the risk of a blowout event. As noted by the Secretary of the Interior in his July 12, 2010 decision memo suspending certain drilling activities, drilling accidents can have a profound, devastating impact on the economic and environmental health of a region. The measures codified in this rule will reduce the likelihood of such an event in the future, at a cost that is not prohibitive, and therefore this rulemaking is justified.

The purpose of a benefit-cost analysis is to provide policy makers and others with detailed information on the economic consequences of the regulatory requirements. The benefit-cost analysis for this rule was conducted using a scenario analysis. This analysis considers a regulation designed to reduce the likelihood of a catastrophic oil spill. The costs are the compliance costs of imposed regulation. If another catastrophic oil spill is prevented, the benefits are the avoided costs associated with a catastrophic oil spill (e.g., reduction in expected natural resource damages owing to the reduction in likelihood of failure).

Avoided cost is an approximation of the “true” benefits of avoiding a catastrophic oil spill. A benefits transfer approach is used to estimate the avoided costs. The benefits transfer method estimates economic values by transferring existing benefit calculations from studies already completed for another location or issue to the case at hand. Accordingly, none of the avoided costs used in this analysis of hypothetical catastrophic spills rely upon, or should be taken to represent, our estimate for the DWH event commencing on April 20, 2010.

Three new requirements account for most of the compliance costs imposed by this regulation. These are (1) use of dual barriers in the final casing string to prevent hydrocarbon flow in the event of cement failure, (2) application of negative pressure tests to the production casing string for wells drilled with a subsea BOP, and (3) testing time for the ROV to close BOP rams after the BOP has been installed on the sea floor. BSEE estimates that these three requirements will impose compliance costs of approximately $118 million per year, representing 91 percent of the total annual compliance costs of $131million associated with this rulemaking. These cost estimates were developed based on public data sources, prior experience and confidential information provided by several offshore operators and drilling companies. The $131 million estimated annual compliance costs are 29 percent less than the $183 million cost estimate for the interim final rule, largely reflecting a reduced estimate of the time it takes to conduct an ROV function test when the BOP is on the seafloor and lower negative pressure test costs resulting from relaxed testing requirements in the final rule relative to the IFR. These reduced costs are partly offset by the costs associated with a revision that precludes use of a float valve to meet the criteria for a second mechanical barrier and by inclusion of paperwork costs omitted from the estimates in the interim final rule.

On the benefit side, the avoided costs for a representative deepwater blowout resulting in a catastrophic oil spill are estimated to be about $16.3 billion (in 2010 dollars).[1] Most of this amount derives from detailed cleanup estimates developed by the Department of the Interior Office of Policy Analysis using damage costs per barrel measures found in historical spill data (from all sources including pipeline, tanker, and shallow water as well as deepwater wells) and from aggregate damage measures contained in the legal settlement documents for past spills applied to a catastrophic deepwater spill of hypothetical size. The rest of this avoided cost amount represents the private costs for blowout containment operations. In sum, three components account for nearly the entire avoided spill cost total: (1) natural resource damage to habitat and creatures, 2) infrastructure salvage and cleanup operations of areas soiled by oil, and (3) containment and well-plugging actions plus lost hydrocarbons.

We believe that the compliance cost estimates are closer to the actual cost than those used in the IFR because of the information gathered since deepwater drilling resumed in the GOM in the Spring of 2011. On the benefit side, the total avoided cost estimate of $16.3 billion (representing a measure of expected benefits for avoiding a future catastrophic oil spill) has not been revised. The true magnitude of an avoided spill is highly uncertain because of the limited historical data upon which to judge the cost of failure, the disparity between the damages associated with spills of different sizes, locations, and season of occurrence, and owing to the fact that the measure employed reflects only those outlays that we have been able to calculate based primarily upon data derived from past oil spills. Possible avoided losses from human health effects or reduced property values have not been quantified in this analysis. Moreover, the likelihood of a future blow out leading to a catastrophic oil spill is difficult to quantify because of limited historical data on catastrophic offshore blowouts.

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[1] We note that the estimates of avoided damages contained in this document, while a useful tool for the purpose of this benefit-cost exercise, are not relevant in calculating damages for any particular oil spill, including the DWH spill. Although the hypothetical spill discussed in this document is similar in volumetric magnitude to estimations of the amount of oil released as a result of the DWH event, damages are highly specific to a particular event, and depend on a multitude of complex and interacting factors. This report addresses a hypothetical Gulf of Mexico spill that is not intended to correspond to any real event, and whose characteristics have been designed to permit modeling and analysis, rather than being designed to reflect to the facts of a specific event or set of events. This document is also not able to incorporate scientific data relating to the specific circumstances of a particular spill or to any other specific spill, among other limitations of the model and analysis applied in this report. Moreover, the nature of the economic analysis contained in this document, and the space limitations of this document, have required that a number of potential factors be excluded from the scope of the analysis, or have entailed other changes. Additionally, the estimate of potential costs avoided used in this analysis do not reflect an assessment or quantification of the costs of injury or fatality resulting from the DWH event. As such, the damage and cost estimates presented herein should not be considered reliable monetary assessments associated with the DWH event. This document is only intended to provide a cost-benefit analysis for a defined regulatory purpose, and is not intended to be used, and should not be used, for any other purpose or in any other situation. In particular, estimates contained in this report are not intended to be used, nor are of any relevance, in litigation relating to damages resulting from the DWH spill or any other spill.

Based on the occurrence of only a single catastrophic blowout, the number of GOM deepwater wells drilled historically (4,123), and the forecasted future drilling activity in the GOM (160 deepwater wells per year), we estimate the baseline risk of a catastrophic blowout to be about once every 26 years. Combining the baseline likelihood of occurrence with the cost of a representative spill implies that the expected annualized damage cost absent this regulation is $631 million ($16.3 billion once in 26 years, equally likely in any 1 year). To balance the $131 million annual cost imposed by these regulations with the expected benefits, the reliability of the well control system needs to improve by 21 percent ($131 million / $631 million). We have found no studies that evaluate the degree of actual improvement that could be expected from dual barriers, negative pressure tests, and a seafloor ROV function test and no additional information was provided during the public comment period. However, based upon the blowout risk reduction that would be achieved primarily from the three most critical safety provisions required by the Interim Final Rule and the Final Rule, it is reasonable to conclude that this rulemaking will reduce the risk for a catastrophic blowout spill event at least enough such that benefits will justify the costs estimated to be imposed by the regulation, or, at a minimum, 21 percent.

INTRODUCTION AND NEED FOR FEDERAL ACTION

Investigative Reports

The final rule amends drilling regulations related to well control in response to recommendations in the Increased Safety Measures Report (Safety Measures Report) that DOI sent to the President on May 27, 2010.[2] This regulation will affect all lessees and operators undertaking drilling operations on the OCS. The Safety Measures Report identified four items for emergency rulemaking:

(1) Develop secondary control system requirements;
(2) Establish new blind-shear ram redundancy requirements;
(3) Establish new deepwater well control procedure requirements; and
(4) Adopt safety case requirements for floating drilling operations on the OCS.

The provisions of this final rule address items 1) secondary control system requirements and 3) deepwater well control procedure requirements. The rule does not include 2) new blind-shear ram redundancy requirements and 4) safety case requirements for floating drilling operations. These and other items in the Safety Measures Report require further study by industry and the Department of Interior to determine their efficiency and effectiveness. Measures considered beneficial will be proposed for future notice and comment rulemaking.

The Joint Investigation Team (JIT) report conducted by BSEE and the United States Coast Guard into the rig operations, and subsequent explosion, fire and sinking of the Mobile Offshore Drilling Unit (MODU) Deepwater Horizon made several recommendations consistent with the regulatory provisions in this rule.[3] This final rule only includes the recommendations from the JIT report that are within the scope of this rulemaking. The only changes made to this rulemaking from the JIT recommendations involve updating certain definitions and adding clarifications including that a dual float valve by its self is not considered a mechanical barrier. Other JIT report recommendations will be addressed in other future rulemakings and will be available for public comment.

The report by the Presidential Oil Spill Commission recommended the Department of the Interior should require offshore operators seeking its approval of proposed well design to

[2]Increased Safety Measures for Energy Development on the Outer Continental Shelf, May 27, 2010, available at: http://www.doi.gov/deepwaterhorizon/loader.cfm?csModule=security/getfile&PageID=33598; Joint
[3] BOEMRE/USCG Report Regarding the Causes of the April 20, 2010 Macondo Well Blowout, available at: http://www.boemre.gov/pdfs/maps/DWHFINAL.pdf

demonstrate that wells are designed to mitigate risks to well integrity during post-blowout containment efforts.[4]

This final rule requires additional testing for the BOP stacks on the seafloor and professional engineering certification of well design. It does not require subsea BOP stacks to be fitted with additional controls and sensors beyond the existing dual blue and yellow control pods. Similar to the regulatory recommendations in other reports, appropriate Oil Spill Commission recommendations will be addressed through future rulemakings.

Need for Well Control and Voluntary Measures

In general, procedures for maintaining or regaining well control can be divided into primary and secondary measures. *Primary* measures include items such as the use of drilling mud, casing and cementing to keep the well under control. These requirements will strengthen primary well control barriers thereby reducing the likelihood that secondary barriers, like the BOPs, will be needed. *Secondary* measures include the BOP stack and its redundant control devices to seal the well and prevent environmental or safety impacts in the case of a blowout event. The final rule also requires increased testing of secondary measures including a check of remotely operated vehicle (ROV) intervention capability and deadman switch on the seafloor to better assure backstop activation of the subsea BOP, should the need arise. These requirements provide greater protections against a catastrophic blowout event. Effective secondary measures eliminate or reduce the urgency of completing a relief well to stanch the flow of oil after a blowout.

The Secretary of the Interior (Secretary) has the duty to ensure that operations on the Outer Continental Shelf (OCS) are managed in a safe manner, under the authority of the OCS Lands Act (OCSLA). Section 21(b) of the OCS Lands Act provides guidance on the discharge of this duty as follows.

> *the Secretary . . . shall require, on all new drilling and production operations and, wherever practicable, on existing operations the use of the best available and safest technologies which the Secretary determines to be economically feasible, wherever failure of equipment would have a significant effect on safety, health, or the environment, except where the Secretary determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies.*

[4] Report of the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, Part III, Lessons Learned: Industry, Government, Energy Policy http://www.oilspillcommission.gov/sites/default/files/documents/FinalReportPartIII.pdf, p. 275.

The BSEE and BOEM carry out this duty through regulations, inspection of OCS oil and gas operations, the terms and conditions of leases and conditions of exploration and development plan approval. Although current regulations extensively address shallow and deepwater drilling operations, the DWH event and related investigations revealed that those regulations insufficiently protect the environment and those conducting operations on the OCS under certain situations.

There are other rationales for this regulation. The first relates to the uncertainty associated with actual damages and related magnitude of liability for those damages, and how that uncertainty may adversely influence operator behavior. Another rationale relates to information asymmetries. The regulatory regime in effect before promulgation of the interim final rule, wherein certain information did not come to the attention of regulators until after the event, perhaps provided too little information to regulators regarding the effectiveness of safe operating incentives embodied in the then existing regulatory regime. A more *prescriptive* regime, such as that contained in the interim final rule and the final rule, could assist in this regard by providing society with greater transparency and assurance that safety measures on all operations perform as expected. Lastly, because of statutory liability limits and the potential to avoid liability by declaring bankruptcy, offshore operators may take certain risks and cost-cutting actions absent explicit federal requirements relating to safety and the environment.

The regulatory changes published in these new drilling regulations are designed to reduce both the frequency of a catastrophic spill and the severity of its impact (through a shorter period of discharge). The frequency of deepwater well control events (blowouts) that could lead to a spill does not appear to have changed materially over time. Historic data shows that blowout frequencies on the OCS have stabilized at about 1 for every 275 deepwater wells over the last several decades (see the Baseline, Section - Chance of another Spill for a more in-depth discussion). Thus, while a greater number of deepwater wells are being drilled in ever deeper water depths, this history indicates that normal evolution of deepwater practices may not have materially reduced the chance of a blowout event. Moreover, a blowout may pose more problems in deepwater where drilling a relief well is likely to take longer. Hence prescriptive regulations are being instituted to increase the control measures that will manage and contain a blowout event with a greater degree of reliability.

We recognize that liability implications and increased insurance costs may compel changes by drilling companies independent of these regulations. Accordingly, BSEE’s predecessor agency (BOEMRE) commissioned an outside assessment of the voluntary measures proposed by Joint Industry Task Forces (JITFs) in May, 2010 as compared to these regulations. (See Appendix F). While the lessons learned or other measures have not been fully implemented, an assessment of existing JITF proposals serve as guidance on how much of the additional costs industry may incur are not really imposed by the new regulations. Joint Industry Task Force draft recommendations include use of mechanical barriers and negative pressure tests which happen to account for a substantial share of the compliance costs we attribute to the final rule. We did not adjust for these potential voluntary actions, so for this reason our compliance cost estimate may be higher than the actual costs imposed by this rule.

While voluntary measures by industry may result in some of the same changes, the federal government has an obligation to protect offshore workers, the environment and our economic interests with regulations that make critical changes in systems legally enforceable. The catastrophic failure of the primary and secondary barriers on the Macondo well (the location of the DWH blowout) supports federal regulations intended to reduce the identified risks.

HISTORICAL INFORMATION ABOUT BLOWOUTS

The "no action" baseline is the recent Gulf of Mexico deepwater oil and gas activity levels and the historical rate of events up to and including the April 20, 2010 DWH blowout. The DWH spill is the first U.S. Gulf of Mexico catastrophic deepwater blowout spill.

Shallow Water Drilling Activity

While well control incidents actually occur more frequently in shallow water, the consequences and spill damage resulting from a blowout tends to be less than in deep water due to the generally lower reservoir pressure, the greater prevalence of gas rather than oil, and the presence of more accessible surface BOPs with diverters. From 1990-2010 BSEE has recorded 6 GOM shallow water well control incidents resulting in a spill of hydrocarbons. The total volume spilled is estimated to be 132 barrels of oil or condensate over these last two decades. If we go back another 20 years to 1970, we add another 6 spills for total hydrocarbon spill volume of 138.5 barrels from 12 blowout events over the last 40 years in the GOM. Since 1970 there have been 32,339 shallow water wells drilled in the GOM and since 1990 there have been 13,675 shallow water wells drilled. Over this period there have been several major revisions to the drilling regulations and some of these regulatory changes have specifically addressed drilling risks in shallow water.

While minimal drilling activity has occurred in the Alaska program areas, spill frequencies are expected to be lower than the Gulf of Mexico. This result excludes consequences. The study supporting this conclusion (Bercha 2008) uses different spill sizes and probabilities than used in this analysis for a catastrophic spill event, but the conclusion remains. Because the

overwhelming share of historical OCS wells and future shallow water drilling is expected to be in the GOM, this analysis relies on historical GOM data.
Approximately 81 percent of the compliance costs for this regulation fall on deepwater wells. Thus, in our analysis the baseline chance of another spill and the calculation of avoided costs focus exclusively on a scenario in which hypothetical catastrophic *deepwater* blowout events may occur randomly at some periodic rate based on the historical evidence.

Deepwater Drilling Activity
BSEE obtained these historical data on deepwater drilling from its Technical Information Management System database. There have been 4,123 wells spudded between 1973 and mid-2010 not counting bypasses in water depths of at least 500 feet.

There have been 20 OCS deepwater blowouts in the history of the program with 3 resulting in a spill during drilling operations. Only one deepwater blowout has resulted in a spill of a catastrophic size. The other two deepwater blowout spills were estimated to be 11 and 200 barrels of crude/condensate spilled.

The 20 deepwater blowouts average one blowout for about every 200 deepwater wells drilled on the OCS. The average number of wells between blowouts increased until about 1990 but has since leveled off at about one for every 275 deepwater wells.

Baseline Size and Duration of a Catastrophic Deepwater Blowout Spill
Since the baseline for this regulatory analysis is the world at the time of the DWH spill and without these regulations, we are using an estimate of spill volume similar to the government volumetric estimate of the DWH event. Estimates of potential natural resource damages and other avoided costs are based upon this blowout spill volume but in all other respects are derived from information not specific to this spill.

The baseline size and duration of the catastrophic spill used in this analysis is taken from the National Incident Command's ("NIC") updated estimate of August 2, 2010 of the DWH spill. The scientific team charged by the NIC with determining flow rate concluded that 53,000 barrels of oil per day were leaking from the well immediately before closure by the capping stack on July 15, 2010. Measurements and modeling showed that, as a result of depletion of the reservoir, the daily flow rate decreased over the 87 days prior to the capping of the well; the scientific team estimated at the beginning of the spill, the flow rate was 62,000 barrels per day. BSEE is using the estimate of 53,000 barrels a day for 90 days as the figure upon which to base the estimated avoided costs for this regulatory analysis. While a catastrophic deepwater spill may have a higher flow rate in a worst-case scenario, the 53,000 barrels a day for 90 days is a reasonable proxy for regulatory cost-benefit analysis purposes. This scenario results in an oil spill of 4.77 million barrels.

This 4.77 million barrel estimate is also consistent with the Central Planning Area Gulf of Mexico Sale 216/222 SEIS.[5] It is approximately the mid-point of a potential catastrophic deepwater GOM spill event. The range for a catastrophic spill event is assumed to be between 2.7 and 7.2 million barrels. The 216/222 SEIS catastrophic spill event assumptions are excerpted below.

> ***3.1.3.2. Deep Water***
> *For the purposes of this analysis, an uncontrolled flow rate of 30,000-60,000 barrels per day is assumed for a catastrophic blowout in deep water. This flow rate is based on the assumption in Section 3.1.3, well test results, and the maximum expected flow rate of the 2010 Deepwater Horizon blowout, which occurred in deep water. Therefore, total volume of oil spilled is estimated to be 2.7-7.2 million barrels over 3-4 months. In addition, deepwater drilling rigs hold a large amount of diesel fuel (10,000-20,000 barrels). Therefore, it is assumed that any remaining diesel fuel from a sunken drilling rig would also leak and add to the spill.*

EXISTING AND NEW REGULATORY PROVISIONS

This final rulemaking revises selected sections of 30 CFR 250 subparts D, E, F and Q as related to the drilling of new wells. As in most benefit-cost analysis studies a full compliance scenario is assumed and analyzed for the baseline and new regulatory requirements. We expect only a portion of the proposed changes in Subpart D will add material capital or operating costs (some of which will be significant) to the drilling of new OCS wells.[6] Table 1 compares the existing 30 CFR 250 Subpart D provisions with the new provisions. As demonstrated since the publication of the IFR these requirements can be implemented immediately using existing equipment and established practices. Those changes that will impose significant costs include:

1. Seafloor function testing of ROV intervention and deadman systems; 250.449(j) and (k), 250.516(d) and 250.616(h).
2. Negative pressure testing of the final casing string for wells drilled with a subsea BOP; 250.423(c).
3. Installation of dual barriers for the final casing string; 250.420(b).

[5] OCS EIS/EA BOEMRE 2011-027 http://www.gomr.boemre.gov/PDFs/2011/2011-027.pdf
[6] Identical costly new requirements for subsea function testing of ROV intervention during drill operations (Subpart D) also apply to well completion (Subpart E) and workover (Subpart F) operations.

4. Professional engineer certification that the well design is appropriate for expected well bore conditions; 250.420(a).
5. Retrieval and testing of BOP after a shear ram has been activated in a well control situation; 250.451(i).
6. Third party verification that the shear rams will shear drill pipe under maximum anticipated pressure; 250.416(e)
7. Additional record keeping and other paperwork required by the regulations.

Table 1 - 30 CFR 250 Subpart D Provisions

EMERGENCY SUBPART D/E/F/Q FINAL RULE PROVISIONS				
Regulation	**Summary**	**Existing Regulatory Provisions (before IFR**	**New Regulatory Provisions (final rule)**	**Cost**
30 CFR §250.415(f)	Evaluate best practices in API RP 65-Part 2	- No evaluation required	- Requires the operator to evaluate the best practices according to API RP 65-Part 2 and submit a written description for the evaluation.	- No meaningful cost
			- Written description must include the mechanical barriers and cementing practices the operator will use for each casing string.	
			- API RP 65 Part 2 addresses cementing practices and factors affecting cementing success.	
30 CFR §250.416(d), §250.1705	Submittal of schematics of all control systems for BOP stack	- Schematic of BOP system showing inside diameter of BOP stack, number and type of preventers, location of choke and kill lines	- Schematics of all control systems, including primary controls, secondary controls, and pods for the BOP system must be submitted.	- No meaningful cost
			- Location of the controls must be included	
30 CFR §250.416(e), §250.1712(g)	Independent third party verification to ensure blind-shear rams are capable of cutting the drill pipe used	- Information that the blind-shear ram is capable of shearing the pipe	- Verification that the blind-shear rams installed in the BOP stack are capable of shearing the drill pipe or tubing in the hole under maximum anticipated surface pressure.	- Independent third party certification will require a small cost per well
		- No independent third party certification required	- Independent third party must be a technical classification society or an API licensed manufacturing, inspection, certification firm, or licensed professional engineering firm.	- Will add moderate costs
30 CFR §250.418(i)	Submit qualifications of independent third parties with APD	- No independent third party certification required	- Description of qualifications in accordance with §250.416 (e)	- No meaningful cost

30 CFR §250.420(a)(6), §250.1712(g)	Professional Engineer certification of well casing and cementing program	- No PE certification required	- Certify the casing cementing design is appropriate for the purpose it was intended under expected wellbore conditions	- Small cost per well if performed by an independent third party - No cost if PE certification is done in house - Assumed that some majors would verify in-house; smaller operators will use third party
30 CFR §250.420(b)(3)	Dual barriers	- No requirement	- Operator must install dual barriers including one mechanical barrier in each annular flow path.	- Installation of dual barriers and the increased drilling depth required to install the mechanical barrier is estimated to be on average 12 hours. - Will add significant costs to regulation.
30 CFR §250.423(b)(2)	Pressure test on the casing seal assembly	- Perform a pressure test on all casing strings (except drive/structural) according to 250.423 (a) - No requirement to ensure proper installation of the casing in the subsea wellhead	- Additional pressure test for the intermediate and production casing strings on the casing seal assembly to ensure proper installation of the casing in the subsea wellhead.	- Pressure tests are already required, no extra equipment time - Each pressure test only takes a few minutes - No meaningful cost

30 CFR §250.423(c)	Negative pressure test	- No negative pressure test required	- Perform a negative pressure test to ensure proper installation of the final casing string or liner and prior to unlatching the BOP for all wells drilled with a subsea BOP.	- Negative pressure test will take 3 hours for each required string of casing - Will result in significant costs for the regulation
30 CFR §250.428	If operator receives indication of inadequate cement job, conduct further tests.	- No specific evaluation required	Operator must: run a temperature survey, run a cement evaluation log; or use a combination of these techniques.	- These tests would normally be conducted by a prudent operator. This regulation will not add additional costs.
30 CFR §250.442(e)	Maintain ROV and a trained crew	- ROVs used for visual inspection every 3 days; 250.446(b)	- Required to maintain an ROV and trained crew on each floating rig on a continuous basis.	- All rigs are assumed to have an ROV on board. This regulation will not add additional costs.
			- ROV must be capable of shutting in the well during emergency situations	- Regulation does not require a timed test, therefore current ROVs will be capable of performing all required functions.
30 CFR §250.442(f)	Provide an autoshear and deadman system for dynamically positioned rigs	- No autoshear/deadman system requirement	- All dynamically positioned rigs must have an autoshear and deadman system	- Industry standard for dynamically positioned rigs is to have autoshear/ deadman systems - No meaningful cost
30 CFR §250.442(g)	Barriers on BOP control panels to prevent accidental disconnect functions	- No two-handed requirement	- Incorporate enable buttons on control panels to ensure two-handed operations for all critical functions.	- No meaningful cost
30 CFR §250.442(h)	Label subsea BOP control panel	- No labeling requirement	- Clearly label all control panels, such as hydraulic control panels and ROV interface on the BOP	- No meaningful cost

30 CFR §250.442(i)	Develop management system for BOP	- No management requirement	- Develop and use a management system for operating the BOP system - Written procedures for operating the BOP stack and LMRP - Minimum knowledge requirements for personnel authorized to operate and maintain critical BOP components	- No meaningful cost
30 CFR §250.442(j)	Training for BOP equipment	- No training requirement	- Train BOP personnel in deepwater well control theory and practice in accordance with 30 CFR 250, Subpart O	- No meaningful cost
30 CFR §250.446(a), §250.1708(a)	Document maintenance and inspections to BOP system	- No documentation requirement	- BOP maintenance and inspections must meet or exceed provisions of Section 17.10 and 18.10 Inspections; 17.11 and 18.11, Maintenance; 17.12 and 18.12 Quality Management in API RP 53	- No meaningful cost

30 CFR §250.449(j), §250.516(d), §250.616(h), §250.1707(h)	Subsea function test for ROV intervention on a subsea BOP stack Additional stump testing requirements	- No initial test on the seafloor	- All ROV intervention functions must be tested during the stump test and one set of rams during the initial test on the seafloor.	- Initial test on the seafloor is not industry standard and is estimated to take about 2 hours.
		- Stump test BOP stack	- ROV hot stabs must be function tested and capable of actuating at least 1 set of pipe rams, 1 set of blind-shear rams and unlatching the LMRP	- No meaningful cost since stump tests can be conducted topside prior to BOP deployment.
			- Operator must examine all surface and subsea well control equipment to ensure that it is properly maintained and capable of shutting in the well during emergency operations	- Will add significant costs to well drilling, workover, abandonment and completion operations
30 CFR §250.449(k), §250.516(d), §250.616(h), §250.1707(h)	Autoshear/ Deadman function test	- No required function test	- The autoshear and deadman systems must be function tested during the stump test and the deadman tested on the seafloor.	The deadman test is estimated to take about 2 hours on average.
30 CFR §250.451(i)	Emergency activation of blind or casing shear rams	- No required action	- If the blind-shear or casing shear rams are activated in a well control situation, the BOP must be retrieved and fully inspected and tested	- Emergency situation only, will incur significant loss of rig time when activated
30 CFR §250.456(j), §250.514(d), §250.614(d), §250.1709	Displacement of kill-weight fluid from the wellbore	- No required action	Submit APM, with reasons for displacing the kill-weight drilling fluid and provide procedures describing how the fluids will safely displace.	- No meaningful cost

Benefit-Cost Approach

The purpose of this regulatory impact analysis is to meet the requirements of Executive Order 12866 (Regulatory Planning and Review) and OMB Circular A-4 by providing policy makers and others with detailed information on the consequences of the regulatory requirements. This is a significant rule because of the policy implications and estimated annual costs of more than $100 million.

A benefit-cost analysis requires estimating the net benefits associated with the rule. Net economic benefits are total benefits less total costs. The benefits from this rulemaking include the reduced potential for catastrophic deepwater blowouts and resulting damage as a consequence of stricter well control requirements. Costs include compliance costs associated with the specific provisions of the rule, such as wider use of best well design practices, extra testing and certification requirements, along with any additional administrative costs anticipated as a result of the rule.

A benefit-cost analysis is different from an economic impact analysis. The effects measured in a benefit-cost analysis reflect direct first-order real resource market outcomes, such as more abundant or higher valued outputs and the accompanying enhancement of consumer utility, along with the costs imposed by the regulatory action as expressed in terms of the market value of the scarce factors of production needed to comply with the rulemaking. In contrast, while an economic impact analysis could include these output measures as well, it tends to focus upon broad macroeconomic measures, such as national income, employment, wages, and revenue transfers, among others, as they may be relate to specific industries and geographical locations associated with the regulatory requirements. Anecdotal economic impact information is provided for commercial fisheries impacts consistent with the avoided cost estimate for this analysis.

The approach used in this benefit-cost report utilizes consumer surplus measures to estimate avoided-cost impacts on recreation, and producer surplus measures to estimate avoided-cost impacts on industry, i.e., the benefits of the regulatory action, rather than measuring these benefits from disparate economic considerations such as lost wages and employment in affected industries (hotels, restaurants, charter fishing boats, etc.). Estimated output impacts do not account for the value of the increased environmental benefits (or reduction in potential environmental damages) that accrue to individuals, as part of consumer surplus.

In the case of this rule, we have not been able to quantify the precise extent to which the new safety measures required by this rulemaking can be expected to reduce the chance of another catastrophic oil spill. A study by Det Norske Veritas for the Canadian National Energy Board titled *Beaufort Sea Drilling Risk Study* dated March 11, 2010 used a fault tree analysis methodology to develop estimates of the change in the probability of a blowout associated with several secondary well control measures like enhancements to the BOP. We have not discovered sufficient data that would allow adapting that methodology to the change in the probability of blowout associated with the enhanced primary well control measures in this rulemaking. Nor have we found other studies that evaluate the degree of improvement that could be expected from enhanced barriers, pressure tests, and a seafloor ROV function check.

The preamble to the interim rule requested comments on the availability of appropriate well design reliability studies. Commenters did not cite any applicable reliability studies.

BASELINE ASSUMPTIONS IN THE BENEFIT-COST ANALYSIS

The baseline for this rulemaking is the world without these new regulations. The "no action" baseline is the recent Gulf of Mexico deepwater oil and gas activity levels and the historical rate of events up to and including the April 20, 2010 DWH blowout. The DWH spill is the first U.S. Gulf of Mexico catastrophic deepwater blowout spill. While there have been other OCS spills and blowouts, the requirements in this rule are primarily focused on deepwater and designed to prevent or more quickly control deepwater blowouts. Estimates of potential natural resource damages are based on a spill volume similar to the government estimate of the DWH blowout spill volume but in all other respects are derived from information not specific to this spill. Estimates are also consistent with projections of future GOM deepwater drilling activity[7].

We estimated the baseline rates of deepwater blowouts, injuries, fatalities and spills directly from historical data. This baseline assumes that industry has not voluntarily implemented additional safety and protection measures as a result of the lessons learned from the DWH spill. This assumption may overstate likely future blowout chances under existing regulations since industry can be expected to implement some new safety measures on its own. Because of this uncertainty about many of these changes, difficulty of quantifying them and the time limitations under which analysis was conducted for this rulemaking, we did not adjust the baseline for any voluntary measures.

Baseline Estimates of Future Deepwater Drilling Activity

The key drilling input for this benefit-cost analysis is the future number of GOM deepwater wells. BSEE projected average deepwater drilling activity for 2011 – 2030 in the Central and Western GOM using 6 different methods and then calculated the 20-year average to determine a reasonable drilling projection. The component projections were based on recent trends in

[7] The damage and loss estimates in this analysis are purely hypothetical and do not provide values applicable to the DWH event. They are not pertinent to the DWH event because they rely on dollar per barrel factors derived from a number of earlier spills. These dollar measures vary widely across the different spills in the sample set so the average is not relevant to any actual spill. The exception is for well containment costs cited directly by BP and extrapolated to a hypothetical GOM deepwater catastrophic blowout event postulated in this analysis. Otherwise, there is insufficient information available at this time to determine the magnitude of the costs that could have been avoided, including natural resource damages, from the DWH event. Moreover, the estimate of potential costs avoided used in this analysis do not reflect an assessment or quantification of the costs of injury or fatality resulting from the DWH event. As such, the damage and cost estimates presented herein should not be considered reliable monetary assessments associated with the DWH event.

drilling, leasing, aggregate production forecasts and other available data. Using these techniques we estimated there will be an average of 160 deepwater wells drilled annually over the next 20 years.

However, going forward this pace of deepwater drilling activity may be optimistic even if drilling regulations did not change. The main reason is that a larger share of future deepwater wells will be deeper (25,000 to 36,000 feet as opposed to under 22,000 feet in the recent past) requiring more time to drill and complete. Together with the new safety regime[8], operators may average fewer wells drilled each year. In the section titled *Sensitivity of Number of Deepwater Wells Drilled per Year (25% lower)* we estimate the benefits/costs under an alternative scenario of 120 deepwater wells per year.

The drilling of 160 deepwater wells per year is used to estimate the expected interval before another catastrophic blowout similar to the DWH. This projection was divided into 112 wells drilled from floating rigs and 48 from rigs on deepwater production platforms. The recent historical annual well count is shown in Figure 1.[9]

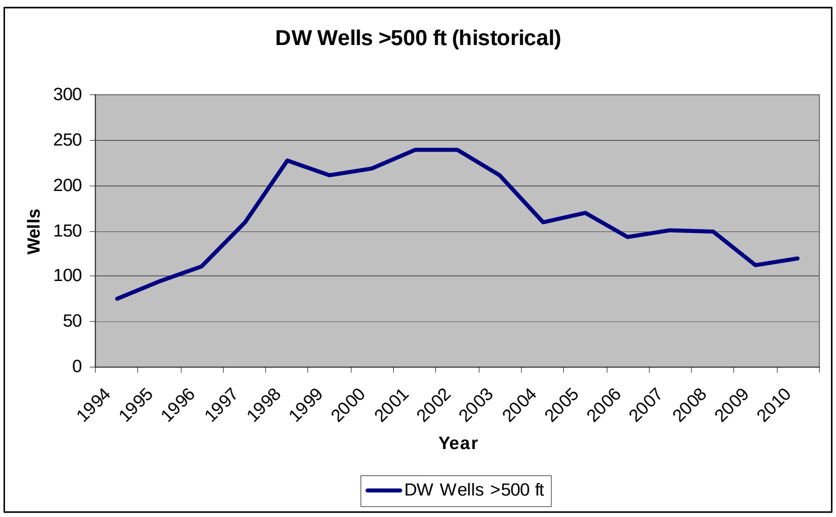

Figure 1 - Historical Deepwater Wells (Greater than 500 feet)

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[8] Under the new safety regime, deepwater drilling permits require more complex analyses by both operators of deepwater leases and BSEE prior to approval. These complex reviews include determination and verification of worst case discharge and planned blowout scenarios (included in revised plans) for potential blowouts, submittal and review of containment plans (including well screening tool) for potential blowouts, review of blowout preventer (BOP) diagrams and shearing capabilities, and review of certifications of casing and cement analyses proposed for the wells.

[9] All counts of wells exclude bypasses which are often included in other BSEE counts of spudded wells. These counts also exclude well completion and workover operations which involve re-entering a wellbore and re-deploying of BOPs and ROVs. The count includes sidetracks.

Shallow Water Drilling Activity

While the greatest cost imposed by this regulation will affect deepwater drilling activities using MODUs, new regulatory testing and casing requirements apply to wells drilled both in shallow water and deep water. Future regulatory compliance costs for shallow water wells are estimated using the 2009 GOM shallow water drilling activity rate of 186 wells a year and the additional costs imposed on shallow wells by this regulation.

Baseline Chance of Another Deepwater Blowout Spill

The baseline chance of another catastrophic deepwater blowout spill uses only deepwater drilling, blowout and spill data on the U.S. federal OCS. BSEE has obtained this historical data from its Technical Information Management System database. There have been 4,123 wells spudded between 1973 and mid-2010 not counting bypasses in water depths of at least 500 feet.

There have been 20 OCS deepwater blowouts in the history of the program with 3 resulting in a spill during drilling operations. Only one deepwater blowout has resulted in a spill of a catastrophic size. The other two deepwater blowout spills were estimated to be 11 and 200 barrels of crude/condensate spilled.

The 20 deepwater blowouts average one blowout for about every 200 deepwater wells drilled on the OCS. The average number of wells between blowouts increased until about 1990 but has since leveled off at about one for every 275 deepwater wells.

Using the estimated 160 new deepwater wells that will be drilled annually, we estimate a catastrophic blowout spill under current regulations and practices to be 1 in 4,123 wells. This implies a baseline major spill once every 26 years under current deepwater drilling rates. A sensitivity analysis was conducted on this baseline probability assumption. The results of that analysis can be found in the section titled Scenario Analysis.

Uncertainties

Available data on drilling system reliability do not allow computation of the blowout risk reduction associated with the specific provisions in this rulemaking. Future long term studies should be conducted to assess the likely effectiveness of these and other increased safety measures, using statistical analysis of historic information on existing well configurations and testing practices. Cross-sectional data that are now collected but not captured in the BSEE TIMS data base may enable studies that assess how requirements for subsea ROV and deadman testing, use of negative pressure tests, dual barriers in the final casing string, along with the remaining items required in this rulemaking, could improve well control performance.

We can expect the risk and impact of a deepwater catastrophic blowout will be lessened by other factors not specifically addressed in this analysis. Industry and government reaction to the DWH spill has added experience that will improve the human factors of planning and response. The technology used to mitigate spill effects before a relief well is completed is currently deployed and on stand-by in case of a blowout and subsea BOP failure. While these are significant advances, the nature and impact of these changes are not easily quantifiable and are not included in the benefit-cost baseline.

Another area for further inquiry involves determining the impact and cost of a catastrophic deepwater oil spill. Ongoing studies will be helpful to more fully record the effects of a catastrophic deepwater blowout on the natural and human environments in the Gulf of Mexico. One ongoing BOEM study is titled Simulation Modeling of Ocean Circulation and Oil Spills in the Gulf of Mexico (GM110-2). Universities and consultants are conducting environmental studies of the Gulf of Mexico and the impact of the DWH event over the next decade. We also note that the basis for our damage estimates relies on dollar per barrel factors derived from historic near-shore spills which may not be the best analogies for a future deepwater spill far from land. If future estimates of the individual cost elements of a hypothetical deepwater spill imply that the resulting social costs vary significantly from our hypothetical $16.3 billion benefit estimate (discussed below), then the future analysis should be adjusted to reflect the new estimate.

COMPLIANCE COSTS FOR THIS REGULATION

This section addresses the main compliance costs resulting from this regulation. The compliance costs fall primarily on lessees and operators operating on the federal OCS because the rule raises drilling costs for each new deepwater well and shallow water well on the OCS. These new requirements add mechanical barriers to well design requirements and time for testing several features during drilling operations. BSEE estimates that each year the seven activities discussed in this section will add $131 million to the cost of operations on the OCS. For purposes of calculating annual costs associated with this rulemaking, we assume that in an average year operators will drill 160 deepwater wells and 186 shallow wells on the federal OCS as well as complete 36 workover, completion and abandonment operations using a subsea BOP.

Seafloor Function Testing of ROV Intervention and Deadman Systems - Drilling

Current regulations at 30 CFR 250.449(b) require a stump test of the subsea BOP system. In a stump test, the subsea BOP system is placed on a simulated wellhead (the stump) on the rig designated area. The BOP system is tested on the stump to ensure the BOP is functioning properly. New sections §250.449(j), §250.516(d), §250.616(h) and §250.1707(h) require that all ROV intervention functions on the subsea BOP stack must be tested during the stump test and one set of rams must be tested by an ROV on the seafloor. New sections §250.449(k), §250.516(d), §250.616(h) and §250.1707(h) require that the autoshear and deadman systems be function tested during the stump test, and the deadman system tested during the initial test on the seafloor. The initial test on the seafloor is performed as soon as the BOP is attached to the subsea wellhead. This section provides the calculations for *drilling* subsea ROV testing compliance costs. The following section provides the calculations for *workovers*, *completions* and *abandonment* operations.

BSEE assumes it is an industry standard to have ROVs on board. Regulation 250.446(b) requires that all subsea BOPs and marine risers must be visually inspected every 3 days; ROVs are the industry standard for meeting this requirement, therefore we reasonably assume all rigs have ROVs. BSEE also assumes dynamically positioned rigs have autoshear/deadman systems. BSEE has data showing that all dynamically positioned rigs being used in the Gulf of Mexico employ an autoshear/deadman system. Therefore, it is assumed to be industry standard for all dynamically positioned rigs to have an autoshear/deadman system.

These new requirements will provide a higher probability that a well will be secured in an emergency situation and prevent a possible loss of well control. Autoshear and deadman control systems activate during an accidental disconnect or loss of power respectively. The ROV test requirement will ensure that the dedicated ROV has the capacity to close a BOP ram on the sea floor using its pump or an available accumulator bank. The deadman test on the seafloor verifies that the BOP closes automatically if both hydraulic pressure and electrical communication are lost with the rig.

BSEE’s predecessor agency conducted a survey to investigate the potential impact of subsea ROV testing. Several drilling contractors, lease operators and equipment manufacturers were asked: “How long would it take to function test the ROV to verify that the ROV could be used to close one set of blind-shear rams, one set of pipe rams, and disconnect the LMRP?” Results averaged about 24 hours of lost rig time to perform these subsea tests.

However, the regulation only requires one set of rams and the deadman system to be tested on the seafloor; not two rams (one pipe ram/one blind-shear ram) nor disconnecting the LMRP. The 24 hour survey average in the IFR was an overestimate based on the final regulations. Since the publication of the interim final rule in October, 2010, BSEE has had the opportunity to observe stump tests and subsea tests required by this rulemaking. The testing of one set of rams on the seafloor is estimated to add about 2 hours on average to the testing time. The deadman system seafloor tests are estimated to take 2 additional hours. The total additional time for the subsea tests is estimated to be about 4 hours on average.[10] The estimate of 4 hours is a reduction from the 24 hours used for the interim final rule analysis. The regulatory provision will not affect platform rigs or shallow wells since they do not use subsea BOPs.

Multiplying the number of estimated deepwater MODU wells each year (112) by the weighted average day rate ($916,622) by 4/24 hours yields a total estimated compliance cost for this provision of **$17.1 million**. This is one-sixth the cost estimated in the analysis for the interim final rule. Table 2 reports the number of the various kinds of deepwater drilling rigs operating in the Gulf of Mexico and the rig (day) rates used to calculate the cost of the extra 4 hours added to drill time. The rig rate was taken from RIGZONE and increased (loaded) to reflect the assumed cost of the assorted support contractors on the rig whose services are not covered in the day rate. The loaded day rate is appropriate because BOP and other tests cannot be scheduled with accuracy so they occur in the middle of the drilling operations. The subsea BOP is not lowered to the seafloor until after the surface casings are set (maybe 10-30 days into the drilling) when the increased down-hole pressure and risks for gas kicks and blowouts are possible. Most deepwater wells are drilled more than 100 miles offshore and contractors and supplies that contribute to the loading of the day rate are contracted for the duration of the drilling operation. Part of the reason that crews stay on the rig for 2 weeks at a time is that round trips to shore are expensive, so “unloading” and “reloading” for part of a day is likely to cost more than maintaining capability at the ready. Additionally, delays and problems occur frequently during drilling operations and it is standard practice to maintain the contractor and company capability available to resume operations as soon as the problem is resolved.

[10] The ROV stump test components are not considered because they are not expected to significantly increase testing time. Some operators simulate the hydraulic flow of an ROV to perform the stump test on the BOP stack, while others use an actual ROV to stump test the BOP stack; this regulation removes the option of simulating hydraulic flow and requires the use of an ROV during the stump test.

Table 2 –Rig Counts, Day Rates, and Annual Drill Rates

Rig Type	Number of Rigs	Loaded Day Rate	Wells Drilled/Year
Drillship	11	$1,000,000	33
Deep Semisubmersible	21	$923,953	63
Low Semisubmersible	4	$715,792	16
MODU Total or Weighted Average	36	$916,622	112
Platform (deepwater)	10	$400,000	48
Shallow water	n/a	$200,000	186

Seafloor Function Testing of ROV Intervention and Deadman Systems – Workover/Completions/Abandonment

As is the case with drilling operations, regulations in place before the IFR did not require subsea ROV function testing of the BOP during workover completions, or abandonment operations. New sections 250.516(d), 250.616(h) and §250.1707(h) require testing of ROV intervention functions and the autoshear/deadman systems during the stump test, and a function test of at least one set of rams and the deadman system during the initial test on the seafloor. These sections extend the requirements added to deepwater drilling operations (discussed in the previous section) to well completion operations, workover and abandonment operations using a subsea BOP stack. Successful exploratory wells are typically temporarily abandoned until additional equipment is installed to produce the reservoir. When the operator is preparing to produce the well it is often completed using a different rig or redeployment of the original rig. This testing time for completion operations is estimated to also be 4 hours. This is in addition to the 4 hours testing time discussed in the previous section for selected wells. BSEE estimates that on average each year there will be 12 completions, 12 workovers and 12 abandonments each year employing a subsea BOP. Using a weighted average of MODU day rates (Table 2), 36 (12 workovers [plus] 12 completions [plus] 12 abandonments) redeployments of a BOP will cost **$5.5 million**. This is one-third of the cost estimated in the interim final rule analysis. This compliance cost reduction is the result of the testing time being reduced to 4 hours from 24 hours while being partially offset by the revised counts of workovers/completions and the addition of the 12 annual abandonment subsea BOP tests not counted in the interim final rule.

Testing the Subsea BOP between Development Wells and Workover/Completions/Abandonment on a Single Project

BSEE past history, practice and custom was that departures were routinely but not always granted when an Operator wished to move a subsea BOP between wells on the same project without pulling the BOP to the surface for a visual inspection and stump test. Comments on the IFR claimed that the compliance cost for rulemaking was greatly underestimated. Commenters claimed the cost to pull a BOP for a visual inspection is underestimated and the real cost of pulling a subsea BOP for a visual inspection would result in a $5 - $15 million opportunity cost.

BSEE's termination of the practice allowing Operators to "hop" a subsea BOP between wells on the same development project is not the result of this regulation, but rather BSEE's cessation of the practice of granting departures to existing regulations (30 CFR 250.446). BSEE acknowledges the opportunity cost to pull a subsea BOP for the full suite of inspections may range between 5 -14 days. BSEE estimates that this practice may have applied up to 50 wells or workover/completions/abandonments using a MODU each year. If an average of 7 days is added to the time required to drill or complete these 50 wells, the increased cost would be approximately $320.8 million (50 wells x 7 days x $916,622/day). This is a significant cost to deepwater Operators, but it is <u>not</u> a cost directly applicable to this rulemaking.[11] It is the result of a tighter regulatory environment through the BSEE practice of no longer granting departures for the regulatory requirement to pull the subsea BOP stack between each well on a project.

Negative Pressure Tests

Section 30 CFR 250.423 currently requires a *positive* pressure test for each string of casing, except for the drive or structural casing string. This test confirms that fluid from the casing string is not flowing into the formation. In the IFR, section §250.423(c) required that a *negative* pressure test be conducted for all intermediate and production casing strings for wells drilled with a subsea BOP. The final rule §250.423(c) only requires that the negative pressure test be conducted on the final casing before the subsea BOP is removed or if the BOP is to be removed during drilling operations.

The *negative* pressure test will reveal whether gas or fluid from outside the casing is flowing into the well and ensures that the casing and cement provide a seal. Maintenance of pressure under both tests ensures proper casing installation and the integrity of the casing and cement. While some companies routinely conduct negative pressure tests on casing strings as a best practice, we do not have the data to determine the frequency at which this occurs, so we assume all negative pressure testing is a new cost imposed by this regulation. Based on typical industry procedures, we estimate each new negative pressure test will take approximately 3 hours.

[11] We discuss this cost, not because it results from this final rule, but because commenters raised the issue.

Three hours is equivalent to 0.125 days. Using the weighted average of the MODU day rates (Table 2) 0.125 days times 1 casing string times 112 MODU wells yields an annual additional costs in deepwater for this test of **$12.8 million**. The estimated duration for an average negative pressure test was doubled from 90 minutes used in the interim rule to 3 hours based upon improved estimates of the time it takes both to create and then hold the low pressure state. The negative pressure test requirement for wells drilled with a surface BOP was removed from the final rule. Therefore compliance costs no longer include estimated costs of negative pressure tests for deepwater wells drilled from a platform or for shallow water wells. Additionally, the number of casing strings subject to the negative pressure test has been reduced substantially from the requirements in IFR. The IFR required that the negative pressure test be conducted on all intermediate and production casing strings. We previously estimated, on average, a deepwater well required 5 negative pressure tests and a shallow water well 3 tests. The final rule only requires a single negative pressure test for deepwater wells drilled with a subsea BOP. This change results in a significantly lower compliance cost for this regulation as shown in Table 5.

Installation of Dual Barriers

Regulations before the issuance of the IFR did not require the installation of dual barriers although this requirement could be considered the use of best available and safety technology (BAST) per § 250.107(d). For this analysis the requirement is considered new because the government had not previously specified this technology in the regulations. New regulatory section § 250.420(b)(3) requires the operator install dual barriers including cement barriers for the final casing string. This second mechanical barrier prevents hydrocarbon flow in the event of cement failure at the bottom of the well. The operator must document the installation of the dual barriers and submit this documentation to BSEE in the End-of-Operations Report (Form BSEE-0125). These new requirements will ensure that the best casing and cementing design will be used for a specific well.

The IFR allowed dual barriers which could include one float valve. We estimated that all wells will require a second mechanical barrier and that the installation time would be 30 minutes and an equipment cost of $20,000. This yielded an IFR annual compliance cost estimate of $10.3 million for all OCS wells.

The regulatory provision for mechanical barriers in § 250.420(b)(3) has been changed from the IFR and now requires the second barrier must be mechanical. BSEE no longer considers a float valve to be a mechanical barrier meeting the requirement of this provision. The result of this change is that the compliance cost estimate for this requirement at § 250.420(b)(3) increases significantly. The provision may add anywhere from 4 to 24 hours of drilling/rig time to all new OCS wells.

A well may require 4 or more hours (depending on the drilling depth) of additional drilling time to extend the well the 50 feet deeper necessary to install the mechanical barrier and the corresponding additional cement necessary to ensure integrity of the mechanical barrier. An alternative to drilling the well 50 feet deeper is to wait until after the primary cement job hardens and install the mechanical plug above the wiper plug. This requires tripping the drill string in and out to install the mechanical barrier and re-cementing. BSEE estimates that if the operator must trip in and out of the hole to install a bridge plug and reconnect, it will require approximately 24 or more hours of additional rig time. For this regulation we are estimating that installing two mechanical plugs will add, on average, 12 hours to the drilling time of all deepwater and shallow water OCS wells.

For all wells we estimate that requiring a mechanical barrier and cement will cost about $10,000 in equipment and cement; this is a reduction from the $20,000 estimate used in the IFR. This yields $1.12 million for deepwater MODU wells, $0.48 million for deepwater platform wells and $1.86 million for shallow water wells.
The average additional drilling time of 12 hours (½ of a day) per OCS well using the day rates from Table 2 is estimated to cost:

- $51.33 million (½ * $916,622 * 112 wells) for deepwater MODU wells,
- $ 9.60 million (½ * $400,000 * 48 wells) for deepwater platform wells, and
- $18.60 million (½ * $200,000 * 186) for shallow water wells.

The combined compliance cost ($millions) of the equipment and additional drilling time is estimated to be: ($1.12 + $51.33) + ($0.48 + $9.60) + ($1.86 + $18.60) = **$83.0 million** for this regulatory provision. This § 250.420(b)(3) change between the IFR and the final rule increases the compliance cost for this regulatory provision as shown in Table 5.

Professional Engineer Certification for Well Design

Regulation 30 CFR 250.420(a) in place before the IFR specified well casing and cementing requirements but did not require certification by a Professional Engineer although certification could be considered the use of best available safety technology (BAST) per § 250.107(d). New regulatory section §250.420 (a)(6) requires that well casing and cementing specifications must be certified by a Professional Engineer. The Professional Engineer will certify that the well casing and cementing design is appropriate for the purpose for which it is intended under expected wellbore conditions. This certification will add assurance that the appropriate design is used for the well thus decreasing the likelihood of a well failure during a blowout. Many of the larger companies probably will certify the well design using in-house expertise for little or no extra cost. Other companies will hire a third-party professional engineering firm. Since a majority of leases are owned by large entities, BSEE assumes that at most 50% of future wells will incur an additional cost for a third party professional engineer certification of the well design. The assumption for shallow water wells is changed from the IFR where we assumed that all wells would incur the cost of an external PE certification. The percentage of shallow water wells using external PE services is now estimated to be the same as deepwater wells. Based on an informal survey of drilling contractors and lease operators, BSEE estimates that the external certifications will cost about $22,500 each.

For MODU wells, those parameters yield **$1.26 million** (112 times 50% times $0.0225 million), for platform wells **$0.54 million**, and for shallow water wells **$2.09 million**.

Retrieval and Testing of a BOP Stack After a Well Control Situation

Regulations in place before the IFR did not specifically address BOP inspection following use of the blind-shear ram or casing shear ram, although a prudent operator would tend to conduct such an inspection to confirm the reliability of the BOPs. Surface inspection following shear ram activation may not have been conducted by the entire industry absent a more specific regulatory requirement; therefore this analysis considers the surface inspection to be a new cost. New regulation §250.451(i) requires that if a blind-shear ram or casing shear ram is activated in a well control situation where the pipe is sheared, the BOP stack must be retrieved, fully inspected and tested. This provision will ensure the integrity of the BOP and that the BOP will still function and hold pressure after the event. This activity, when triggered, will add about 13 days to drilling time. According to a Det Norske Veritas study[12], out of 5,611 deepwater wells, there were 12 situations where either the blind-shear or casing shear ram was activated; this implies one activation for every 515 wells drilled. With 112 wells drilled per year from drillships or semisubmersibles; one can expect 0.22 (112/515) relevant activities per year for costing purposes. At the day rates quoted in Table 2, 13 days times a 22% annual chance of occurrence yields **$2.61 million** expected annual compliance cost for this provision.

Third Party Verification of Shear Ram Capability

Before promulgation of the IFR, 30 CFR 250.416(e) required submission of information showing that BOP blind-shear rams are capable of cutting through the drill pipe in the hole under maximum anticipated conditions. The IFR and the final rule modifies this earlier regulation to require a BOP verification of shear ram capability by an independent third party. The independent third party provides an objective assessment that the blind-shear rams can cut any

[12] Det Norske Veritas. *Beaufort Sea Drilling Risk Study*. March 11, 2010.

drill pipe (including workstring and tubing) in the hole if the shear rams are functioning properly. This confirmation will be required for both subsea and surface BOPs, thereby adding a small cost to each well drilled. While the requirement to demonstrate shear ram capability is not new, independent verification and submission of that verification is a new provision; therefore this analysis considers the independent verification to be a new cost. Based on in-house expert judgment, we assume this will add $3,250 to the cost of each well. Applied to 346 wells per year, this yields a compliance cost estimate of **$1.1245 million** for this provision.

Paperwork Costs

Paperwork burden costs were not fully incorporated into the benefit-cost analysis for the interim final rule. This final rule analysis adds recordkeeping and other paperwork costs from the PRA (Paperwork Reduction Act) burden to the compliance costs for the regulation. Rather than repeat the PRA analysis by listing individual regulatory citations, the aggregate paperwork costs from that analysis are summarized in a single line in Table 4. This cost includes both the paperwork burden included in the IFR (75 FR 63368) and also includes the paperwork burden added in this final rule. Because the IFR was effective immediately, the paperwork burden summarized in the IFR (75 FR 63368) is already approved by OMB and is not included in this final rule.

The estimate of annual responses for the paperwork costs in the IFR PRA table (75 FR 63368) differs slightly from the estimates used in this RIA analysis. This difference is the result of different methods used to estimate future drilling activity. Generally the paperwork burden estimates a 3-year historical average of responses or actions. This RIA estimates drilling activity using both historical activity and forecast scenarios. For example in this rulemaking the paperwork burden analysis number of deepwater MODU wells drilled is 110 versus 112 used in this RIA analysis. The differences are minor and are not considered to have a material impact on the compliance cost estimates.

The estimated total annual burden hours includes both the burden hours from the IFR (75 FR 63368, OMB Control Number 1014-0014) of 44,731 burden hours and the additional burden hours included in the final rule (5,347 hours). The paperwork costs are estimated using the total annual burden hours and the average respondent cost of $92*/hour (rounded). This cost is broken out in the below table using the Bureau of Labor Statistics data for the Houston, TX area. See BLS website: http://www.bls.gov/bls/wages.htm. The total paperwork burden for this rulemaking is estimated to be $4.6 million (50,078 hours x $92hr = $ 4,607,176).

Table 3 – Hourly Salary Rate for Industry

Position	**Level**	**Hourly Pay rate ($/hour estimate)**	**Hourly rate including benefits (1.4** x $/hour)**	**Percent of time spent on collection**	**Weighted Average ($/hour)**
Secretaries and Administrative assistants	6	$21	$29	10%	$3
Management***	13	$64	$90	40%	$36
Petroleum Engineers /Geologists	All Workers	$68	$95	50%	$48
Supv. Engineer	15	$68	$95	5%	$5
				Weighted Average ($/hour):	**$92**

* Note that this BLS source reflects their last update from December 2009.
** A multiplier of 1.4 (as implied by BLS news release USDL 11-1718, December 7, 2011 (see http://www.bls.gov/news.release/ecec.nr0.htm)) was added for benefits.
*** This position is closest representative to Regulatory Specialist.

Summary of Annual Recurring Costs

Table 4 summarizes the cost estimates for these recurring cost categories for three subgroups of wells affected by the new regulations.

Table 4 – Estimated Recurring Cost Summary

Regulation	Recurring Costs:	MODU Wells (112/yr)	Fixed Platforms (48/yr)	Shallow Wells (186/yr)	Cost Shares
		Total ($MM)	**Total ($MM)**	**Total ($MM)**	
250.449(j)(k)	Subsea BOP and ROV function testing (drilling)	17.1	0.0	0.0	***13%***
250.516(d)(8), 250.616(h)(1) §250.1707(h)	Subsea ROV function testing (completions/workover/abandonment) Total of 36 instances.	5.5	0.0	0.0	***4%***
250.423(c)	Test casing strings for proper installation (negative pressure test)	12.8	0.0	0.0	***10%***
250.420(b)(3)	Installation of dual mechanical barriers	52.5	10.1	20.5	***63%***
250.420(a)(6)	PE certification for well design	1.3	0.5	2.1	***3%***
250.451(i)	Retrieval and Testing of a BOP Stack After a Well Control Situation	2.6	0.0	0.0	***2%***
250.416(e)	Independent third party shear ram verification	0.4	0.2	0.6	***1%***
All	Paperwork Costs taken from PRA tables in IFR & Final Rule.	2.5	0.4	1.7	***4%***
	Estimated Cost per year:	**94.6**	**11.2**	**24.8**	**$ 130.7**
	Estimated Cost per well:	**0.85**	**0.23**	**0.13**	

The regulations impact well costs differently depending on the category of drilling rig and type of well being drilled. As can be observed in Table 4, deepwater wells drilled by platform rigs and shallow wells drilled by jackups will incur lower incremental costs, primarily because they use surface BOPs while wells drilled by MODU's (drillships and semisubmersibles) will incur the greater incremental cost due to the new subsea BOP and dual barrier requirements.

Compliance Cost Changes between IFR and Final Rule

The reasons for the compliance cost changes between the IFR and the final rule vary from regulatory changes to revised BSEE counts and rig time. The following table provides a side-by-side comparison between the IFR compliance costs and those in this final rule.

Table 5 – Compliance Cost Comparison between IFR and Final Rule

Annual Recurring Costs	IFR ($millions)	Final Rule ($millions)	Compliance Cost Change between IFR and Final Rule
Subsea ROV function testing (drilling)	102.7	17.1	Estimated time was reduced. BSEE over estimated the time required for the subsea tests.
Subsea ROV function testing (completions/workover/abandonments)	15.5	5.5	Estimated time was reduced. BSEE over estimated the time required for the subsea tests. Count of abandonment operations added to revised count of workover/completions.
Test casing strings for proper installation (negative pressure test)	45.1	12.8	Regulation was changed and the count of actions is reduced. BSEE no longer requires a negative pressure test on all intermediate casing strings, but only on the final casing before the subsea BOP is removed.
Installation of dual mechanical barriers	10.3	83.0	Regulation was changed. A float valve no longer meets the definition of a second mechanical barrier. The estimated time to install the second mechanical barrier increased to 12 hours.
PE certification for well design	6.0	3.9	Cost estimate reduced because the large companies drilling in shallow water are now assumed to have Professional PE available for in-house certification.
Retrieval and Testing of a BOP Stack After a Well Control Situation	2.6	2.6	No change.
Independent third party shear verification	1.2	1.2	No change.
Paperwork Costs taken from PRA tables in IFR & Final Rule.	0.0	4.6	Paperwork costs were not included in the IFR benefit-cost analysis, but are added to the compliance cost for the final rule.
Total:	**183.4**	**130.7**	

Voluntary Measures by Industry

Some part of the roughly $131 million in annual compliance cost total may not be rightfully assigned to the regulation as industry is undertaking a number of steps following the DWH event that may overlap those in this regulation. An independent analysis by Industrial Economics Inc. for the IFR (See Appendix F) indicates overlap exists for the second barrier and negative pressure test provisions. However, these actions by industry are voluntary and, as such, not subject to enforcement. For these reasons, we have not adjusted the compliance cost estimate to account for these new potential actions, but acknowledge that our cost estimate may overstate compliance costs.

AVOIDED PRIVATE-SOCIAL COSTS

The objective of this section is to describe the avoided *private-social costs* resulting from a catastrophic oil spill in the Gulf of Mexico. Private-social costs as defined in this analysis are the costs incurred by the lessees and operator contractors based on the actual property loss and containment costs emerging from a catastrophic blowout on their rig and OCS lease. The avoided private-social costs include damage to the drilling rig, costs for containment and plugging of the blowout well and the value of hydrocarbons lost as a result of a blowout spill. Costs for clean-up of spilled oil are considered *external-social costs* in this analysis since they are incurred off the lease and are focused on mitigating the external costs to society from a catastrophic blowout event. Estimates of external-social costs are provided in the section on Avoided External-Social Costs. The combination of private-social costs and external-social costs equal the avoided social costs in this analysis.

Damage to Drilling Rig

A catastrophic deepwater blowout event can cause serious damage to or even destroy the MODU. Recently delivered floating deepwater semisubmersible drilling rigs reportedly cost about $560 million and a drillship $750 million. In addition to the DWH event where the drilling rig sank, there is only one other deepwater blowout event with rig damage and fatalities. This blowout occurred on September, 1984 in Green Canyon, Conoco (Zapata Lexington Drilling Rig). Salient points of that event include:

- There were deaths, serious injuries and damage to the drilling rig.
- While the blowout bridged (i.e., closed off on its own by cave-in or material falling in the well bore) and did not spill oil, the explosion did cause $15 million of damage to the drilling rig.

We use only these two deepwater blowout events to estimate the avoided costs for drilling rig damage because even in serious blowout events there are redundant systems designed to protect the rig and its workers, including disconnect of the lower marine riser package (LMRP).

For a prospective catastrophic blowout event, BSEE is assuming the value of a rig is $650 million, which is the approximate midpoint of the new construction cost of a deepwater semisubmersible rig ($560 million)[13] and the cost of a new drillship ($750 million)[14]. We take

[13] May 4, 2010, The replacement cost of the Deepwater Horizon is estimated at $560 million. http://www.nytimes.com/gwire/2010/05/04/04greenwire-warnings-on-backup-systems-for-oil-rigs-sounde-30452.html

this as the expected loss if the rig is destroyed. Additionally, we assume there is an equal likelihood of damaging but not sinking the rig, with resulting damage estimated at $26 million ($15m in 1984$ from the Zapata Lexington rig accident, inflated to 2010$). The calculation used to estimate the expected damage/loss of the drilling rig per catastrophic spill event is ($26m + $650m) / 2) = **$338 million**.

Well Containment and Plugging

This analysis uses containment and well plugging costs for a deepwater well blowout extrapolated from the amount provided by the North America BP Investor Relations desk on July 23, 2010 for the DWH event. In a phone call, BP stated the company had spent a total of $4.3 billion through July 22, 2010 which is approximately 90 days after the explosion. Of the $4.3 billion, $200 million had been spent on the two relief wells and $900 million on other source control efforts (e.g., failed ROV intervention efforts, containment structures, etc.). BSEE assumes that while the oil will flow for 90 days in the baseline (pre-regulation) case, the containment and well plugging efforts will extend to 120 days. The $1.1 billion ($200m + $900m) for the first 90 days extrapolated to 120 days yields **$1.467 billion per catastrophic spill event**.

While BP has now paid out more than this figure for its DWH well containment and plugging, BSEE is not increasing our estimate for this analysis. Both the Marine Well Containment Company and Helix well containment system are operational.[15] In the unlikely chance of another significant blowout event, specialized equipment has become available and response time to stem the flow from the well is anticipated to be reduced. Cognizant that every situation and event is different, the **$1.467 billion** estimate remains.

Hydrocarbon Losses

In addition to the well containment efforts, private-social costs include the market value of the lost oil and gas as a result of an uncontrolled blowout event. BSEE assumes that a deepwater well that has suffered an uncontrolled blowout would flow 53,000 barrels of oil a day for 90 days. This equates to 4.77 million barrels of oil spilled[16]. While some oil may be captured through various skimming systems, the overwhelming majority of captured oil is likely to be flared or disposed of as waste rather than sold into the market. Moreover, for our purposes we can ignore the relatively modest size of the hypothetical extraction costs of the lost oil.

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[14] Total capital costs to be incurred for the construction of the drillship are estimated to be $750 million http://www.redorbit.com/news/business/1446859/transocean_inc_announces_agreement_to_acquire_newbuild_ultradeepwater_drillship_under/index.html

[15] The cost to stand-up and maintain the MWCC and Helix systems is a significant regulatory cost to industry. However it is not a specific compliance cost of this regulation and is not otherwise considered in this analysis.

[16] See footnote number 1 and page 12 for cautions about this estimate.

Accordingly, assuming a market oil price of $70/barrel, the value of lost crude oil is estimated to be **$334 million**.

In the deepwater Gulf of Mexico oil averages 80 percent and natural gas the other 20 percent of hydrocarbon production on a BOE basis. If the oil spilled is 4.77 million barrels, associated natural gas would be another 1.19 million BOE or 6.92 million MMBtu, implying a total of 5.96 million BOE is lost [17]. For computing the value of lost natural gas, BSEE estimates a market value of $4.00/MMBtu for a total lost value of almost **$28 million**.

Fines and Criminal Penalties

A number of statutes, including the Clean Water Act (33 U.S.C. 1321(b)(7)), and the Outer Continental Shelf Lands Act (43 U.S.C. 1350) provide for fines against the parties responsible for an oil spill or for violations related to an oil spill. In the context of benefit-cost analysis, fines and other penalties not specifically for natural resource damages or other social costs incurred by society are considered "transfer payments." These transfer payments simply move funds from the responsible party to the government. Transfer payments do not involve real resource costs and are therefore excluded from the avoided benefit-cost estimate for this rulemaking.

Summary of Avoided Private-Social Costs

Table 6 summarizes the avoided private costs estimated for this analysis, stated in 2010 dollars. These estimates have not changed from the IFR. Note that only about one-sixth of the private cost total is from lost hydrocarbon values which the lessees would have realized had the spill not occurred.

[17] 5.8 MMBtu per BOE.

Table 6 - Summary of Estimated Avoided Private-Social Costs

Private-Social Cost	Estimated Value
Damage/loss of Drilling Rig	338,000,000
Well Containment, 120 days	1,466,666,667
Lost Crude Oil, 4.77 million barrels	333,900,000
Lost Natural Gas, 6.92 million MMBtu	27,666,000
Total:	**$2,166,232,667**

AVOIDED EXTERNAL-SOCIAL COSTS

This section evaluates (in quantitative terms where possible) the avoided natural resource and cleanup costs, categorized as external-social costs, from a major oil spill in the deepwater Gulf of Mexico (GOM). The results from the avoided external-social costs estimated in this section are combined with the estimated private-social costs summarized in the table above to provide the estimate ($16.3 billion) of avoided social costs (benefits) used in this analysis. External-Social costs associated with oil spills may include loss of property value, natural resource damages, health effects, litigation costs, non-use values, loss of consumer surplus from recreational users, loss of producer surplus from commercial fishing or shell-fishing businesses, welfare effects associated with price changes in seafood markets, operational disruptions at marinas, commercial ports, or Naval facilities, temporary or permanent displacements of families or businesses, and reduction of supply of water for certain industrial purposes.[18]

The main categories of external-social costs considered in this section of the analysis include

- Natural resource damages;
- Lost recreational values;
- Lost commercial fishery production; and
- Oil spill response (cleanup) and damage assessment costs.

The avoided external-social cost estimate focuses on these categories of avoided social costs because information appropriate to a benefit-cost analysis is readily available to estimate their magnitude from studies and historical data. Recall that costs for the containment and the killing of an uncontrollably flowing well, damage to drilling equipment from a blowout, and lost hydrocarbons have already been discussed in the section on External-Private Costs.

[18] Water of a certain quality is required for various industrial uses, power generation, and desalination. There are nineteen thermoelectric plants on the Gulf coast (Florida, Mississippi and Texas). There is a Gulf-water fed desalination plant located in Tampa Bay, and one planned for San Antonio.

Three main factors affect the economic value of the avoided external-social costs of an oil spill: the spill's location, the time of year it occurs, and the type of oil spilled. Spill location and timing affect all categories of costs. Spills near locations with sensitive biota, significant fishery resources or recreational areas, or in locations where the oil could easily spread to such locations will have relatively greater costs. Little is known about the short- and long-term impacts of deepwater oil spills on the water column or deepwater biota. Timing also has situation-specific effects. A spill occurring near bird habitats during nesting or breeding season might be associated with greater natural resource damages, while a spill occurring near a shrimp fishery during harvesting season would be associated with larger fishery-related costs.

The specific type of oil affects the amount of cleanup needed and the amount of natural resource damages incurred. Light oils naturally dissipate and evaporate quickly—requiring minimal cleanup—but are highly toxic and create severe environmental impacts. Heavy oils do not evaporate, and therefore may require intensive structural and shoreline cleanup. While they are less toxic than light oils, heavy oils can harm waterfowl and fur-bearing mammals through coating and ingestion. Each spill's cost reflects the particular mix of these factors, and no factor is clearly predictive of the outcome.

Conceptual Approach

Typically, the external-social cost of damages to natural resources, fisheries and recreational areas is evaluated *after* a spill has occurred and subsequent to the completion of response activities. This evaluation includes collecting data that allow assessing the nature and extent of the damages (both spatially and over time) to all of the impacted resources relative to the pre-spill baseline and then, where possible, monetizing the damages using economic techniques designed to value resources that are not typically bought and sold in markets. In concept, damages include use and non-use values, for example, both the value of a trip to the beach now and the value of being able to take such a trip in the future.

For the proposed regulation, this level of information is not readily available. Baseline information such as the number, timing, duration, and location of potential spills during the period of analysis are not known. In addition, while baseline projections for the number of future deepwater wells drilled are assumed for this benefit-cost analysis, it is not possible to forecast the timing, magnitude, duration, and trajectory of future spills. This introduces a considerable degree of uncertainty into estimates of the value of the avoided costs associated with the proposed regulation. The analysis addresses this uncertainty by providing a range of values associated with different categories of avoided costs, and reporting averages or most likely values to determine point estimates for calculations.

Given the limited information available to evaluate the avoided natural resource costs, the technique used in this analysis falls into the category of "benefit transfer." This technique can be implemented in a variety of ways, ranging from simply transferring values from sufficiently similar studies, to adapting willingness-to-pay functions for new site-specific changes in environmental conditions, prices, and other values. In situations where time or resources do not permit extensive data collection or primary research, benefit transfer may be an appropriate technique for evaluating the magnitude of economic benefits. There are many caveats that accompany use of this approach, the most important perhaps being the extent to which the study site/situation is similar to the study from which the values are to be transferred.

As discussed in the Baseline section of this analysis, BSEE estimated the probability of a catastrophic spill based on the history of deepwater blowout events and the resulting spills on the Federal outer continental shelf (OCS).

The BSEE estimates that about 160 new deepwater wells will be drilled annually over the next several decades. BOEMRE also assumes that the baseline scenario includes one catastrophic deepwater spill every 26 years, with the probability of a spill in any given year during the period of analysis being 3.85%. In this analysis, the hypothetical spill is assumed to be 4.77 million barrels of oil. The analysis does not assume a specific grade of crude oil for future spills, although oil from a deepwater GOM blowout would likely be a sour light crude typical in the GOM. The type of oil spilled affects spill dispersion and clean-up costs.

Valuing Natural Resource Damages

The avoided costs for natural resource damages depend on the particular circumstances associated with an oil spill. Natural resource damages from prior oil spills (excluding the DWH spill) were used to inform the cost-benefit analysis of this rulemaking. We collected information on coastal oil spills that were responded to under the authority of the Oil Pollution Act, including the natural resource damage settlements associated with these events. For the purposes of this benefit-cost analysis, the values contained in the legal settlement documents represent the best source of available information on the monetary value of the natural resource damages associated with coastal oil spills. Settlement amounts reflect compromises based on factors other than the actual amount of damages, such as litigation risk with respect to legal issues in the case or the ability of parties to support protracted, complex litigation. Further, although this information is useful for the purpose of a benefit-cost analysis, it should not be relied on to determine the amount of natural resource damages associated with any particular oil spill, including the DWH spill.

The dataset includes 62 coastal spills, none of which occurred a significant distance offshore. While vessel-related spills have previously occurred offshore, primarily in foreign waters, there is little information available on the associated natural resource damages. Similarly, little information is available on natural resource damages associated with blowouts occurring in foreign waters. Information on the spills contained in the data set is summarized in Figure 2 through Figure 5 and in the Appendix.

- Figure 2 shows a histogram of the per-barrel response costs in the dataset, with the majority of spills below $10,000/bbl, and a large number below $10/bbl;
- Figure 3 shows a histogram of the per-barrel restoration and assessment costs in the dataset, with the majority of spills below $10,000/bbl, and a large number below $1,000/bbl;
- Figure 4 shows a histogram of the total spill costs in the dataset, with the majority of spills below $10 million, and a large number below $1 million;
- Figure 5 shows a histogram of claims requested and claims paid out by the U.S. Coast Guard from the National Pollution Trust Fund. The majority of these are below $10,000 per claim; many are below $1,000 per claim.

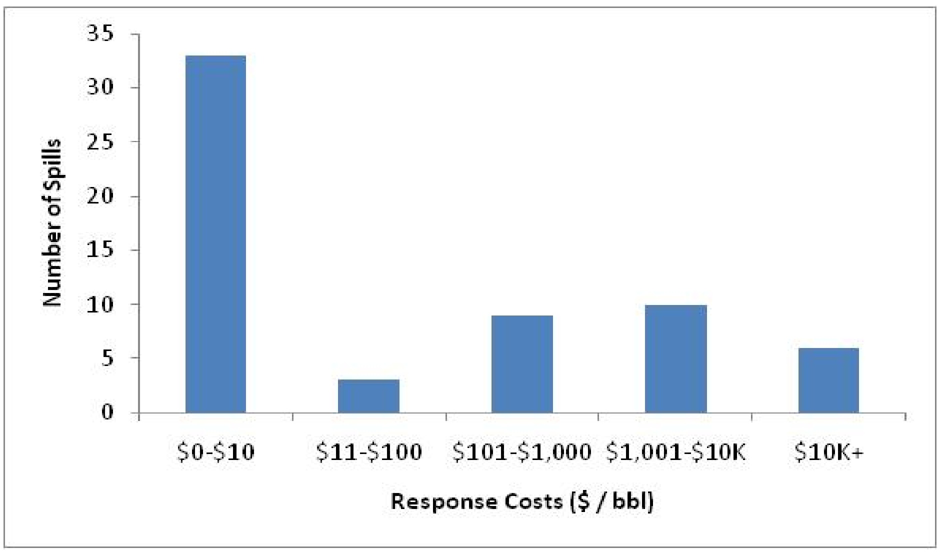

Figure 2. Distribution of Dataset Spills by Response Costs per Barrel ($2009)

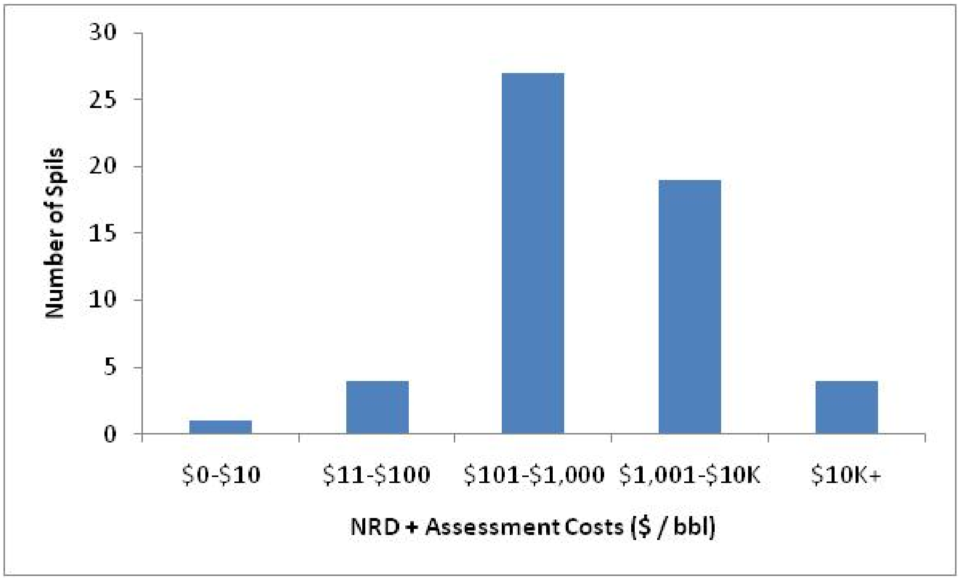

Figure 3. Distribution of Spills, by NRD + Assessment Cost per Barrel ($2009)

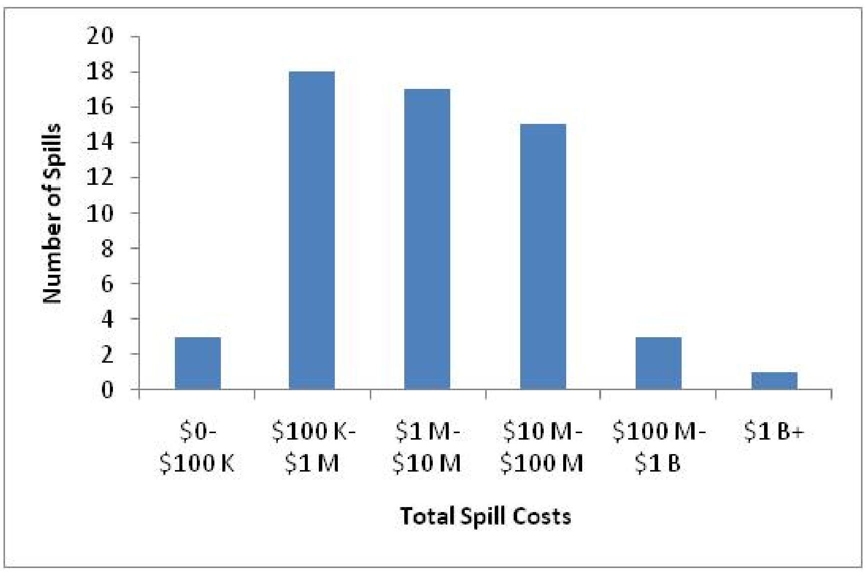

Figure 4. Distribution of Spills, by Total Spill Costs ($2009)

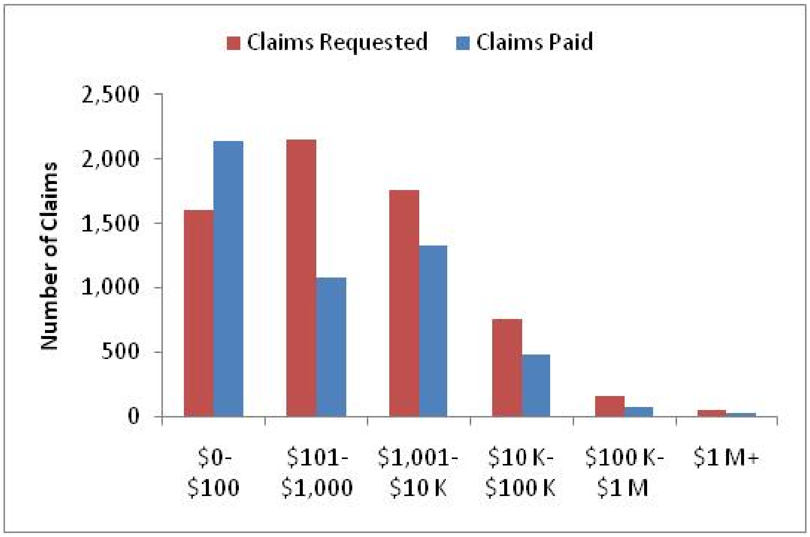

Figure 5. Oil Spill Liability Trust Fund Claims Requested and Paid (Sep 1972-Feb 2010)

The 62-spill dataset is characterized by a wide range of volumes spilled (24 to 262,000 barrels) as well as a wide range of per-barrel natural resource damages ($7 to $76,000 per barrel).[19] The vast majority of the spills were 10,000 barrels or less. As stated, this data set does not include the DWH spill. For the 62 spills, the average monetary value of the natural resource damages (including assessment costs) was about $3,700 per barrel, the median spill was about $850 per barrel, and the standard deviation was about $11,300 per barrel. The per-barrel damage values are related to both spill size and type of hydrocarbon.

Of the 62 spills, 10 spills occurred in the Gulf region. Natural resource damages (including assessment costs) for the Gulf spills range from $49 to $1,287 per barrel (in 2010 dollars), with an average of $456, per barrel, a median of $244 per barrel, and a standard deviation of $470 per barrel. For this analysis of a hypothetical catastrophic oil spill, we selected seven Gulf spills that appear most germane. Summary information on these seven spills is reported in Table 5. The average damages across these spills were $604/bbl, which is used as a conservative estimate for our avoided cost calculations. The Ocean 255 spill was highest-damage Gulf spill prior to April 2010, and the only non-crude oil spill in the Gulf data.

Although the hydrocarbons spilled in the Ocean 255 spill were fuel oil, rather than crude, the resources impacted were typical of some of the marine resources throughout the Gulf that could be affected by a catastrophic spill: sea turtles, mangroves, sea grasses, oyster beds, and beaches. These impacts suggest that the Ocean 255 spill may be a good representation of a future large

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[19] The upper end of the range of natural resource damages is given by the M/T Command oil spill in San Francisco Bay in 1998. Spills occurring in or near northern California are associated with some of the largest dollar-per-barrel damages.

spill. As discussed below, while the model used for this analysis appears to predict natural resource damage costs for smaller spills reasonably well, this model may have poor predictive capability for the NRD costs of catastrophic spills.

Table 7 Seven Gulf Coast Spills: Natural Resource Damages

Event	**Volume spilled (bbls)**	**NRD+Assessement Costs $/bbl $2010**	**Injured Resources**
OCEAN 255/B-155/BALSA 37 Spill	8,619	1,287	366 birds, 2117 sea turtles, 5.5 acres mangroves, 255 acres seagrasses, 0.85 acres salt marshes, 0.22 acres oyster beds, 20 linear miles seawalls, surface waters, 1.34 acres bottom sediments and 39,827 cubic yards of oiled sands (13 linear miles)
Blake IV and Greenhill Petroleum Corp. Well 25	2,905	1,122	Intertidal marshes, marine and estuarine fish, bottom dwelling species, birds, sediments
Equinox Cockrell-Moran #176 well	1,500	891	1,221 acres saltmarshes, Birds/Wildlife, 12 acres mangroves, 21 acres subtidal sediments, recreational activities
Chevron BLDSU #5, West Bay Field	262	346	200 Acres Fresh Water Marsh Vegetation, Birds/Wildlife
Ocean Energy/Devon Energy North Pass Storage Facility	300	424	120 acres freshwater marsh
Texaco Pipeline Company Lake Barre oil spill	6,548	109	4,237 acres of marshes, 7,465 finfish and shellfish, 333 birds,
M/VWestchester	13,095	49	Oiled shoreline and surface waters; lost recreational use of the Mississippi River.
Average per Event		**604**	

Caveats and Assumptions

The analysis includes the following caveats and assumptions:

- The estimate of natural resource damages from the table above, while a useful tool for the purpose of this cost-benefit exercise, is not relevant in calculating damages for any particular oil spill, including the DWH spill.
- For the purposes of this exercise, it is assumed that the average natural resource damage value for Gulf cases per barrel spilled, equal to $604 from the table above, is a reasonable approximation of the value of avoided natural resource damages for a spill significantly larger than the cases contained in the dataset of natural resource damage cases. It is worth noting, however, that a future catastrophic spill could result in a significantly higher natural resource damage value per barrel spilled, depending on the circumstances. In the Exxon Valdez oil spill, which resulted in a release of 261,905 barrels of oil, natural resource damages plus assessment costs averaged $5,005 per barrel (2009 dollars). See Appendix B.
- Total damages for a given hypothetical event are a linear function of the amount spilled.
- The average damage value is not adjusted to account for distance to shore, evaporation, degradation, dispersion, containment, etc. It is assumed that reported natural resource damage values already incorporate these effects.
- The injured resources for the cases in the dataset are similar to the resources potentially damaged from a large Gulf spill in the future.
- This analysis translates estimated avoided costs into dollar-per-barrel values. This metric is useful because barrels are a common measure of spill volume. However, the wide variation in social spill costs across events is noted. In short, the damages ultimately depend on the characteristics of an individual spill as noted earlier in the reference to the Exxon Valdez spill.

Relationship between Natural Resource Damages and Spill Size and Type of Oil Spilled

Similar to previous analysis by Dunford and Freeman (2001), a statistical model was developed to explain the factors that affect the monetary value of natural resource damages in the oil spill data set. The regression analysis used the log of natural resource damage and assessment costs (in $/barrel) as the dependent variable. Independent (explanatory) variables included the type of oil spilled (with dummy variables included for crude, diesel and gasoline), a time trend, the log of the volume of oil spilled (in barrels), and a dummy variable indicating if the oil spill occurred in California. The regression results explain a reasonable amount of variation in the sample; however, the predictive ability of the model appears to be better for small size spills. The model is able to predict costs for smaller spills in the sample reasonably well, although predictions of larger spills in the sample result in smaller values than expected. Based on the historic spill data available, the model appears to have poor predictive capability for the NRD costs of catastrophic spills.

Valuing Commercial Fishery Losses

Commercial fishing as an industry must be differentiated from other types of fishing, such as recreation, "subsistence" consumption, or informal sale. One approach to calculating commercial fishing profits[20] requires tallying revenue earned by industry operators, and subtracting operating costs. Operating costs include labor costs, such as wages for harvesting and processing; and non-labor costs such as fuel and supplies.

The commercial fishing industry includes various species of aquatic life (shrimp, crabs, oysters, finfish) and types of economic activity (fishermen, processors/cleaners, dealers, marinas, support facilities). Impacts to the industry from an oil spill can be expected to affect all sectors of the industry.

Economic damages related to an oil spill can result from:

- Fishery closures, when fishermen must either shift to different areas or not fish at all;
- Fish population impacts that result in lower catch rates, different target species, or changes in fishing methods; and
- Market price changes, for example due to public reluctance to consume fish from the region.

This approach for assessing damages related to an oil spill requires identifying changes in catch rates, prices, fishing areas, and methods employed.

Data Availability

Background

The Gulf States include, from West to East, Texas, Louisiana, Mississippi, Alabama and Florida. The region's shrimp landings are the nation's largest: 188.3 million pounds, for 73 percent of the national total (Fisheries of the United States 2008). The region landed approximately 30 percent of the total blue crabs for the nation (48.7 million pounds) in 2008. The Gulf region leads the nation in the production of oysters, some 67 percent of the nation's total.

Gulf fishery total landings (in pounds) and the revenues from those landings have tended to fall over the past decade, as shown in Figure 6. Fluctuations in prices do not appear to contribute to the decline in revenues. For the top ten commercial species, which together account for over 96

[20] We use producers' profits as a proxy for producer surplus.

percent of annual harvests, prices show no steady downward trend in Figure 7, while landings of all species show moderate declines in Figure 8.

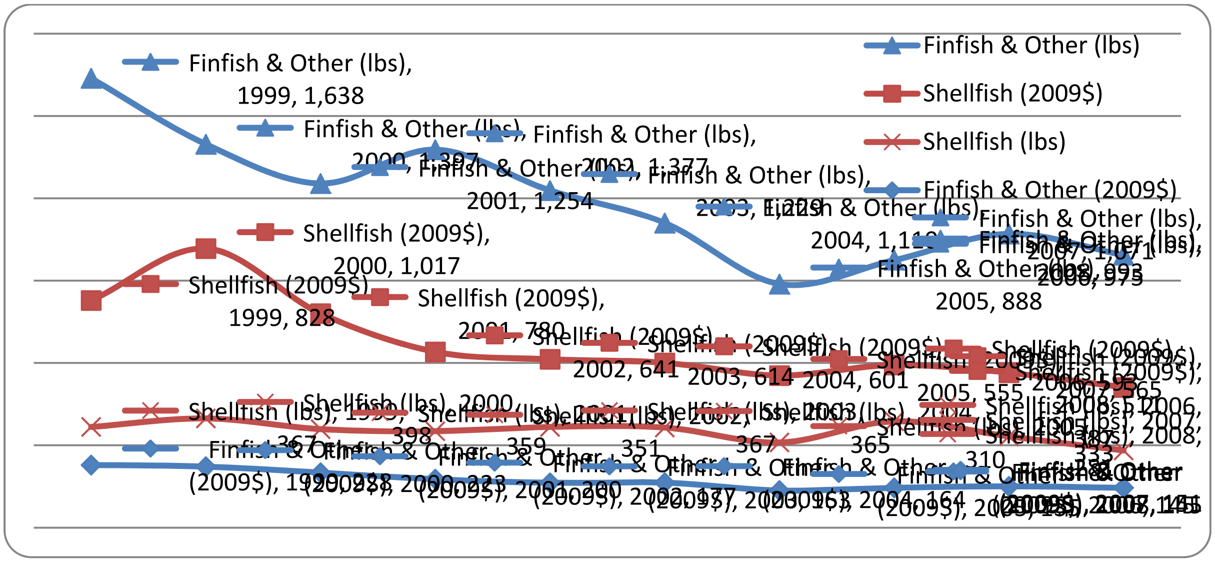

Figure 6 Gulf State Landings and Revenue, 1999-2008 (2009$)

Note: Data include landings for Florida's Gulf coast and Atlantic coast.

Source: NMFS Fisheries Economics of the United States 2008.

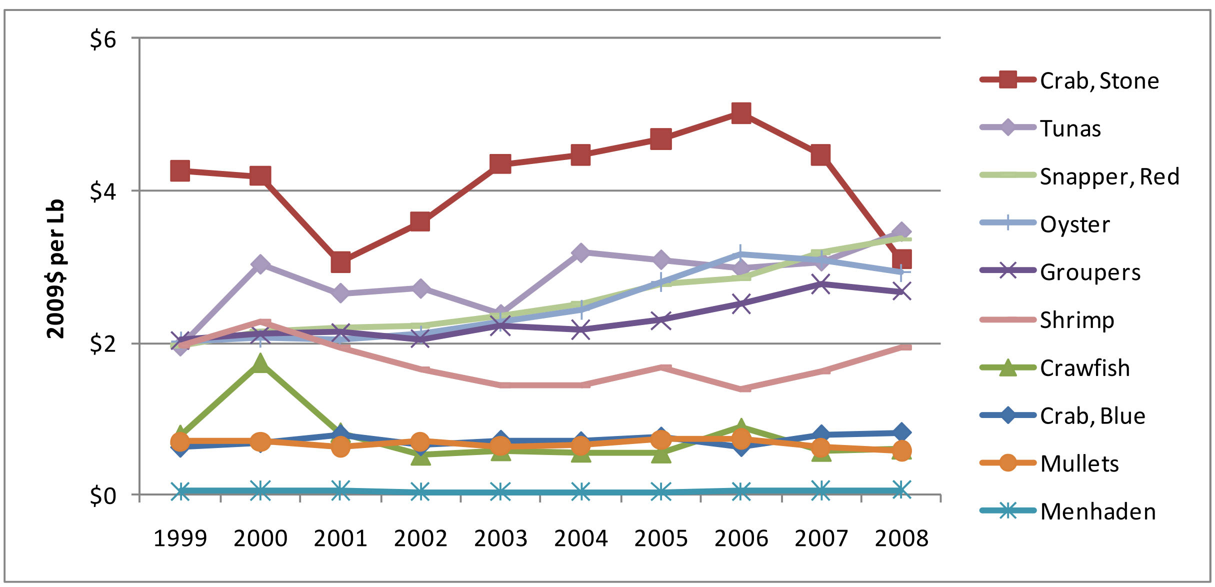

Figure 7 Average Annual Price per Pound (2009$)

Source: NMFS Fisheries Economics of the United States 2008.

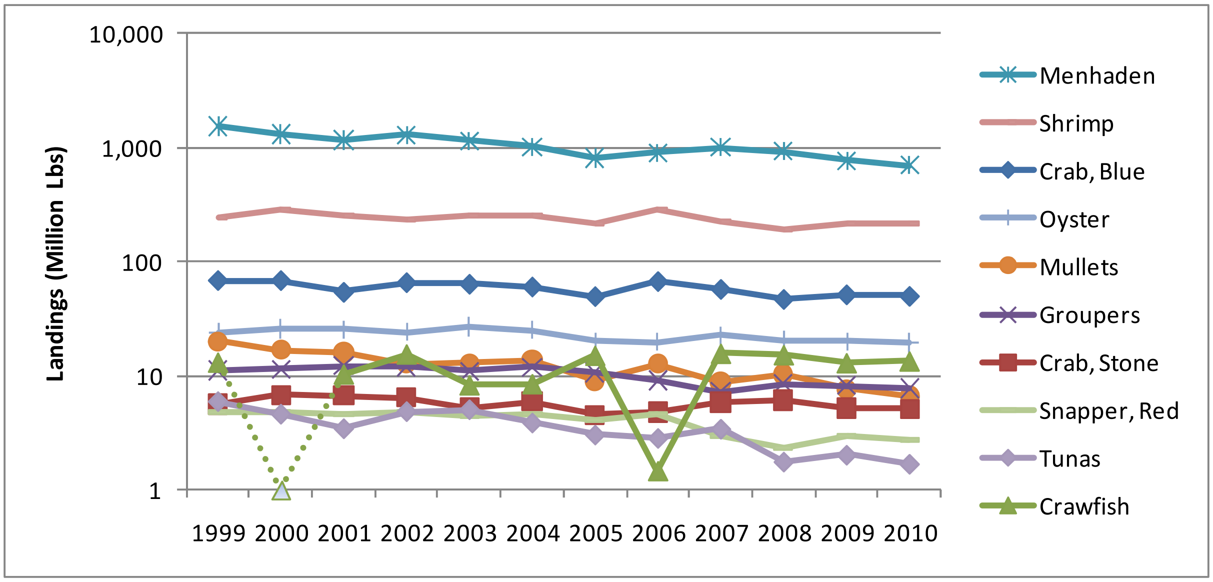

Figure 8 Gulf State Landings, 1999-2008 (mmlbs)

Notes: Data include landings for Florida's Gulf coast and Atlantic coast.
Crawfish landings for 2000 totaled 393,000 lbs.
Source: NMFS Fisheries Economics of the United States 2008.

Datasets were more readily available for commercial shrimp fishing than for other Gulf fisheries. The domestic shrimp industry has been in decline since the 1980s and may not be a good indicator of the overall commercial fishing industry in the Gulf. Louisiana accounts for about 50% of Gulf Coast shrimp landings. By 2007 resident shrimping licenses in Louisiana had fallen to less than one-third of their 1989 value, as shown in Figure 9.

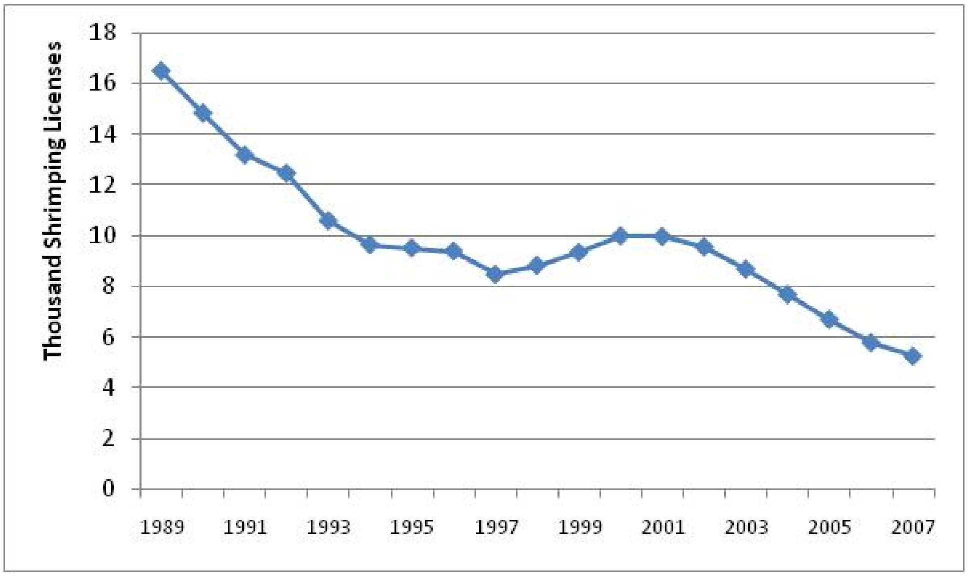

Figure 9 Resident Louisiana Shrimping Licenses (Trawl, Butterfly Net, and Skimmer Net)
Source: Louisiana Department of Wildlife and Fisheries

Revenues

In calculating producer surplus, we estimated gross revenues using the gross value of landings, multiplying pounds of fish landed by the wholesale price for that fish. The National Oceanic and Atmospheric Administration (NOAA) provides summary data on the value of commercial fisheries in the Gulf of Mexico, as shown in Table 8.

Table 8 Gulf of Mexico Commercial Fisheries Data, 2008

	Texas	Louisiana	Mississippi	Alabama	West Florida	Total
Shrimp						
Volume (million lbs)	63.9	89.0	8.6	17.2	9.9	188.5
Value (million $)	157.1	130.3	17.1	38.4	23.3	366.3
Crabs (Blue crabs)						
Volume (million lbs)	2.3	39.8	0.5	1.8	2.6	47.3
Value (million $)	2.6	31.1	1.0	1.5	3.3	38.7
Oysters						
Volume (million lbs)	2.7	12.6	2.6	0.7	2.4	20.4
Value (million $)	8.8	38.2	6.9	0.1	5.3	59.5
Finfish (and other)						
Volume (million lbs)	3.7	759.3	190.2	5.4	34.7	993.4
Value (million $)	7.7	64.0	19.2	4.1	50.5	145.6
Source: NOAA Fisheries Economics of the U.S.						

These data were accessed on-line at
http://www.st.nmfs.noaa.gov/st5/publication/fisheries_economics_2008.html#

NOAA's National Marine Fisheries Service (NMFS) data on weights and values of landings exhibit strong seasonality: Figure 10 and Figure 11 show a pronounced peak in each State's landings during one or two summer months each year; Figure 12 and Figure 13 show revenues by State during the summer months. This seasonality indicates that the timing of closures and population impacts should be considered in an analysis of oil spill damages. The seasonality is also rather stable,[21] suggesting that reasonable future monthly harvest values might be inferred from the data. We used the early summer months which correspond to the high revenue season for convenience rather than employing more sophisticated assumptions to reflect the seasonality. This choice deviates from our usual practice of using conservative assumptions to generate avoided social costs, but the values involved are so small relative to other social costs that further efforts in this regard do not appear warranted.

[21] Within-month coefficients of variation for May, June, July and August are below 0.45 for all five Gulf States over 1997 through 2008, and below 0.37 outside of Mississippi. The variation is lower still (outside of Mississippi) for 2002 through 2008: below 0.26 for all months.

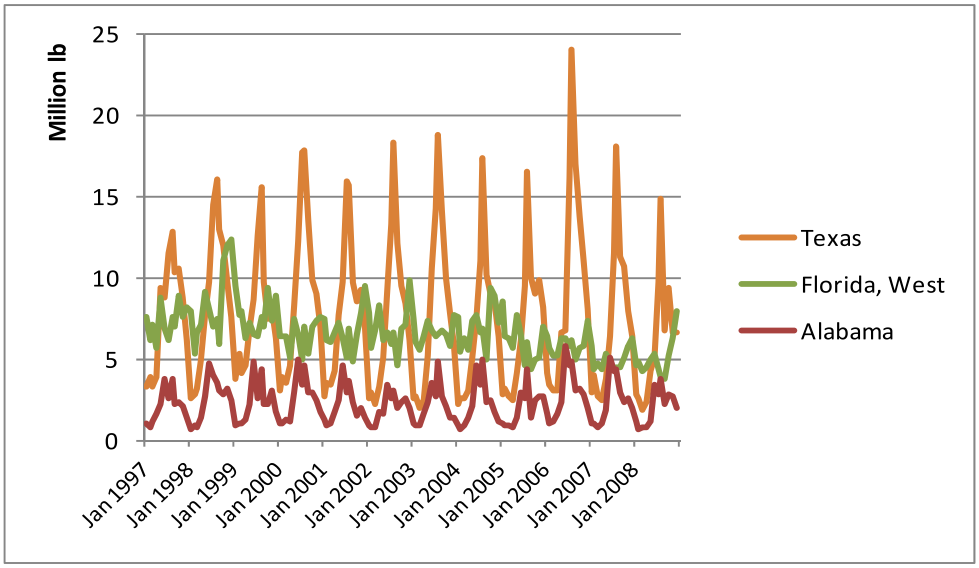

Figure 10 Monthly Commercial Fishery Landings (Texas, West Florida, Alabama)

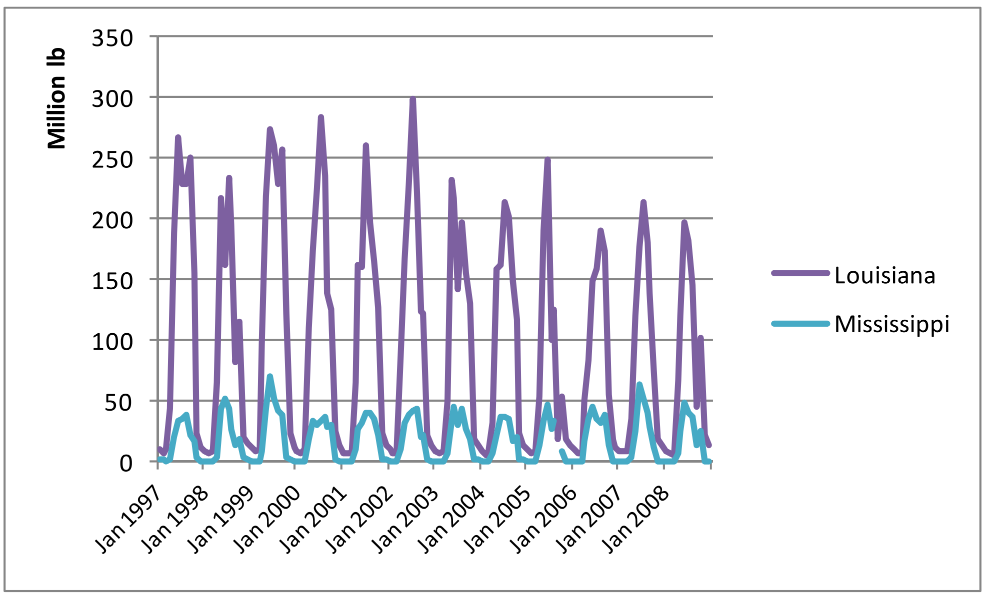

Figure 11 Monthly Commercial Fishery Landings (Louisiana, Mississippi)

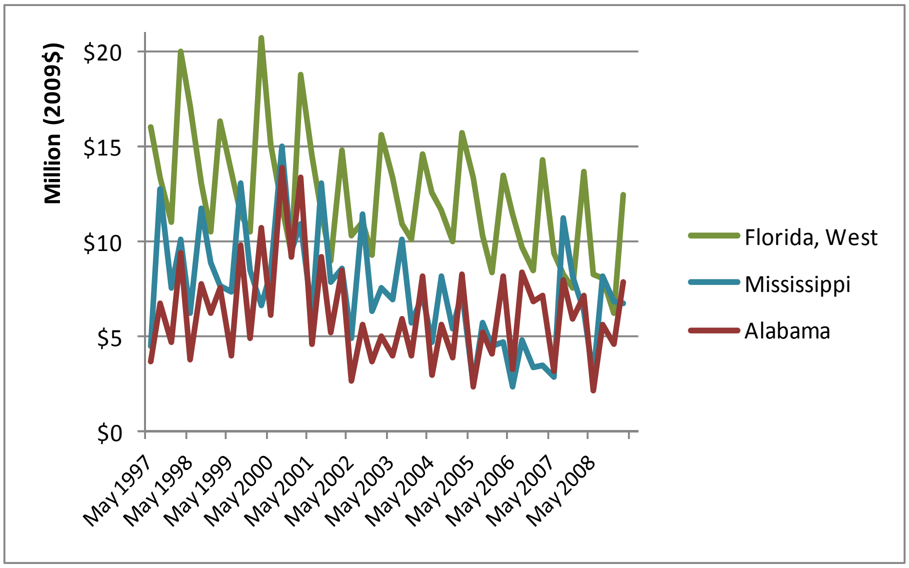

Figure 12 Summer Commercial Fishery Landing Revenues (West Florida, Mississippi, Alabama)

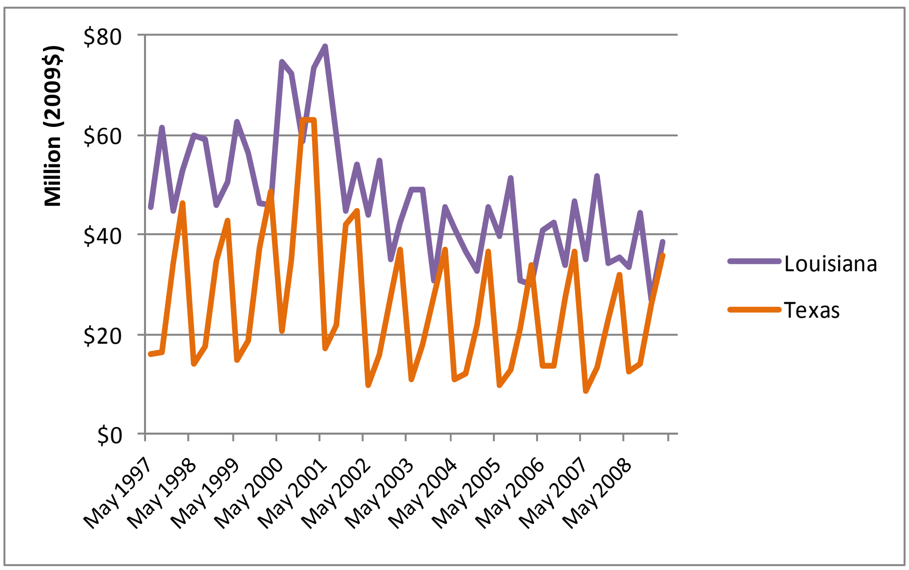

Figure 13 Summer Commercial Fishery Landing Values (Louisiana, Texas)

Baseline monthly landings values were estimated separately for each month of 2010 by sorting the 2002-2008 data by month, and finding the monthly trend for each State using ordinary least squares. These values are reported in Table 9.

Table 9 Estimated 2010 Baseline Values for Gulf State Commercial Fisheries ($ millions, trend 2002-2008)

	Texas	Louisiana	Mississippi	Alabama	West Florida
May	$12.0	$29.8	$0.9	$2.5	$8.5
June	$11.7	$43.6	$6.5	$7.6	$7.2
July	$23.2	$29.3	$6.6	$6.4	$5.8

Operating Costs

Liese *et al.* (2009) performed a cash-flow analysis based on a sample of Gulf commercial shrimpers. They found the average net revenue (before taxes) for a gulf shrimping operation was $2,654, with a 95% confidence interval spanning -$4,138 to +$9,446. This wide confidence interval, which includes zero, suggests that while the average vessel may be earning positive net revenues, there are at least some vessels that are earning negative net revenues. This was observed in spite of the fact that "the effective economic environment actually improved somewhat from 2006 as shrimp prices increased proportionally more than fuel prices. However, with the liquidity constraint implied by a negative cash flow and following many marginal years, it seems the average vessel simply did not have the ability to exploit this improvement and had to cut its overall effort (Liese et al. 2009).

Travis and Griffin (2004) had predicted the improvement noted by Liese in a simulation that assumed that variable costs as a percentage of revenues would fall for Gulf commercial shrimping. Their assumptions are given in Table 10.

Table 10 Gulf Commercial Shrimping Costs as a Percentage of Revenues (simulated)

	2002	2007	2010-2018 (lowest-cost period)
Large Vessels (at least 60 feet long)	98%	78%	75%
Small Vessels (<60 feet long)	114%	96%	93%

Liese's 2007 survey results can be used to make some inferences about how the Gulf fleet is divided between "large" and "small" vessels. They found 12% of the fleet was less than 50 feet long, and 56% of the fleet was more than 75 feet long. For the 31% of the sample that was 50 to 75 feet long, the average length was 65 feet. We assume that vessels are evenly distributed by size within this category, so that half the vessels (16 percent of the fleet) are longer than 65 feet. Of the 16% of vessels that are 50 to 65 feet long, two-thirds of the vessels are 50 to 60 feet long, and one-third of the vessels are 60 to 65 feet long. Tallying the proportions below 60 feet indicates that 23 percent of the fleet consists of "small" vessels (by Travis and Griffin's definition), while 77% of the fleet consists of "large" vessels. These results are summarized in Table 11, where the same approach is used to apportion the total fleet shrimp landings and landings revenue.

Table 11 Gulf Shrimping Fleet: Large and Small Vessels

	Categories from Liese et al. (2009)					Categories from Travis and Griffin (2004)	
	< 50 feet	50 feet to 60 feet	60 feet to 65 feet	65 feet to 75 feet	> 75 feet	< 60 feet	>= 60 feet
% of Fleet Vessels	12%	10%	5%	16%	56%	23%	77%
% of Fleet Shrimp Landings	4%	10%	5%	15%	66%	14%	86%
% of Fleet Landings Revenue	3%	9%	5%	14%	69%	12%	87%

*A small percentage (0.2 percent) of the landings revenue is from non-shrimp landings.

As shown in Table 11, the smallest vessels in Liese's survey (those less than 50 feet long) form a disproportionately small part of the industry: these vessels make up 12% of the fleet, but bring in only 4% of the landings, and receive only 3% of the landings revenue. In part this is due to the lower price that they receive for shrimp ($2.40 per pound versus the fleet average of $3.00). Likewise, the largest vessels form a disproportionately large part of the industry. Vessels over 75 feet long make up 56% of the fleet, but bring in 66% of the landings, and receive 69% of the landings revenue. We preserve this imbalance when we switch to the 60-foot designation for "large" vessels.

The proportions of Gulf commercial shrimp landing revenues going to large and small vessels is combined with the baseline revenue projections in Table 9 to determine the contribution of each vessel class to baseline revenues for the entire commercial fishing industry (see Table 12). We then apply the assumptions from Travis and Griffin (2004) about variable costs as a percentage of revenues to determine baseline profits accruing to each vessel class (see Table 13). Finally, in

Table 14 the results for large and small vessels are summed together to find the 2010 baseline for total industry profits by month.

Table 12 Large and Small Vessel Contributions to Gulf Commercial Fishing Revenues (2009$ millions)

	Vessels	**Texas**	**Louisiana**	**Mississippi**	**Alabama**	**West Florida**
May	Fleet	$12.0	$29.8	$0.9	$2.5	$8.5
	Large	*$9.2*	*$22.9*	*$0.7*	*$1.9*	*$6.5*
	Small	*$2.8*	*$6.9*	*$0.2*	*$0.6*	*$2.0*
June	Fleet	$11.7	$43.6	$6.5	$7.6	$7.2
	Large	*$9.0*	*$33.6*	*$5.0*	*$5.9*	*$5.5*
	Small	*$2.7*	*$10.0*	*$1.5*	*$1.7*	*$1.7*
July	Fleet	$23.2	$29.3	$6.6	$6.4	$5.8
	Large	*$17.9*	*$22.6*	*$5.1*	*$4.9*	*$4.5*
	Small	*$5.3*	*$6.7*	*$1.5*	*$1.5*	*$1.3*

Table 13 Estimated Baseline Profits for 2010: Large and Small Gulf Commercial Fishing Vessels (2009$ millions)

	Vessels	**Texas**	**Louisiana**	**Mississippi**	**Alabama**	**West Florida**
May	*Large*	*$2.3*	*$5.7*	*$0.2*	*$0.5*	*$1.6*
	Small	*$0.2*	*$0.5*	*$0.0*	*$0.0*	*$0.1*
June	*Large*	*$2.3*	*$8.4*	*$1.3*	*$1.5*	*$1.4*
	Small	*$0.2*	*$0.7*	*$0.1*	*$0.1*	*$0.1*
July	*Large*	*$4.5*	*$5.6*	*$1.3*	*$1.2*	*$1.1*
	Small	*$0.4*	*$0.5*	*$0.1*	*$0.1*	*$0.1*

The calculations presented in Table 13 assume that all Gulf commercial fishing operations have similar cost structures, namely that variable costs average 75% of revenues for large vessels, or 93% for small vessels. This is a conservative estimate: commercial shrimping is a high-cost industry, and other types of fishing are likely to have lower costs. Applying this percentage to the 2010 baseline revenues from Table 9 gives the 2010 baseline profits in Table 14.

If labor used in commercial fishing is not easily redeployed to alternatives, i.e., it does not have an opportunity cost, then this lost labor would also be included as an avoided social cost. We did not attempt to include estimates of this effect since the entire lost fishing and recreation item is such a small fraction of the total avoided cost estimate. Even counting all lost fishing revenue adds only one percent to our total avoided cost estimate.

Table 14 Estimated Baseline Profits for 2010: Gulf Coast Commercial Fisheries (2009$ millions)

	Texas	Louisiana	Mississippi	Alabama	West Florida
May	$2.5	$6.2	$0.2	$0.5	$1.8
June	$2.4	$9.1	$1.4	$1.6	$1.5
July	$4.8	$6.1	$1.4	$1.3	$1.2
August	$6.9	$7.4	$1.0	$1.8	$2.5

Closures

Gulf fishery closures in the Federal Exclusive Economic Zone (EEZ) are tracked over time in Table 15. As of July 21, 2010, about a third of Federal waters in the central Gulf were closed, while Texas had not experienced any closures, and shrimping season in the western Gulf opened as usual on July 15.[22] The eastern edge of the Gulf has also remained open, and Florida has closed only about 20 miles of the coastline near Pensacola.[23] All of Alabama State coastal waters (outside of Mobile Bay) have been closed to commercial fishing since June 24, though some shrimping and catch-and-release fishing are allowed.[24] On July 20, Mississippi State coastal waters re-opened to live-bait shrimping and catch-and-release fishing.[25] As of July 5, about half of Louisiana oyster harvest areas were closed, as was about half of the Louisiana coastline (from Oyster Bayou to the Mississippi border) for commercial fishing. A smaller set of areas was closed to recreational fishing.[26]

[22] Texas data were taken from the Texas Parks and Wildlife Department website "BP Oil Spill in the Gulf of Mexico" at http://www.tpwd.state.tx.us/site/emergency/oil_spill/.
[23] Florida closure data were taken from a Florida Fish and Wildlife Conservation Commission press release dated June 13, 2010.
[24] Alabama closure data were taken from an Alabama Department of Conservation and Natural Resources press release dated June 28, 2010.
[25] Mississippi closure data were taken from a Mississippi Department of Environmental Quality/Department of Marine Resources news release dated July 19, 2010.
[26] Louisiana closure data were taken from the Interactive Closure Maps on the website of the Louisiana Department of Wildlife and Fisheries (LDWF) at http://www.wlf.louisiana.gov/oilspill/map/.

Table 15 2010 Gulf Fishery Closures in Federal Exclusive Economic Zone (EEZ)

Closure Date (2010)	Percent Coverage of Gulf EEZ	Days Closure was in Effect	Effective Days of Full EEZ Closure
2-May	2.8%	5	0.1
7-May	4.5%	4	0.2
11-May	6.6%	1	0.1
12-May	7.3%	2	0.1
14-May	8.0%	3	0.2
17-May	10.0%	1	0.1
18-May	18.9%	3	0.6
21-May	19.8%	4	0.8
25-May	22.4%	3	0.7
28-May	25.1%	3	0.8
31-May	25.6%	1	0.3
May 2010		**Subtotal**	3.9
1-Jun	31.4%	1	0.3
2-Jun	36.6%	2	0.7
4-Jun	32.3%	1	0.3
5-Jun	32.5%	2	0.7
7-Jun	32.3%	9	2.9
16-Jun	33.4%	5	1.7
21-Jun	35.9%	2	0.7
23-Jun	32.5%	5	1.6
28-Jun	33.2%	6	2.0
June 2010		**Subtotal**	10.9
4-Jul	33.5%	8	2.7
12-Jul	34.8%	1	0.3
13-Jul	34.7%	10	3.5
23-Jul	23.8%	8	1.9
July 2010		**Subtotal**	8.4
May-July 2010		**Total**	**23.2**

source: http://sero.nmfs.noaa.gov/ClosureSizeandPercentCoverage.htm

We applied the "effective days of full EEZ closure" by month to the profits for Louisiana, Alabama and Mississippi. This approach relies on the assumption that landings, costs and vessel classes are evenly distributed throughout a State's waters and the adjacent portion of the EEZ. We are also assuming that the timing for landings is seasonally fixed, so that applying extra effort ahead of the spill could, but did not shift profits to that particular point in time.

Table 16 Estimated Gulf State Profits Lost to Closures

	Days of Closure	Days in Month	2010 Baseline Profits (LA, MS, AL), millions (2009$)	Lost profits, millions (2009$)
May	3.9	31	$6.9	$0.9
June	10.9	30	$12.0	$4.4
July	7.7	31	$8.8	$2.2
		Total	**$27.8**	**$7.5**

A total of $7.5 million in lost profits due to a spill of 4.8 million barrels is equivalent to $1.56 per barrel.

Valuing Lost Recreation

Recreation activities are often affected when oil spills result in contamination of coastal or ocean resources. These damages can result in value losses to consumers who either are unable or choose not to participate in a given recreation activity due to the contamination or do participate but have a lower quality experience than if there was no contamination. In order to arrive at a value of lost recreation, estimates must be obtained for the number of recreation trips (or days) lost per barrel of oil spilled and the average value for a particular type of recreation trip.

Economists use consumer surplus, or the difference between what an individual is willing to pay for a good and what they actually pay for it, to arrive at these recreation values. Since market price data is lacking for the value of recreational activities, these values are inferred from consumer behavior (such as the costs incurred to travel to the recreation site) or from individual stated preferences about their willingness to pay for the resource. Ideally, survey-based data would be collected from individuals to obtain information about the value that they place on the resource in a particular geographic location and the value loss incurred from an oil spill. However, when it is not feasible to undertake an original study to obtain these values, the benefit transfer approach is often used. Benefit transfer is a method that applies values obtained from previous studies to a new situation where primary data has not been collected.

In this section, benefit transfer is used to produce estimates of the value of lost recreation associated with a catastrophic oil spill event in the Gulf of Mexico for recreational fishing and beach recreation. Other recreational activities such as scuba diving, snorkeling and boating are likely to be affected as well but estimates for those activities are not included in this analysis due to lack of information about the impacts and potential overlap among activities. In order to arrive at an estimate of the impact of a catastrophic oil spill, several assumptions are required about the size, duration and location of the spill. In this analysis, the spill is assumed to result from a catastrophic blowout event in the GOM. In addition, this analysis does not account for the substitution of less desirable or more costly recreation sites for those that are affected by the spill.

Recreational Fishing

In order to estimate the value of lost recreational fishing trips, historic data on the total number of trips is first required. Historic data from the NOAA Marine Recreational Fishing Statistics Survey (MRFSS) for the Gulf Coast Region including Alabama, Mississippi, Louisiana, and Western Florida (data for Texas was not available) was used to arrive at an estimate of number of trips over a three month period including May, June and July (Wave 3 and half of Wave 4 in the MRFSS data set). These totals were not adjusted to reflect non- offshore fishing since such adjustments would be arbitrary and the overall cost of this element is small, relative to the much larger social cost estimate. Using a five-year average from 2005-2009, an estimate of 7,667,567 recreational fishing trips was obtained (Table 17).

Table 17 Average Number of Trips (May-July) (2005-2009)

Area	Number of Trips
Alabama	572,907
West Florida	4,576,280
Louisiana	1,455,094
Mississippi	384,055
Federal EEZ	679,261
Total	**7,667,597**

Source: NOAA Marine Recreational Fishing Statistics Survey

The number of effective days of full closure (see Table 15) was then applied to the average number of trips per day for each month to estimate the number of trips lost during the period of closure. Effective days of closure for the Federal EEZ were also applied to each of the States due to lack of specific data on State water closures. This is likely to result in an underestimate for Alabama, Mississippi and Louisiana, and an overestimate for Florida. In addition, this estimate does not account for certain areas that re-opened to catch-and-release recreational fishing after initial closures. It should also be noted that these estimates do not explicitly account for the availability of substitute fishing destinations, or the differences in behavior of local versus out of state fishermen (local fishermen may be less likely to find a suitable substitute if recreational fishing is affected throughout the region). If suitable substitutes are available, it is likely that the decrease in number of trips would be smaller than if fewer substitutes are available.

Benefit transfer was then used to value the lost recreational fishing trips. Consumer surplus estimates (in dollars per activity day) were obtained from previous non-market valuation studies of recreational fishing in the Gulf Coast region. All values were converted to current (2010) dollars, and an average value of $54.48/day was obtained from the 7 studies considered. This value was multiplied by the number of trips lost for State waters in each state and the Federal EEZ to arrive at total estimated consumer surplus over the three-month period. The total recreation value lost over the period is estimated to be $111.8 million. In this catastrophic spill scenario, we assume the impacts discussed result from a spill of 4.8 million barrels. Dividing the recreation value lost by the number of barrels spilled gives a value loss of $23.43 per barrel.

Beach Recreation

Historic data on the annual number of visitor days for beach recreation in the Gulf Coast States was obtained from the 2000 National Survey of Recreation in the Environment (NSRE) conducted by the U.S. Forest Service and NOAA. In order to estimate the number of visitor days in May, June and July, the monthly visitation data from Gulf Islands National Seashore (located in MS and FL) was used to estimate the percentage of visitation during this three month period (48%) and this percentage was applied to the annual state visitation data. For the State of Florida, information from Murley et al. (2005) was used to estimate the percentage of beach recreation visits that occur on the western coast (25.7%). The estimated recreation days in each state during the period are shown in Table 18.

Table 18. Estimated Number of Recreation Days (May-July)

State	Recreation Days
Alabama	5,683,200
West Florida	21,853,224
Louisiana	1,939,200
Mississippi	4,161,600
Texas	16,910,400
Total	**50,547,624**

Ideally, in order to estimate the number of recreation days lost, actual visitation data would be collected from beach surveys or over flight surveys during the affected period and compared to average visitation levels for that time of year. In the absence of actual visitor counts, certain assumptions must be made to estimate the recreation days lost. In this case, the percentage of oiled shoreline in each state as of July 22, 2010 was used to approximate the percentage of recreation days in each state that were affected (12% in AL, 2% in FL, 5% in LA, 30% in MS and 0% in TX). This is likely to be an underestimate for much of the area because the total shoreline used to calculate the percentage of area affected includes areas that are not used for beach recreation.

Although most beaches along the Gulf Coast may remain open after a deepwater catastrophic oil spill, decreased visitation and a reduction in quality experience for those that still participate in beach recreation are likely to occur. In this analysis, we assume that all beaches remain open, with a decrease in recreation days of 20% compared to historic levels. We also assume that remaining visitors experience a loss in consumer surplus due to decreased quality of the recreation activity. We assume a 20% loss in quality for each recreation day affected, following Chapman and Hanemann (2001).

Consumer surplus values for beach recreation per activity day were obtained from 8 studies conducted in the Gulf Coast region. All values were converted to current (2010) dollars and averaged to obtain a value of $88.47 per activity day. This value was then multiplied by the number of recreation days in each state to arrive at a total consumer surplus value for beach recreation during the three month period. Using these values, we estimate a loss in the value of beach recreation of $75.5 million over the period, or $15.82 per barrel for a spill of 4.8 million barrels. It should be noted that these estimates do not explicitly account for the availability of substitute beach sites, or the differences in behavior of local versus out of state visitors. If suitable substitutes are available, it is likely that the decrease in consumer surplus would be smaller than if fewer substitutes are available.

As with the commercial fishing analysis, we used selected characteristics of the BP spill as a proxy for a future catastrophic spill simply for analytical convenience. These factors include the closure periods and time of year. The minor size of the recreational fishing and beach use values relative to the total social cost estimate did not justify devoting further effort to refining the spill circumstances such as randomizing time of year or adjusting for fishing trip substitution.

Table 19. Recreation Studies

Recreational Fishing		
Year	**State**	**Reference**
1991-1992	Florida (Tampa Bay)	Greene et al., 1997
1991	Gulf of Mexico	Gillig et al., 2000
1991	Florida	Leeworthy, 1990
1992	Florida	Bell et al., 1982
1999	Louisiana	Bergstrom et al., 2004
1990	Florida	Bell, 1992
1988	Florida	McConnell and Strand, 1994
Beach Recreation		
Year	**State**	**Reference**
1996	Florida (Keys and Key West)	Leeworthy and Bowker, 1997
1984	Florida	Bell and Leeworthy, 1986
1984	Florida	Bell and Leeworthy, 1986
2008	Texas (Padre Island Nat. Seashore)	Parsons et al., 2009
1990	Florida (Clearwater Beach)	Leeworthy and Wiley, 1994
1990	Florida (Honeymoon Island State Park)	Leeworthy and Wiley, 1995
1984	Florida	Bell and Leeworthy, 1990
1988	Florida (John Pennekamp State Park)	Leeworthy (1991)

Oil Spill Response and Damage Assessment Costs

Response or removal expenditures include rescue and rehabilitation of personnel and wildlife, salvage of infrastructure, cleanup of oil from aquatic and terrestrial areas, and hearings and investigations into causes of a spill. Removal costs include the equipment used in the response—skimmers to pull oil from the water, booms to contain the oil, airplanes for aerial observation or dispersant application—as well as salaries, travel and lodging costs for responders. Response expenditures can be incurred by: Federal, State, Tribal governments; industry; non-governmental organizations; private companies; and foreign entities. Response costs exclude the wellhead containment costs to secure and kill the uncontrolled flow from a well blowout. Although technically "response costs" under the Oil Pollution Act (OPA), those containment costs are considered private-social costs for this analysis and covered in the section on Avoided Private-Social Costs. Damage assessment costs can include costs associated with data collection and analysis required to evaluate the impacts of the spill relative to pre spill conditions.

In a 2003 report to Congress, (*Informing Regulatory Decisions: 2003 Report to Congress on the Costs and Benefits of Federal Regulations and Unfunded Mandates on State, Local, and Tribal*

Entities), OMB considered benefits of vessel response plans and double-hull vessels by valuing avoided spills at $2,000 per barrel, noting that "This is double the sum of the most likely estimates of environmental damages plus cleanup costs contained in a published journal article."

Estimates of response costs can also be found in the literature. Table 20 presents estimates in current dollars of oil spill cleanup costs by oil type; Table 21 presents estimates by kilometer of shoreline oiled; Table 22 presents estimates by proximity to shore. Table 23 presents information by spill volume.[27]

Table 20 Cost of Spills by Fuel Type

Oil Type	US Spills (2010 $/bbl)
No. 2 diesel fuel	638
Light crude	554
No. 4 fuel	Data not available
No. 5 fuel	1,539
Crude	2,570
Heavy crude	3,733
No. 6 fuel	3,198
Per-unit cleanup costs by degree of shoreline oiling	
Source: Etkin, June 2000.	

Table 21 Cost of Spills by Length of Shoreline Oiled

Shoreline Length	Oiled US Spills (2010 $/bbl)
0-1 km	468
2-5 km	1,060
8-15 km	1,866
20-90 km	2,684
100 km	4,832
500 km	9,197

[27] Etkin, D. June 2000. Worldwide Analysis of Marine Oil Spill Cleanup Cost Factors. Presented at Arctic and Marine Oil Spill Program Technical Seminar; Etkin, D. 2001. Comparative Methodologies for Estimating on Water Response Costs for Marine Oil Spills, International Oil Spill Conference.

Table 22 Cost of Spills by Location

Location	US Spills (2010 $/bbl)
In-port	6,033
Nearshore	4,437
Offshore	1,217
Source: Etkin, 2001.	

Table 23 Oil Spill Response Costs by Spill Volume

Spill Volume (bbls)	Total Cost ($2010)	$ per bbl ($2010)
240	203,803	856
2,400	2,072,094	870
12,000	10,953,217	920
120,000	46,885,858	394
240,000	90,476,930	380
Source: Etkin, 2001.		

For the purposes of the benefit-cost analysis it is assumed that one third of the response efforts occur nearshore and two-thirds offshore. The weighted average of the near- and offshore response cost estimates presented above is $2,300 per bbl.

Avoided Costs Associated with Reduced Loss of Life and Nonfatal Injuries

There have been 20 blowouts from deepwater wells, with 2 resulting in injuries or fatalities. Those two events are a 1984 blowout with 4 fatalities and 3 injuries and the 2010 BP-Deepwater Horizon explosion and resulting spill with 11 fatalities and 17 injuries. For purposes of estimating costs avoided from reduce loss of life and injuries, the following uses the average fatalities and injuries for these 2 cases as values for a hypothetical catastrophic deepwater blowout.

Value of Statistical Life

The proposed regulation, because it is anticipated to reduce the probability of catastrophic blowout events, is likely to reduce the risk of premature death of rig workers. The oil and gas extraction industry is characterized by a relatively small percentage of the Nation's workforce and a higher fatality rate than most other industries. Approximately 161,600 workers were employed in oil and gas extraction occupations in 2008 (Bureau of Labor Statistics 2010). The fatality rate for oil and gas extraction workers is high compared to many other industries, with a rate of 23.4 fatalities per 100,000 full-time equivalent workers (Table 24).

Table 24 Selected Fatal Occupational Injury Rates by Industry, 2008

Industry	**Fatality Rate** (per 100,000 Full-Time Equivalent Workers)
Agriculture, forestry, fishing, and hunting	30.4
Oil and gas extraction	23.9
Transportation and warehousing	14.9
Construction	9.7
Protective service occupations (includes protective service occupations such as fire fighters, law enforcement)	9.1
Manufacturing	2.5
Management, professional, and related occupations	1.6
Finance, insurance, real estate and leasing	1.1
Source: Bureau of Labor Statistics, 2010.	

The benefits of occupational risk reduction are usually measured using the concept of "value of statistical life" (VSL). The VSL concept is based on individual willingness to pay for reductions in small risks of premature death and not on the present value of future earnings. In concept, the VSL is the measurement of the sum of society's willingness to pay (WTP) for one unit of fatal risk reduction, which is society's willingness to pay for reducing each individual's risk by a small amount.

VSL estimates are derived from aggregated estimates of individual values for small changes in mortality risks. For the analysis of benefits, mortality risks can generally be classified across the characteristics of the affected population and the characteristics of the risk itself. These factors should be addressed in any analysis that transfers values from one study to a new policy context. The literature on VSL identifies the following factors that affect risk perceptions that could be considered in selecting and adjusting any VSL values:

- Voluntary/involuntary;
- Ordinary/catastrophic;

- Delayed/immediate;
- Natural/man-made;
- Old/new;
- Controllable/uncontrollable;
- Necessary/unnecessary; and
- Occasional/continuous.

Whether adjustments are made to the VSL value depends on a variety of factors, including the extent to which such adjustments could be made on a systematic and defensible basis. To date there has been a lack of consensus on the merits of using a single VSL for all situations versus adjusting the VSL estimates to reflect the specific rule context.

Income has been found to have a clear and measurable effect on the VSL: as income increases, WTP for risk reductions usually increases. While this effect could be measured both cross-sectionally (across individuals or subpopulations) and longitudinally (over time), most studies are cross-sectional. However, using different VSL estimates for individuals with different incomes is controversial and has raised issues about the equitable treatment of richer and poorer segments of the population in policy decisions (Robinson, 2007). Some recent studies only consider samples from extremely dangerous jobs, such as police officers. Workers in these jobs may have different risk preferences and face risks much higher than those evaluated in typical environmental policy contexts (Kochi, 2006). Other recent research has examined how VSL varies with age, how it varies between males and females, and how worker heterogeneity may impact VSL.

A large number of estimates of VSL exist in the academic literature. This literature involves either explicit or implicit valuation of fatality risks, and generally involves the use of estimates of VSL from studies on wage compensation for occupational hazards, on consumer product purchase and use decisions, or from an emerging literature using stated preference approaches. Values reported have varied over time, geographic location, and worker heterogeneity. VSL estimates from under $1 million to around $3 million that were used to assess policies in the early 1980s have now been replaced by estimates as high as $9 million (Viscusi, 2010). A substantial majority of the resulting estimates of VSL vary from roughly $1 million to $10 million per statistical life. The literature based on estimates using U.S. labor market data typically shows a VSL in the range of $4 million to $9 million.

EPA recommends that the central estimate of $7.4 million ($2006), updated to the base year of the analysis, be used in all benefits analyses that seek to quantify mortality risk reduction benefits regardless of the age, income, or other population characteristics of the affected population. This approach was vetted and endorsed by the Agency when the 2000 *Guidelines for*

Preparing Economic Analyses were drafted. A recent report of the EPA's Science Advisory Board (SAB) concluded that the available literature does not support adjustments of VSL for most factors. However, the panel did support adjustments to reflect changes in income (EPA allows the adjustment of VSL based on increases in future income but not on cross-sectional differences in income), adjustments for inflation and time lags in the occurrence of adverse health effects.

VSL Value Used in Offshore Safety Regulation

For the purpose the analysis to estimate the avoided costs associated with reduced mortality, $8 million is used to value each statistical life. This is the EPA recommended estimate of $7.4 million updated to current dollars ($2010). Although oil rig workers are involved in an inherently risky occupation, based on the lack of consensus in previous research focused on adjusting VSL values for occupational risk, the EPA VSL recommendation was chosen for this analysis.

Based on the estimated value of 8 deaths per blowout event, using a VSL value of $8 million, for a 4.8 million barrel spill, the loss of life value from a blowout would be $13/barrel.

Nonfatal Injuries

On average, workers value non-fatal loss injuries on the job at values ranging from $20,000 to $70,000 per expected job injury. Thus, for example, a worker at the high end of this range would require $2,000 to face a one-in-25 chance of being injured that year (Viscusi, 2005).

We estimate an average value of job injuries at $45,000 per injury. With 10 injuries expected per catastrophic blowout event, a 4.8 million barrel spill would result in an estimated cost of $0.09 per barrel.

Other Health Effects

The Centers for Disease Control and Prevention (CDC) report that the Gulf Coast oil spill has the potential to affect human health. CDC and the Gulf States have a plan to track symptoms[28] occurring in the affected communities and will be able to investigate whether there is an association between symptoms and the oil spill. As of July 20, 2010, the American Association of Poison Control Centers reports receiving 843 "exposure calls" involving someone exposed to an oil-spill related toxin (e.g., oil, dispersant, food contamination).

[28] Symptoms may be related to the eyes, skin, and respiratory, cardiovascular, gastrointestinal, and neurological systems, including worsening of asthma, cough, chest pain, eye irritation, nausea, and headache.

Human health effects from oil spills include short-term physical effects from exposure of clean-up workers and residents of the area, mental health effects on workers and residents, as well as long-term effects. However, the research on health effects of oil spills is limited to date. There has been some evidence of acute physical effects and psychological effects in a number of cases. For example, CDC's National Institute for Occupational Safety and Health reports 186 injuries and 80 illnesses[29] among spill responders in the Gulf. However, evidence of long-term health effects is lacking. Much of the research on the physical effects of oil spills has been conducted outside of the United States. Some researchers have found evidence that oil spills affect the health of individuals involved in clean-up activities (Pérez-Cadahía et al. 2006), residents in the immediate vicinity of a spill (Janjua et al. 2006, Lyons et al. 1999), and residents involved in clean-up efforts (Morita et al. 1999). Physical effects on residents near oil spills have included sore eyes and throat (Lyons et al. 1999, Janjua et al. 2006) as well as headaches and general malaise (Janjua et al. 2006). Pérez-Cadahía et al. (2006) show evidence of cytogenetic damage and alterations in hormonal status.

Evidence of mental health effects have been shown for the Exxon Valdez and Prestige oil spills (Palinkas et al. 1993a, Palinkas et al. 1993b, Sabucedo et al. 2010). Palinkas et al. (1993a) show links between the oil spill and increased rates of depression, anxiety and post-traumatic stress disorder, and declines in subsistence activities and traditional social relationships. Sabucedo et al. (2010) show similar results with greater psychopathological symptoms in individuals living closer to the location of the oil spill and in fishermen.

Avoided Costs Associated with Other Activities Linked Economically to Avoiding an Oil Spill

A large oil spill will have economic costs that accrue beyond the area directly impacted. These costs will be incurred by businesses and households that are linked economically to coastal areas or to activities occurring in areas damaged by the spill. The oil spill may result in reduced producer surplus, lost producer surplus on products or services that are no longer produced, or some combination of the two. The magnitude and timing of any reduced producer surplus is difficult to predict, however the larger the spill and the more extensive its geographic impacts the larger the potential for producer surplus losses. The lost producer surplus associated with economic losses is not quantified for this analysis due to the uncertainties associated with the scope, magnitude, and timing.

[29] As of June 6, 2010; mostly contusions/abrasions and heat stress.

Summary – Avoided External-Social Costs

Table 25 summarizes the estimated avoided external-social costs of the hypothetical catastrophic blowout spill conditional on the spill being precluded from occurring. Spill costs that are avoided could be much higher if all costs discussed previously could be monetized. Efforts to quantify even rough estimates for those rows left blank in the table by reference to other oil spills were not fruitful because such private settlements are not reported publicly. Nevertheless, given the relative size of those sub-elements that could be monetized, the findings indicate that recreation, fishing and mortality losses are quite small compared to the costs for spill cleanup, damage assessment, and the imputed value of natural resource damages. Thus, provision for the lingering effects which an oil spill might have on fishing losses is not likely to affect the overall results.

Table 25 Summary of Estimated Avoided External-Social Costs

Social Cost Category	**Cost**	**Avoided Cost for 1 Hypothetical Spill**
	($ per bbl)	**(4.8 mm bbl)**
Natural Resource Damages	$604	$2.88 billion
Recreational Losses (Recreational Fishing and Beach Recreation)	$42	$0.20 billion
Commercial Fishing Losses	$2	$0.01 billion
Value of Life and Nonfatal Injury	$13	$0.06 billion
Other Health Effects	Not Quantified	
Oil Spill Response & Damage Assessment Costs	$2,300	$10.97 billion
Staging, training, and other costs associated with prepositioning oil spill response assets	Not Quantified	
Price effects in seafood markets	Not Quantified	
Property values	Not Quantified	
TOTAL		**$14.12 billion**

TOTAL ESTIMATED AVOIDED SOCIAL COSTS (BENEFITS)

Table 26 combines the conditional avoided private-social and external-social costs from Table 6 and Table 25. This is the potential benefit per catastrophic spill in the baseline from fully eliminating the possibility of a spill.

Table 26 - Summary of Private and External Social Costs

Social Cost Category	Conditional Avoided Cost Amount	Expected Avoided Cost Given 1 Spill in 25.8 years (3.85% probability of a spill each year)
Private Costs	\$2.17 billion	\$84.1 million
External Costs	\$14.12 billion	\$547.3 million
Total:	**\$16.29 billion**	**\$631.4 million**

The policies being promulgated can reduce, but not necessarily eliminate, the occurrence of a catastrophic spill and hence the resulting spill costs. Since the compliance costs are fully represented by annual expense outlays, it is convenient to express the expected avoided costs on an annual basis as well. Moreover, the coincident timing of compliance costs and risked avoided costs dispenses with the need to complicate the calculations and presentation by converting streams of monetary costs and benefits into discounted present value amounts.

There has been the only one deepwater blowout spill large enough to be considered in the catastrophic class. Based on this single observation, the number of deepwater wells drilled (4,123), and the anticipated annual number of future deepwater wells to be drilled (160), the baseline risk absent this rule is estimated to be 1 event in 26 years for this benefit-cost analysis. Compliance with the requirements in this rule will partly reduce the expected annualized spill costs by reducing the spill frequency, thereby increasing the expected interval between such spills and hence spreading the conditional spill costs over more years. The resulting reduction in the expected annualized spill costs represents the social costs associated with the hypothetical spill scenario avoided because of the provisions in this rule.

SCENARIO ANALYSIS

In order to compare the relative magnitudes of the expected benefits and costs associated with avoiding a blowout resulting in catastrophic oil spill, the agency examined several scenarios based on extrapolation from historical information on deep water blowouts. Given the paucity of information on specific effectiveness of various measures and the likelihood of another catastrophic blowout, this approach aims to evaluate the Final Rule in the context of alternative assumptions.

The methodology we used to compare the economic effects of the Final Rule under the various scenarios was to determine the hypothetical improvement in spill frequency that would have to occur under each scenario for the expected benefits to match the expected costs (the breakeven point). Calculating the breakeven point for each scenario is a useful analytical tool for comparing the sensitivity of the various factors in our analysis. It will also assist agency policymakers in getting a sense of whether promulgation of the final rule would likely have a net economic benefit under differing assumptions. These calculations, however, are not an agency determination of the actual expected improvement in spill frequency that the final rule will bring about. Such a determination is based upon assessing the expected effects of the provisions of the final rule, and not upon hypothetical economic analyses.

By varying selected important assumptions from those of the Baseline Scenario in reasonable ways, we have provided a range of reasonable alternative scenarios that could be expected to occur. For each of those scenarios, we have calculated the improvement in spill frequency under which expected benefits could justify the costs of the regulation (the economic breakeven point). The Scenarios have been developed by varying the assumptions from the Baseline Scenario as follows:

1) The compliance costs are lowered by about 50% to $65.4 million reflecting improvements in the efficiency of safety practices.
2) The compliance costs are raised by about 100% to $261 million reflecting more frequent compliance problems and work stoppages during drilling operations, as discussed in the next section.
3) The population of deepwater wells subject to a future catastrophic blowout spill is limited to those in water deeper than 3,000 feet, where the spill size and consequences (but not the spill probability) from a blowout are estimated to be greater. For the purpose of conducting this sensitivity analysis only, we employed the historical population of 1,475 wells drilled in the GOM at a water depth of 3000 feet or greater to set the baseline risk, and forecast that an average of 110 wells will be drilled each year at this depth. Elaboration of this scenario is provided in the *Sensitivity of Population of Deepwater Wells and Drilling Activity Subject to a Catastrophic Blowout Spill.*

4) The baseline of the expected number of deepwater wells drilled each year is reduced by 25 percent. This would reduce the number of deepwater wells in the analysis from 160/year to 120/year. This scenario is closer to the number of deepwater wells drilled in the two years before the DWH spill.

Baseline Scenario

For the Baseline Scenario, the hypothetical spill from Table 26 gives an avoided social cost of $16.3 billion for a major event. The compliance costs of this regulation from Table 4 give an annual compliance cost of $131 million per year. The baseline assumption is that there was one major event for every 4,123 deepwater wells and we assume an average of 160 wells will be drilled annually. Under these circumstances, a major event is projected to occur at an average rate of approximately once every 26 years.[30]

Using the avoided social cost of $16.3 billion and dividing it by the rate of a major event, one per every 26 years, we calculate an annual avoided cost of $631 million. To calculate the level of improvement in spill frequency for the expected benefits to equal the costs of regulation, we divide the compliance costs by the annualized avoided costs. An annual compliance cost of $131 million divided by annualized avoided costs of $631 million results in a 21 percent improvement in spill frequency that would be the level at which expected benefits would match the expected compliance costs.

Sensitivity of Compliance Costs

A **lower compliance cost estimate** of $65.4 million annually assumes the industry can achieve longer term productivity improvements for the requirements in this regulation. Over time, companies can increase the efficiency of conducting tests and use technology to improve safety; however, a 50 percent improvement appears unlikely to be achieved in the near term. Using this lower compliance cost of $65.4 million, divided by the annual avoided cost of $631 million, an improvement in spill frequency of 10 percent would be sufficient for estimated benefits to match estimated compliance costs.

An **upper compliance cost estimate** of $261 million annually assumes that the time required for conducting the tests for this regulation are doubled due to unforeseen and time consuming problems encountered in fulfilling the additional requirements imposed by this regulation. Using this upper compliance cost of $261 million divided by the annual avoided cost of $631 million,

[30] 4123 wells divided by 160 wells per year gives us 25.8 years, or 26 years.

an improvement in spill frequency of 41 percent would be the level at which estimated benefits would match the estimated compliance costs.

Sensitivity of Population of Deepwater Wells and Drilling Activity Subject to a Catastrophic Blowout Spill

To analyze the sensitivity of the population of deepwater wells and drilling activity, along with the underlying effect on the baseline risk assumption, we identified the water depth at which the consequences of a blowout event may be more severe. In the baseline analysis we used a 500 foot water depth demarcation since it is the upper limit of jackup rigs and where subsea BOP stacks start to be used for MODUs. While there is no specific water depth demarcation for an increase in the consequences of deepwater blowout, wells which are drilled at a water depth greater than 3,000 feet may have an increased potential for a catastrophic event due to changes in the surrounding geology and reservoirs as well as greater difficulty mitigating the consequences of an uncontrolled flowing well.

The changes in the geological formations allow for greater accumulation potential with porous and permeable sands at these depths and result in higher flow rates. The most recent public Gulf of Mexico Reserves Report[31] indicates that 6 of the 20 largest GOM fields are in water depths greater than 2,860 feet and discovered since 1989. Fourteen of the fields are in water depths 247 feet or less and discovered in 1971 or earlier. The GOM shelf is in decline and few large fields are likely to be discovered in the GOM shallow water. Over the last 40 years the largest fields with booked reserves have all been in deepwater. Thus the reservoirs being discovered at depths greater than 3000 feet are generally more prolific than their shallow water counterparts.

It is important to note that the probability of a blowout does not appear to be greater beyond 3,000 feet water depth and based on OCS drilling history is actually lower than shallower water depths. However, the consequences of an uncontrolled blowout event in deeper water depths are more likely to be catastrophic because of the additional complications in restoring well control at the water depths as demonstrated by the DWH event. In this sensitivity analysis we are considering a scenario which based on the occurrence of a single catastrophic blowout event (DWH) in water depths greater than 3,000 feet.

Historically, there have been 1,475 GOM wells drilled in water depths of greater than 3,000 feet, with approximately 1,100 wells in the past 10 years. This gives a 1/1475 probability of a

[31] Reserve Data for 1,229 Proved Fields - Gulf of Mexico Outer Continental Shelf, December 31, 2006, http://www.gomr.boemre.gov/homepg/offshore/fldresv/2006-Table4.pdf.

catastrophic blowout spill event, and about 110 wells drilled per year. At this rate, one event occurs every 13.4 years in this alternate scenario.[32]

By dividing the expected avoided social cost of $16.3 billion by the alternate scenario catastrophic event rate of 13.4 years per event, the annual avoided cost is $1.216 billion. Dividing the compliance costs of $131 million per year by the alternate annual avoided costs of $1.216 billion per year would result in an improvement in spill frequency of 11 percent for the estimated benefits to match the estimated costs in this alternate hypothetical scenario.

Sensitivity of Number of Deepwater Wells Drilled per Year (25% lower)

The baseline assumption in this is for an average of 160 new deepwater wells drilled each year. This alternate scenario reduces the baseline number of deepwater wells by 25 percent from 160 to 120 wells per year. The number of shallow wells remain constant at 286 per year. This scenario is plausible given likely reactions to drilling activity in the aftermath of the DWH event. Several deepwater MODU's have left the Gulf of Mexico and other new build deepwater rigs previously scheduled to drill in the deepwater Gulf have announced moves overseas. Additionally there are other factors that may lengthen the time to drill deepwater wells including deeper drilling depths and the stricter application of existing regulations. These factors are discussed in the section titled *Baseline Estimates of Future Deepwater Drilling Activity*. While the long-term GOM drilling activity is subject to many factors, it is not unreasonable to assume that drilling activity could remain relatively flat and continue in the range of the number of deepwater wells drilled in 2009 and originally projected for 2010 (Figure 1). The following table provides the compliance costs estimates for the scenario of 120 (85 MODU plus 35 platform) deepwater wells per year.

[32] 1475 wells drilled divided by 110 wells per year equals 13.4 years.

Table 27 – Estimated Recurring Cost Summary (25% fewer deepwater wells per year)

Regulation	Recurring Costs:	MODU Wells (85/yr)	Fixed Platforms (35/yr)	Shallow Wells (186/yr)	Cost Shares
		Total ($MM)	**Total ($MM)**	**Total ($MM)**	
250.449(j)(k)	Subsea ROV function testing (drilling)	12.8	0.0	0.0	***12%***
250.516(d)(8), 250.616(h)(1)	Subsea ROV function testing (completions/workover)	4.1	0.0	0.0	***4%***
250.423(c)	Test casing strings for proper installation (negative pressure test)	9.6	0.0	0.0	***9%***
250.420(b)(3)	Installation of dual mechanical barriers	39.3	7.6	20.5	***65%***
250.420(a)(6)	PE certification for well design	1.0	0.4	2.1	***3%***
250.451(i)(j)	Emergency cost of activated shear rams or LMRP disconnect	2.0	0.0	0.0	***2%***
250.416(e)	Independent third party shear certification	0.3	0.2	0.6	***1%***
All	Paperwork Costs taken from PRA table in final rule.	1.9	0.3	1.6	***4%***
	Estimated Cost per year:	**71.0**	**8.4**	**24.8**	**$ 104.2**
	Estimated Cost per well:	**0.84**	**0.24**	**0.13**	

Dividing the compliance costs of $104.2 million per year by the alternate annual avoided costs of $466 million per year ($16.3B/[4123/120]) would result in an improvement in spill frequency of 22 percent for the benefits to match the costs in this alternate hypothetical scenario.

Scenario Analysis Summary

The following table summarizes the baseline and alternative scenario analysis:

Table 28 – Alternative Scenario Summary

Scenario	Annual Compliance Costs ($MM)	Annual Avoided Costs ($MM)	Catastrophic Spill Frequency Improvement Required for Benefits to Match Costs of Rule (percent)
Baseline	$131	$631	21 percent
Compliance Costs lowered 50 Percent	$65	$631	10 percent
Compliance Costs Increased 100 Percent	$261	$631	41 percent
>3,000 feet (110 deepwater wells/year)	$131	$1,216	11 percent
Number of Deepwater Wells Drilled per Year (25% lower)	$104	$466	22 percent

As can be seen from the Table 28, changing assumptions yields different risk reductions of a catastrophic spill event (spill frequency improvement) needed for the estimated economic benefits to match the estimated compliance costs of rulemaking (the breakeven point). The reduction in spill frequency for this match to occur would range from 10 to 41 percent, with the Baseline Scenario improvement level at 21 percent. Based upon this range, and upon the agency's analysis of the provisions of the rule (discussed below), it is reasonable to conclude that this rulemaking will reduce the risk for a catastrophic blowout spill event at least enough such that estimated benefits will justify the estimated costs of this regulation.

Alternatives

This final rule implements selected safety measures recommended in the report entitled, "Increased Safety Measures for Energy Development on the Outer Continental Shelf" (Safety Measures Report), dated May 27, 2010 and the subsequent JIT report of BOEMRE and the USCG. Given the critical nature of the BP Deepwater Horizon (DWH) explosion and resulting oil spill and the apparent inadequacy of existing well control procedures and BOP requirements, the Safety Measures Report recommended that BSEE's predecessor agency address some items through an emergency rulemaking. The requirements in this final rule include practices related to well control, including well casing and cementing, ROV intervention, unplanned disconnects, recordkeeping, well completion, and well plugging. These requirements are determined by the Secretary to be urgently needed to protect worker safety and the OCS environment.

Other measures recommended in the investigative reports but not included in this rulemaking include additional blind shear and casing ram requirements, enhanced ROV intervention capability, increased accumulator capacity for operating BOPs and safety case requirements for floating drilling operations. These and other items require further study and public input to determine their efficiency and effectiveness. Measures considered beneficial will be considered for future notice and comment rulemaking.

Small Business Alternatives

A separate Initial Regulatory Flexibility Analysis (IRFA) was performed for the interim final rule (75 FR 80717). A Final Regulatory Flexibility Analysis (FRFA) for this rule is found in Appendix A.

CONCLUSION

On June 2, 2010, the Secretary of the Interior directed BSEE' predecessor agency BOEMRE to adopt the recommendations contained in the Safety Measures Report and to implement them as soon as possible. On September 14, 2011, the BOEMRE published the final joint investigation report (DWH JIT report), on the causes of the Deepwater Horizon incident, which included multiple regulatory recommendations. To implement the most practical recommendations identified by experts in the Safety Measures Report and DWH JIT report, this rulemaking amends corresponding drilling, well completion, well workover, and decommissioning regulations related to well control, including those covering: subsea and surface blowout preventers, well casing and cementing, secondary intervention, unplanned disconnects, recordkeeping, well completion, and well plugging.

BSEE has analyzed the costs and benefits of this rule using data available at the time of this rulemaking under various scenarios to assess when expected benefits might justify the expected costs. Under different assumptions about the magnitude of costs, benefits and drilling activity, we assessed how the frequency and the magnitude of future blowouts resulting in catastrophic spills should change for the expected benefits to justify the compliance costs. We have calculated the breakeven threshold this rulemaking would need to achieve for its potential benefits to balance the compliance costs. Relative to the baseline deepwater drilling experience, the breakeven threshold for this rulemaking is a 21 percent reduction in the probability of a catastrophic spill event. Although drilling system reliability data are unavailable to compute the blowout risk reduction associated with the specific provisions in this rulemaking, blowout risk reduction should result from the three most critical safety provisions required by the Interim Final Rule and the Final Rule. We expect these new requirements will reduce the chances of another catastrophic spill and that the breakeven risk reduction is a modest goal for the improvement in drilling safety likely to stem from these provisions. We confidently expect the improvement in drilling safety through the requirements in this rulemaking, will reduce the probability of a catastrophic spill by at least 21 percent.

Appendix A Final Regulatory Flexibility Act Analysis, RIN 1014-AA02

Agency: Department of the Interior, Bureau of Safety and Environmental Enforcement (BSEE).

Regulatory Citations: The Safety Measures Rule is amending the drilling regulations at 30 CFR 250, subparts D, E, F, and Q. The rule is titled RIN 1014–AA02, Final Rule, Increased Safety Measures for Energy Development on the Outer Continental Shelf and was originally published as an Interim Final Rule on October 14, 2010 (75 FR 63346).

Summary: BSEE is publishing this Final Regulatory Flexibility Analysis (FRFA) in conjunction with the final rule. The Bureau's publication of the interim final rule did not include a full Initial Regulatory Flexibility Analysis (IRFA) pursuant to the Regulatory Flexibility Act (5 U.S.C. 603). A supplemental IRFA was published on December 23, 2010 (75 FR 80717) with a 30 day comment period which closed on January 24, 2011. The changes from the IRFA are minor and relate to lower compliance cost estimates for the regulation. The revised cost estimates are the result of changes to the regulatory language and improved estimates of the counts and the operational timeframes required to comply with the regulatory provisions.

Supplementary Information

BSEE has updated the estimated compliance costs and small business impacts from the projections reported in the IRFA. These changes are minor and mostly result from updated compliance costs for several of the provisions and the including of paperwork and recordkeeping costs for this regulation.

Over the last few years there have been some notable trends in the Gulf of Mexico. First, several of the new companies entering the Gulf of Mexico (GOM) are large foreign companies and not small businesses. Second, the number of deepwater wells drilled by small companies has increased as capital and technology has become more accessible to small entities. Third, a few of the smaller companies with meaningful OCS acreage have either sold their OCS assets to larger companies, become wholly owned subsidiaries, or merged with larger companies. Cumulatively, these trends result in a greater share of acreage, drilling, and production attributed to large companies.

Our analysis shows there are currently about 130 Operators of Federal oil and gas OCS leases. Small lessees that operate under this rule fall under the Small Business Administration's North American Industry Classification System (NAICS) codes 211111, Crude Petroleum and Natural Gas Extraction, and 213111, Drilling Oil and Gas Wells. For these NAICS code classifications, a small company is one with fewer than 500 employees. Based on these criteria, we estimate 65 percent of these companies are small entities. This proposed rule, therefore would affect a substantial number of small entities.

Much of the information in this FRFA is covered and discussed in the final rule preamble and elsewhere in this RIA for the Safety Measures Rule. These documents can be found at http://www.regulations.gov under the Docket ID: BSEE-2012-0002. This FRFA is not intended to duplicate all the explanations and analysis in those documents, but rather meet the requirement and intent of the Regulatory Flexibility Act. This FRFA analyzes and considers the impact of the Safety Measures Rule on small entities.

Summary of Small Business Impacts

We estimate the Safety Measures Rule will impose a recurring operational cost of $131 million each year on operators drilling OCS wells. The rule affects every new well drilled after October 14, 2010; some requirements also apply to wells undergoing completion, workover, or abandonment operations on the OCS. Every operator both large and small must meet the same criteria for these operations regardless of company size. However, the overwhelming share of the cost imposed by these regulations will fall on the operating companies drilling deepwater wells, which are predominately the larger companies. We estimate that about 81 percent of the total costs will be imposed on deepwater lessees and operators where small businesses only hold 8 percent of the leases and drill 12 percent of the wells. About 19 percent of the total costs will apply to shallow water leases where small companies hold 45 percent of OCS leases and also drill 45 percent of the wells.

Nonetheless, small companies as both operators and lease-holders will bear meaningful costs under these regulations. Of the annual $131million in annual cost imposed by the rule, we estimate that $12.3 million will apply to small businesses in deepwater and $11.0 million in shallow water. In total we estimate that $23.3 million or 18 percent of the regulations' cost will be borne by small businesses.

The GOM represents 98 to 99 percent of annual OCS oil and gas drilling activity. Fiscal year 2009 aggregate annual GOM OCS oil and gas revenues were $31.3 billion.[33] Using the lease ownership profiles of GOM producing wells, we estimate that 87 percent ($27.2 billion) of the OCS revenues are ultimately received by large companies and 13 percent ($4.1 billion) by small companies. As a share of fiscal year 2009 revenues, the interim final rule will cost approximately 0.39 ($0.107/$27.2) percent of OCS revenue for large companies and 0.58 ($0.024/$4.1) percent for small companies. Although the difference in these ratios is not significant, small companies may experience a somewhat greater economic impact than large companies from the regulation primarily because they have a lower production share in deepwater relative to the number of deepwater wells they drill. The likely reason for this difference is the migration of smaller companies into deepwater as they have accessed the technology and capital required for exploration and development. It can take a decade for an economic discovery in deepwater to reach production. Additional data on lease ownership, wells drilled, and production can be found in Table 29, Table 30, Table 31, and Table 32.

Description of the Reasons that Action by the Agency is Being Considered

The final rule establishes regulations based on certain recommendations in the May 27, 2010, report from the Secretary of the Interior to the President entitled, "Increased Safety Measures for Energy Development on the Outer Continental Shelf" (Safety Measures Report) and selected subsequent recommendations from reports by the President's National Oil Spill Commission and Joint BSEE/USCG

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[33] The fiscal year 2010 GOM OCS revenues decreased to $24.7 billion. The corresponding share of costs as a share of revenues is estimated to remain essentially the same; the revenue figures have not been updated for the FRFA.

Joint Investigation Team. The President directed that the Department of the Interior (DOI) develop the Increased Safety Measures Report as a result of the Deepwater Horizon event on April 20, 2010. This event, which involved a blowout of the BP Macondo well and an explosion on the Transocean Deepwater Horizon mobile offshore drilling unit (MODU), resulted in the deaths of 11 workers, an oil spill of National significance, and the sinking of the Deepwater Horizon MODU. On June 2, 2010, the Secretary of the Interior directed BSEE to adopt the recommendations contained in the Safety Measures Report and to implement them as soon as possible.

The selected measures from the Safety Measures Report and other reports being implemented initially are those in the Final Rule, AA-02 Increased Safety Measures for Energy Development on the Outer Continental Shelf. This FRFA is for the estimated impacts on small entities from this rulemaking. Some recommendations in the Safety Measures Report require additional review by the DOI, and yet other measures will be addressed through notice and comment rulemaking, as appropriate.

The Safety Measures Rule preamble and Table 1 provide a table summarizing the rulemaking provisions.

Description of, and Where Feasible, an Estimate of the Number of Small Entities to Which the Rule will Apply

In order to understand the entities that will be impacted by the Safety Measures Rule, the role both *operators* and *lessees* play within the OCS oil and gas regulatory structure should be understood.

The regulations at 30 CFR 250.105 defines "lessee" as:

> ***Lessee*** *means a person who has entered into a lease with the United States to explore for, develop, and produce the leased minerals. The term lessee also includes the BOEM-approved assignee of the lease, and the owner or the BOEM-approved assignee of operating rights for the lease.*

While there may be multiple lessees holding an ownership interest, there can only be a single designated OCS operator for drilling or production operations on a lease. The regulations at 30 CFR 250.105 define "operator" as:

> ***Operator*** *means the person the lessee(s) designates as having control or management of operations on the leased area or a portion thereof. An operator may be a lessee, the BSEE-approved or BOEM-approved designated agent of the lessee(s), or the holder of operating rights under an BOEM-approved operating rights assignment (30 CFR 250.105).*

Although the designated *operator* is the person BSEE typically holds responsible for complying with all regulations and ensuring the safety of drilling operations on a lease or unit, under BSEE regulations, joint and several responsibility for compliance exists among co-lessees, the operator, and persons (such as contractors) actually performing an activity to which a regulatory requirement applies.[34]

[34] Such responsibilities are expressly described in 30 CFR 250.146.

Consistent with the court's interpretation that the RFA applies to entities directly affected by the rulemaking,[35] the designated operator and the co-lessees are the entities directly regulated by BSEE, impacted by this rulemaking and considered in the estimation of compliance costs.

While the requirements in this rulemaking apply to drilling operations under control of the operator, lessees are the project owners and will bear the compliance costs for the increased safety measures in this rulemaking. This analysis considers impacts on small and large entities based upon the lease ownership profiles for OCS activities because the lease owners will bear the cost of these regulations. The three OCS activities analyzed are (1) lease ownership, (2) wells drilled, and (3) production.

Additionally, this rulemaking requires drilling contractors to preserve certain maintenance and testing records. BSEE has only identified two active shallow water or platform drilling rigs operated by a small company on the GOM OCS among the approximately 50+ usually working there. This increased cost incurred by owners of drilling rigs is expected to be negligible compared to the added expense incurred by the Operators and Lessee owners due to the lengthened time to drill wells and additional permitting paperwork requirements.

Our updated analysis shows there are currently about 130 Operators of Federal oil and gas OCS leases, all of which will be impacted by this regulation if conducting drilling operations. Approximately 65 percent) of the companies operating on the OCS are considered small companies and 35 percent are considered large companies.

Breakout of Small and Large Companies Operating on the OCS

There are many arrangements for sharing project risks and expenses for OCS exploration and development projects. These include original and revised ownership agreements where the risk, equity, and other interests may be complex. When there is an assignment of lease rights among different parties, BOEM records the OCS lease assignments in a manner similar to county court property records. A snapshot of the OCS lease ownership profile and wells drilled on those leases for small and large companies' form the basis for the Safety Measure Rule's estimated impact on small entities.

We analyzed OCS activity for both deepwater and shallow water by company size. Operating in the shallower water depths is generally less expensive and the concentration of smaller companies is greater in shallow water. The most costly requirements in the Safety Measures Rule apply to deepwater MODU drilling operations using a subsea blowout preventer (BOP). The following results for lease ownership, wells drilled, and production reflects leases with sole or fractional ownership as recorded by BOEM.

Deepwater

The categorization of company lessees shows that large companies (greater than 500 employees) hold 92 percent of deepwater leases (greater than 500 feet) and small companies hold 8 percent. Cobalt International Energy is the only small company (less than 500 employees) among the top 30 companies holding deepwater acreage since Mariner merged with Apache.

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[35] Mid-Tex Electric Cooperative, Inc., v. FERC (Mid-Tex), 773 F.2d 327 (D.C. Cir. 1985).

When we consider deepwater drilling activity, the results are similar; of the wells spudded in deepwater during 2007-2009, 88 percent of deepwater wells were attributed to large company lessees and only 12 percent to small company lessees. These results include the factional ownership by some small entities that are only equity investors in projects including some venture capital funds.

An even greater share of OCS deepwater hydrocarbon production and corresponding revenues accrued to large companies in calendar year 2009. While deepwater drilling activity attributed to small companies is increasing, economic projects cannot be brought to production for several more years. We use 2009 as a long-term proxy for the production split between small and large companies. Large companies produced 97.5 percent of oil and 92.1 percent of gas production in deepwater. Only 2.5 percent of deepwater oil production and 7.9 percent of deepwater gas production is from leases owned by small companies.

Shallow water

We find that small companies hold a much greater share of acreage in shallow water (less than 500 feet) than in deepwater. The top two acreage-holding lease owners, Apache and Chevron, are not small companies, but the next four lessees in rank order are small entities: McMoRan, W & T Offshore, Stone Energy, and LLOG Exploration. In shallow water, small companies hold 45 percent of the leases while large companies hold 55 percent.

The drilling activity over the past 3 years matches the small and large companies lease ownership profile. Of the wells spudded during 2007-2009, 45 percent of the wells were spudded by small companies and 55 percent by large companies.

Hydrocarbon production in the shallow water depths shows that larger companies hold the most productive leases. Slightly less than two-thirds of both oil and gas production accrues to large companies and slightly more than one-third is produced by small entities.

Summary of Large and Small Company OCS Activity

The following tables[36] summarize the small and large company percentage breakouts of leases, wells drilled (2007-2009), production of oil and gas and value of OCS production. The results reflect lease fractional ownership shares among different companies.

Table 29 Lease Ownership among Small and Large Companies (11/1/2010)

Leases 11/01/2010	**Shallow Water Leases**	**Deepwater Leases**	**All Leases**
Large Co.	55%	92%	80%
Small Co.	45%	8%	20%
	100%	**100%**	**100%**

[36] The categorization of companies as small or large is based upon publically available data as measured by number of employees as of October 2010. BOEMRE collects data on lease ownership, wells drilled and operator production in our Technical Management System Database (TIMS).

Table 30 Wells Spudded among Small and Large Companies (2007-2009)

Wells (2007-2009)	**Shallow Water Wells Spudded**	**Deepwater Wells Spudded**	**All Wells Spudded**
Large Co.	55%	88%	65%
Small Co.	45%	12%	35%
	100%	**100%**	**100%**

Table 31 Production based on Recorded Lease Share for Small and Large Companies (2009)

2009 Production	**Shallow Water Oil Production**	**Deepwater Oil Production**	**Shallow Water Gas Production**	**Deepwater Gas Production**	**All BOE Production**
Large Co.	64.6%	97.5%	63.2%	92.1%	85%
Small Co.	35.4%	2.5%	36.8%	7.9%	15%
	100%	**100%**	**100%**	**100%**	**100%**

Table 32 Estimated Production Value* ($millions) for Small and Large Companies (2009)

Est. 2009 Production Value ($million)	**Shallow Water Oil Production**	**Deepwater Oil Production**	**Shallow Water Gas Production**	**Deepwater Gas Production**	**All BOE Production**
Large Co.	2,581	17,284	3,271	4,079	27,215
Small Co.	1,415	442	1,905	351	4,113
TOTAL:	**3,996**	**17,726**	**5,176**	**4,430**	**31,328**

*Office of Natural Resource Revenue, http://www.onrr.gov/ONRRWebStats/default.aspx

Recurring Regulatory Costs Imposed by the Regulation

Table 4 summarizes the estimated recurring operational costs categories for three subgroups of wells affected by the new regulations. Those categories are (1) deepwater wells drilled by a MODU, (2) deepwater wells drilled from a platform and (3) all shallow water wells.

The regulations impact well costs differently depending on the type of drilling rig and category of well being drilled. As can be observed in Table 4, deepwater wells drilled by platform rigs and shallow wells drilled by jackups or platforms will incur lower incremental costs than deepwater wells drilled by MODUs, primarily because they use surface BOPs; while wells drilled by deepwater MODUs (drillships and semisubmersibles) will incur the greater incremental cost due to the new subsea BOP requirements. Additional explanation about these costs is provided in the Benefit-Cost Analysis for the Safety Measures Rule.

For this analysis, BSEE estimates that 160 deepwater wells will be drilled each year, split between MODU wells (112/yr) and platform wells (48/yr). An estimated 186 wells will be drilled each year in the shallow water depths. Using the recent drilling profiles for small and large company lessees in Table 30, the following table estimates the number of wells to be drilled each year by large and small entities.

Table 33 – Estimate of Future Wells Drilled (annually)

	MODU Deepwater Wells (112/yr)	Fixed Platforms Deepwater Wells (48/yr)	Shallow Wells (186/yr)
Large Co.	99 (88%)	42 (88%)	102 (55%)
Small Co.	13 (12%)	6 (12%)	84 (45%)
TOTAL	**112**	**48**	**186**

The estimated annual increased costs for each well type drilled are taken from Table 4 to estimate the annual compliance costs for large and small companies by type of well. Of the $131 million in annual cost imposed by the rule, we estimate that the $12.3 million will apply to small businesses in deepwater and $11.0 million in shallow water. In total, we estimate that $23.3 million or 18 percent of the regulation's costs will be borne by small businesses. The following table shows the calculations for these estimates.

Table 34 – Large/Small Company Estimated Additional Drilling Costs

$millions	Additional MODU Deepwater Well Cost (112/yr)	Fixed Platforms Deepwater Wells (48/yr)	Shallow Wells (186/yr)	Total Estimated Cost
Large Co.	**$83.3** (88% * 94.6)	**$9.9** (88% * $11.2)	**$13.7** (55% * $24.8)	**$106.8**
Small Co.	**$11.4** (12% * $94.6)	**$1.3** (12% * $11.2)	**$11.2** (45% * $24.8)	**$23.9**
TOTAL	**$94.6**	**$11.2**	**$24.8**	**$130.7**

**Numbers may not add due to rounding.*

Determining a precise number of small entities that will be "regulated" is complicated by the fact that the actual number fluctuates as OCS properties are bought, sold, the designated operator changes and not all operators conduct drilling operations. The same difficulty follows for the lease ownership profile of small and large entities. However, our best estimate of the impact on small entities when we consider how project and drilling costs are shared among lease owners is that small entities will bear 12 percent of increased regulatory costs in deepwater, and 45 percent in shallow water. The annual small entity regulatory compliance cost imposed by this rulemaking is estimated to be $23.9 million or 18 percent of the total.

Description of the projected reporting, recordkeeping, and other compliance requirements of the proposed rule, including an estimate of the classes of small entities that will be subject to the requirement and the type of professional skills necessary for preparation of the report or record.

The benefit-cost analysis for the Safety Measures Rule identifies $131 million in annual operational costs; these costs are summarized in Table 4 and discussed in the section titled *Compliance Costs for this*

Regulation. Greater details of the regulatory provisions are provided in the rule preamble. This section primarily discusses the paperwork burden on drilling contractors.

The Paperwork Reduction Act (PRA) section of the Safety Measures Rule (which combines both the IFR and Final Rule) identifies 50,078 hours of paperwork, reporting, and recordkeeping required annually by the regulation. Using the Bureau of Labor Statistics estimated loaded hourly rate of $83/hr, the estimated paperwork cost to industry for this rulemaking is $4.6 million. The burden tables of the estimated annual burden hours of these rulemakings can be found in both the IFR and final rule procedural matters section of the Federal Register preamble.

Reporting and recordkeeping falls primarily on the OCS lessees and operators, although drilling rig operators do have some additional recordkeeping requirements. The frequency of response varies depending upon the requirement but is primarily based on drilling activity. Responses and recordkeeping by the drilling companies fall primarily on the Deepwater MODUs where all the deepwater MODU operators in the GOM are large companies. Some additional recordkeeping requirements will fall on all OCS drilling rig operators. As of early November, 2010 (11/4/2010 Rigzone), there are two shallow water rigs operating in the GOM OCS owned by a small company. They are both owned by Blake International and are under contract to Apache. The estimated additional recordkeeping cost for jack-up rig surface BOP stacks is about $5,000 annually for each rig. The direct estimated paperwork burden on the single small drilling operator currently active in the GOM is about $10,000 per year. The paperwork costs impacting this small entity are found in Table 35 and sourced from the IFR PRA table found at 75 FR 63368.

Table 35 – Selected Paperwork Burden Requirements from AD68 IFR PRA*

Citation 30 CFR 250	Reporting & Recordkeeping Requirement	Hour Burden	Average No. of Annual Responses	Annual Burden Hours
Subpart E				
516(g)(l)	Document the procedures used for BOP inspections; record results; maintain records for 2 years; make available to BSEE upon request.	7 days x 12 hrs/ day = 84	105 rigs / once every 3 years = 35 per year	2,940
516(h)	Document the procedures used for BOP maintenance; record results; maintain records for 2 years; make available to BSEE upon request.	1	105 rigs	105
Subpart F				

Citation 30 CFR 250	Reporting & Recordkeeping Requirement	Hour Burden	Average No. of Annual Responses	Annual Burden Hours
617(a)(l)	Document the procedures used for BOP inspections; record results; maintain records for 2 years; make available to BSEE upon request.	7 days x 12 hrs/ day = 84	105 rigs / once every 3 years = 35 per year	2,940
617(b)	Document the procedures used for BOP maintenance; record results; maintain records for 2 years; make available to BSEE upon request.	1	105 rigs	105

*Full table can be found in the Preamble Procedural Matters of the IFR (75 FR 63368).

Much of the paperwork is recording the results of tests and maintenance procedures and is expected to be completed by workers concurrently with the tests or in between other drilling tasks. The paperwork costs are a moderate component of the added costs imposed by this rule and minor in comparison to the cost of drilling an OCS well.

Identification, to the extent practicable, of all relevant Federal rules that may duplicate, overlap, or conflict with the rule

The only regulations from other Federal agencies that may closely relate to the scope of BSEE regulations in this rulemaking are from the U.S. Coast Guard. However, for the Safety Measures Rule there is no overlap, conflict, or duplication with Coast Guard regulations. Under BSEE/USCG Memorandum of Understanding (MOU), BSEE has authority over spill abatement - which includes well control. All of the regulatory provisions in the rulemaking are focused on well control. Additionally and consistent with the MOU, BSEE has regulatory authority for drilling operations of MODUs on station while conducting drilling operations.

There are several MOUs between the agencies that outline the division of duties and shared responsibilities. BSEE has authority over drilling and oil and gas operations on the OCS while the Coast Guard has authority over the integrity and safety of floating vessels conducting OCS operations. The MOUs can be found at: http://www.uscg.mil/hq/cg5/cg522/cg5222/mou.asp

Description of any significant alternatives to the rule that accomplish the stated objectives of applicable statutes and that minimize any significant economic impact of the rule on small entities, including alternatives considered, such as:

1. **Establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities.**
2. **Clarification, consolidation, or simplification of compliance and reporting requirements under the rule for such small entities.**

3. **Use of performance rather than design standards.**
4. **Any exemption from coverage of the rule, or any part thereof, for such small entities.**

Under the published Safety Measures Rule, the requirements are prescriptive and lease operators submitting permits to BOEMRE or conducting drilling operations must comply with the requirements. Even though this rule may not have a significant economic impact on small businesses, BOEMRE has analyzed several alternatives for the provisions included the Safety Measures Rule.

Alternative 1, Different Compliance Requirements for Small Entities

During the drafting of the IFR, BOEMRE considered lengthening the compliance deadline for both large and small companies. The primary reason for not including additional compliance time or different requirements is the overriding need to reduce the chance of a catastrophic blowout event. The risk is not lower for small entities and BSEE cannot compromise the safety of offshore personnel and the environment for any entity including small businesses. Offshore drilling is highly technical and can be hazardous; any delay in the implementation of Safety Measures Rule may increase the risk of OCS drilling operations.

The regulatory provisions do not require significant equipment or capital upgrades and as the 2011 resumed deepwater drilling shows, can be met in short order. The compliance costs are mostly the increased time to conduct drilling operations. Thus, any additional time to comply with the rule would not result in cost savings in the form of reduced short-term cash flow expenditures that might be expected if the rule required the installation of capital equipment.

BSEE is continuing to review other safety measures that may be appropriate for rulemaking in the near future. These may be included in a proposed rulemaking or an advanced notice of proposed rulemaking.

Alternative 2, Testing Requirements

Alternative Testing Methods: BSEE considered if the required testing for subsea ROV intervention and negative pressure tests could be performed in an alternative manner. Because of the failings that occurred in, and lessons learned from, the BP Deepwater Horizon event, BSEE has concluded that alternative testing is not a viable option. No alternative testing methods have been identified that will provide the same assurance of reliability.

The subsea ROV intervention test upon installation of the BOP stack is required to demonstrate that the rams can be closed as required under realistic subsea conditions. The BOP ROV function test occurs upon installation on the sea floor and is in addition to the “stump” tests conducted prior to subsea installation. The only alternative to the subsea tests would be to only conduct the “stump test.” However, the stump test would not provide the same assurance of BOP ram operability as the subsea test which is performed under the actual conditions that would occur if the BOP rams needed to be employed.

The new requirement to perform a negative pressure test after the final casing string is installed is necessary to verify that no fluids are entering the well and the cement is sealing the wellbore.

Alternative Testing Periods: An IRFA public comment offered an alternative to the current BOP testing requirement. The suggestion was to change the existing regulation at 30 CFR 250.449(h) which requires a BOP function test every 7 days including the blind-shear rams to a 14 day requirement

A Joint Industry Project study completed in 2009 analyzed BOP Equipment Reliability. The results of this study suggest that up to $193 million per year could be saved through less frequent testing while achieving the same reliability for BOP performance.[37] Though counter intuitive, it may be possible that less frequent testing can provide the same BOP reliability because of the wear that more frequent tests may exert on the BOP equipment. While the testing alternative may have value, and is a topic that merits greater study, it is outside of the scope of this rulemaking.

Alternative 3, Paperwork Consolidation

BSEE did not identify any provisions of the rule that could provide efficiencies through consolidation or other streamlining. Some of the regulatory provisions apply to different Subparts and are necessarily duplicated. Most reporting requirements are dependent on drilling activity and closely related to the number of wells drilled or Application for Permit to Drill/Application for Permit to Modify (APDs/APMs) submitted. No efficiencies would be expected through further simplification or consolidation.

Alternative 4, Use Performance Rather than Design Standards

The provisions in the final rule generally prescribe a combination of performance and design standards for well design (cementing and casing), testing drilling equipment, and certifying the well's integrity. Although, for instance, the rule requires the use of two independent barriers, including one mechanical barrier, the rule does not mandate the specifications for the particular type of barrier. BSEE or commenters did not identify equivalent performance standards that provide the same level of reliability and well integrity and that can be implemented as quickly as the provisions in this rule.

The BOEMRE is carefully evaluating how to integrate performance based systems into our regulatory regime. This includes the SEMS (Safety Environmental Management Systems) and the Safety Case. The first SEMS rule was published on October 15, 2010 (75 FR 63610) and a second SEMS proposed rule was published on September 14, 2011 (76 FR 56683). The Safety Case approach to risk management championed by the International Association of Drilling Contractors (IADC) is also receiving careful consideration and study by BSEE.

Implementation of a performance based solution requires long lead times and careful strategic and tactical implementation. Because of the immediate need to address well design, testing and reliability issues, BSEE is relying on a combination of performance and design standards in the Safety Measures Rule.

[37] BOP Equipment Reliability Joint Industry Project At A Glance, West Engineering Services, http://www.westengineer.com/pdfs/JipTrifoldr3.pdf.

Departures to the provisions in the Safety Measures Rule can be approved under the current regulations if the alternative procedures afford an equal or greater degree of protection, safety, or performance. *Departures* are discussed in the next section.

Alternative 5, Exemptions from Rule Requirements

One alternative is to exempt small businesses from the requirements of this interim final rule. The "exemption" or "no action" alternative was not adopted by BSEE because of the overriding need to reduce the chance of a catastrophic blowout event. The risk is not lower for small entities and BSEE cannot compromise the safety of offshore personnel and the environment for any entity including small businesses.

BOEMRE can approve departures to existing regulations when the departure would assure the continued safety of drilling operations. In 30 CFR 250.105 Departures means:

> *Approvals granted by the appropriate MMS representative for operating requirements/procedures other than those specified in the regulations found in this part. These requirements/procedures may be necessary to control a well; properly develop a lease; conserve natural resources; or protect life, property, or the marine, coastal, or human environment.*

There are several general and drilling specific regulatory provisions that identify the availability of departures. Those regulatory citations are:

30 CFR 250, Subpart A, General Information, Special Approvals

> **§ 250.142 How do I receive approval for departures?** We may approve departures to the operating requirements. You may apply for a departure by writing to the District Manager or Regional Supervisor.
>
> **30 CFR Subpart D, Oil and Gas Drilling Operations, General Requirements**
>
> **§ 250.409 May I obtain departures from these drilling requirements?** The District Manager may approve departures from the drilling requirements specified in this subpart. You may apply for a departure from drilling requirements by writing to the District Manager. You should identify and discuss the departure you are requesting in your APD see §250.414(h)).
>
> **§ 250.414 What must my drilling prognosis include?**
>
> (h) A list and description of all requests for using alternative procedures or departures from the requirements of this subpart in one place in the APD. You must explain how the alternative procedures afford an equal or greater degree of protection, safety, or performance, or why you need the departures;

Although not a specific provision of the Safety Measures Rule, departures to the requirements in this rulemaking will be considered and may be approved if the alternative proposed method does not compromise safety and environmental protection. These provisions are available to both large and small companies.

Appendix B Natural Resource Damage Data

Table 36 - Dataset of Spill Costs: Restoration and Assessment Costs

Event	Year of Settlement	Max Volume (bbl)	NRD plus Assessment Costs (2009$/bbl)*
American Trader Inc.	2006	143	1,313
Anacortes	1998	952	491
Apex Houston Spill	2006	25,000	244
B.T. Nautilus	1994	6,024	816
Barge Morris J. Berman	2000	11,905	480
Barge RTC 380	1994	643	411
Bermuda Islander	2008	24	11,340
Blake IV and Greenhill Petroleum Corp. Well 25	1995	2,905	786
Bouchard Barge 120	2006	2,333	
BP American Trader Vessel	1997	9,919	300
Chevron BLDSU #5, West Bay Field	1996	262	249
Chevron Perth Amboy Facility	2006	342	
Chevron, HI	1999	982	2,189
Chiltipin Creek	1994	2,950	69
Cibro Savannah	1999	2,381	138
Cold Spring Harbor Barge	2004	2,357	
ConocoPhillips Bayway	2005	250	
El Segundo	1993	500	300
Equinox Cockrell-Moran #176 well	2005	1,500	800
Evergreen International M/V Ever Reach Vessel	2003	298	3,021
Exxon Bayway	1991	13,500	905
Exxon Valdez	1991	261,905	5,005
Fish Creek	1993	714	3,511
International Petroleum Corporation (IPC)	2009	286	882
Chelsea Creek (Global Oil/Irving Oil Pipeline)	2006	524	20
Jahre Spray	1996	1,400	121

Event	Year of Settlement	Max Volume (bbl)	NRD plus Assessment Costs (2009$/bbl)*
M/T Athos I	2009	6,271	16
M/T Kentucky	1995	310	81
M/TCommand Oil Spill	1999	71	59,181
M/V Cosco Busan	2010	1,262	1,585
M/V Fortuna Reefer	1997		
M/V Kure	2008	108	33,890
M/V Kuroshima	2002	929	1,661
M/V New Carissa	2004	1,667	16,118
M/V Presidente Rivera	1993	5,952	426
M/V Selendang Ayu	2006	8,000	7
M/V World Prodigy	1993	7,000	119
M/VWestchester	2003	13,095	41
Martinez	1990	9,524	1,138
McGrath Lake	1997	2,071	635
Milos Reefer	1993	5,952	67
Neches River	1997	2,095	105
Nestucca	1991	5,500	609
North Cape Barge	1999	19,714	625
Northridge	1997	4,595	1,599
OCEAN 255/B-155/BALSA 37 Spill	1996	8,619	928
Ocean Energy/Devon Energy North Pass Storage Facility	2006	300	393
Oil and Crooked Creeks	1996	107	2,539
Olympic Pipeline Company Event	2004	5,619	631
PEPCO Chalk Point Generating Station	2002	3,333	813
Pirates Cove	1996	600	2,333
Quinnipiac River	1996	119	334
Reedy River	1998	22,619	294
Santa Barbara, CA	1969	71,429	
SS Cape Mohican Oil Spill	1998	2,286	1,761
Sugarland Run	1998	9,714	257
T/V Julie N	2002	4,277	348

Event	Year of Settlement	Max Volume (bbl)	NRD plus Assessment Costs (2009$/bbl)*
Tenyo Maru	1994	10,776	867
Tesoro, HI	2001	117	4,359
Texaco Pipeline Company Lake Barre oil spill	2000	6,548	87
Williams Field/Transcontinental Natural Gas Spill	2010	3,000	84
Yoncalla Creek	1995	143	1,505
* Where a spill has a range of sizes recorded, per-barrel costs were calculated using the upper range.			

Table 37 - Gulf Shrimp Landings, Revenue, and Price

			Federal Permit	No Federal Permit	Total
Average revenue per vessel ($)			199,111	22,429	74,847
Average landings per vessel (lbs)			67,386	13,160	29,247
Average price (dollars per lb)			$2.95	$1.70	$2.56
Average price (dollars per lb)			$2.87	$1.73	$2.07
Number of Vessels			1,388	3,290	4,678
Total revenue ($ millions)			$276	$82	$358
Total landings (millions lbs)			94	47	141
Note: Table for Gulf shrimp only; excludes S. Atlantic shrimp					
Source: The Annual Economic Survey of Federal Gulf Shrimp Permit Holders:					
Report on the Design, Implementation, and Descriptive Results for 2007; NOAA Technical Memorandum NMFS-SEFSC-590 (2009).					

Appendix C Well Data

Table 38 – GOM Deepwater Wells by Water and Drilling Depth

Distribution of 4,133 GOM Wells Drilled in Water > 500 Feet
by Drilling Date, Water Depth, and Well Depth

Counts of All GOM Wells Drilled in Water >500 feet According to Well Drilled Depth

Water Depth (feet)	Well Total Depth (thousands of feet)								**Totals**
	0 to 5	5 to 10	10 to 15	15 to 20	20 to 25	25 to 30	30 to 35	35 to 40	
500-1,500	140	900	607	61	15	1	1	-	**1,725**
1,500-3,000	39	205	349	253	71	5	1	-	**923**
3,000-5,000	21	153	324	218	123	77	17	-	**933**
5,000-7,500	-	39	121	123	82	45	10	1	**421**
7,500-10,000	-	-	51	47	11	10	-	-	**119**
>10,000	-	-	1	-	1	-	-	-	**2**
All WD	200	1,297	1,453	702	303	138	29	1	**4,123**
>3,000 ft	21	192	497	388	217	132	27	1	**1,475**

Counts of GOM Wells Drilled before 1980 in Water >500 feet According to Well Drilled Depth

Water Depth (feet)	Well Total Depth (thousands of feet)								Totals
	0 to 5	5 to 10	10 to 15	15 to 20	20 to 25	25 to 30	30 to 35	35 to 40	
500-1,500	11	83	32	-	-	-	-	-	126
1,500-3,000	-	3	5	1	-	-	-	-	9
3,000-5,000	-	-	-	-	-	-	-	-	-
5,000-7,500	-	-	-	-	-	-	-	-	-
7,500-10,000+	-	-	-	-	-	-	-	-	-
All WD	11	86	37	1	-	-	-	-	135
>3,000 ft	-	-	-	-	-	-	-	-	-

Counts of GOM Wells Drilled During the 1980's in Water >500 feet According to Well Drilled Depth									
Water Depth (feet)	Well Total Depth (thousands of feet)								Totals
	0 to 5	5 to 10	10 to 15	15 to 20	20 to 25	25 to 30	30 to 35	35 to 40	
500-1,500	47	324	252	19	2	-	-	-	644
1,500-3,000	12	59	94	16	-	-	-	-	181
3,000-5,000	1	3	25	1	1	-	-	-	31
5,000-7,500	-	-	1	8	-	-	-	-	9
7,500-10,000+	-	-	-	-	-	-	-	-	-
All WD	60	386	372	44	3	-	-	-	865
>3,000 ft	1	3	26	9	1	-	-	-	40

Counts of GOM Wells Drilled During the 1990's in Water >500 feet According to Well Drilled Depth									
Water Depth (feet)	Well Total Depth (thousands of feet)								Totals
	0 to 5	5 to 10	10 to 15	15 to 20	20 to 25	25 to 30	30 to 35	35 to 40	
500-1,500	55	334	230	28	8	1	-	-	656
1,500-3,000	15	74	129	142	18	2	-	-	380
3,000-5,000	10	60	106	72	21	2	-	-	271
5,000-7,500	-	5	34	20	8	3	-	-	70
7,500-10,000	-	-	1	1	-	-	-	-	2
>10,000	-	-	-	-	-	-	-	-	-
All WD	80	473	500	263	55	8	-	-	1,379
>3,000 ft	10	65	141	93	29	5	-	-	343

Counts of GOM Wells Drilled After 1999 in Water >500 feet According to Well Drilled Depth									
Water Depth (feet)	Well Total Depth (thousands of feet)								Totals
	0 to 5	5 to 10	10 to 15	15 to 20	20 to 25	25 to 30	30 to 35	35 to 40	
500-1,500	27	159	93	14	5	-	1	-	299
1,500-3,000	12	69	121	94	53	3	1	-	353
3,000-5,000	10	90	193	145	101	75	17	-	631
5,000-7,500	-	34	86	97	74	42	10	1	344
7,500-10,000	-	-	50	44	11	10	-	-	115
>10,000	-	-	1	-	1	-	-	-	2
All WD	49	352	544	394	245	130	29	1	1,744
>3,000 ft	10	124	330	286	187	127	27	1	1,092

Appendix D Definitions

Baseline: describes the regulatory environment before promulgation of the Interim Final Rule. The baseline is compared to regulatory environment following promulgation of the rule for the cost-benefit analysis.

Benefits: are the favorable effects of a policy or action.

Blowout: is an uncontrolled flow of reservoir fluids into the wellbore. A catastrophic blowout occurs when fluids flow to the surface. The most damage from a catastrophic blowout event is caused if the hydrocarbons ignite at the surface. If reservoir fluids flow into another formation and do not flow beyond the wellhead, the result is called an underground blowout because the well bridges over and seals itself. Similar to kicks, the BOP rams are designed to shut-in the well until control is reestablished.

BOP (Blowout Preventer) Stack: Is a series of valves (or rams) at the wellhead that may be closed if the drilling crew loses control of formation fluids. These valves are often referred to as BOP rams. A stack might consist of four to six ram-type preventers and one or two annular-type preventers. A BOP stack is used to ensure pressure control of a well.

Costs: Is the dollar values of resources needed to produce a good or service, and hence are not available for use elsewhere.

Compliance Cost is the expenditure of time or money needed to conform to government's regulatory requirements. It may be defined as the sum of all opportunity costs incurred as a result of the regulation. These opportunity costs consist of the value lost to society of all the goods and services that will not be produced and consumed if firms comply with the regulation and reallocate resources away from production activities and towards compliance with the regulation.

External (social) costs are the costs the oil spill imposes on society regardless of who pays for them and in this analysis exclude the private (social) costs.

Deepwater: While BOEMRE has traditionally defined deepwater as greater than 1,000 feet, for the purposes of this analysis *deepwater* is defined as water depths where floating drilling rigs are used rather than gravity based rigs and where submersibles or ROVs must replace divers. This is generally at 300 to 500 of water depth and also the depth where subsea BOPs are required on floating mobile drilling rigs. We use 500 feet of water depth for our baseline analysis.

Discount Rate: Per OMB Circular A-94, where appropriate all cost estimates are calculated back to a net present value in 2010 dollars using a discount rate of 7 percent.

Kick: is a flow of fluids from a formation into the wellbore during drilling operations. A kick is caused by the pressure in the wellbore being less than that of the formation fluids and most often happens during drilling operations from a depth other than the targeted reservoir. Kicks are most frequently controlled by increasing the drilling mud weight, circulating out the kick or using one of the BOP rams to control the flow.

Loaded Rig Rate: The loaded rig rate used in this analysis is the daily rate charged by the owner of the rig for use of the rig and the operating crew **plus** the operator's engineers, supplies, supply craft and supporting contractors.

Net benefits: are calculated by subtracting total costs from total benefits.

Oil Spill: An oil spill as referenced in this cost/benefit analysis is oil spilled as a result of a loss of well control event. An oil spill for this analysis excludes spills from production or logistical activities if the spillage is unrelated to a loss of well control event.

Private (social) costs: are the costs of the blowout and spill that the responsible party pays for containment and recovery of productive capability.

Unloaded Rig Rate: The unloaded rig rate used in this analysis is the daily rate charged by the owner of the rig for use of the rig and the operating crew. It does not include supplies, supply craft, the operator's drilling engineers or supporting contractors.

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Transocean announcement describing the total capital costs to be incurred for the construction of the drillship are estimated to be $750 million. http://www.redorbit.com/news/business/1446859/transocean_inc_announces_agreement_to_acquire_newbuild_ultradeepwater_drillship_under/index.html

Appendix F Voluntary Industry Measures Review

MEMORANDUM | 18 August 2010

TO Radford Schantz and Martin Heinze, BOEMRE

CC Debra Bridge, BOEMRE

FROM John Weiss, Industrial Economics, Incorporated

SUBJECT Review of Additional Literature with Potential Relevance to OECM Development, Contract No. M09PC00036

Industrial Economics, Incorporated (IEc) is engaged in the development of a new version of the Offshore Environmental Cost Model (OECM), a decisionmaking tool used by the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) as it develops five-year leasing programs for oil and gas exploration and production on the outer continental shelf (OCS). An important component of this effort is the review of literature relevant to the identification and evaluation of the environmental costs that the model will consider. Many of those costs are the direct or indirect result of oil spills associated with OCS exploration and production activities. In the aftermath of the Deepwater Horizon event, additional information has become available that BOEMRE has asked IEc to review for relevance and potential application during OECM development. This memorandum describes the results of our review and analysis of one category of additional information, that associated with (1) the Department of the Interior's 30-Day Report to the President, which describes recommended actions to reduce the probability of a similar event in the future, and (2) industry's consideration of recommended voluntary safety and protection measures that would be designed to achieve the same objective.

In addition to reviewing relevant information for its potential applicability to the specification of OECM inputs, IEc has compared the currently available descriptions of proposed voluntary measures to a set of proposed changes to the rules governing OCS oil and gas activities. BOEMRE is currently developing an analysis of the costs and benefits of the proposed rules, including the estimated incremental cost to industry to comply with new requirements. BOEMRE can use the results of the IEc analysis to determine whether industry's recommendations provide a basis for any reconsideration of industry's compliance costs (i.e., whether adoption and implementation of voluntary measures might shift the baseline against which BOEMRE should consider the incremental compliance costs).

DOCUMENTS REVIEWED

IEc reviewed the following documents as part of this effort:

- *Increased Safety Measures for Energy Development on the Outer Continental Shelf*, U.S. Department of the Interior, May 27, 2010 (the "30-Day Report").

- Proposed amendments to 30 Code of Federal Regulations (CFR) Part 250 – Oil and Gas and Sulphur Operations in the Outer Continental Shelf (as of August 6, 2010); these proposed amendments are a direct result of the recommendations contained in the 30-Day Report.
- *White Paper: Recommendations for Improving Offshore Safety*, prepared by the Joint Industry Task Force to Address Offshore Operating Procedures and Equipment, May 17, 2010.
- Draft report of the Joint Industry Task Force to Address Subsea Well Control and Oil Spill Response, July 6, 2010.
- *Isolating Potential Flow Zones During Well Construction*, American Petroleum Institute (API) Recommended Practice 65 – Part 2, First Edition, May 2010 (referenced in the Joint Industry Task Force White Paper).
- *Health, Safety and Environmental Case Guidelines for Mobile Offshore Drilling Units*, International Association of Drilling Contractors (IADC), Issue 3.2.1, May 1, 2009 (referenced in the Joint Industry Task Force White Paper).
- Testimony of Andy Radford, API Senior Policy Advisor, before the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, July 12, 2010.

IEc did not complete a detailed review of API Recommended Practice 65 – Part 2 or the IADC guidelines, as they present a level of technical detail that is beyond the scope of the intended general comparison of proposed rules and voluntary measures. In addition, the July 6, 2010 draft report of the Joint Industry Task Force to Address Subsea Well Control and Oil Spill Response does not contain recommendations for voluntary measures but rather the context for the Task Force’s near-term and long-term efforts, and thus does not contribute to the IEc analysis.

To facilitate the analysis, IEc retrieved electronic versions of each section of 30 CFR Part 250 in which BOEMRE is proposing a change and copied the text into a Microsoft Word document. Based on a careful review of the rulemaking document, IEc inserted, modified, or deleted text, using the redline/strikeout feature, to highlight the location and substance of each proposed change. The resultant document served as the basis for a comparison between proposed regulatory changes and the industry recommendations for voluntary safety and protection measures.

RESULTS

The results of the IEc analysis are described in Tables 1 and 2. Table 1 highlights the industry recommendations that BOEMRE explicitly addresses in its proposed rule changes. Table 2 lists selected additional industry recommendations that the proposed rules do not address and that could result in additional industry operating costs.

TABLE 1 COMPARISON OF RECOMMENDED INDUSTRY VOLUNTARY MEASURES TO PROPOSED CHANGES IN 30 CFR PART 250

RECOMMENDED INDUSTRY VOLUNTARY MEASURE	RELEVANT SECTION OF REGULATIONS	PROPOSED REGULATORY CHANGE
Upon release, adopt AP RP 65 Part 2: Isolating Potential Flow Zones During Well Construction.	30 CFR 250.415(f)	New requirement for a discussion of how the best practices described in API RP 65 Part 2 were evaluated in the casing and cementing program.
Engage casing hanger latching mechanisms when casing is installed in the subsea wellhead.	30 CFR 250.423(b)	New requirement to perform a pressure test after the intermediate and production casing strings are installed to verify that the casing hanger latching mechanisms or lock down mechanisms are engaged and the casing has been sealed.
Provide two independent barriers, including one mechanical barrier, for each flow path prior to displacement to underbalanced fluid columns.	30 CFR 250.420(a)(6)	New requirement for a professional engineer to verify two independent tested barriers, including one mechanical barrier, across each flow path during well completion activities.
Perform negative tests to a differential pressure greater than or equal to anticipated pressures after displacement.	30 CFR 250.423(c)	New requirement to perform a negative pressure test after the intermediate and production casing strings are installed. Test procedures and criteria must be submitted with the APD for approval.
Ensure shearable drillstring components are positioned in the shear rams during displacement.	30 CFR 250.442(a)	New requirement for two BOPs, rather than one, equipped with a blind-shear rams, with a further requirement that the blind-shear rams are appropriately spaced to ensure that at least one cuts the drillpipe and seals the wellbore.
Ensure BOP can automatically close blind/shear ram(s) and close choke/kill line valves	30 CFR 250.442(f)	Provide autoshear and deadman systems for dynamically positioned rigs.
Ensure ROV can close blind shear rams, pipe rams, casing shear rams, and choke and kill valves. Ensure ROV can unlatch the lower marine riser package.	30 CFR 250.442(d)	When drilling with a subsea BOP system, the BOP must be equipped with ROV intervention capability; at a minimum, the ROV must be capable of closing all pipe rams, all shear rams, and unlatching the LMRP.

TABLE 2 SELECTED ADDITIONAL RECOMMENDED INDUSTRY VOLUNTARY MEASURES

• Deepwater mobile offshore drilling unit produces safety case, following guidelines established by the IADC.
• Develop Well Construction Interfacing Document to manage well construction activities and mitigate unexpected events that impact health, safety and the environment.
• Positively test each casing barrier to a pressure exceeding the highest estimated integrity of casing shoes below that barrier.
• Close blowout preventers during displacement to underbalanced fluid columns.
• Perform separate displacement operations for riser and casing. Monitor displacement volumes in and out.
• At prescribed intervals, conduct subsea testing of hydraulic function of rams and valves downstream of the trigger to simulate 1) unintended disconnect of lower marine riser package (LMRP); and 2) loss of surface control of the subsea BOP stack.
• Verify proper operation of the system by testing to MMS-approved Application for Permit to Drill (APD) casing pressure below blind / shear rams after system activation.
• Arm the system when BOP stack is latched on the wellhead. Disarm and rearm only if approved through a formalized Management of Change process.
• Standardize ROV hot stab and receptacle per API Spec 17H. Standardize hot stab designs between drilling and production operations.
• Stage ROV tooling / external hydraulic power supplies strategically in Gulf of Mexico for rapid mobilization.

CONCLUSIONS

IEc has reviewed literature that has recently become available in the aftermath of the Deepwater Horizon event in order to determine whether and how it might suggest changes in the development of the new OECM. As part of this effort, IEc compared proposed regulatory changes with industry recommendations for safety and protection measures that industry could voluntarily adopt during the course of OCS oil and gas exploration and development activities.

None of the literature IEc reviewed suggests a need for any immediate changes in the methodologies or inputs currently associated with OECM development. However, since spill rates are an important model element, changes may be warranted in the future if and when new regulatory requirements or the voluntary adoption of new procedures or technologies result in measurable changes in the expected frequency of spill events.

The comparison of recommended voluntary industry measures with proposed changes to 30 CFR Part 250 indicates several areas of overlap, as noted above in Table 1. However, it is not possible at this time to conclude that the articulation of industry recommendations will necessarily translate into measurable changes in baseline industry costs against which BOEMRE would compare the cost to comply with new regulatory requirements. If, in the context of a benefit-cost analysis, the measures in Table 1 were assumed to have been adopted, it would be appropriate to consider any associated costs as part of the baseline (i.e., the incremental cost to industry of the new regulations would be reduced). As BOEMRE considers additional regulatory changes, further comparison to industry recommendations, including those listed in Table 2, would be warranted.