Benefit-Cost Analysis for the Interim Final Rule on Increased Safety Measures for Energy Development on the Outer Continental Shelf

RIN 1010 AD68

Bureau of Ocean Energy Management, Regulation and Enforcement

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EXECUTIVE SUMMARY

This document describes the benefit-cost analysis conducted for this interim rule, RIN 1010 AD68, Increased Safety Measures, Drilling Operations on the Outer Continental Shelf (OCS). It represents a joint effort by the BOEMRE Economics Division and the Office of Policy Analysis (OPA) in the Department of the Interior. The preamble to the regulation gives instructions for providing public comment on this analysis.

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, BOEMRE 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 BOEMRE as part of the public forums and information gathering that the bureau has conducted since July 12, 2010.

While the estimated costs of this rulemaking, as reflected in the compliance costs of the enumerated requirements of approximately $180 million per year, have a strong foundation and are based on 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 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 BPDH event commencing on April 20, 2010.

Three new requirements account for virtually all of the compliance costs imposed by this regulation (1) use of dual mechanical barriers in addition to cement barriers in the final casing string to prevent hydrocarbon flow in the event of cement failure, (2) application of negative pressure tests to all intermediate and the production casing strings to ensure their proper installation, and (3) maintenance of standby ROV capability to close BOP rams and testing that capability after the BOP has been installed on the sea floor. BOEMRE estimates that these three requirements will impose compliance costs of approximately $174 million per year, representing 95 percent of the total annual compliance costs of $183 million associated with this rulemaking. These cost estimates were developed by BOEMRE based on public data sources and confidential information provided by several offshore operators and drilling companies.

On the benefit side, the avoided costs for a hypothetical 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 OPA using damage costs per

[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 BPDH spill. Although the hypothetical spill discussed in this document is similar in volumetric magnitude to recent estimations of the amount of oil released as a result of the BPDH 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 BPDH event. As such, the damage and cost estimates presented herein should not be considered reliable monetary assessments associated with the BPDH 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 BPDH spill or any other spill.

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.

The above estimate of compliance costs is somewhat uncertain. This is the case primarily because the $183 million annual estimate is perhaps higher than the actual costs that will be incurred by society from this rule because industry is voluntarily undertaking some steps following the BPDH event that overlap those in this regulation. The Joint Industry Task Force draft recommendations include use of mechanical barriers and negative pressure tests. Voluntary action, perhaps spurred on as well by revised liability expectations and increased insurance prospects, means the incremental costs associated with these overlapping measures are not truly imposed solely by the new regulations. Less incremental required costs reduce the improvement in reliability necessary for expected benefits to cover the cost of complying with the new regulations. 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) 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 factors derived from past oil spills. Possible 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.

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), the baseline risk of a catastrophic blowout is estimated to be about once every 26 years. Combining the baseline likelihood of occurrence with the cost of a hypothetical spill implies that the expected annualized spill cost is about $631 million ($16.3 billion once in 26 years, equally likely in any 1 year). To balance the $183 million annual cost imposed by these regulations with the expected benefits, the reliability of the well control system needs to improve by about 29 percent ($183 million / $631 million). We have found no studies that evaluate the degree of actual improvement that could be expected from dual mechanical barriers, negative pressure tests, and a seafloor ROV function test.

INTRODUCTION AND NEED FOR FEDERAL ACTION

The interim 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 interim 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 Interior Strike Teams to determine their efficiency and effectiveness. Measures considered beneficial will be considered for future notice and comment rulemaking.

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 interim 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.

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[2] Available at: http://www.doi.gov/deepwaterhorizon/loader.cfm?csModule=security/getfile&PageID=33598

> *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.*

The BOEMRE carries out this duty through regulations, the terms and conditions of leases, conditions of exploration and development plan approval, and inspections of OCS oil and gas operations. Although current regulations extensively address shallow and deepwater drilling operations, the BPDH 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 current *ex post* compensation regime perhaps provides too little information to regulators regarding the effectiveness of safe operating incentives embodied in the existing regulatory regime. A more *prescriptive* regime 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 because of the potential to avoid some or all of the liability.

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. BOEMRE 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, BOEMRE commissioned an outside assessment of the voluntary measures proposed by Joint Industry Task Forces (JITFs) as compared to these regulations. (See Appendix E). While the work of the JITFs is not complete and the lessons learned or other measures have not been 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 interim 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 BPDH 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 BPDH blowout. The BPDH spill is the first U.S. Gulf of Mexico catastrophic deepwater blowout spill.

Shallow Water Drilling Activity

While blowouts 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. BOEMRE has recorded 6 GOM shallow water blowouts resulting in a spill of hydrocarbons from 1990-2010. 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.

The compliance costs for this regulation fall over 90 percent 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

BOEMRE has 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 BPDH spill and without these regulations, we are using an estimate of spill volume similar to the most recent government volumetric estimate of the BPDH 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 BPDH 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. BOEMRE 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.

EXISTING AND NEW REGULATORY PROVISIONS

This interim rulemaking will revise selected sections of 30 CFR 250 subparts D, E, F, O, 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.[3] Table 1 compares the existing 30 CFR 250 Subpart D provisions with the new provisions. We expect that all of 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 intermediate and production casing strings; 250.423(c).
3. Installation of dual mechanical barriers for the final casing string; 250.420(b).
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 certification that the shear rams will shear drill pipe under maximum anticipated pressure; 250.416(e)

[3] 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.

Table 1 - 30 CFR 250 Subpart D Provisions

EMERGENCY SUBPART D INTERIM FINAL RULE PROVISIONS				
Regulation	**Summary**	**Existing Regulatory Provisions**	**New Regulatory Provisions**	**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)	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)	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 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
			- Independent third party must not be the OEM.	
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

EMERGENCY SUBPART D INTERIM FINAL RULE PROVISIONS				
Regulation	**Summary**	**Existing Regulatory Provisions**	**New Regulatory Provisions**	**Cost**
30 CFR §250.420(a)(6)	Professional Engineer verification of well casing and cementing program	- No PE verification required	- PE will verify there are two independent barriers	- Small cost per well if performed by an independent third party
			- Verify the casing cementing design is appropriate for the purpose it was intended under expected wellbore conditions	- 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 mechanical barriers	- No requirement	- Operator must install dual mechanical barriers in addition to cement in the final casing string and document to BOEMRE. - Dual float valves, or one float valve and a mechanical plug.	- Installation of dual mechanical barriers is estimated to take 30 minutes. - Estimated additional float valve cost of $20,000
				- Will add significant costs to regulation
30 CFR §250.420(a)(6)	Professional Engineer verification of well casing and cementing program	- No PE verification required	- PE will verify there are two independent barriers	- Small cost per well if performed by an independent third party
			- Verify the casing cementing design is appropriate for the purpose it was intended under expected wellbore conditions	- No cost if PE certification is done in house
				- Assumed that some majors would verify in-house; smaller operators will use third party
				- Will add significant costs to regulation

EMERGENCY SUBPART D INTERIM FINAL RULE PROVISIONS				
Regulation	**Summary**	**Existing Regulatory Provisions**	**New Regulatory Provisions**	**Cost**
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)	- 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
		- No requirement to ensure proper installation of the casing in the subsea wellhead		- 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 intermediate and production casing strings	- Negative pressure test will take 90 minutes for each required string of casing
				- Will result in significant costs for the regulation
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 to have autoshear/deadman systems - No meaningful cost

EMERGENCY SUBPART D INTERIM FINAL RULE PROVISIONS				
Regulation	**Summary**	**Existing Regulatory Provisions**	**New Regulatory Provisions**	**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	- No meaningful cost
			- Written procedures for operating the BOP stack and LMRP	
			- Minimum knowledge requirements for personnel authorized to operate and maintain critical BOP components	
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)	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	- No meaningful cost

EMERGENCY SUBPART D INTERIM FINAL RULE PROVISIONS				
Regulation	**Summary**	**Existing Regulatory Provisions**	**New Regulatory Provisions**	**Cost**
30 CFR §250.449(j)	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
		- 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 - 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	- ROV seafloor test is estimated to take about 24 hours - Will add significant costs
30 CFR §250.449(k)	Autoshear/Deadman function test	- No required function test	- The autoshear and deadman systems must be function tested during the stump test and during the initial test on the seafloor.	- No meaningful cost
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
30 CFR §250.456(j)	District Manager approval for displacing kill-weight drilling fluid	- No approval requirement	- Approval required from District Manager before displacing kill-weight drilling fluid from the wellbore	- No meaningful cost
			- Submit reasons for displacing and provide detailed procedures of displacement process.	
			- Follow procedures in 250.456	

EMERGENCY SUBPART D INTERIM FINAL RULE PROVISIONS				
Regulation	**Summary**	**Existing Regulatory Provisions**	**New Regulatory Provisions**	**Cost**
30 CFR §250.516(d)(8)	Subsea function test for ROV intervention on a subsea BOP stack	- Stump test BOP stack before installation	- All ROV intervention functions must be tested during the stump test and one set of rams during the initial test on the seafloor	- Will add costs for well completions operations
			- 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	
			- 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	
30 CFR §250.616(h)(1)	Subsea function test for ROV intervention on a subsea BOP stack	- Stump test BOP stack before installation	- All ROV intervention functions must be tested during the stump test and one set of rams during the initial test on the seafloor	- Will add costs for well workover operations
			- 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	
			- 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	

Benefit-Cost Approach

The purpose of this benefit-cost 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 rule is considered major and economically significant because it is expected to impose annual costs on the economy 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 interim rule, we have not been able to quantify the 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 has requested comments on the availability of appropriate well design reliability studies. If such studies are identified, their results will be included in future analysis.

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 BPDH blowout. The BPDH 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 interim 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 most recent government estimate of the BPDH 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[4].

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 BPDH spill. This assumption may understate 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 this analysis must be conducted for the emergency interim rulemaking, we did not adjust the baseline for any voluntary measures. A further discussion of voluntary measures can be found in the section on Compliance Costs for this Regulation.

[4] The damage and loss estimates in this analysis are purely hypothetical and do not provide values applicable to the BPDH event. They are not pertinent to the BPDH 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 BPDH 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 BPDH event. As such, the damage and cost estimates presented herein should not be considered reliable monetary assessments associated with the BPDH event.

Baseline Estimates of Future Deepwater Drilling Activity

The key drilling input for this benefit-cost analysis is the future number of GOM deepwater wells. BOEMRE 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 drilling, leasing, aggregate production forecasts and other available data.

BOEMRE estimates that there will be an average of 160 deepwater wells drilled annually over the next 20 years. The drilling of 160 deepwater wells per year is used to estimate the expected interval before another catastrophic blowout similar to the BPDH. 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[5] is shown in the following figure.

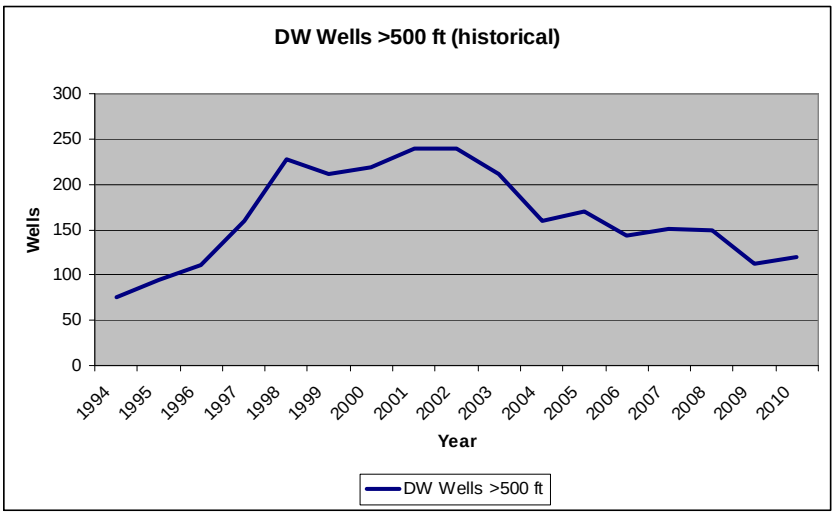

Figure 1 - Historical Deepwater Wells (Greater than 500 feet)

The GOM deepwater is generally expected to follow a progression similar to the GOM shelf. That means most of the remaining deepwater wells will be drilled farther from shore. Because of the extremely high cost of exploring and developing deep and ultra-deep prospects, the number of wells drilled in the deeper water depths is unlikely to again reach the peak set in 2001-2002.

[5] All counts of wells exclude bypasses which are often included in other BOEMRE 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.

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. BOEMRE 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, a catastrophic blowout spill under current regulations and practices is estimated 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.

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 emergency rule raises drilling costs for every new deepwater well on the OCS. These new requirements add mechanical barriers to well design requirements and time for testing several features during drilling operations. BOEMRE estimates that each year the seven activities discussed in this section will add $183 million to the cost of operations on the OCS. For purposes of calculating

annual costs associated with this rule, 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 17 workover and completion operations on successful (wet) exploratory wells.

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 floor. The BOP system is tested on the stump to ensure the BOP is functioning properly. New section §250.449 (j) requires 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 section §250.449 (k) requires 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.

BOEMRE assumes it is 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. BOEMRE also assumes dynamically positioned rigs have autoshear/deadman systems. BOEMRE 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 confirm 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. The deadman-switch test on the seafloor verifies that the well bore closes automatically if both hydraulic pressure and electrical communication are lost with the rig.

BOEMRE 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 interim 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. Although the 24 hour survey average is an overestimate based on the interim regulations, the additional stump testing requirements and the deadman system seafloor tests are estimated to take about the same amount of time as the extra ram test and LMRP disconnect.[6] Using the additional stump tests and deadman seafloor test as a proxy for the extra ram test and LMRP disconnect, BOEMRE maintains the 24 hours of lost rig time for costing purposes. The regulation will not affect platform rigs or shallow wells since they do not use subsea BOPs or ROVs.

Multiplying the number of estimated MODU wells each year (112) by the weighted average day rate ($916,622) yields a total estimated compliance cost for this provision of **$102.66 million**. 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 24 hour 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 negative pressure tests for intermediate casings cannot be scheduled with accuracy and 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 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.

[6] 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 require the use of an ROV during the stump test.

Table 2 – Deepwater 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	10	$400,000	48

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

Current regulations do not require subsea ROV function testing of the BOP during workover or completions operations. New sections 250.516(d)(8) and 250.616(h)(1) 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 on the seafloor. These sections extend the requirements added to deepwater drilling operations (discussed in the previous section) to well completion operations and workover 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 24 hours. This is in addition to the 24 hours testing time discussed in the previous section for selected wells. BOEMRE data shows that two-thirds of deepwater wells drilled are exploratory wells, and approximately 23% of exploratory wells are completed. Using our estimate of 112 MODU wells each year results in an additional 17 subsea BOP tests from workover and completions operations. Using a weighted average of MODU day rates from Table 2, 17 redeployments of a BOP will cost **$15.47 million**.

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. New section §250.423 (c) requires that a negative pressure test be conducted for all intermediate and production casing strings. This 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 conduct

negative pressure tests on selected casing strings as a best practice, we do not have the data available in an easily accessible database to determine the frequency at which this occurs. Based on typical industry procedures, we estimate each new negative pressure test will take approximately 90 minutes for each casing string. We also estimate that on average deepwater wells use one production and four intermediate casing strings and shallow wells use one production and two intermediate casing strings.

Ninety minutes is equivalent to 0.0625 days. Using the weighted average of the MODU day rates in Table 2, and a platform day rate of $400,000, 0.0625 days times 5 casing strings times 112 MODU wells and 48 platform wells yields an annual average additional costs in deepwater for this test of **$38.08 million**. A loaded day rate of $200,000 for a shallow water rig (jackup) times 0.0625 days times 3 casing strings for each of 186 wells adds another **$6.975 million** to the extra cost for the universal requirement for the negative pressure test.

Installation of Dual Mechanical Barriers

Current regulations do not require the installation of dual mechanical barriers although this requirement can be considered the use of best available and safety technology (BAST) per § 250.107(d). For this benefit-cost analysis this 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 mechanical barriers in addition to cement barriers for the final casing string. These barriers prevent hydrocarbon flow in the event of cement failure at the bottom of the well. The operator must document the installation of the dual mechanical barriers and submit this documentation to BOEMRE within 30 days after installation. These new requirements will ensure that the best casing and cementing design will be used for a specific well. Dual mechanical barriers may include two float valves, or one float valve and one mechanical plug. Based on in-house expertise, BOEMRE estimates that all wells will require a second mechanical barrier. We estimate an average cost of $20,000 for each mechanical barrier and 30 minutes of installation time.

For the 112 MODU wells each year, these parameters yield **$2.24 million** for the barriers (112 times $0.02 million) plus [2.08% of a day (half hour divided by 24 hours) times the weighted average day rate from Table 2 times 112 wells] **$2.14 million** in installation costs. Similar calculations for 48 platform and 186 shallow water wells yields a total annual compliance cost of **$10.3 million** for this requirement.

Professional Engineer Certification for Well Design

Current regulation 30 CFR 250.420(a) specifies well casing and cementing requirements but does not require verification by a Professional Engineer although verification could be considered the use of best available and 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 verify that the well casing and cementing design is appropriate for the purpose for which it is intended under expected wellbore conditions. This verification will add assurance that the appropriate design is used for the well thus decreasing the likelihood of a blowout. We assume that many of the larger companies will verify 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 deepwater leases are owned by large entities, BOEMRE assumes that 50% of future deepwater wells and all shallow water wells will incur an additional cost for a third party professional engineer certification of the well design. Based on an informal survey of drilling contractors and lease operators, BOEMRE 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 **$0.540 million**, and for shallow water wells **$4.185 million**.

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

Current regulations do 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 meet the regulatory standard for BOPs. Surface inspection following shear ram activation may not have been enforced by the government or 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[7], 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. We estimate 112 wells drilled per year from drillships or semisubmersibles; therefore we 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 Certification of Shear Ram Capability

Section 30 CFR 250.416(e) requires information verifying that BOP blind-shear rams are capable of cutting through any drill pipe in the hole under maximum anticipated conditions. This regulation has been modified to require the BOP verification be conducted by an independent

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

third party. The independent third party provides an objective assessment that the blind-shear rams can shear any drill pipe 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 these standards are not a new regulatory requirement, independent verification and submission of that verification was apparently not enforced by the government; 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.

Summary of Annual Recurring Costs

Table 3 summarizes the cost estimates for these recurring cost categories for three subgroups of wells affected by the new regulations.

Table 3 – 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 ($MM)	
250.449(j)(k)	Subsea ROV function testing (drilling)	102.7	0.0	0.0	***56%***
250.516(d)(8), 250.616(h)(1)	Subsea ROV function testing (workover/completions)	15.5	0.0	0.0	***8%***
250.423(c)	Test casing strings for proper installation	32.1	6.0	7.0	***25%***
250.420(b)(3)	Installation of dual mechanical barriers	4.4	1.4	4.5	***6%***
250.420(a)(6)	PE certification for well design	1.3	0.5	4.2	***3%***
250.451(i)(j)	Emergency cost of activated shear rams or LMRP disconnect	2.6	0.0	0.0	***1%***
250.416(e)	Independent third party shear certification	0.4	0.2	0.6	***1%***
	Estimated Cost per year:	**158.8**	**8.1**	**16.3**	**$ 183.1**
	Estimated Cost per well:	**1.42**	**0.17**	**0.09**	

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 3, 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 requirements.

Voluntary Measures by Industry

Some part of the roughly $183 in annual compliance cost total may not be rightfully assigned to the regulation as industry is undertaking a number of steps following the BPDH event that may overlap those in this regulation. An independent analysis by Industrial Economics Inc. (See Appendix E) indicates overlap exists for the mechanical barriers 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 potential actions, but acknowledge that our cost estimate may overstate compliance costs for this reason.

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 social avoided 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 BPDH 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, BOEMRE 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[8]) and the cost of a new drillship ($750 million[9]). We take 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 BPDH 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.). BOEMRE 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**.

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. BOEMRE assumes that a deepwater well that has suffered an uncontrolled blowout would flow 53,000 barrels of oil a day

[8] 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

[9] 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

for 90 days. This equates to 4.77 million barrels of oil spilled[10]. 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. 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 [11]. For computing the value of lost natural gas, BOEMRE estimates a market value of $4.00/MMBtu for a total lost value of almost **$28 million**.

Fines and Criminal Penalties

The Clean Water Act provides for fines against the responsible party for 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 4 summarizes the avoided private costs estimated for this analysis, stated in 2010 dollars. 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.

[10] See footnote number.
[11] 5.8 MMBtu per BOE.

Table 4 - 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.[12]

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

[12] 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.

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.

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, BOEMRE 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 BOEMRE 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 BPDH 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 BPDH 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.

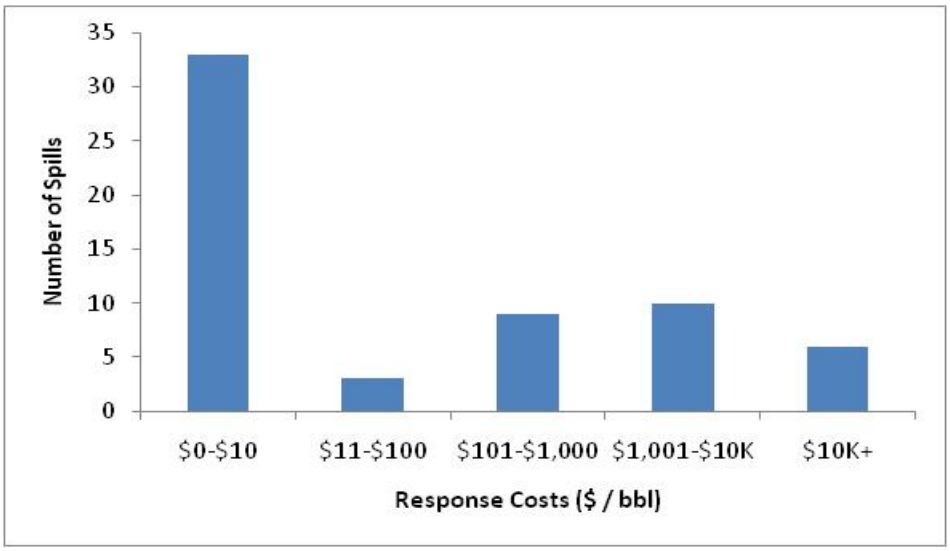

Figure 2. Distribution of Dataset Spills by Response Costs per Barrel ($2009)

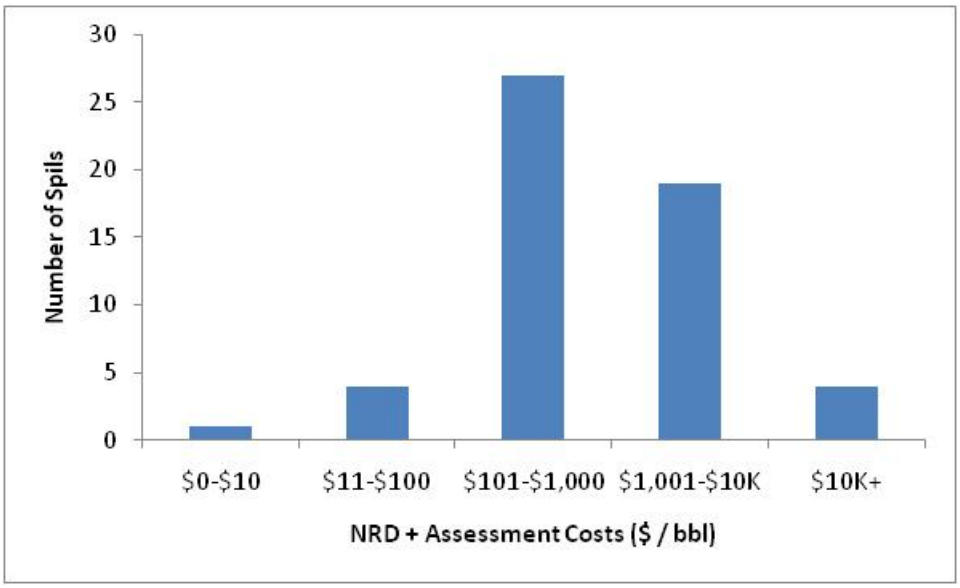

Figure 3. Distribution of Spills, by NRD + Assessment Cost per Barrel ($2009)

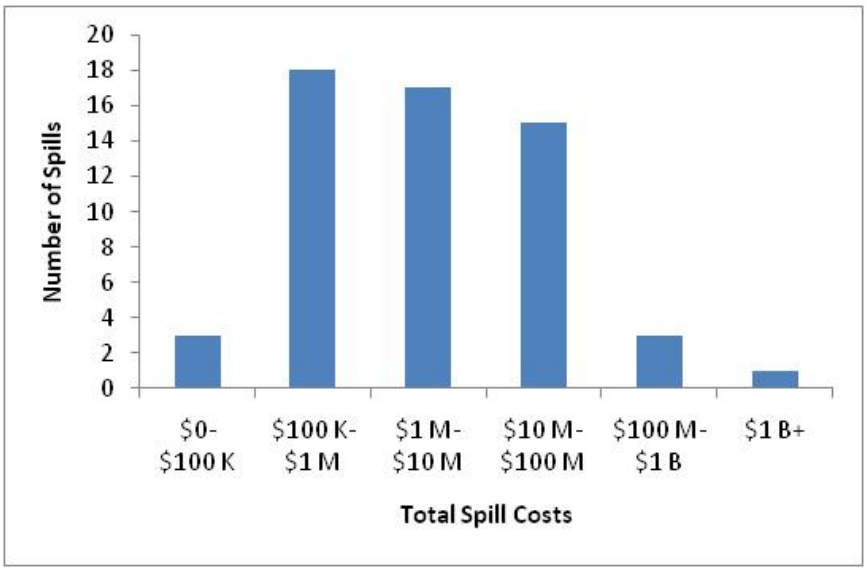

Figure 4. Distribution of Spills, by Total Spill Costs ($2009)

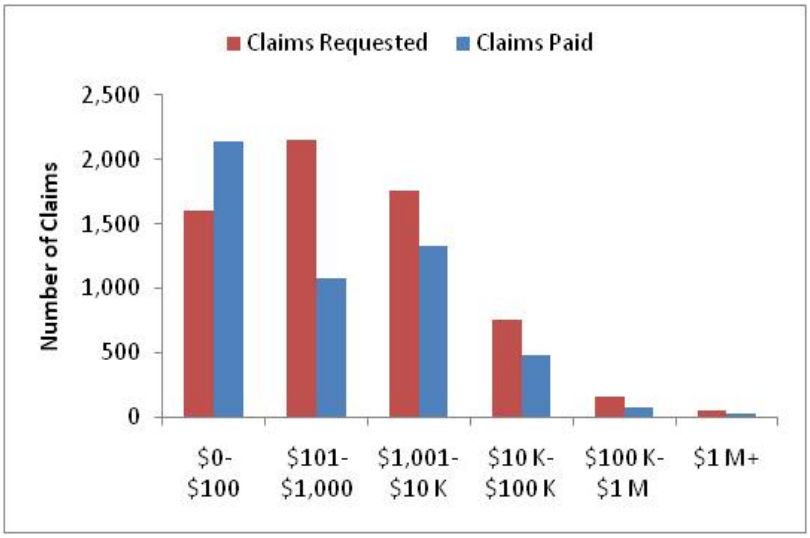

Figure 5. Oil Spill Liability Trust Fund Claims Requested and Paid (Sep 1972-Feb 2010)

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).[13] The vast majority of the spills were 10,000 barrels or less. As stated, this data set does not include the BPDH 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

[13] 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 5 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 to relevant in calculating damages for any particular oil spill, including the BPDH 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 A.
- 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[14] 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. Prices do not appear to contribute to the decline in revenues. For the top ten commercial species, which together account for over 96 percent of

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

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

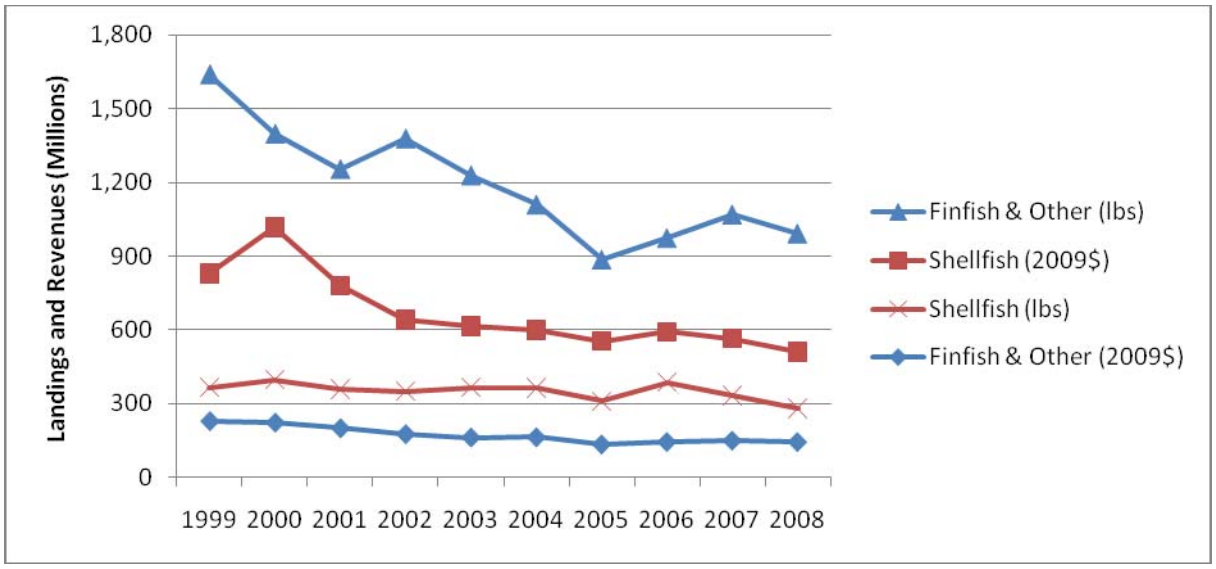

Figure 6 Gulf State Landings and Revenue, 1999-2008 (2009$)

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

Source: NMFS Fisheries Economics of the United States 2008.

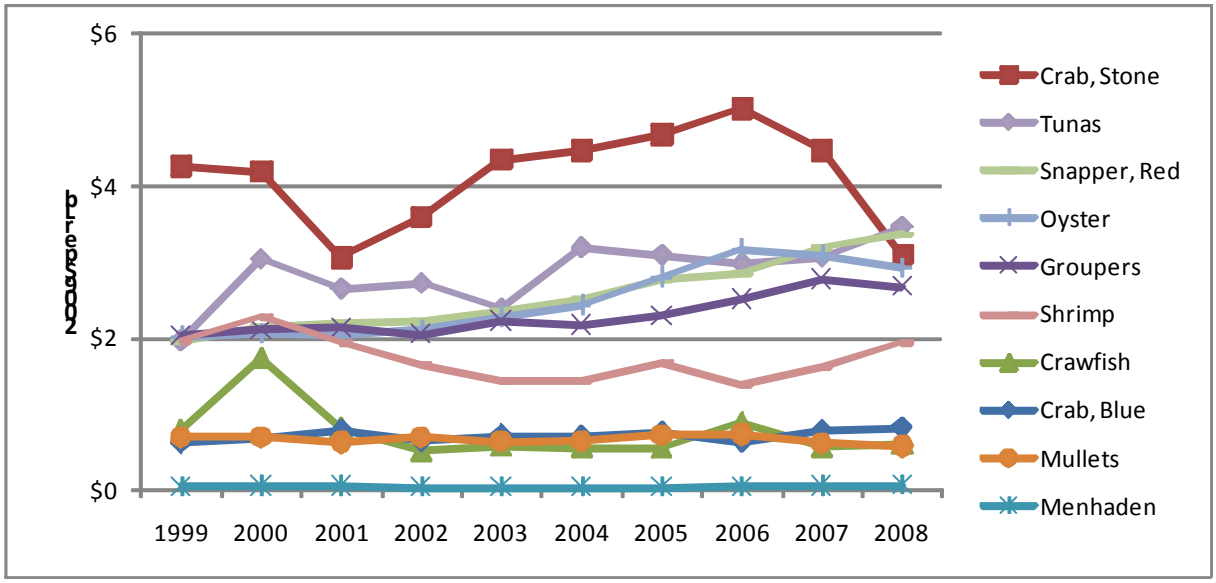

Figure 7 Average Annual Price per Pound (2009$)

Source: NMFS Fisheries Economics of the United States 2008.

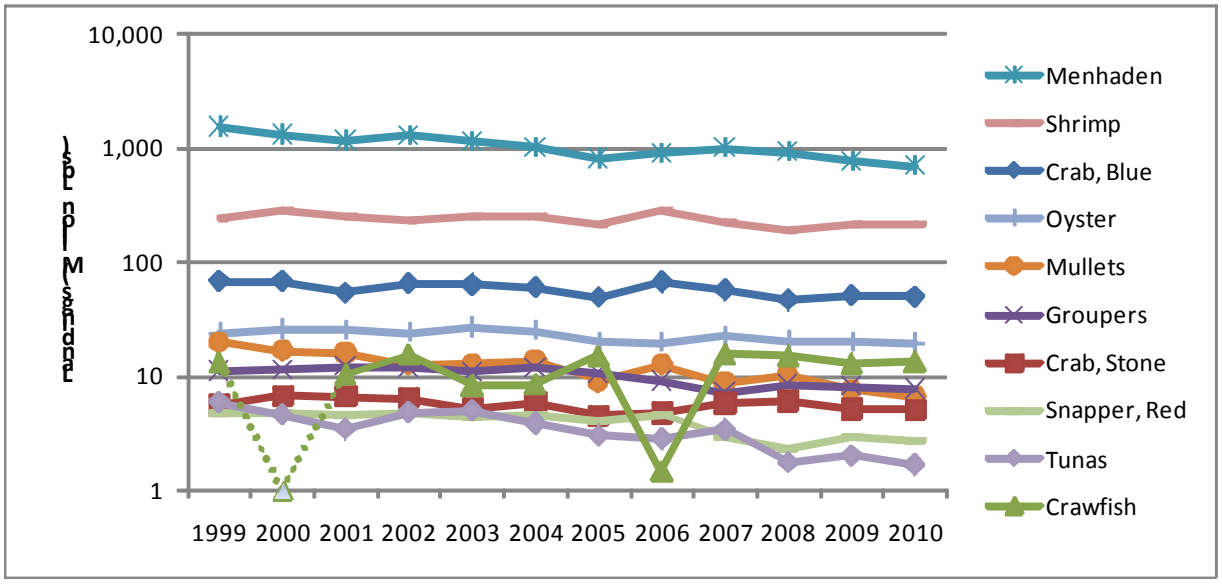

Figure 8 Gulf State Landings, 1999-2008 (mmlbs)

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.

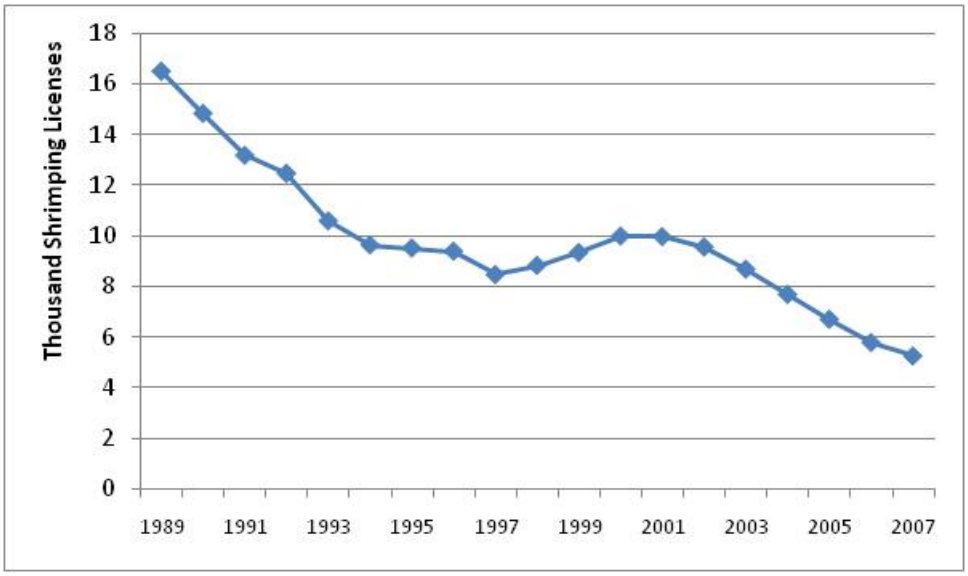

Figure 9 Resident Louisiana Shrimping Licenses (Trawl, Butterfly Net, and Skimmer Net)
Source: Louisiana Department of Wildlife and Fisheries

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 6.

Table 6 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, [15] 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.

[15] 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.

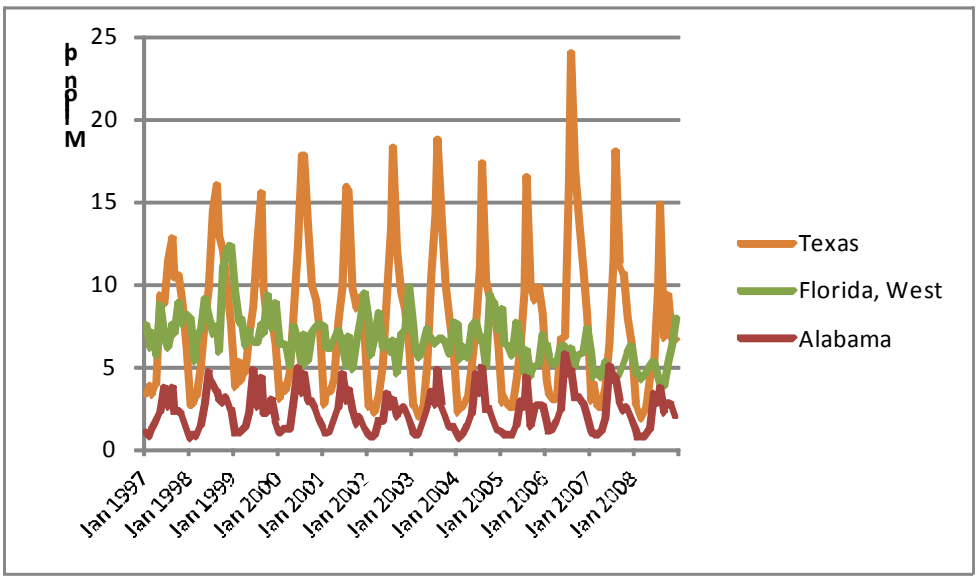

Figure 10 Monthly Commercial Fishery Landings (Texas, West Florida, Alabama)

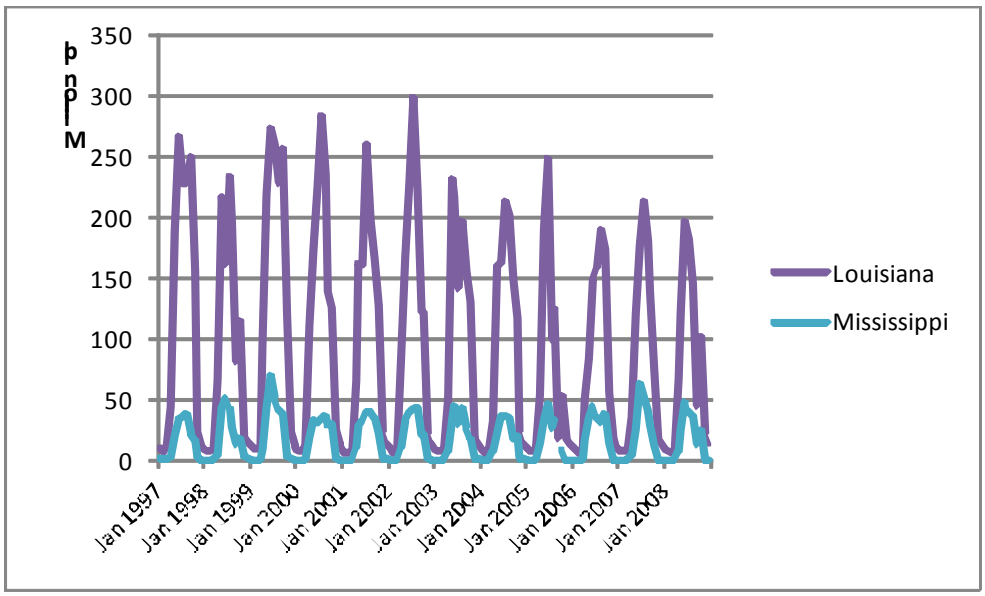

Figure 11 Monthly Commercial Fishery Landings (Louisiana, Mississippi)

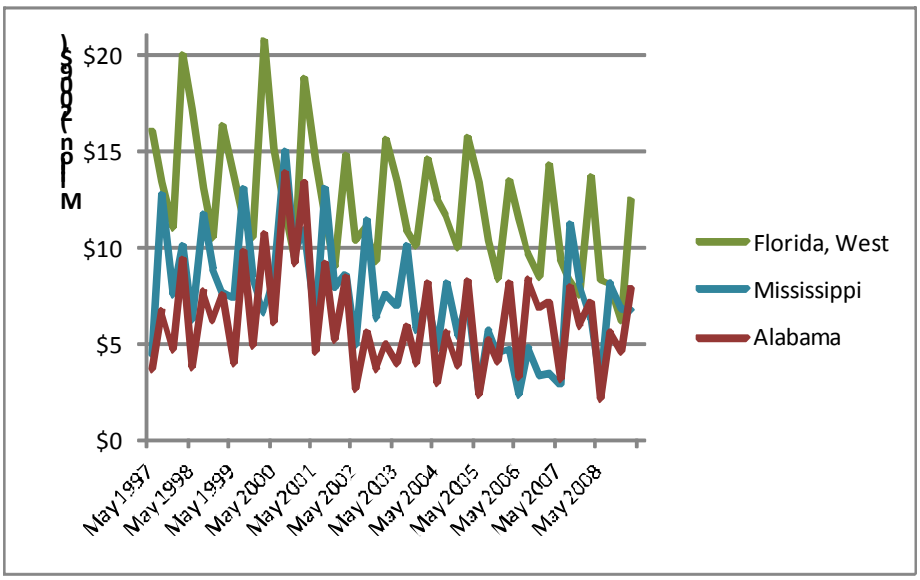

Figure 12 Summer Commercial Fishery Landing Revenues (West Florida, Mississippi, Alabama)

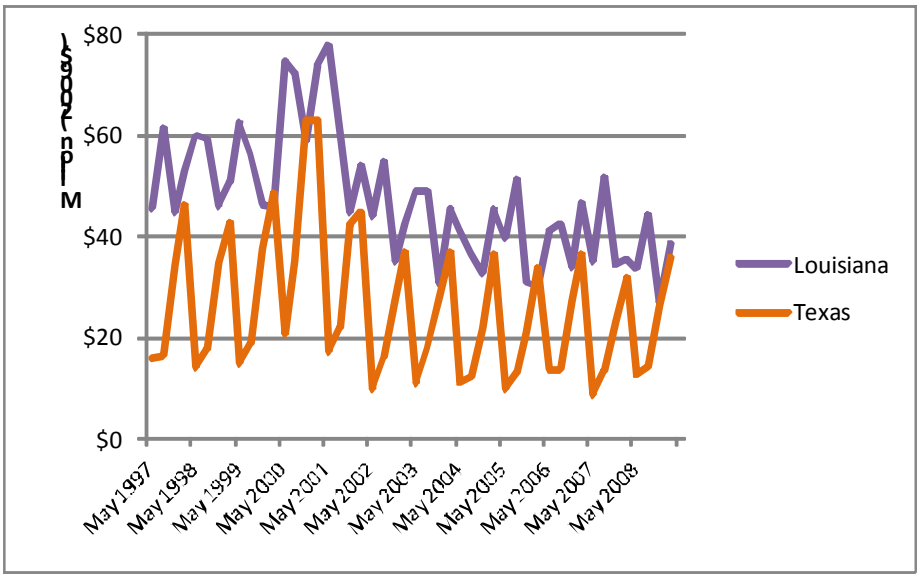

Figure 13 Summer Commercial Fishery Landing Values (Louisiana, Texas)

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 7.

Table 7 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 8.

Table 8 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 9, where the same approach is used to apportion the total fleet shrimp landings and landings revenue.

Table 9 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 9, 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 7 to determine the contribution of each vessel class to baseline revenues for the entire commercial fishing industry (see Table 10). 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 11). Finally, in Table 12 the results for large and small vessels are summed together to find the 2010 baseline for total industry profits by month.

Table 10 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 11 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 11 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 7 gives the 2010 baseline profits in Table 12.

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 12 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 13. 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.[16] The eastern edge of the Gulf has also remained open, and Florida has closed only about 20 miles of the coastline near Pensacola.[17] 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.[18] On July 20, Mississippi State coastal waters re-opened to live-bait shrimping and catch-and-release fishing.[19] 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.[20]

[16] 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/.

[17] Florida closure data were taken from a Florida Fish and Wildlife Conservation Commission press release dated June 13, 2010.

[18] Alabama closure data were taken from an Alabama Department of Conservation and Natural Resources press release dated June 28, 2010.

[19] Mississippi closure data were taken from a Mississippi Department of Environmental Quality/Department of Marine Resources news release dated July 19, 2010.

[20] 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 13 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 14 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 15).

Table 15 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 13) 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 16.

Table 16. 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 17. 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 18 presents estimates in current dollars of oil spill cleanup costs by oil type; Table 19 presents estimates by kilometer of shoreline oiled; Table 20 presents estimates by proximity to shore. Table 21 presents information by spill volume.[21]

Table 18 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 19 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

[21] 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 20 Cost of Spills by Location

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

Table 21 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 22).

Table 22 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[22] 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).

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

[22] 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.

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[23] 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.

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

Summary – Avoided External-Social Costs

Table 23 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 23 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 24 combines the conditional avoided private-social and external-social costs from Table 4 and Table 23. This is the potential benefit per catastrophic spill in the baseline from fully eliminating the possibility of a spill.

Table 24 - 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. The compliance 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 avoided associated with the hypothetical spill scenario owing to 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 extending 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 identify scenarios in which the expected benefits justify the expected costs.

The hypothetical spill from Table 24 gives us an avoided social cost of $16.3 billion for a major event. The compliance costs of this regulation from Table 3 give an annual compliance cost of $183 million per year. The baseline assumptions establish that there was 1 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.[24]

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 required proportional 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 $183 million divided by annualized avoided costs of $631 million suggests a finding of a 29 percent improvement in spill frequency when expected benefits justify the expected compliance costs.

By varying selected important inputs in reasonable ways, we can provide a range for the scenarios under which expected benefits justify the costs of the regulation.

1) The compliance costs are lowered by about 50% to $97 million reflecting productivity improvements, and raised by about 100% to $352 million reflecting more frequent compliance problems and work stoppages during drilling operations, as discussed in the next section.

2) 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.*

[24] 4123 wells divided by 160 wells per year gives us 25.8 years, or 26 years.

Sensitivity of Compliance Costs

A **lower compliance cost estimate** of $97 million annually assumes the industry can achieve longer term productivity improvements for the requirements in this regulation. The lower compliance cost estimate for the sensitivity analysis is determined by taking ½ of the ROV testing time (12 hours) for the subsea BOP on the stack and seafloor for drilling and workover/completions operations and ½ of the casing strings required (an average of 2.5 strings tested for deepwater wells and 1.5 strings tested for shallow wells) for the negative pressure test. Additionally, we include only the capital cost of the second mechanical barrier and exclude the 30 minutes of lost rig time due to installation from the baseline estimate and assume the frequency of emergency activation of the BOP is halved. Over time, companies will improve the efficiency of conducting these tests, improve technology to use fewer casing strings and find other methods to improve lost productivity; however, a 50 percent improvement appears unlikely to be achieved in the near term. Using this lower compliance cost of $97 million, divided by the annual avoided cost of $631 million, the required proportional improvement in spill frequency is found to be 15 percent.

An **upper compliance cost estimate** of $352 million annually assumes that the time required for conducting the tests for this regulation were underestimated due to unforeseen and time consuming problems encountered through the additional requirements imposed by this regulation. The higher compliance cost estimate for the sensitivity analysis is determined by doubling the ROV subsea BOP testing time for drilling and workover/completion operations and doubling the time needed to complete negative pressure tests for all intermediate and production casing strings. The subsea BOP stack testing components would take a full 48 hours and each negative pressure test would take 3 hours in this scenario. Additionally, the lost rig time for installing the second mechanical barrier would be doubled to 60 minutes and the frequency of the emergency activation of the subsea BOP stack would occur twice as often. The upper bound annual compliance cost consistent with these assumptions is found to be $352 million annually. Using this upper compliance cost of $352 million, divided by the annual avoided cost of $631 million, the required proportional improvement in spill frequency is found to be 56 percent.

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. Thus the reservoirs 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 is not 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 of the water depths as demonstrated by the BPDH event.

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 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.[25]

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. Taking the compliance costs of $183 million per year, divided by the alternate annual avoided costs of $1.216 billion per year, results in a required proportional improvement in spill frequency of 15 percent for the benefits to justify the costs in this alternate scenario.

Alternatives

This interim 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. Given the critical nature of the BP Deepwater Horizon (BPDH) explosion and resulting oil spill and the apparent inadequacy of existing well control procedures and BOP requirements, the Safety Measures Report recommended that BOEMRE address some items through an emergency rulemaking. The requirements in this interim 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 were determined by the Secretary to be urgently needed to protect worker safety and the OCS environment.

Other measures recommended in the Safety Measures Report but not included in this emergency interim rulemaking include additional blind shear and casing ram requirements, enhanced ROV

[25] 1475 wells drilled divided by 110 wells per year equals 13.4 years.

intervention capability, increased accumulator capacity for operating BOPs and safety case requirements for floating drilling operations. These and other items in the Safety Measures Report require further study by industry and Interior Strike Teams to determine their efficiency and effectiveness. Measures considered beneficial will be considered for future notice and comment rulemaking.

Small Business Alternatives

Two alternatives to ease impacts on small business were considered. One alternative is to exempt small businesses from the requirements of this interim final rule. A second alternative is to delay the implementation timelines to comply with the regulation. Both of these alternatives are being rejected by BOEMRE because of the overriding need to reduce the chance of a catastrophic blowout event. We do not believe it is responsible for a regulator to 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 may increase the interim risk of OCS drilling operations. Additionally, more than 90 percent of the costs will be imposed on deepwater lessees and operators where small businesses only hold 12 percent of deepwater leases. Every operator and drilling contractor both large and small must meet the same criteria for drilling operations regardless of company size. However, the overwhelming share of the cost imposed by this regulation will fall on companies drilling deepwater wells, which are predominately the larger companies. Nonetheless, small companies as both lease-holders and contractors serving lease-holders will bear meaningful costs under this regulation.

To better understand the economic impact of this rule on small entities, the BOEMRE will conduct a supplemental Initial Regulatory Flexibility Analysis (IFRA) to examine in greater detail the impact of this regulation on the small entities. We are requesting comments on the economic analysis for this interim final rule and this rulemaking's impact on small entities. The supplemental IFRA will be made available to the public when completed.

CONCLUSION AND UNCERTAINTIES

The BOEMRE has analyzed the costs and benefits of this interim 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 and benefits, 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.

Future long term studies should be conducted to assess the likely effectiveness of these 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 BOEMRE TIMS data base may enable studies that assess how requirements for extra subsea ROV and deadman testing, widespread use of negative pressure tests, dual mechanical barriers in the final casing string, along with the remaining items required in this rulemaking, could improve well control performance. Parenthetically, such data are available to conduct statistical tests on prospective BOP enhancements which are not included in this rule. Absent the ability to conduct these studies of the key features that are included in this rule, we turn to possible refinements in the baseline assessments.

We can also expect the risk and impact of a deepwater catastrophic blowout will be lessened by other factors not specifically addressed in this benefit-cost analysis. Industry and government reaction to this spill has added experience that will improve planning, response and technology used to mitigate spill effects before a relief well is completed. However, the nature and impact of these changes are not easily quantifiable at this stage of the investigative process and are not included in the benefit-cost baseline.

One area of further study involves the voluntary measures being recommended by the Joint Industry Task Forces. If the American Petroleum Institute's (API) Recommended Practices (RP) are published and incorporated into BOEMRE regulations, we would consider those RP's to be part of the inherent cost of sound well design and best practice drilling operations. In this circumstance the RP's would not be considered a new compliance cost for the purposes of this benefit-cost analysis. Rather, the benefits and costs would be included in our baseline for this analysis. Therefore, to the extent that voluntary measures recommended by the Industry Joint Task Forces become API RP's and are incorporated into BOEMRE regulations, the actual compliance costs imposed by this rule would be reduced. As a result, the required proportional improvement in spill reliability necessary for the benefits from the expected costs avoided by these provisions to exceed their compliance costs would be lowered, unless the voluntary measure also reduced the baseline risk of a spill under current regulations by a proportionally equal or greater amount than the reduction in costs.

Another area for further inquiry involves determining the impact and cost of a catastrophic deepwater oil spill. Future studies and analyses are necessary to more fully reflect all the effects of a catastrophic deepwater blowout on the natural and human environments in the Gulf of Mexico. 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, then the future analysis should be adjusted to reflect the new estimate.

Appendix A Natural Resource Damage Data

Table 25 - 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

Event	Year of Settlement	Max Volume (bbl)	NRD plus Assessment Costs (2009$/bbl)*
Jahre Spray	1996	1,400	121
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

Event	Year of Settlement	Max Volume (bbl)	NRD plus Assessment Costs (2009$/bbl)*
T/V Julie N	2002	4,277	348
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 26 - 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 B Well Data

Table 27 – 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 C Definitions

Baseline: describes the status quo scenario ("the world absent the new regulation"). The baseline is compared to "the world with the regulation" 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 BOP's are required on floating mobile drilling rigs.
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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Joint Industry Task Force to Address Offshore Operating Procedures and Equipment, May 17, 2010, White Paper: Recommendations for Improving Offshore Safety http://www.noia.org/website/download.asp?id=38556

DNV – Beaufort Sea Drilling Risk Study Energy Report, Imperial Oil Resources Ventures Limited, DNV ref no: EP00485, Rev. 6, March 11, 2010, submitted to the Canadian-National Energy Board (www.neb-one.gc.ca) https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90463/589151/594086/594088/600443/609664/C-05-6C_-_Appendix_A_Beaufort_Sea_Drilling_Risk_Study__-_A1S2V8_.pdf?nodeid=609512&vernum=0

Executive Order 12866, Regulatory Planning and Review http://www.whitehouse.gov/sites/default/files/omb/inforeg/eo12866.pdf

OMB Circular A-4, Regulatory Analysis http://www.whitehouse.gov/sites/default/files/omb/assets/omb/circulars/a004/a-4.pdf

OMB Circular A-94, Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs http://www.whitehouse.gov/sites/default/files/omb/assets/a94/a094.pdf

NYT Article on the replacement cost of the Deepwater Horizon which is estimated at $560 million. http://www.nytimes.com/gwire/2010/05/04/04greenwire-warnings-on-backup-systems-for-oil-rigs-sounde-30452.html

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 E 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.