Oil Spill Response Equipment Capabilities Analysis (Volume II)

U.S. Department of the Interior Bureau of Safety and Environmental Enforcement (BSEE)

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EXECUTIVE SUMMARY

The Bureau of Safety and Environmental Enforcement (BSEE), within the Department of the Interior (DOI), is charged with the responsibility to permit, oversee and enforce the laws and regulations associated with the development of oil and natural gas resources on the Outer Continental Shelf (OCS). BSEE's Oil Spill Preparedness Division (OSPD) is responsible for developing and administering regulations, found at 30 CFR 254, that oversee the oil and gas industry's preparedness to contain, recover and remove oil discharges from facilities operating seaward of the coastline. Current regulations require that operators of these offshore oil and gas facilities submit an Oil Spill Response Plan (OSRP) that identifies the procedures and contracted spill response resources necessary to respond, to the maximum extent practicable, to the facilities worst case discharge (WCD).

Nearly two decades has passed since BSEE's OSRP regulations were promulgated. During this time, changes occurred in drilling trends, as well as the risks associated with oil spills. The national response system has matured, and Area/Regional Contingency Plans have been developed and approved that now contain preauthorized strategies for the use of dispersants and in situ burning, in addition to mechanical recovery equipment. Remote sensing technologies have been improving and are now commercially available. To better understand and analyze changes that have occurred in offshore drilling and their impacts on oil spill response planning, this study has undertaken a series of related analyses to assist BSEE in updating its oil spill response plan requirements, with a particular focus on required oil removal capabilities.

METHODOLOGY

This study uses a variety of methods, including literature review, computer modeling, and a market survey, to identify recommended practices and develop regulatory recommendations for potential oil spill response plan requirements. These recommendations pertain primarily to requirements for oil spill response capabilities that must be contracted for and maintained in a readiness status in advance of responding to a WCD oil spill. This report investigates oil spill response efforts for eleven WCD scenarios, using a computer model that simulates the fate, transport, and removal of spilled oil using a variety of response methods. The report also features a case study of the Deepwater Horizon oil spill, the largest offshore oil spill in U.S. history, a review of U.S. government planning documents for oil spill response, and a literature review of nine national oil spill response regulatory regimes. Figure ES 1 shows how the analyses within this report lead to the development of response equipment capability recommendations.

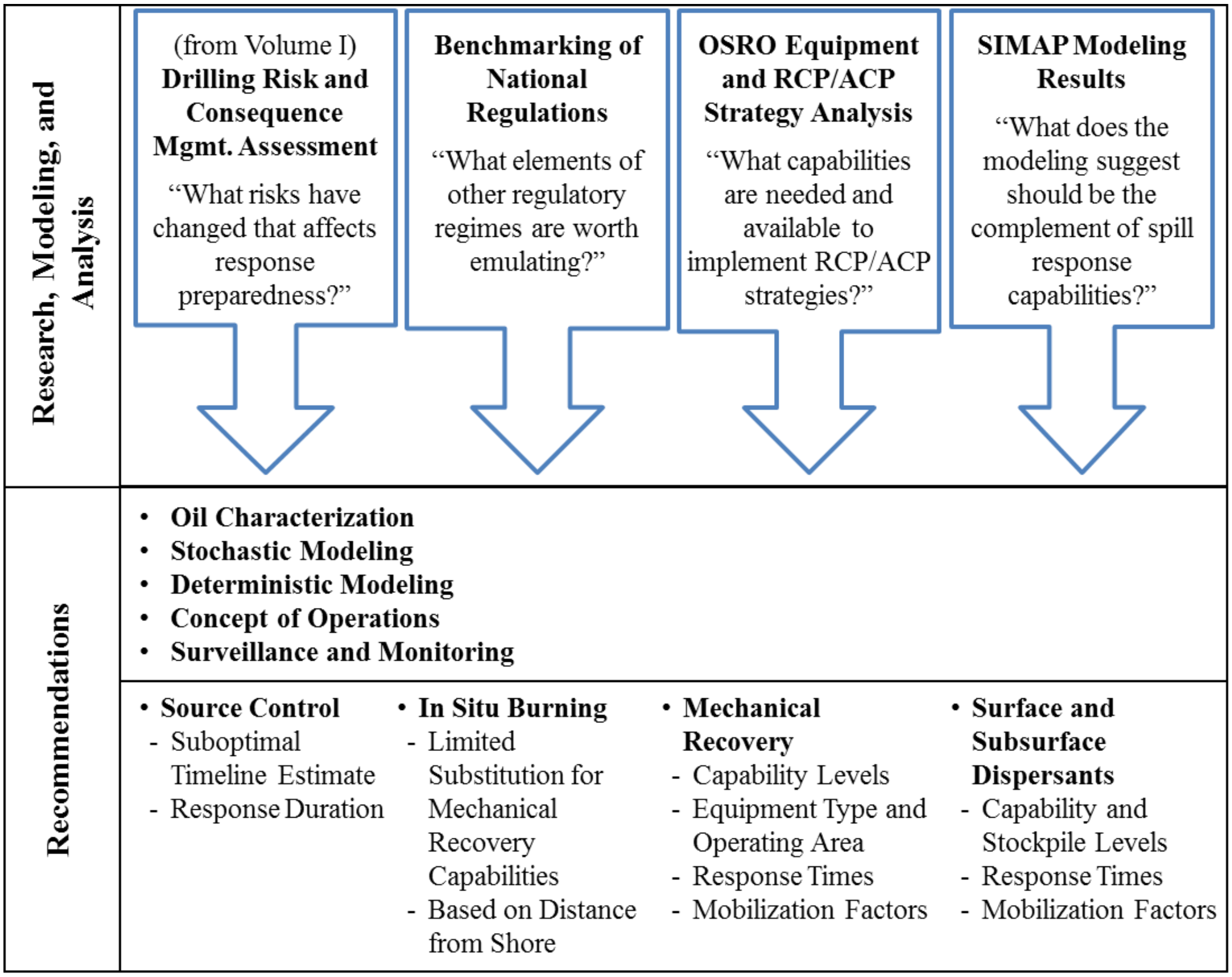

Figure ES 1: Conceptual Diagram of OSRP Equipment Capabilities Review Study

Regulatory Review and Benchmarking

The oil spill response plan regulations of eight countries were reviewed and summarized in order to provide BSEE with an inventory of regulatory best practices to consider as they update the U.S. oil spill response regulations for OCS facilities. Detailed information on the regulations for the eight countries listed below is presented in tables in Appendix B.

- Australia
- Brazil
- Canada
- Denmark
- Greenland
- New Zealand
- Norway
- United Kingdom

The USCG regulations for response to oil spills from vessels were also reviewed and summarized, as they contained highly developed and detailed policies for oil spill response in the offshore environment. All the regulatory regimes were evaluated based on the regulatory categories in Table ES 1.

Table ES 1: Information Collected From National Oil Spill Response Regulatory Regimes

Regulatory Category	Requirements and Documents
Regulatory Approach	• National Regulations and Guidance Documents
Operator Roles	• Facility-Level Planning Documents
Risk Assessment and Scenario Planning	• Oil Characterization • WCD Scenario • Modeling • Risk Assessment
Response Options	• General Guidance, Principles, and Approach • Open Water Mechanical Recovery • Shoreline Cleanup Mechanical Recovery • Surface Applied Dispersants • Subsurface Applied Dispersants • In Situ Burning • Shoreline Protection
Oil Spill Tracking	• Spill Tracking, Aerial Reconnaissance/Surveillance & Remote Sensing
Source Control	• Relief Well • Capping and Well Intervention

The results of the benchmarking assessment show that there are many different regulatory approaches that are influenced by a variety of factors. No single system appears to be, at face value, inherently more effective or better than the others. Often these regimes are significantly influenced by the nation's national contingency plans and factors such as the subsequent division of responsibility for response activities between the private and public sector. This comparison did allow, however, for a broad examination of many varied practices currently used by regulating entities on a global scale, as well as the identification of a number of elements that should be considered as recommended practices. The findings were then used to generate a number of recommendations, including requirements for oil characterization, aerial surveillance capabilities, oil spill modeling, and an offshore concept of operations. It was also recommended that BSEE consider prescriptive regulations for arrival times and equipment levels for mechanical recovery and dispersant application based, in part, on the USCG regulations for response to spills from vessels.

Deepwater Horizon Case Study

A literature review was conducted to determine the geographic scope of the Deepwater Horizon (also referred to as Macondo, which was the well name) oil spill and the equipment types, quantities and mobilization times that were used during the response. Because the Deepwater Horizon oil spill was an actual WCD-scale incident that occurred relatively recently, with the use of modern drilling and response technologies, it serves as an informative example with many lessons learned for BSEE to consider as the Bureau updates oil spill response regulations for OCS facilities. It is estimated that the total volume of oil spilled was 4.2 million bbl, resulted in 46,324 square miles cumulative water surface oiling[1] and 1,100 miles of shoreline oiling.[2]

[1] ERMA Deepwater Gulf Response
[2] Ylitalo, Gina M. et al., 2012, Federal Food Safety Response to Deepwater Horizon Oil Spill

More than 3,000 vessels were simultaneously deployed in the Gulf of Mexico at the peak of the Deepwater Horizon spill response over, including more than 800 skimming vessel. The USCG BP Deepwater Horizon Incident Specific Preparedness Review (ISPR) estimated that 3% to 4% of the oil spilled in the Macondo incident was mechanically recovered.[3] Aerial dispersant operations were carried out using 14 spray aircraft and 8 spotter aircraft, which flew 816 reconnaissance and spotter sorties, and 412 spray sorties that applied 972,880 gallons of dispersant. Across the 18,000 square mile operating area, approximately 305 square miles of ocean surface was sprayed with dispersant, which dispersed an estimated 12 to 18 million gallons of oil.[4] Subsurface dispersant[5] was also applied during the Macondo oil spill. Approximately 770,000 gallons of dispersant were injected at the wellhead between late April and the capping of the well in July 2010.[6] The USCG estimates that about 5% of the oil spilled in the Macondo incident was removed with in situ burning. The flow of oil from the Macondo well was stopped 87 days after the oil discharge began with a successful source control operation using a capping stack.[7] The well was permanently sealed 66 days later through a relief well on September 19, 2010

The review of the Deepwater Horizon oil spill showcased many things, in particular, the critical importance of temporary source control measures, the inherent limitations on mechanical recovery equipment due to oil weathering, the necessity for direct aerial surveillance and spill tracking support to response countermeasures, and the potential for dispersants and in situ burning to remove oil in a large WCD event.

Regional/Area Contingency Plan Review

Regional Contingency Plans (RCPs) and Area Contingency Plans (ACPs) are federal, state, and local joint planning documents for response to spills of oil and hazardous substances. The RCPs and ACPs whose jurisdictions would intersect with spilled oil from the study's WCD scenarios were reviewed for this study. Oil spill response strategies and tactics from the RCPs and ACPs were recorded, including exclusion and pre-authorization zones for dispersants and in situ burning. The strategies and tactics from the RCPs and ACPs were used to inform the execution of simulated oil spill response operations in the WCD scenarios that were modeled. It was also noted that the offshore response strategies for many of these lacked detail and require further development.

Oil Spill Response Equipment Inventory Review

A market survey of the major Oil Spill Removal Organizations (OSRO) that provide response resources to the offshore oil industry was conducted to determine existing equipment inventory levels and mobilization times for the three OCS regions studied. Information on equipment quantity, type, and mobilization was also collected from publically available online databases, as well as the U.S. Coast Guard Response Resource Inventory (RII) System and the Western Response Resource List (WRRL). OSROs were also consulted regarding equipment availabilities and mobilization times for responses to the hypothetical WCD scenarios.

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[3] U.S. Coast Guard. BP Deepwater Horizon Oil Spill Incident Specific Preparedness Review. 2011
[4] U.S. Coast Guard. After Action Report Deepwater Horizon MC252 Aerial Dispersant Response. Houma, LA, 2010
[5] With respect to undersea application of oil dispersants, this report uses the term "subsurface." Other studies and reports may use the term "subsea." Both terms are used interchangeably by industry and regulators, and should be considered synonyms.
[6] U.S. Coast Guard, On Scene Coordinator Report, Deepwater Horizon Spill, Washington: Government Printing Office, 2011
[7] http://www.iadc.org/archived-2014-osc-report/response/stemming-the-flow-capping-stack.html

Estimated Recovery System Potential (ERSP) Analysis

Effective Daily Recovery Capacity (EDRC) is a method for calculating mechanical oil recovery rates that is currently codified under BSEE regulations at 30 CFR 254. BSEE is considering replacing EDRC with a new calculation called Estimated Recovery System Potential (ERSP). Both calculations are intended to estimate the oil recovery capacity of mechanical recovery response operations for regulatory planning purposes. Total regional EDRC and ERSP were calculated based on information collected in the OSRO surveys, RRI, WRRL, and online databases, and are summarized in Table ES 2.

If ERSP is adopted by BSEE, holders of OSRPs (or plan holders) will be impacted because the oil recovery rates of their equipment will be reduced. These impacts were assessed by comparing calculations of EDRC and ERSP for the same mechanical recovery equipment. Table ES 2 shows a comparison for EDRC and ERSP values nationally, and for each OCS region. ERSP was not calculated for shoreline skimming equipment because the calculation of ERSP requires a vessel platform. Therefore, a comparison of total EDRC and total ERSP is biased toward EDRC because it was calculated based upon more skimming equipment. To correct for this, Table ES 2 includes a column titled "EDRC without Shoreline," which was calculated based upon the exact same equipment as total ERSP. This comparison clearly shows that EDRC results in a much higher estimate of mechanical recovery rate than ERSP. Total EDRC for the Gulf of Mexico OCS Region was calculated to be about 8 times greater than ERSP on a same-equipment basis (i.e., comparing the two rightmost columns in Table ES 2). Continuing this comparison, EDRC is about 3 times greater than ERSP in the Pacific, 2.5 times greater in the Arctic, and 6 times greater than ERSP nationally.

Table ES 2: Comparison for Total EDRC and ERSP for the Three OCS Regions and Nationally

OCS Region	Shoreline [a]	Nearshore		Offshore		Total EDRC	EDRC w/o Shoreline	Total ERSP
	EDRC	EDRC	ERSP	EDRC	ERSP			
Gulf of Mexico	249,795	708,825	104,450	2,686,625	547,313	3,645,245	3,395,450	651,763
Pacific	101,642	423,181	78,707	800,047	295,102	1,324,870	1,223,228	373,809
Arctic	179,260	200,792	51,409	393,048	150,002	773,100	593,840	201,411
NATIONAL	**530,697**	**1,332,798**	**234,566**	**3,879,720**	**992,417**	**5,743,215**	**5,212,518**	**1,226,983**

[a] ERSP was not calculated for shoreline skimming devices because the calculation of ERSP requires a platform (e.g., a vessel), and platforms are not applicable for more shoreline oil removal.

WCD Response Countermeasure Modeling

The computer modeling portion of this study simulated WCD events at nine hypothetical well locations in the U.S. OCS. Six of these well locations are in the Gulf of Mexico OCS Region, one is in the Pacific OCS Region, and two are in the Arctic OCS Region. The Arctic WCD well locations were both modeled using separate early drilling season and late drilling season scenarios to investigate the effects of varying sea ice coverage during spill responses. The scenarios were designed to investigate potential oil spill trajectories and response efforts among a variety of distances from shore, geographic locations, oil types, depths, and discharge volumes.

BSEE subject matter experts were consulted to provide model inputs for the WCD flow rates and the times estimated to drill a relief well. In Volume I of this study, 100 stochastic model runs were performed for each WCD scenario location under varying simulated atmospheric and oceanic conditions to determine the single WCD trajectory that would result in the greatest length of shoreline oiling for each well. These 'worst case trajectory' WCD scenarios were then modeled with a variety of oil spill response countermeasures to investigate the impact of using multiple response options. Two baselines were generated, one using only a relief well to secure the discharge, and a second that included the implementation of a temporary source control measure to secure the discharge. Using the second baseline, various combinations of spill response countermeasures were added and modeled to include mechanical recovery, surface and subsurface dispersant application, and in situ burning. Table ES 3 shows the response countermeasure combinations used for the eleven WCD modeling scenarios.

Table ES 3: List of Response Countermeasures Modeled for Each WCD Scenario.

Scenario Number	Scenario Name	Source Control (SC)	Source Control+ Mechanical Recovery (SC+MR)	Source Control + Mechanical Recovery + Surface Dispersant (SC+MR+D)	Source Control + Mechanical Recovery + Surface Dispersant + In Situ Burning (SC+MR+D+ISB)	Source Control + Mechanical Recovery + Surface Dispersant + In Situ Burning + Subsurface Dispersant (SC+MR+D+ISB+SubD)
1	**MC807**	✓	✓	✓	✓	✓
2	**WD28**	✓	✓	✓	✓	
3	**WC168**	✓	✓	✓	✓	
4	**HIA376**	✓	✓	✓	✓	
5	**KC919**	✓	✓	✓	✓	✓
6	**DC187**	✓	✓	✓	✓	✓
7	**SM6683**	✓	✓	✓		
8	**P6912 Early**	✓	✓	✓	✓	
9	**P6912 Late**	✓	✓	✓	✓	✓
10	**FI6610 Early**	✓	✓	✓	✓	
11	**FI6610 Late**	✓	✓	✓	✓	✓

Source control (SC): the process of stopping the flow of oil from a well blowout by plugging (also called "capping") or containing the wellhead with a large device such as a capping stack or a containment dome.

Mechanical recovery (MR): the physical collection of oil from the water's surface using a skimming device that is often mounted on a vessel.

Dispersants (D): chemicals that physically break up oil particles similar to a detergent and allow oil to more easily disperse into the water column. Dispersants are often sprayed on spilled oil from aircraft, and more recently have been applied underwater (subsurface dispersant application, **SubD**) at the wellhead to treat subsurface blowout oil spills.

In situ burning (ISB): ignition and burning of spilled oil on the water surface.

One of the key observations from the model results was the finding that oil removal rates for the various response countermeasures were heavily influenced by wind, sea state, and rapid weathering of the floating oil. In many cases, the oil had emulsified, thinned out, and increased in viscosity to a point where the oil was no longer dispersible or recoverable (i.e. > 20,000 cST) within a few days of surfacing near the wellhead.

Figure ES 2 illustrates this weathering behavior as seen during the DeSoto Canyon 187 (DC187) WCD scenario. As the oil is transported away from the discharge site by winds and currents, the oil's progression in viscosity is clearly visible. This weathering behavior has significant impacts for determining where oil is fresh enough to be dispersed or recovered. In the case of mechanical recovery, this progression in viscosity is a critical factor in determining the geographical boundaries of the divisions where these countermeasures will operate, and what types of recovery equipment must be present in these areas.

DC187 No Response - Day 9 - Surface Spillet Viscosity

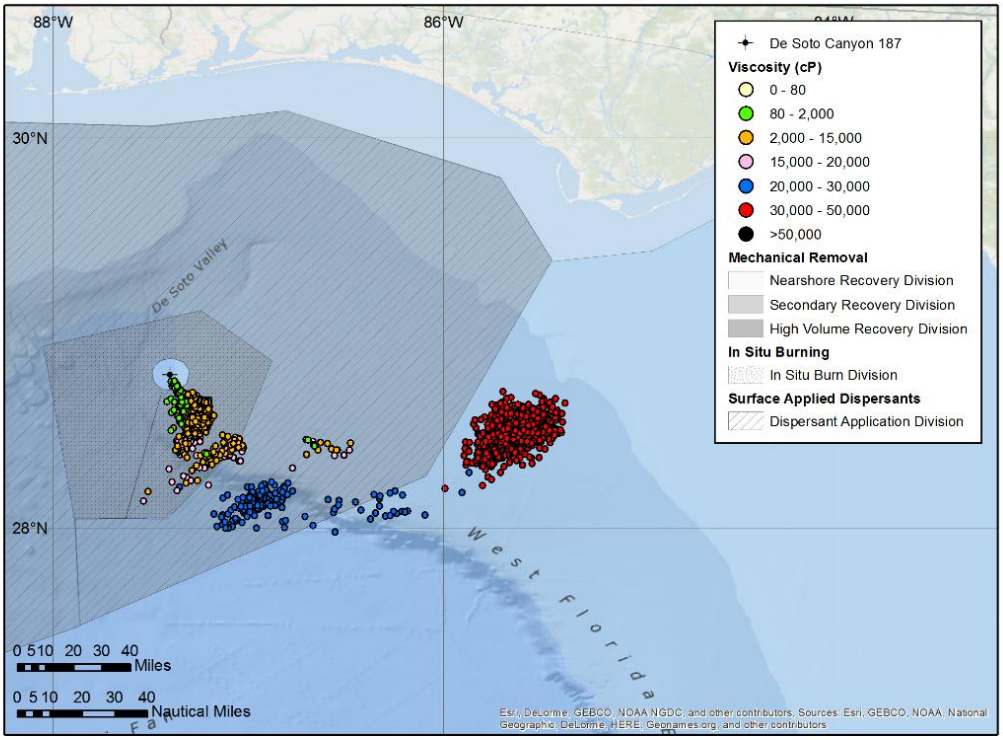

Figure ES 2: Illustration of Surface Oil Weathering: Scenario 6, De Soto Canyon Surface Spillet Viscosity at Day 9, with No Response

Response Capability Recommendations

The results of the WCD oil spill response modeling, the Macondo oil spill literature review, the summaries of national oil spill response regulations, and the ERSP analysis were assessed to generate recommendations for BSEE as it considers updating OSRP regulations for offshore facilities.

Oil Spill Characterization. Previous research has shown that the effectiveness of response countermeasures decrease as oil weathers and viscosity increases. Response countermeasures, including dispersant performance, vary widely based on the chemical properties of oil and its behavior once released into the environment. The review of national oil spill regulations and guidance showed that several countries (e.g., New Zealand) require oil characterization for offshore oil spill plans. Prior knowledge of the likely behavior of a spilled oil, and pre-spill analyses of the feasibility of response strategies are important to determine the windows of opportunity for effective recovery, burning, and dispersibility of the oil. BSEE should require OSRPs to include characterization of the chemical and physical attributes of the produced oil.

Oil Spill Modeling and an Offshore Response Concept of Operations. BSEE should require plan holders to use oil spill modeling to identify areas at risk from a WCD and to support the development of an offshore Concept of Operations (CONOPS) for spill response. Stochastic modeling should be used to identify the likelihood of geographic areas coming into contact with spilled oil and minimum travel times to sensitive endpoints. Deterministic trajectory modeling should be used as a basis for developing an offshore CONOPS. The deterministic modeling should track the fate and transport of the oil as it rises through the water column from subsurface releases and as it moves away from the discharge site on the surface. The modeling should predict changes in oil viscosity and oil thickness over time and distance, to estimate the location of surface oil, develop response divisions, and match response capabilities to areas where they will be effective. Oil spill modeling platforms used by plan holders should also have the ability to track spills in real-time to support ongoing response efforts.

BSEE should require that the CONOPS in the OSRPs be readily adaptable to changes in the oil's fate and transport throughout the WCD area of operations, to ensure that as the spill weathers, thins, and expands in size, resources will be distributed according to individual capabilities of the systems. Recovery systems should be assigned to areas of the spill plume according to their individual capabilities and the predicted properties of the oil in each division, including oil thicknesses, viscosities, and its distribution on the surface. The effectiveness of this approach was demonstrated in the modeling simulations (Figure ES 3). The more efficient systems, which are often the less maneuverable, should be assigned to the division/group where the oil is concentrated, thick, and remains low in viscosity, such as near the wellhead or where the majority of the oil surfaces. More maneuverable systems adapted to more viscous oils may be better suited to areas where the oil has been broken up into weathered streamers and patches. Each division/group grid should be supported with proper secondary storage, surveillance, and other support to ensure operations are conducted efficiently and are as successful as possible. Dispersants, due to their ability to treat widely distributed patches of oil over large areas, should be used throughout the large secondary removal areas between the well site and the nearshore/shoreline oil removal areas. Dispersants should also be considered for use near the source when mechanical recovery assets have not yet arrived or are not able to operate due to weather conditions.

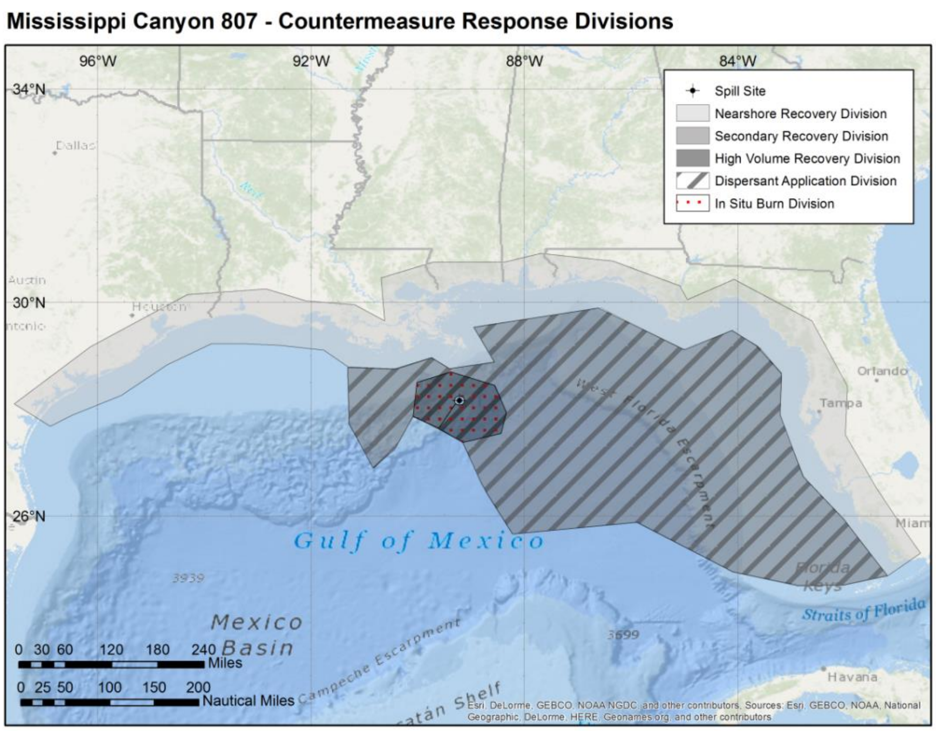

Figure ES 3: Example of Geographic Distribution of Countermeasure Response Divisions for Offshore Response Concept of Operations: Scenario 1, Mississippi Canyon

Temporary Source Control. BSEE should require OSRPs to include detailed planning for the use of various temporary and permanent source control methods that are specific to each well site, or require that plan holders have a definitive source control plan that is coordinated with the OSRP. The WCD modeling results provide strong evidence that the most significant impact in reducing the amount of oil released into the environment is attributable to the prompt implementation of a temporary source control measure to secure the discharge from a well blowout (see Table ES 4). Whether source control is regained from a top kill or a subsurface capping stack, the ability to rapidly shut down the discharge with a temporary measure in lieu of the much longer timeframe associated with the drilling of a relief well must be emphasized as one of the highest priority preparedness and response actions that can be undertaken.

Table ES 4: Response Modeling Results for Relief Well and Source Control Intervention

Scenario Well	Relief Well Only		Source Control		Source Control Reduction	
	Bbl Released	Shoreline Miles Contaminated	Bbl Released	Shoreline Miles Contaminated	Volume Reduction (%)	Shoreline Contamination (Miles, %)
MC 807	81,718,000	4,528	20,205,000	2,233	-75.3%	2,295 -50.7%
WD 28	3,589,000	1,430	2,037,000	1,266	-41.6%	164 -11.5%
WC 168	2,006,400	539	554,400	122	-72.4%	417 -77.4%
HIA 376	3,850,000	1,452	1,617,000	851	-58%	601 -41.4%
KC 919	30,240,000	2,602	11,340,000	1,135	-61.8%	1,467 -56.4%
DC 187	25,546,000	2,990	10,845,000	1,075	-57.6%	1,915 -64.1%
SM6683	884,000	1,620	52,000	620	-94.1%	1,000 -61.7%
P6912 Early	700,000	600	350,000	223	-50%	377 -62.8%
P6912 Late	700,000	729	350,000	440	-50%	289 -39.6%
FI6610 Early	480,000	782	224,000	353	-53.3%	429 -54.9%
FI6610 Late	480,000	583	224,000	501	-53.3%	82 -14.1%

Plan holders should realistically estimate their optimal and suboptimal well kill time frames for specific wells. The suboptimal timeline for securing the discharge should take into account potential delays that may arise from the following causes: adverse weather, delays in the requisition of support vessels, government agency approvals, debris removal around the well head, difficulties in installing the containment and capping devices, mechanical failures, and excessive volatile organic compounds (VOCs) or other unsafe working conditions on the surface over the well head. Plan holders should use the suboptimal timeline for implementing the temporary source control measures as the base period for planning a sustained response to the spill.

Aerial Surveillance and Oil Spill Tracking. A rapid initial assessment of the nature and scope of an offshore oil spill incident is critical to commencing the deployment of other response resources and the effective removal of any spilled oil. BSEE should require that OSRPs provide for aerial oil spill surveillance and tracking resources that are capable of arriving on scene and providing an initial assessment of an offshore oil spill within six hour of notification to deploy. Aerial surveillance is also a key asset for providing real time information to coordinate a Concept of Operations and a Common Operating Picture.

Oil spill surveillance is needed to ensure that all response countermeasures operate efficiently. Given the large size of potential surface area of oil slicks resulting from WCDs, the present level of surveillance resources available for OCS response are inadequate. Oil spill surveillance is an essential aspect of achieving recovery system maximum efficiency, especially when chasing patches of oil in the secondary recovery division. Problems with surveillance data acquisition and communication reduced the potential effectiveness of skimming systems during the Macondo response. BSEE should require a multi-tiered system of oil spill tracking and surveillance capabilities to support oil removal activities:

- Tier 1 capabilities should be in the immediate vicinity of a response asset, and are focused on increasing that asset's effectiveness to remove, burn, or disperse oil. In the case of mechanical recovery platforms, these capabilities should be a vessel-mounted sensor system that can detect thick oil in the vicinity of the vessel (e.g., x-band radar), be used to direct thick oil into the recovery device, and improve the efficiency of the oil removal operation.
- Tier 2 capabilities should be able to provide a larger area of oil spill surveillance coverage for a task force or group assigned to recover, burn, or disperse oil. These systems may use sensors (e.g., infrared) mounted on an airborne platform, such as an aerostat or drone to give a broader view of the surrounding area.
- Tier 3 capabilities should be aircraft-mounted, multi-spectral sensor capabilities that are capable of providing oil surveillance and tracking capabilities over a large area, with abilities to transmit real-time data to response groups, task forces, and incident command posts.

Tier 1 and 2 tracking resources must be capable of arriving on scene and providing oil spill surveillance tracking and direction commensurate with the start of conducting those oil removal activities. Tier 3 capabilities should be capable of arriving at the site of a discharge within 12 hours of being notified of the spill.

Multiple Response Countermeasures. The modeling of the WCD scenarios clearly demonstrated cumulative reductions in surface and shoreline oiling through application of additional response countermeasures to the spill response baseline.[8] Using multiple countermeasures consistently provided greater reductions in surface and shoreline oiling than just using significantly greater amounts of mechanical recovery equipment. Significant reductions could readily be seen for the larger spill scenarios when mechanical recovery (MR), surface dispersants (D), and subsurface dispersant injection (SSDI) were sequentially added into the modeling simulation. The smaller WCDs had similar trend lines on a much smaller scale (see Figure ES 4 and Figure ES 5). As a result, this study recommends capability requirements for multiple response countermeasures as a key underlying principle for an OSRP.

[8] WCD spill response baselines were established using Source Control as the lone response action.

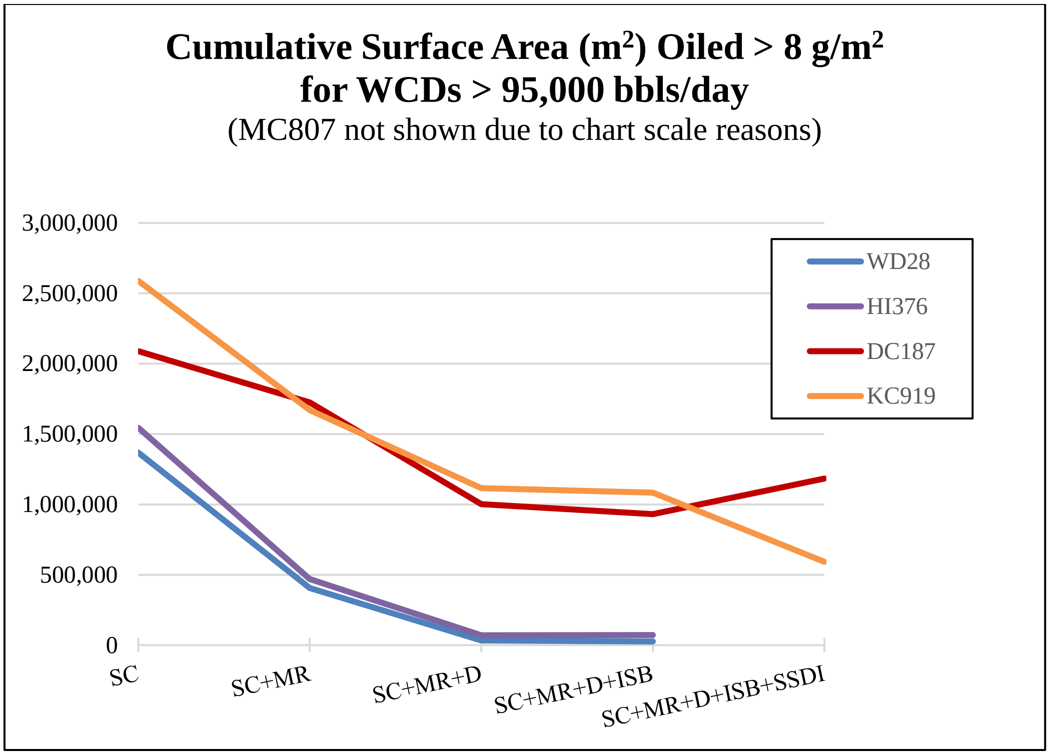

Figure ES 4: Effectiveness of Multiple Response Options for Cumulative Surface Area Oiled, WD28, HIA376, DC187, and KC919

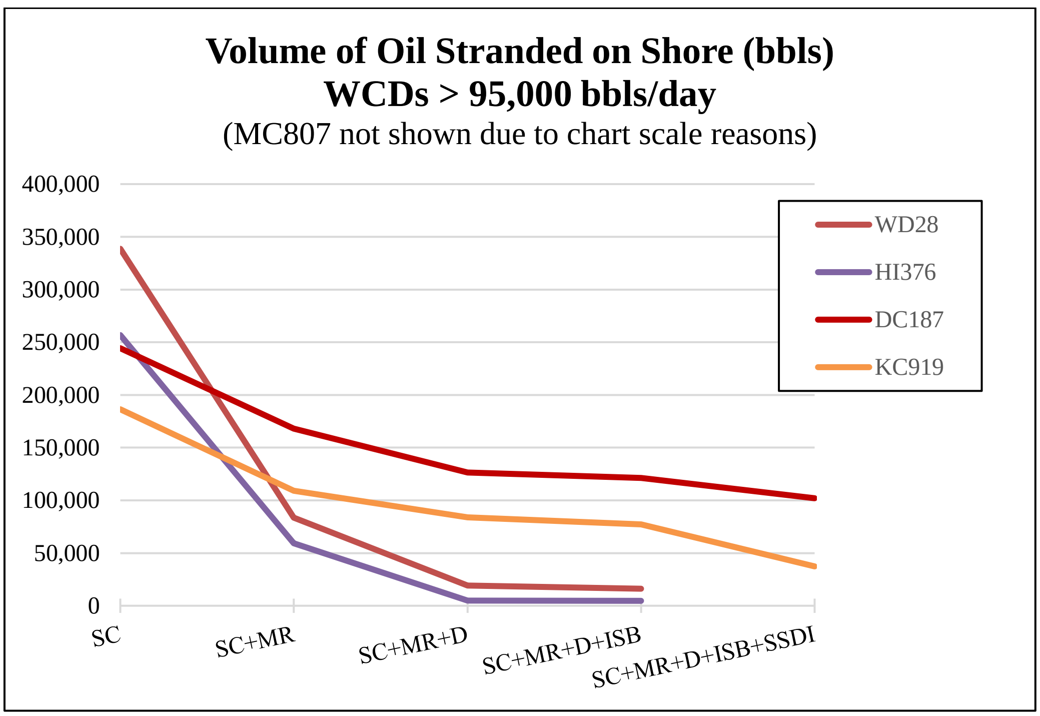

Figure ES 5: Effectiveness of Multiple Response Options for Oil Stranded on Shore, WD28, HIA376, DC187, and KC919

Simulated response countermeasures were applied to the spilled oil in the following order: (1) in situ burning, (2) mechanical recovery, and (3) dispersants. The order in which response countermeasures was applied likely had a significant effect on their relative contribution to the total oil removal and recovery. Due to the limited scale of in situ burning capabilities simulated in the modeling, the reductions due to in situ burning are small in size relative to the other countermeasures. Simulated weather conditions also had differing impacts on the effectiveness of various countermeasures.

The SIMAP modeling also showed some interesting trends for response countermeasures in the Arctic (see Figure ES 6 and Figure ES 7). For the late-season simulations in both the Chukchi, Posey 6912 (P6912) and Beaufort Sea, Flaxman Island 6610 (FI6610) scenarios, mechanical recovery and surface dispersants had modest reductions in surface and shoreline oiling. However, for the P6912 scenario, which was largely an offshore event with much more oiling occurring on the water's surface than on shoreline, subsurface dispersant application provided substantial reduction of surface oiling. Similarly, in the FI6610, which had high levels of shoreline oiling due to its close proximity to land, the use of subsurface dispersants significantly reduced the amount of oil standing on the shorelines.

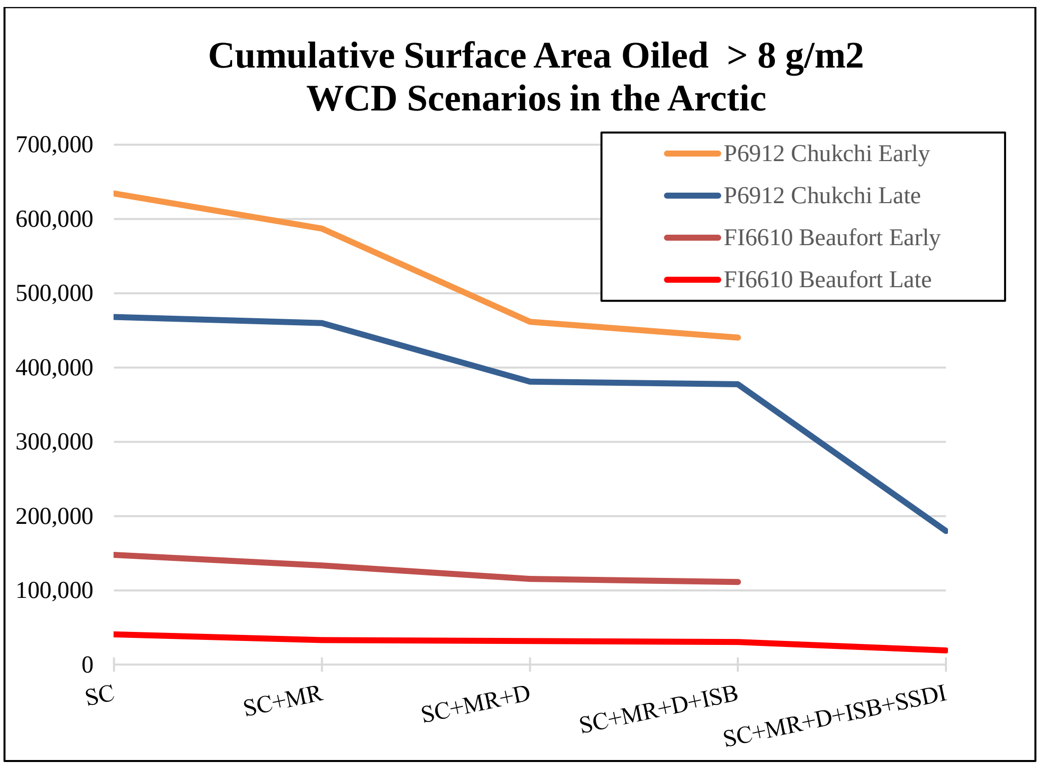

Figure ES 6: Effectiveness of Multiple Response Options for Surface Area Oiled, Arctic Scenarios

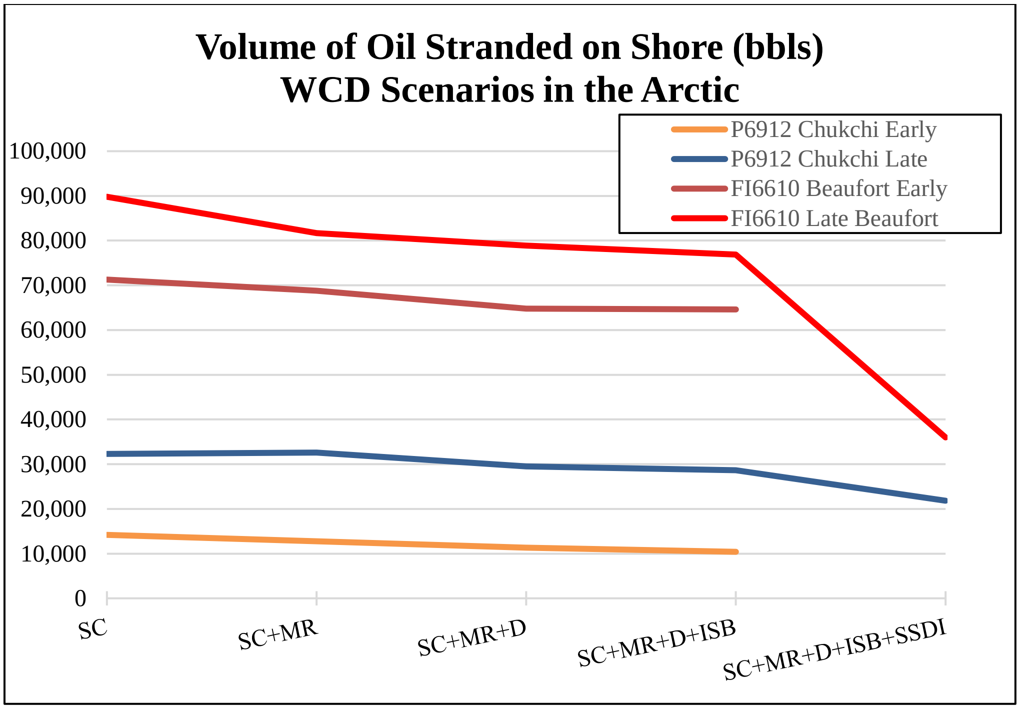

Figure ES 7: Effectiveness of Multiple Response Options for Oil Stranded on Shore, Arctic Scenarios

Resource Readiness and Mobilization Times. The use of time-related mobilization factors in calculating the response times for equipment requirements provides incentives for OSROs to have their equipment in a higher state of readiness. These time factors should differentiate whether response equipment is owned or subcontracted by a given OSRO, and whether the equipment is solely dedicated to the purposes of oil spill response, or is used in other commercial activities and would need to be recalled from other activities before it could be deployed to a spill. The time factors should also take into account whether equipment operators are available on site (i.e., where the response equipment is stored) or are "on-call" and must be recalled to the equipment deployment location. These mobilization factors, when added to transportation times necessary for equipment to travel from their staging sites to the spill site, provide for a realistic assessment of their ability to arrive on scene. Table ES 5 illustrates the relationship between the equipment and associated personnel readiness factors and mobilization times.

Table ES 5: Resource Readiness/Mobilization Times in Hours

Resource Status	Additional Mobilization Times (hrs)	
	For On-Site Personnel	For On-Call Personnel
Owned and Dedicated	1.0	2.0
Contracted and Dedicated	1.5	2.5
Owned, not Dedicated	2.5	3.5
Contracted, not Dedicated	3.0	4.0
Source: USCG, 2013, Guidelines for the U.S. Coast Guard Oil Spill Removal Organization Classification Program		

Response Equipment Requirements and Response Times. Recommendations were developed for equipment levels and response times based on the overall results of the analyses contained within this study, including results of the Deepwater Horizon oil spill response (Volume II, Section 3.0), the Geographical Analyses of the Gulf of Mexico, Pacific, and Arctic OCS Region WCD Volumes from Volume I of this study (Volume I, Sections 3.1, 4.1, and 5.1), the Market Research of Available Response Equipment (Volume II, Section 1.7), and the Oil Spill Response Countermeasures Modeling Analysis (Volume II, Section 2.0), and National Oil Spill Response Regulations Review (Volume II, Section 4.0).

It was determined that response times should be based upon distance from shore and WCD volumes. The ranges of distances from shore and WCD volumes in the three OCS Regions were studied to generate broad categories of distance from shore and WCD volume to assign response times. The model results showed that there is not a consistent relationship among the oil discharge volume, the cumulative oil removal potential of the equipment deployed to the site, and the actual amount of oil removed. The modeling results indicate that oil removal rates appear to be closely related to the environmental conditions (e.g., wind and waves) during the countermeasure period, the subsequent change in in the characteristics of the floating oil, and the capabilities of the removal equipment to deal with the oil characteristics encountered. Overall, the model results suggest that the removal potential of the combined response countermeasures must be significantly greater than the volume of the oil discharged in order to achieve significant oil removal levels in these large WCD events. The vast resources deployed and limited results achieved during the Deepwater Horizon spill also support this conclusion. Therefore, the planning thresholds presented in in Table ES 6 through
Table ES 15 were developed for the various countermeasures based on the following three principles:

1. The combined levels for mechanical recovery and dispersant removal capability required for each WCD category should be substantially greater than the WCD planning volume.
2. Response times should be achievable from shore-based depots that can accommodate the vessels, equipment, and crews that will be necessary. It is unreasonable (and likely economically impossible) to pre-position high-capacity OSRO assets offshore in the vicinity of OCS facilities.
3. Response times should be comparable and consistent across OCS Regions as much as possible; however, challenges associated with each region may require region-specific requirements in some cases.

Because there is a diminishing return on requiring and deploying more equipment, and a significant economic cost to maintaining large caches of equipment, this study is recommending sustainable capped limits for the amounts of equipment (and associated trained personnel) that should be contracted in advance and maintained in a high readiness status.

Mechanical Recovery. BSEE should require plan holders to have access to, through ownership or contract, mechanical recovery resources that can arrive in the following pre-established quantities and response times at the site of the discharge. The arrival times and quantities of ERSP are shown in Table ES 6 through Table ES 9, which are organized into categories based upon facility maximum daily discharge flowrate, adjusted for oil weathering through oil spill modeling (otherwise referred to as a planning volume), and distance from the closest shorelines.

Table ES 6: Recommended Mechanical Recovery Response Times for WCDs <15,000 bbl/day

WCD Daily Flowrate Planning Volume <15,000 bbl/day				
Response Time (hrs)	ERSP Required (bbl/day)			
	0-20 miles from shore	20 -100 miles from shore	100-200 miles from shore	200+ miles from shore
12	10,000			
18	25,000	15,000	10,000	
24	50,000	30,000	25,000	15,000
48		50,000	50,000	50,000
96				

Table ES 7: Recommended Mechanical Recovery Response Times for WCDs 15,000 to 50,000 bbl/day

WCD Daily Flowrate Planning Volume between 15,000 to 50,000 bbl/day				
Response Times (hrs)	ERSP Required (bbl/day)			
	0-20 miles from shore	20-100 miles from shore	100-200 miles from shore	200+ miles from shore
12	25,000			
18	35,000	25,000	15,000	
24	50,000	35,000	30,000	25,000
48	150,000	100,000	75,000	50,000
96		150,000	150,000	150,000

Table ES 8: Recommended Mechanical Recovery Response Times for WCDs from >50,000 to 100,000 bbl/day

WCD Daily Flowrate Planning Volume between 50,000 to 100,000 bbl/day				
Response Times (hrs)	ERSP Required (bbl/day)			
	0-20 miles from shore	20-100 miles from shore	100-200 miles from shore	200+ miles from shore
12	25,000			
18	50,000	30,000	15,000	
24	75,000	50,000	35,000	25,000
48	200,000	150,000	125,000	100,000
96	250,000	250,000	250,000	250,000

Table ES 9: Recommended Mechanical Recovery Response Times for WCDs >100,000 bbl/day

WCD Daily Flowrate Planning Volume >100,000 bbl/day				
Response Times (hrs)	ERSP Required (bbl/day)			
	0-20 miles from shore	20-100 miles from shore	100-200 miles from shore	200+ miles from shore
12	25,000			
18	50,000	35,000	25,000	
24	75,000	50,000	35,000	25,000
48	250,000	200,000	150,000	125,000
96	300,000	300,000	300,000	300,000

In Situ Burning. BSEE should allow plan holders to substitute in situ burning capabilities for some of their required mechanical recovery capacity, up to a prescribed percentage of the total oil removal target. It is recommended that facilities more than 20 miles offshore should be allowed to offset up to 20% of the required ERSP mechanical capabilities with in situ burning. Facilities within 20 miles of shore should be allowed to offset up to 10% of the required ERSP mechanical recovery capabilities with in situ burning. The reduced percentage closer to shore is reflective of limitations that may be put on large-scale burning operations as the operations move closer to shoreline communities and their population centers. Due to the limitations placed on in situ burning in the southern California, BSEE should not allow for an offset of mechanical recovery ERSP requirements using in situ burning equipment in this region.

BSEE should require plan holders to use the Estimated Burn System Potential (EBSP) Calculator to estimate the removal capability of all in situ burning equipment listed in their OSRPs. Plan holders who offset a portion of their ERSP requirements with in situ burning capabilities in their OSRP should also include the other components of a the system that are necessary to conduct in situ burning operations, including support from aerial spill tracking and surveillance, a means of ignition, vessels to tow fire booms, equipment and trained personnel for air monitoring, and the ability to collect burn residue.

Surface Applied Dispersants. Due to the significant differences in the WCD profiles and supporting OSRO infrastructure present in each OCS Region for dispersants, it is recommended that BSEE establish distinct requirements for surface applied dispersant capabilities that are tailored to each OCS Region. As such, BSEE should establish dispersant application capability requirements for each of the OCS Regions, as shown in Tables ES 10 through ES 14. These requirements are for the first 36 hours of an incident; however, for continuous releases, the EDSP capability requirements for the 36-hour response time would be required to be available for each following day of the response until the discharge is secured.

Surface-applied dispersant stockpiles should be immediately available to sustain the response for the first 14 days of the response based on an offshore facility's dispersant capability requirements as outlined in the Tables ES 10 through ES 14, or until the source of the spill can be secured based on an optimal source control timeline, whichever is greater. Plan holders should have arrangements in place to sustain surface-applied dispersant capabilities through either existing stockpiles or through replenishment by a dispersant manufacturer until the source can be secured in accordance with a suboptimal source control timeline.

Table ES 10: Recommended Surface Dispersants Response Times for WCDs <50,000 bbl/day in the Gulf of Mexico OCS Region

WCD Daily Flowrate Planning Volume < 50,000 bbl/day			
Response Time for EDSP (hrs)	EDSP (bbl/day oil treated using a 1:20 DOR)		
	0-20 miles from shore	20-150 miles from shore	150+ miles from shore
12	10,000	7500	5000
36	15,000	12,500	10,000

Table ES 11: Recommended Surface Dispersants Response Times for WCDs ≥50,000 bbl/day in the Gulf of Mexico OCS Region

WCD Daily Flowrate Planning Volume ≥ 50,000 bbl/day			
Response Time for EDSP (hrs)	EDSP (bbl/day oil treated using a 1:20 DOR)		
	0-20 miles from shore	20-150 miles from shore	150+ miles from shore
12	20,000	15,000	10,000
36	35,000	25,000	15,000

Table ES 12: Recommended Surface Dispersants Response Times for WCDs <15,000 bbl/day in the Pacific OCS Region

WCD Daily Flowrate Planning Volume < 15,000 bbl/day	
Response Time for EDSP (hrs)	EDSP (bbl/day oil treated using a 1:20 DOR)
12	4000
36	10,000

Table ES 13: Recommended Surface Dispersants Response Times for WCDs ≥15,000 bbl/day in the Pacific OCS Region

WCD Daily Flowrate Planning Volume ≥ 15,000 bbl/day	
Response Time for EDSP (hrs)	EDSP (bbl/day oil treated using a 1:20 DOR)
12	10,000
36	15,000

Table ES14: Recommended Surface Dispersants Response Time for the Arctic OCS Region

Response Time for EDSP (hrs)	EDSP (bbl/day oil treated using a 1:20 DOR)
36	10,000

Subsurface Dispersant Injection (SSDI). The use of SSDI has been increasingly seen by response experts as a powerful response option, and the modeling results of this study support this conclusion. However, the simultaneous use of aerial surface dispersants and subsurface dispersants has the potential to rapidly deplete dispersant stockpiles during a large WCD event. BSEE should require plan holders who list SSDI as a response capability in their OSRP to have immediately available existing dispersant stockpiles sufficient to sustain surface-applied dispersant capabilities as required for their facility in Tables ES 10 through ES 14, until the application of subsea dispersants can be commenced. These plan holders must also have access to dispersant stockpiles to sustain simultaneous surface-applied and subsurface dispersant applications in accordance with the amounts specified in Table ES 15 once subsea dispersant operations are commenced. Plan holders must make arrangements for access to sufficient dispersant stockpiles to sustain simultaneous surface-applied and subsea dispersant operations until the well is secured in accordance with their suboptimal temporary source control (i.e., well capping) timeline. Stockpile arrangements for simultaneous application operations may be met through both existing stockpiles and arrangements for replenishment by dispersant manufacturers. Existing stockpiles should be immediately available in quantities sufficient to sustain simultaneous surface and subsea application capabilities outlined in Table ES 15 for a minimum of 14 days, or the time necessary to install a temporary source control measure such as a capping stack on a suboptimal timeline, whichever is less.

Table ES 15: Dispersant Stockpile Planning Requirements for Simultaneous Surface and Subsurface Application

Dispersant Application Method	WCD Daily Flowrate <50,000 bbl/day		WCD Daily Flowrate ≥50,000 bbl/day	
	Dispersant (gal)	EDSP (bbl/day)	Dispersant (gal)	EDSP (bbl/day)
Surface-Applied at 1:20 DOR	10,000	4,750	28,400	13,525
Subsurface Injection at 1:100 DOR	7,200	17,000	21,600	51,425
Daily Dispersant Stockpile Amounts	**17,200**	**21,750**	**50,000**	**77,625**

1.0 INTRODUCTION

The Bureau of Safety and Environmental Enforcement (BSEE) Oil Spill Preparedness Division (OSPD) is responsible for ensuring that the U.S. offshore oil industry has the proper regulations in place for planning, preparedness, and response to worst case discharge (WCD) oil spills from offshore oil facilities. This report investigates hypothetical oil spill response efforts to offshore WCD scenarios using a computer model that simulates the fate, transport, and removal of spilled oil using a variety of response methods. The report also features a case study of the Deepwater Horizon oil spill, the largest offshore oil spill in U.S. history, a review of U.S. government planning documents for oil spill response, and a literature review of nine national oil spill response regulatory regimes. The best practices and lessons learned from these modeling, case study, and literature review studies are summarized as a comprehensive series of recommendations to BSEE as the Bureau considers whether to update regulations for Oil Spill Response Plans (OSRP) for U.S. Outer Continental Shelf (OCS) oil facilities.

This study investigated and simulated major oil spill response methods and equipment used worldwide which are mechanical recovery, in situ burning, surface dispersant application, subsurface dispersant application, and source control.

Mechanical recovery is the process of recovering spilled oil floating on the water surface using devices called skimmers. A variety of skimmer designs exist, all of which mechanically collect oil and oil emulsions from the water's surface and pump the recovered liquid into storage tanks. Small skimming devices can be hand-held and can be used to recover spilled oil from nearshore areas such as beaches and marshes. Larger skimming devices are typically mounted on small to medium sized vessels and are used in conjunction with a buoyant boom that is towed over the water surface to collect oil, thereby facilitating mechanical recovery. Mechanical recovery vessels can store limited volumes of recovered liquid, and therefore must transfer stored liquid at regular intervals during oil spill response operations.

In situ burning is the process of igniting and burning oil on the water's surface. To achieve this, responders collect surface oil with floating, fire resistant boom, called "fire boom," as oil must be above a threshold thickness or concentration to burn effectively. In situ burning can remove large quantities of oil from the water surface relatively easily, but produce large plumes of smoke that are often undesirable in nearshore areas.

Dispersants are a mixture of surfactants that chemically break oil into small droplets. After the oil is broken into droplets, it is more readily degraded by biological (microbial) and physical processes. The application of dispersants does not remove oil from the water's surface or from the water column. Rather, dispersants alter the transport and fate of spilled oil in an attempt to minimize environmental and socioeconomic impacts. Dispersants are often applied or sprayed onto surface oil from aircraft, but can also be applied from vessels. Dispersants can also be applied underwater, at the source of a subsurface blowout. Dispersants applied to the subsurface have the same chemical makeup as surface-applied dispersants, and are injected into subsurface oil plumes using hoses and tubes.

Source control is the process of stopping or plugging a subsurface well blowout at the wellhead. A variety of devices can be used for source control including well caps or 'capping stacks', containment domes, or cap and flow systems. These are all large devices that are lowered to the wellhead during a blowout and physically block the flow of oil to the environment.

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PART I: METHODS

The methodologies and analyses throughout Volumes I and II are interconnected and part of an integrated study process that begins with an examination of the worst case discharges within each OCS region, and ends with recommendations for the response equipment capabilities that will be necessary to respond to these spills. The following diagram maps out the flow and processes contained within the overall study, and cross-references these processes with the appropriate sections of this Volume II report.

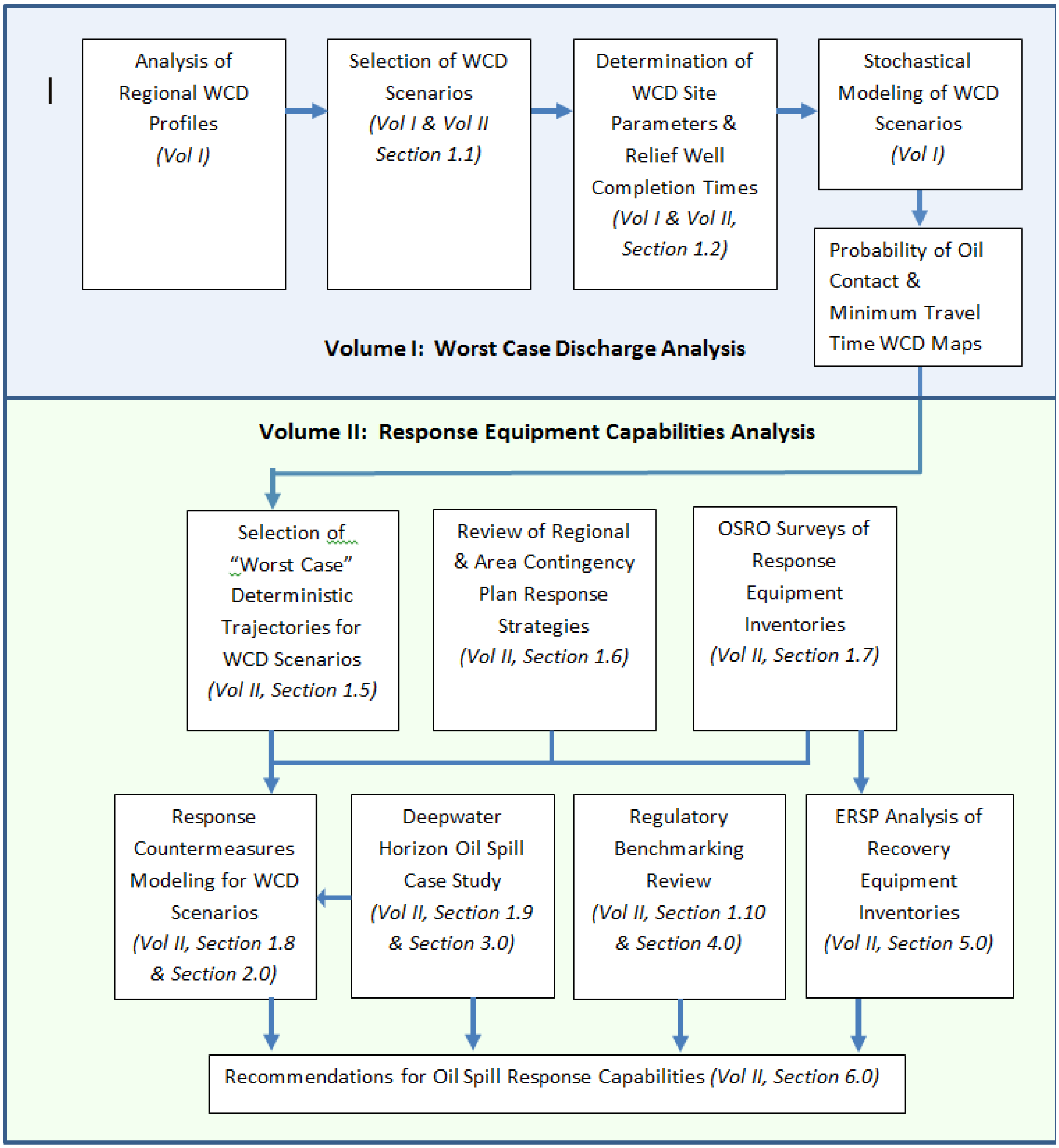

Figure 1: Flow Diagram of the Study Methodology for the OSRP Equipment Capabilities Review

1.1 SELECTION OF WELL LOCATIONS

Nine well locations were selected in order to model the responses to a representative set of WCD events (Figure 2, Figure 3, and Figure 4). Six wells are in the Gulf of Mexico OCS Region, one is in the Pacific OCS Region, and two are in the Arctic OCS Region. Each well site in the Arctic had two seasonal scenarios that were modeled (one spill scenario initiated early during the ice-free season in and one initiated later that would involve ice at some point after the spill occurred).

The scenarios were designed to investigate potential oil spill trajectories and response efforts among a variety of distances from shore, geographic locations, oil types, depths, and discharge volumes. While the WCD scenario locations are often near actual exploration or production wells, the locations and discharge parameters of the scenarios were adjusted to evaluate a range of oil discharges and spill response options.

Each simulated well was located in the center of its respective lease block. Distance from shore and depth to seafloor were calculated from GIS data. Gas-to-oil ratio (GOR) and oil type were selected based on characterized oil types most likely encountered at the well locations. Major model inputs for the nine WCD locations are shown in Table 1.

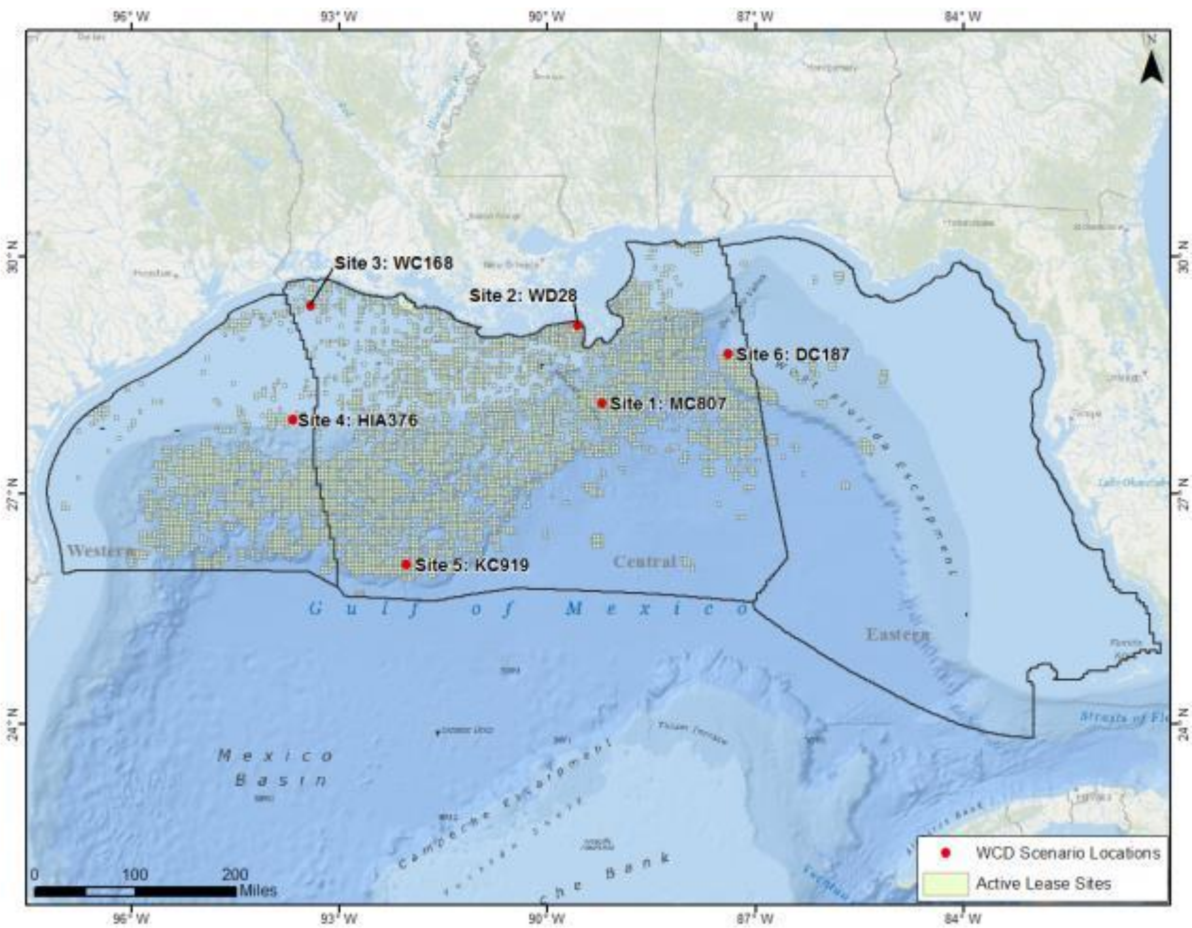

Figure 2: Gulf of Mexico OCS Region Locations for Worst Case Discharge Modeling Analysis

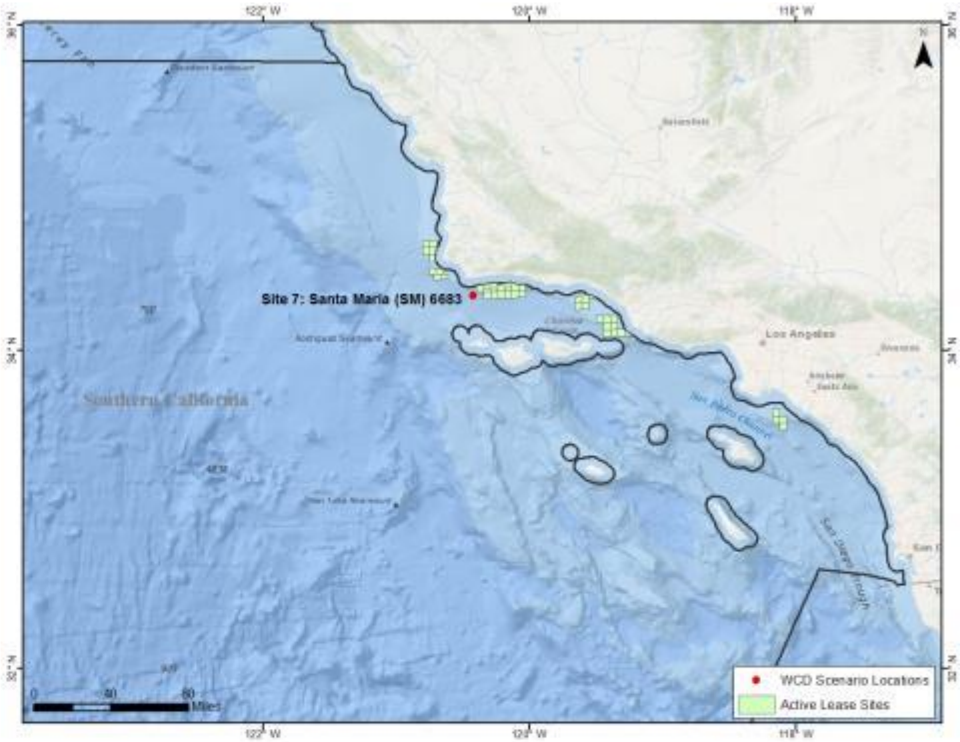

Figure 3: Pacific OCS Region Location for Worst Case Discharge Modeling Analysis

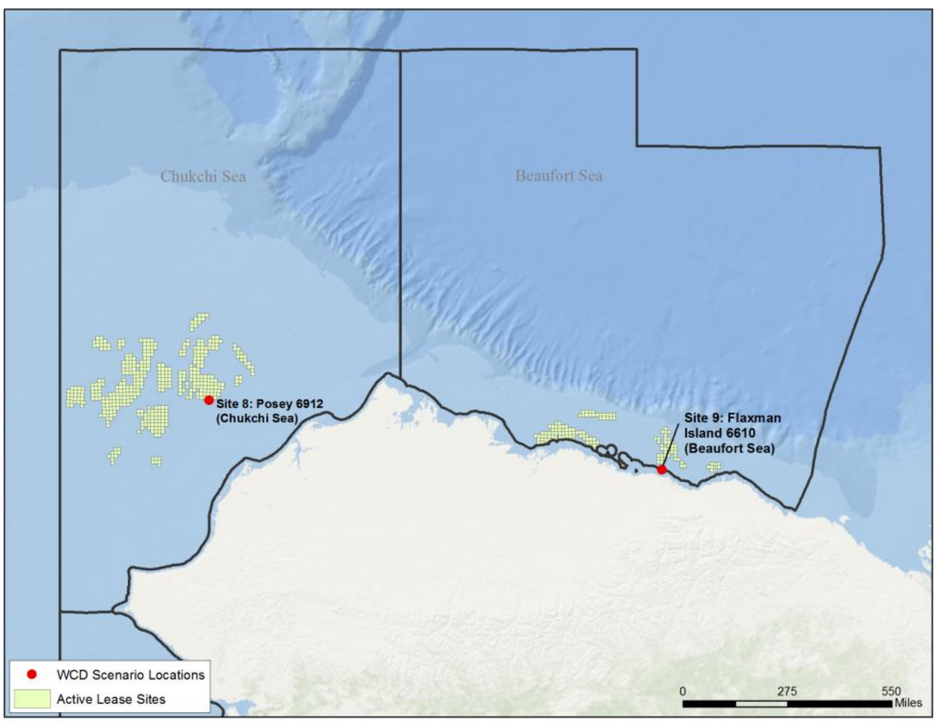

Figure 4: Locations of Arctic OCS Region Scenarios for Worst Case Discharge Analysis

Table 1: WCD Model Scenario Locations and Oil Characteristics

Scenario Number[a]	Planning Area	Lease Block	Latitude/ Longitude	Depth to Seafloor (ft.)	Distance from Shore (NM)	Gas/Oil Ratio (scf/STB)[b]	Oil Name/°API[c]
1	Central GOM	Mississippi Canyon (MC807)	28.157842 -89.2156	3,030	46	894	South Louisiana Crude 34.5
2	Central GOM	West Delta (WD28)	29.13848 -89.563623	35	5.6	588	South Louisiana Crude 34.5
3	Central GOM	West Cameron (WC168)	29.388171 -93.406424	42	25	3,448	South Louisiana Condensate 57.5
4	Western GOM	High Island East South Extension (HIA376)	27.943209 -93.667917	334	112	1,220	South Louisiana Crude 34.5
5	Central GOM	Keathley Canyon (KC919)	26.080171 -92.037507	6,940	217	893	South Louisiana Crude 34.5
6	Central GOM	DeSoto Canyon (DC187)	28.785337 -87.39878	4,490	101	654	South Louisiana Crude 34.5
7	Southern California	Santa Maria 6683	34.33732 -120.4209	1,073	8	3,000	Point Arguello Light Crude 30.3
8, 9	Chukchi Sea – Early and Late Season	Posey 6912	71.102403 -163.2819	150	60	800	Alaskan North Slope Crude 30.9
10, 11	Beaufort Sea – Early and Late Season	Flaxman Island 6610	70.227 -146.0186	120	1-4	900	Prudhoe Bay Crude Low Volatile 24.8

[a] For each of the two Arctic locations, there are two seasonal scenarios – one early and one late season, the latter of which may involve ice.
[b] Standard cubic feet per stock tank barrel.
[c] An alternative measure of density of oil; the higher the °API, the lighter the oil.

1.2 Selection of Worst Case Discharge Volume

Actual well blowouts have variable discharge rates over the course of the incident due to the properties of the hydrocarbon formations and the surrounding geology, as well as actions to secure the well and bring it under control. Flow rates were not varied for the WCDs modeled in this study. For each scenario, discharge flow rates were selected based on WCD flow rates reported in the Oil Spill Response Plans (OSRP) of comparable actual wells in the OCS region. Discharge volumes were calculated by multiplying the flow rate (volume/time) by discharge period (time).

The duration of each simulated discharge was based on the assumption that a relief well would ultimately stop the flow oil to the environment. BSEE experts estimated the number of days required to transport a relief well rig to the specific WCD location and drill a relief well to stop the discharge of oil.

Periods to achieve well control by a drilling relief well ranged from 28 days for Scenario 8/9 (Posey 6912) in the Arctic OCS Region to 182 days for Scenario 1 (MC807) in the Gulf of Mexico OCS Region (see Table 2). Model simulations were run for 45 days after the discharge of oil was stopped. This was done to investigate the fate, transport, and weathering of oil persisting in the environment after the wells are brought under control, and to investigate the efficacy of other response options.

Table 2: Discharge Parameters for Study Baseline WCD Scenarios

Scenario Number	Planning Area	Lease Block	WCD Flow Rate (bbl/day)	Flow Duration Relief Well Only (days)	Total WCD Volume (bbl)
1	Central GOM	MC807	449,000	182	81,718,000
2	Central GOM	WD28	97,000	37	3,589,000
3	Central GOM	WC168	26,400	76	2,006,400
4	Western GOM	HIA376	77,000	50	3,850,000
5	Central GOM	KC919	252,000	120	30,240,000
6	Central GOM	DC187	241,000	106	25,546,000
7	Southern California	Santa Maria 6683	5,200	170	884,000
8,9	Chukchi Sea (Early and Late Season)	Posey 6912	25,000	28	700,000
10,11	Beaufort Sea (Early and Late Season)	Flaxman Island 6610	16,000	30	480,000

1.3 Stochastic Trajectory Modeling

Actual oil spill trajectories are a function of oil properties and the environmental conditions over the duration of a spill. Wind, currents, waves, water temperature, air temperature, presence of sea ice, and oil weathering vary over time, resulting in different oil spill trajectories. In Volume I, stochastic modeling was performed with SIMAP™ to determine the probability of the discharged oil coming into contact with shorelines. The stochastic modeling is a statistical analysis of results generated from many different individual trajectories of the same spill event, with each trajectory having a different spill start time selected at random from a relatively long-term window. The random start time allows for the same type of spill to be analyzed under varying conditions. To reproduce the natural variability of winds, the model uses historical wind data which vary spatially (multiple points) and temporally (changing with time). The hydrodynamic and wind data hindcast data sources used for each study region are described in the Volume I report. The stochastic analysis provided two types of information: 1) probability of various areas experiencing oil exposure, and 2) the shortest time required for oil to reach any point within the areas predicted to be oiled.[9]

1.4 Model Assumptions for the Display of Spilled Oil

SIMAP model results show areas exposed to oil over a prescribed minimum threshold value. The thresholds are usually selected based on environmental impact criteria or oil spill response capabilities. For this study, the thresholds in Table 3 were assessed in the stochastic analysis.

[9] These two endpoints are used to support evaluation of OSRPs.

Table 3: Modeling Thresholds for Water Surface and Shoreline Oiling

Stochastic Threshold Type	Threshold (Mass/Unit Area)	Threshold (Thickness)	Rationale	Visual Appearance	References
Oil on Water Surface	8.0 g/m^2	8.0 µm, 0.08 mm, 0.0003 in	Minimum thickness for which response equipment can skim/remove oil from the surface, surface dispersants are effectively applied, or oil can be boomed/collected for in situ burning.	Fresh oil at this thickness corresponds to a slick being a dark brown or metallic sheen.	NOAA 2010
Shoreline Oil	1.0 g/m^2	1.0 µm, 0.001 mm, 3.94 x 10^{-5} in	This is the threshold for potential effects on socioeconomic resource uses, as this amount of oil may conservatively trigger the need for shoreline cleanup on amenity beaches, and impact shoreline recreation and tourism.	May appear as a coat, patches or scattered tar	French-McCay et al. 2011; French McCay et al. 2012

1.5 Selection of Worst Case Trajectories for Oil Spill Response Modeling

Following the completion of the SIMAP stochastic modeling involving 100 individual trajectories for each of the scenarios at the nine well locations, the "worst case" trajectory from a set of 100 was selected and evaluated in terms of how various oil spill response countermeasures can reduce the impacts of this "worst case" oil spill trajectory. "Worst case" is placed in quotes because only the 95th percentile[10] worst trajectory in terms of shoreline oiling by length was selected for evaluation. The results of these individual trajectory (i.e., deterministic) simulations provide a time history of oil fate and weathering over the duration of the spill, expressed as the percentage of spilled oil on the water surface, on the shoreline, evaporated, entrained in the water column, and biodegraded[11] or in the sediments.

1.6 Assessment of Strategies in Regional and Area Contingency Plans

The National Contingency Plan (NCP) is the U.S. government's national response system for responding to spills of oil and hazardous substances. The NCP features a hierarchical structure in which the responsibility for response planning is delegated to officials at the regional, state, and local levels. As a result, the Regional Contingency Plans (RCP) and Area Contingency Plans (ACP) are the primary planning documents that contain the actual strategies and tactics for responding to spills of oil and hazardous substances. RCPs are developed by Regional Response Teams (RRTs), and ACPs are developed by local Area Committees. Some Area Committees have also chosen to develop Geographic Response Plans (GRP), which are even more site-specific than ACPs, and often feature information about shoreline protection and cleanup equipment and strategies. The ACPs and RCPs, whose planning jurisdictions would be affected by the WCD scenarios, were reviewed for response strategies and tactics, to define the oil spill response parameters in the modelled scenarios. The plans reviewed for this study are shown in Table 4, and a more detailed summary of the RCPs and ACPs are contained in Appendix A.

[10] The *true* worst case trajectory (i.e., 100th percentile worst) was not used because the 100th percentile of any statistical distribution is highly sensitive to the number of observations in the distribution. The 95th percentile is far more stable and, therefore, more statistically appropriate for this study.

[11] Note that the SIMAP model simulates primary biodegradation and does not include photooxidation by UV light at the surface (Li and French McCay, in prep).

Table 4: RCPs and ACP Reviewed for Response Strategies and Tactics

Plan Name	Type of Plan	OCS Region
Region 4 Regional Contingency Plan	**RCP**	**Gulf of Mexico**
West Central Florida Area Contingency Plan	ACP	Gulf of Mexico
Alabama, Mississippi, Northwest Florida Area Contingency Plan	ACP	Gulf of Mexico
Southeast Florida Area Contingency Plan	ACP	Gulf of Mexico
Northeast and Eastern Central Florida Area Contingency Plan	ACP	Gulf of Mexico
Florida Keys Area Contingency Plan	ACP	Gulf of Mexico
Region 6 Regional Contingency Plan	**RCP**	**Gulf of Mexico**
South Texas Coastal Zone Area Contingency Plan	ACP	Gulf of Mexico
Southeast Texas and Southwest Louisiana Area Contingency Plan	ACP	Gulf of Mexico
New Orleans Area Contingency Plan	ACP	Gulf of Mexico
Central Texas Coastal Area Contingency Plan	ACP	Gulf of Mexico
Southeast Louisiana Area Contingency Plan	ACP	Gulf of Mexico
Region 9 Regional Contingency Plan	**RCP**	**Pacific**
Los Angeles/Long Beach Oil Spill Contingency Plan	ACP	Pacific
San Diego Area Contingency Plan	ACP	Pacific
Alaska Unified Plan: Federal/State Preparedness Plan for Response to Oil and Hazardous Substance Discharges/Releases	**RCP**	**Arctic**
North Slope Subarea Contingency Plan	ACP	Arctic
Northwest Arctic Subarea Contingency Plan	ACP	Arctic

1.7 Market Research of Available Response Equipment

Surveys of major Oil Spill Removal Organizations (OSRO) and other private owners of response equipment were conducted to determine the types, quantities, and mobilization times for existing oil spill response equipment in the three OCS regions studied.

1.7.1 Calculating Removal and Recovery Capacity and Mobilization Times

This information was then used to generate model inputs for the oil spill response WCD scenarios in SIMAP. The surveys were used to collect information on in situ burning, mechanical recovery, surface and subsurface dispersant application, and source control equipment. Four OSROs, one operator, and two source control companies provided information for this study.

- **For in situ burning equipment,** OSROs provided information on their available assets, and oil removal rates were calculated using the National Atmospheric and Oceanic Administration (NOAA) In Situ Burn Calculator.[12] The calculated in situ burn oil removal rates were then used as inputs for applicable WCD response model scenarios. In situ burning was not used in the Pacific OCS Region scenario because in situ burning is not pre-authorized in the area surrounding the WCD scenario location.
- **For surface-applied dispersants,** OSROs provided information on the types, quantities, and mobilization times for dispersant application aircraft. OSROs also provided information on the

[12] The NOAA In Situ Burn Calculator can be downloaded at http://response.restoration.noaa.gov/spilltools

size of available stockpiles of dispersants, and the rate at which additional dispersants could be acquired if current stockpiles are exhausted. The NOAA Dispersant Mission Planner 2[13] was then used to calculate dispersant application rates for the WCD response model scenarios.

- **For subsurface applied dispersants,** non-OSRO offshore support companies provided information including planned dispersant application rates, quantities of dispersant stockpiles, and possible competition between surface-applied dispersant operations and subsurface dispersant operations for the same dispersant stockpiles.
- **For mechanical recover**y, OSROs were asked to provide the types, quantities, and mobilization factors that would be employed by the OSROs when responding to each of the hypothetical WCD model scenarios. In some cases, information on OSRO equipment was acquired from publically available online databases at the direction of OSROs. Equipment was categorized based on the marine environment in which it would operate optimally: shoreline, nearshore, or offshore/open ocean. This categorization was done based upon expert opinion from OSROs and manufacturer-nameplate pump rates. Generally, equipment with pump rates of less than 200 gallons per minutes was considered shoreline equipment, equipment with pump rates from 201 g/m to 400 g/m was considered nearshore equipment, and equipment with pump rates above 400 g/m was considered offshore/open ocean equipment. The recovery potential for this equipment was calculated using the Estimated Recovery System Potential (ERSP) calculation, which is discussed in Section 5.0 of this volume. These oil recovery rates were then used as inputs for the WCD response model scenarios.
- **For source control,** the two largest providers of subsea source control equipment were surveyed to identify the location and quantity of well capping devices. The companies were asked to provide reasonable estimates for deployment and mobilization times required to successfully install well capping devices for the MC807, KC919, and DC187 model scenarios. These three model scenarios were the only locations where well capping was simulated (the other WCD scenarios were simulated with other source control methods including top kill and surface kill). BSEE subject matter experts reviewed and adjusted, as needed, the well capping timing estimates generated by the surveyed companies and decided upon final well capping times for MC807, KC919, and DC187. BSEE experts generated estimates of optimal and suboptimal time frames for well capping. The optimal time frame for source control was defined as the shortest period of time required to apply source control given minor delays such as adverse weather conditions, government agency approvals, subsurface debris removal near the wellhead. Optimal does not mean the absolute shortest time achievable under any circumstances. The suboptimal source control time frame includes delays that exceed expectations that include adverse weather, delays in the requisition of contracted equipment, delays in government approvals, and excessive debris removals around the wellhead, difficulties in securing the source control around the wellhead, mechanical failures, and excessive volatile organic compounds (VOCs) at the surface above the wellhead. Suboptimal does not mean the absolute worst case time frame possible. Table 5 shows BSEE estimates for optimal and suboptimal time frames for the model scenarios in which well capping was simulated.

[13] The NOAA Dispersant Mission Planner 2 can be accessed at: http://response.restoration.noaa.gov/oil-and-chemical-spills/oil-spills/response-tools/dispersant-mission-planner-dmp2.html

Table 5: BSEE Estimates of Suboptimal and Optimal Time Frames for Well Capping

Model Scenario	Sub-Optimal Well Capping Time Frame (days)	Optimal Well Capping Time Frame (days)	Modeled Capping Time Frame (days)
Mississippi Canyon 807	60	21	45
Keathley Canyon 919	60	21	45
De Soto Canyon 187	60	21	45
Posey 6912	21	7	14
Flaxman Island 6610	21	7	14

Ultimately, BSEE experts decided to model well capping time frames based on a mid-point between the suboptimal and optimal time frames, however the estimation of optimal and suboptimal time frames was a key step in determining the best well capping time frame for the model scenarios.

1.7.2 Calculating National Recovery Capacity

To understand and evaluate national-level mechanical recovery capacity (in addition to what was needed for WCD scenario model inputs), information was collected from three additional sources:

- OSRO-owned equipment that would not be deployed during a WCD because of insufficient vessel platforms;
- U.S. Coast Guard (USCG) Response Resource Inventory (RII) System[14] data; and
- Western Response Resource List (WRRL)[15] data.

Response capabilities available through the additional OSRO equipment could potentially be used if additional vessels, such as vessels of opportunity (VOO), were available to deploy the equipment. Since the owners of equipment are not listed in the USCG RII, the inventories for MSRC, NRC and Clean Gulf had to be carefully reviewed to ensure that sub-contracted equipment listed in the RRI was not double-counted with the equipment contained in the OSRO surveys when calculating total oil recovery capacities for each OCS region.

Total oil recovery capacity was calculated for each OCS region using the EDRC calculation. BSEE is also considering replacing the EDRC calculation with the Estimated Recovery System Potential (ERSP) calculation, which takes into account specific characteristics of the overall recovery system, including the vessel platform, and may therefore be a more accurate calculation for regulatory and planning purposes. Because the calculation of ERSP requires the inclusion of other characteristics such as temporary storage onboard the vessel platform, ERSP cannot be calculated for individual skimming devices unless it is known what platforms will be used to support the skimming device. Therefore, for this study, when information on mechanical recovery equipment was collected without accompanying information on vessel platform characteristics, generic vessel characteristics were applied to the ERSP calculation to generate an estimate of recovery potential. One set of generic vessel characteristics was used for nearshore equipment (Table 6) and a separate set of vessel characteristics was used for the offshore/open ocean equipment (Table 7). Total ERSP calculations for each OCS region (shown in Table 15, Table 53,

[14] The USCG RRI System can be accessed at https://cgrri.uscg.mil/logon.aspx?ReturnUrl=%2fdefault.aspx
[15] Equipment from the WRRL was used to calculate ERSP and EDRC totals for the Pacific OCS Region only.

and Table 63) are based on the assumption that all available equipment in each OCS region would be deployed in the event of a WCD.

Table 6: Nearshore Vessel Characteristics for Calculation of Total OCS Region ERSP

ERSP Input	Generic Value
Operating period (hrs)	12 hours
Speed (kts)	0.75 kts
Swath (ft)	150 feet
Maximum Total Fluid Recovery Rate (gpm)	Actual gpm between 201 and 400
Throughput Efficiency (%)	75%
Recovery Efficiency (%)	75% for Oleophilic skimmers or 50% for Weir skimmers
On-Board Storage (bbl)	250 bbl
Percent Decant (%)	40%
Decant Pump Rate (gpm)	300 gpm
Rig-Derig Time (min)	30 min
One Way Transit Time (min)	30 min
Discharge Pump Rate (gpm)	300 gpm
Note: Skimmers with gpm less than 200 were assigned to shoreline. Skimmers with gpm between 201 and 400 were assigned to Nearshore. Skimmers with gpm over 400 were assigned to Offshore/Open Ocean. Since the ERSP Calculator does not address static skimmers, EDRC was used to provide the recovery rates for shoreline equipment totals in each Region.	

Table 7: Offshore Vessel Characteristics for Calculation of Total OCS Region ERSP

ERSP Input	Generic Value
Operating period (hrs)	12 hours
Speed (kts)	0.75 kts
Swath (ft)	150 feet
Maximum Total Fluid Recovery Rate (gpm)	Actual gpm 400 and over
Throughput Efficiency (%)	75%
Recovery Efficiency (%)	75% for Oleophilic skimmers or 50% for Weir skimmers
On-Board Storage (bbl)	2,000 bbl
Percent Decant (%)	40%
Decant Pump Rate (gpm)	750 gpm
Rig-Derig Time (min)	30 min
One Way Transit Time (min)	30 min
Discharge Pump Rate (gpm)	750 gpm
Note: Skimmers with gpm less than 200 were assigned to shoreline. Skimmers with gpm between 201 and 400 were assigned to Nearshore. Skimmers with gpm over 400 were assigned to Offshore/Open Ocean. Since the ERSP Calculator does not address static skimmers, EDRC was used to provide the recovery rates for shoreline equipment totals in each Region.	

1.8 Response Countermeasures in Oil Spill Response Modeling

The WCD scenarios were modeled using simulated countermeasures to remove or mitigate the spill, including source control, mechanical recovery, surface dispersants, in situ burning, and subsurface dispersants. Each of the WCD scenarios was modeled with five different response simulations, as shown in Table 8. All WCD wells were modeled with SC, SC+MR, and SC+MR+D response scenarios. The SM6683 well was not modeled with SC+MR+D+ISB because in situ burning is not a recommended strategy in the associated RCP/ACP for this scenario site. Only MC807, KC919, DC187, P6912, and FI6610 were modeled with the SC+MR+D+ISB+SubD response scenario. The results of these modeling response modeling simulations are presented in Section 2.0 of this report.

Note that in this study, there is likely an overestimate in the influence of source control in the overall modeling results, as these oil spill scenarios assume a constant rate of discharge. In reality, the discharge rate is likely to decrease as oil is released from the formation, and the pressure decreases; thus, likely resulting in less influence of source control on the overall fate of the oil following its release.

Table 8. List of Response Countermeasures Modeled for Each Scenario Location

Scenario Number	Scenario Name	Source Control (SC)	Source Control+ Mechanical Recovery (SC+MR)	Source Control + Mechanical Recovery + Surface Dispersant (SC+MR+D)	Source Control + Mechanical Recovery + Surface Dispersant + In Situ Burning (SC+MR+D+ISB)	Source Control + Mechanical Recovery + Surface Dispersant + In Situ Burning + Subsurface Dispersant (SC+MR+D+ISB+SubD)
1	MC807	✓	✓	✓	✓	✓
2	WD28	✓	✓	✓	✓	
3	WC168	✓	✓	✓	✓	
4	HIA376	✓	✓	✓	✓	
5	KC919	✓	✓	✓	✓	✓
6	DC187	✓	✓	✓	✓	✓
7	SM6683	✓	✓	✓		
8	P6912 Early	✓	✓	✓	✓	
9	P6912 Late	✓	✓	✓	✓	✓
10	FI6610 Early	✓	✓	✓	✓	
11	FI6610 Late	✓	✓	✓	✓	✓

1.8.1 Application of Response Countermeasures in Oil Spill Response Modeling

Responding to an actual oil spill is a variable and dynamic process of deploying assets where they are most efficient and cause the least conflicts and risk to adjacent response personnel and equipment. The SIMAP model applies response operations to spill scenarios in a predetermined manner. For this modeling study, response operations were applied to spill polygons in this order: (1) in situ burning, (2) mechanical recovery, and (3) surface-applied dispersants. The model's spill polygons are referred to as "divisions," as per the Incident Command System (ICS) operations organization terminology matrix. In the Gulf of Mexico scenarios each scenario was comprised of the following divisions:

- High Volume Recovery Division – High volume mechanical recovery operations were employed beyond a site-specific radius area established around the well for source control.
- In situ Burning Division – In situ burning operations were used in the same geographical area as the high volume mechanical recovery operations a site specific distance away from the source control area.
- Secondary Recovery Division – Secondary mechanical recovery operations were used to remove oil that was not previously removed in the high volume recovery area.
- Nearshore Recovery Division – Nearshore mechanical recovery operations were used to remove oil from the surface of the water before it was washed onto shorelines.
- Dispersant Application Division – Surface applied dispersants were employed in the high volume and secondary recovery geographical areas as appropriate.

The source control areas applied to the Gulf of Mexico scenarios are provided in Table 9.

Table 9. Radius Areas Established Around the Well for Source Control in the Gulf of Mexico Scenarios

Scenario Names	Mechanical Removal Source Control Radius Area (NM)	In Situ Burning and Surface Dispersant Source Control Radius Area N(M)
West Delta (WD28), West Cameron (WC168), High Island (HIA376)	0.5	2.5
Mississippi Canyon (MC807), Keathley Canyon (KC919), De Soto Canyon (DC187)	5	5

Subsurface dispersants, which were applied at the point of discharge in the vicinity of the wellhead, for the Mississippi Canyon (MC807), Keathley Canyon (KC919), De Soto Canyon (DC187) scenarios were not assigned to a geographic response division.

The Pacific SM6683 scenario was comprised of the following divisions:

- High Volume Recovery Division – High volume mechanical recovery operations were employed beyond a 0.6 mile (0.5 nm) radius area established around the well for source control.
- Secondary Recovery Division – Secondary mechanical recovery operations were used to remove oil that was not previously removed in the high volume recovery area.
- Nearshore Recovery Division – Nearshore mechanical recovery operations were used to remove oil from the surface of the water before it was washed onto shorelines.
- Dispersant Application Division – Surface applied dispersants were employed in the high volume and secondary recovery geographical areas beyond a 2.9 mile (2.5 nm) radius area established around the well for source control, as appropriate.

No subsurface dispersants were applied in the Pacific SM6683 scenario.

Each Arctic scenario was comprised of the following divisions:

- High Volume Recovery Division – High volume mechanical recovery operations were employed beyond a 3.5 mile (3 nm) radius area established around the well for source control.
- In situ Burning Division. In situ burning operations were used in the same geographical area as the high volume mechanical recovery operations (3.5 mile [3 nm]) away from the source control area.
- Nearshore Recovery Division – Nearshore mechanical recovery operations were used to remove oil from the surface of the water before it was washed onto shorelines.
- Dispersant Application Division – Surface applied dispersants were employed in the High Volume Recovery Division to 3.5 mile (3 nm) from shore and beyond a 3.5 mile (3 nm) radius area established around the well for source control, as appropriate.

No subsurface dispersants were applied in the early season Arctic scenarios. However, subsurface dispersants were applied for the late season scenarios, but were not assigned to a geographic response division.

1.8.2 Mechanical Removal Assumptions in Oil Spill Response Modeling

The efficiency of mechanical recovery operations are limited by the condition of the oil, particularly its viscosity and thickness on the water surface, as well as environmental conditions that will affect the ability of booms to contain oil for recovery and the effectiveness of the mechanical skimming equipment itself. In the response modeling, limiting thresholds were incorporated into model inputs to simulate the effectiveness of mechanical recovery systems in the field. These limiting factors are summarized in Table 10.

In the modeling simulations, mechanical recovery was assumed to be occurring in the relevant geographic areas, as specified by the "removal polygons" and as stipulated by the equipment efficiencies determined by the ERSP calculator during 12-hour daily operation times, except when the threshold values were exceeded.

Table 10: Factors Limiting Mechanical Recovery System Oil Removal Rates in Modeling

Factor	Equipment Type	Threshold Value		
		GOM	**Pacific**	**Arctic**
Oil Viscosity [a]	Skimmer Group A	15,000 cp	15,000 cp	15,000 cp
	Skimmer Group B	2,000 cp	2,000 cp	2,000 cp
	Skimmer Group C	80 cp	80 cp	80 cp
Winds	Skimmer All Groups	30 kts	30 kts	30 kts
Wave Height [b]	Skimmer All Groups	1.0 to 3.5 ft	1.0 to 3.5 ft	1.0 to 3.5 ft
Current Velocity [c]	Skimmer All Groups	0.7 kts	0.7 kts	0.7 kts
Oil Thickness on Surface	Skimmer All Groups	8.0 µm	8.0 µm	8.0 µm
Daylight Operation Restriction [d]	Skimmer All Groups	12 hours	12 hours	12 hours
Weather Restriction [e]	Skimmer All Groups	21%	21%	62.5%

[a] Based on the viscosity analysis summarized in Table 11.
[b] Wave height restrictions vary by individual equipment specifications. Specific wave height thresholds were input into the SIMAP model by equipment specification. Wave height affects boom and skimmer effectiveness.
[c] Current velocity affects boom and skimmer effectiveness.
[d] Operations are assumed to occur during daylight hours only, which also incorporates restrictions for shift length. Model input is assumed to be 12 hours of daily operation regardless of location. Some mechanical recovery systems with the appropriate remote sensing capabilities were given credit for extended operating periods greater than 12 hours.
[e] Weather restrictions include storm events, fog, precipitation, and other issues that may preclude operations in addition to any wind events. Weather restrictions for GOM and Pacific regions were based on expert inputs. Arctic weather restrictions were based on studies conducted on Arctic operations. Additional 20% of time added for remobilization after demobilization due to weather. Weather restrictions were applied in a way that reduced the oil removal rates for equipment by a corresponding amount for all time steps rather than eliminating a certain percentage of time steps were equipment would not be operable.

Mechanical recovery (skimming) systems are usually most effective on relatively fresh oil. Once emulsification occurs, the oil becomes more viscous (by as much as 1,000 times) and increases its water content to about 70%.[16] These changes in oil properties present challenges for spill response operations. Many oil skimmers work considerably less efficiently (if at all) on emulsified, viscous oil, though some types of systems work better with increasing viscosity. The high water content of emulsified oil means considerably more volume of oil-water emulsion to recover, which increases the requirements for temporary storage capacity and transport for disposal or processing.

The Response Option Calculator (ROC) developed by Genwest Systems presents skimmer efficiencies based on viscosity, as shown in Figure 5 and summarized in Table 11. Recovery is more efficient at lower viscosities for all skimmer groups, but skimmers in Skimmer Group A are able to recover oil at higher viscosities than the other two groups. For the purposes of modeling, viscosities that would allow

[16] Fingas 2001, 2011a, 2011b.

for recovery efficiencies greater than 50%, based on the ROC, were used to determine the thresholds for the three skimmer groups: 15,000 cp for Skimmer Group A, 2,000 cp for Skimmer Group B, and 80 cp for Skimmer Group C. When the oil reached viscosities above these thresholds, the oil was deemed unrecoverable by the response equipment in question.

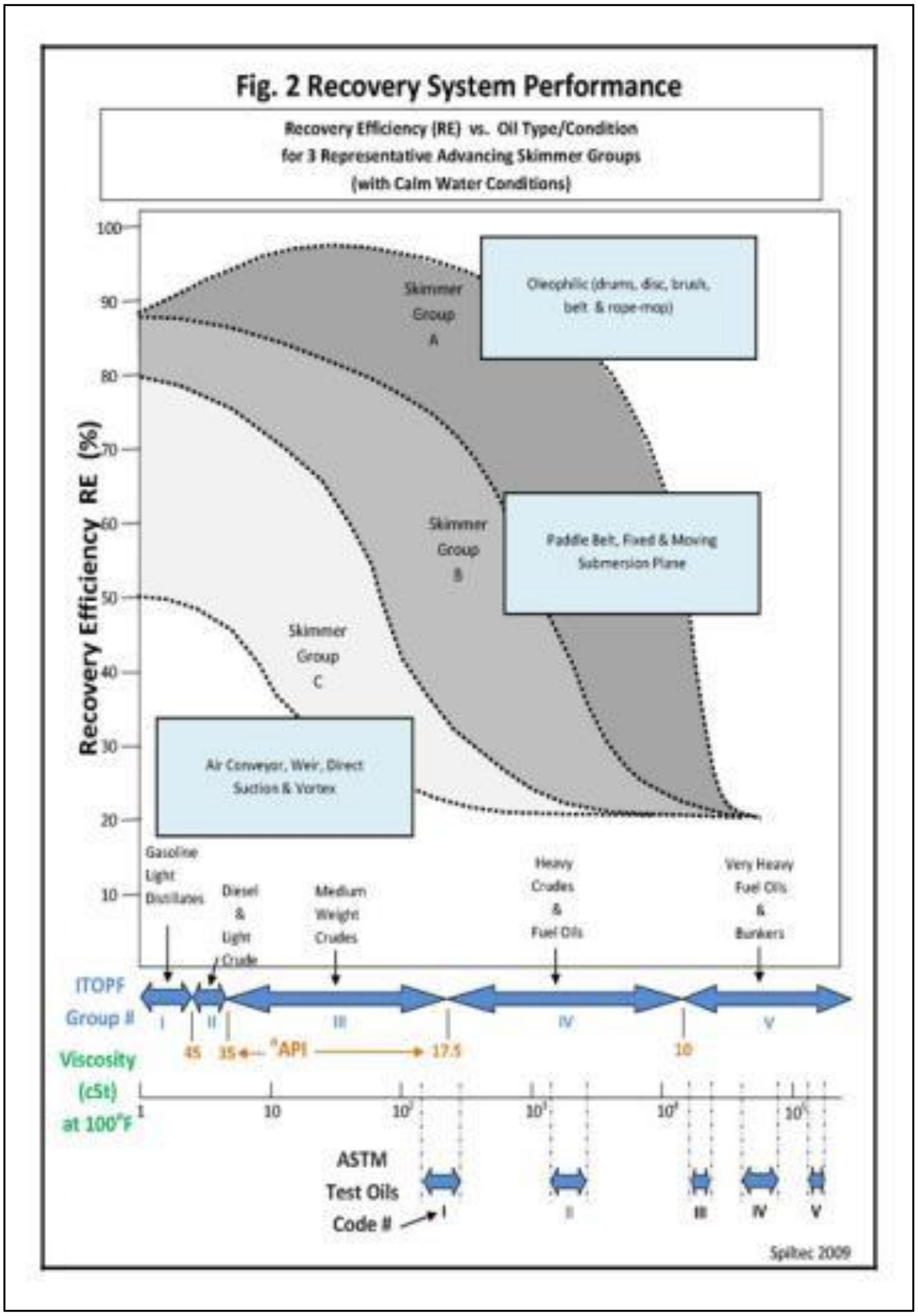

Figure 5: Response Option Calculator Skimming Recovery Performance by Oil Characteristics[17]

[17] Dale 2011a, 2011b.

Table 11: Skimming Response System Efficiencies by Viscosity[18] Based on ROC Calculator[19]

Skimmer Group	Skimmer Types	Viscosity (cp) Limit			
		Recovery Efficiency >80%	Recovery Efficiency> 50%	Recovery Efficiency <50%	Recovery Efficiency <30%
A	Oleophilic (drums, disc, brush, belt, and rope mop)	1 – 8,000	10,000 – 20,000	30,000	35,000
B	Paddle belt, submersion plane	1 – 80	2,000	3,000	5,000
C	Weir, air conveyor, direct suction, vortex	1 – 3	80	400	900

1.8.3 Dispersant Applications Assumptions in Oil Spill Response Modeling

Surface dispersant operations were also limited by oil conditions, primarily viscosity, as well as weather conditions that may affect flight operations, as summarized in Table 12. The geographic area of coverage is determined by guidance in the RCPs and ACPs that prohibit dispersant applications within 2.5-5 NM of the shoreline.

In the modeling simulations, surface dispersion was assumed to be occurring in the relevant geographic areas, as specified by the "removal polygons" during 12-hour daily operation times, except when the threshold values were exceeded.

Table 12: Factors Limiting Surface Dispersant Removal Rates in Modeling

Factor	Threshold Value		
	GOM	Pacific	Arctic
Oil Viscosity	20,000 cp	20,000 cp	20,000 cp
Oil Thickness on Surface	8.0 µm	8.0 µm	8.0 µm
Wind Velocity Range [a]	3.0 to 27.0 kts	3.0 to 27.0 kts	3.0 to 27.0 kts
Minimum Water Depth [b]	10.0 m	10.0 m	10.0 m
Operation Restriction [c]	12 hours	12 hours	12 hours
Weather Restriction [d]	21%	21%	62.5%

[a] Wind speeds cannot exceed safe operating conditions for planes, but also need to be sufficient to allow for mixing of the chemical dispersants and oil at the water surface (API et al. 2001; USCG, 2004)
[b] A minimum water depth is required to allow for adequate mixing and to minimize the concentration of dispersed oil in the water column (USCG, 2004).
[c] Operations are assumed to occur during daylight hours only, which also incorporates restrictions for shift length. Model input is assumed to be 12 hours of daily operation regardless of location.
[d] Weather restrictions include storm events, fog, precipitation, and other issues that may preclude operations in addition to any wind events. Weather restrictions for GOM and Pacific regions were based on expert inputs. Arctic weather restrictions were based on studies conducted on Arctic operations. Additional 20% time added for remobilization after demobilization due to weather.

The blowout model includes two subordinate models, the plume model, and a droplet size model. The plume model predicts the plume evolution through the water column and the droplet size model predicts the distribution of droplet sizes in response to the release turbulence and oil properties, namely the oil-

[18] Viscosity (cp) at 100°F.
[19] Based on approximate visual interpretation of Figure 2.

water interfacial tension. Subsurface dispersant application was implemented in the droplet model through incorporation of a reduced interfacial tension (IFT) associated with the dispersant treatment as a function of the dispersant to oil ratio (DOR) of the treated fraction of the release. Reduction of IFT results in smaller droplets. The model includes a proxy for the relationship between IFT and DOR based on experimental studies presented in Venkataraman et al (2013). For this study, subsurface dispersant was applied to the entire cross section (100% treated fraction) of the release during subsurface dispersant application periods at a DOR of 1:100 with 100% dispersant effectiveness (DE)[20].

However, in some cases the subsurface dispersant was not applied to all time steps due to the scenario assumption that (1) there would be a period of time after the onset of the spill event (4 days) that it would take to prepare for subsurface dispersant response and (2) available dispersant volumes were limited. For each scenario, an allotment of dispersant was established (based on the amounts of dispersants available in U.S. and internationally) and then, using a treatment ratio of 1:100 for subsurface dispersants, the volume of oil that could be treated with subsurface dispersants was then allotted dispersant volumes that were calculated to continue reduced surface applications. If it was determined that less than 100% of the release could be treated based on the dispersant allotment, it was then assumed that the allotment would be allocated equally across the days of the release. Therefore an equal amount of dispersant would be applied daily and the number of hours treated per day was calculated based on this daily dispersant volume and the daily oil release rate. The SIMAP input file defining the mass of oil within various droplet diameters was then defined to alternate between the untreated and treated diameters depending on the hour of the day for each day of the release.

1.8.4 In Situ Burning Assumptions in Oil Spill Response Modeling

In situ burning operations are limited by oil conditions, including viscosity and water content, and various weather conditions that would affect flight operations for directing the collection of oil or the effectiveness of containment boom (also called fire boom), as summarized in Table 13. The geographic locations of in situ burning operations was limited by the relevant removal polygons, which were developed to take into account restrictions on these operations due to the proximity of shoreline or source control activities.

In the modeling simulations, in situ burning was assumed to be occurring in the relevant geographic areas, as specified by the "removal polygons" during 12-hour daily operation times, except when the threshold values were exceeded.

[20] 100% effectiveness is theoretical based on mathematics and 100% effectiveness only applies mathematically to the portion of the WCD flow that calculates at the 1 gallon dispersant to 100 gallons of oil. Only a portion of the WCD flow is treated based on the theoretical calculations.

Table 13: Factors Limiting In Situ Burning Oil Removal Rates in Modeling

Factor	Threshold Value		
	GOM	Pacific [h]	Arctic
Oil Viscosity	60 cp	N/A	60 cp
Maximum Water Content [a]	25.0%	N/A	25.0%
Winds [b]	30 kts	N/A	30 kts
Current Velocity [c]	0.7 kts	N/A	0.7 kts
Wave Height [d]	1.0 ft	N/A	1.0 ft
Oil Thickness on Surface	8.0 µm	N/A	8.0 µm
Operation Restriction [e]	12 hours	N/A	12 hours
Weather Restriction [f]	21%	N/A	62.5%

[a] Maximum water content varies based on oil type (McCourt et al., 2000; Michel et al., 2005). API gravity can also be used as an indicator of how the oil will burn (Michel et al., 2005; McCourt et al., 2000).
[b] Based on Fingas (2004)
[c] Based on effectiveness limits of containment boom (Etkin et al. 2006).
[d] Based on effectiveness limits of containment boom (Etkin et al. 2006).
[e] Operations are assumed to occur during daylight hours only, which also incorporates restrictions for shift length. Model input is assumed to be 12 hours of daily operation regardless of location.
[f] Weather restrictions include storm events, fog, precipitation, and other issues that may preclude operations in addition to any wind events. Weather restrictions for GOM and Pacific regions were based on expert inputs. Arctic weather restrictions were based on studies conducted on Arctic operations. Additional 20% time added for remobilization after demobilization due to weather.
[g] ISB operations were not simulated in the Pacific region scenarios due to the guidance in the RCP and ACPs.

1.9 Deepwater Horizon Oil Spill Literature Review

A case study was conducted to determine the geographic scope of the Deepwater Horizon oil spill and the response capabilities that were used to respond to the spill. Publically available government reports were reviewed including a report from the U.S. Coast Guard and the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. These reports were used to generate summaries of the quantities and types of equipment used, including aircraft, aerial surveillance and remote sensing technology, vessels, boom, source control technology and environmental monitoring, the response strategies and tactics employed, and the lessons learned regarding the use of these capabilities. This information was also used in designing the response divisions for the SIMAP WCD modeling. The Deepwater Horizon data also served as a benchmark when analyzing the results of the SIMAP WCD response modeling.

1.10 National Oil Spill Response Regulation Review

Research on the regulatory regimes was conducted using current statutes, regulations, and guidance documents available online on the websites of the government agencies responsible for developing and implementing oil spill response regulations. In most cases, this involved both an environmental agency analogous to the U.S. EPA and a coastal safety and law enforcement agency analogous to the U.S. Coast Guard. In some cases, other analytical studies of oil spill response regulatory regimes were reviewed in order to validate and enhance the analysis of the primary regulatory source documents. The information was collected and organized into various subject matter categories as outlined shown in Table 14.

The information collected for this analysis is summarized in Section 4.0, and is also presented in much greater detail in a series of tables in Appendix B. This summary of oil spill response regulations for OCS facilities accurately summarizes key regulatory language (including terms such as "should" vs. "must"). However, this is not a comprehensive legal analysis of the regulations and policies, and does not present the often complex legal and administrative rules applicable to the policy tiers, including relationships among national statutes, implementing regulations, and agency guidance.

The national regulatory regimes were also assessed based on their relative composition of either prescriptive or performance-based policies. Prescriptive regulations are those that prescribe a specific action that the regulated community must take based on specific numeric targets. For example, an OCS facility operator could be required to have 50 skimmers under contract that can be deployed within 12 hours. Performance-based regulations direct the regulated community to conduct any action sufficient to achieve a given outcome without prescribing exactly *how* that outcome will be achieved. For example, an OCS facility operator could be required to have enough oil spill response equipment on contract to remove 50% of all oil spilled within 24 hours. Most regulatory regimes use a mixture of both types of policies and can, therefore, be assessed based on a sliding scale from entirely prescriptive regulations to entirely performance-based regulations.

Table 14: Information Collected From National Oil Spill Response Regulatory Regimes

Regulatory Category	Requirements and Documents
Regulatory Approach	• National Regulations and Guidance Documents
Operator Roles	• Facility-Level Planning Documents
Risk Assessment and Scenario Planning	• Oil Characterization
	• WCD Scenario
	• Modeling
	• Risk Assessment
Response Options	• General Guidance, Principles, and Approach
	• Open Water Mechanical Recovery
	• Shoreline Cleanup Mechanical Recovery
	• Surface Applied Dispersants
	• Subsurface Applied Dispersants
	• In Situ Burning
	• Shoreline Protection
Oil Spill Tracking	• Spill Tracking, Aerial Reconnaissance/Surveillance & Remote Sensing
Source Control	• Relief Well
	• Capping and Well Intervention

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PART II: RESULTS

2.0 OIL SPILL RESPONSE CAPABILITIES ANALYSIS

Response modeling was conducted for the 11 WCD scenarios across the 9 site locations. Deterministic trajectories and start dates were selected based on the stochastic modeling runs that yielded the greatest amounts of shoreline oiling for each WCD. Oil spill response operations were designed and simulated based on the response strategies in the RCPs/ ACPs and the existing oil spill response equipment quantities and mobilization factors identified in the OSRO surveys and available equipment databases.

2.1 WCD PROFILES AND RESPONSE COUNTERMEASURES MODELING IN THE GULF OF MEXICO (GOM) OCS REGION

The Gulf of Mexico OCS Region produces 97% of all U.S. offshore oil and gas, about 17% of the country's total production.[21] The three planning areas – Western, Central, and Eastern – cover more than 159 million acres and contain about 4,900 active leases as of September 2015. The majority of the leases are concentrated in the Western and Central Gulf of Mexico Planning Areas, partially due to a Congressional drilling moratorium in much of the Eastern Planning Region that was established in 2006 by the Gulf of Mexico Energy Security Act. The U.S. Energy Information Administration projects that oil production in the Gulf of Mexico will remain at or near its current levels for the foreseeable future, which means that the Gulf of Mexico will remain the focal point of offshore oil and gas development activities in the United States.

The water depth of wells drilled in the Gulf of Mexico in the past decade range from 33 to 9,000 feet, with an average depth of 630 feet for production wells. About 75% of all production wells during this period were in 34 to 328 feet; only about 5% of production wells were in water greater than 3,281 feet deep. Offshore facilities in the Gulf of Mexico are between 1 and 250 miles from shore. Only about 10 offshore facilities in the Gulf of Mexico in 2014 were more than 150 miles from shore.

Figure 6 shows WCD locations and volumes in the Gulf of Mexico OCS Region based on data from OSRPs collected on December 12, 2014. While this is not an exhaustive representation of all WCDs in the region, it gives an informative overview of WCD sizes and locations in the Gulf of Mexico (for more information on the how these data were collected, see Section 3.1 of Volume I of this study). WCDs in the region range from less than 10,000 bbl/day to greater than 250,000 bbl/day. The largest WCDs tend to be found between 50 and 200 miles offshore in the Central Planning Area, although some smaller WCDs are also far offshore.

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[21] U.S. Energy Information Administration, Gulf of Mexico Fact Sheet, http://www.eia.gov/special/gulf_of_mexico/

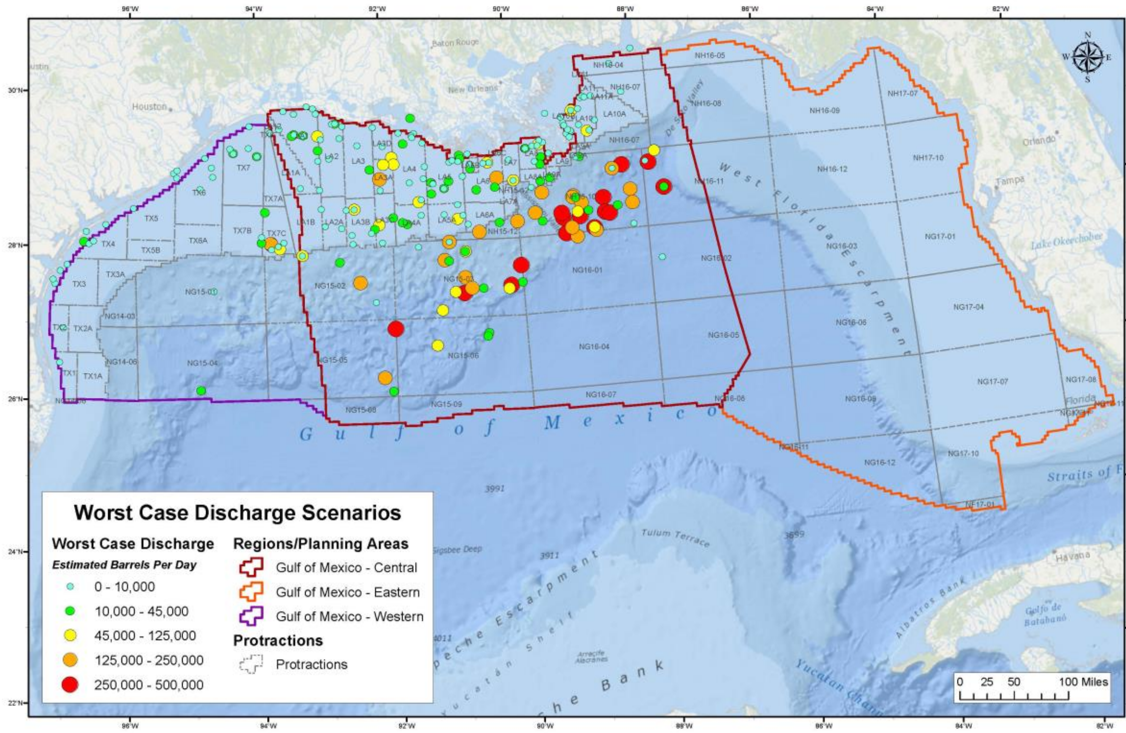


Figure 6: Worst Case Discharge Volume (bbl/day) Specified in the OSRP Locations in the Entire Gulf of Mexico OCS Region as of December 12, 2014

Six scenarios were modeled in the Gulf of Mexico OCS Region, which included five in the Central Planning Area and one in the Western Planning Area. The Central Planning Area scenarios are in blocks West Delta 28, West Cameron 168, Keathley Canyon 919, Mississippi Canyon 807, and DeSoto Canyon 187. The Western Planning Area Scenario is in the High Island East South Extension 376 block. These scenarios were selected to investigate a variety of different drilling depths, potential discharge volumes, and distances from shore; the scenario sites are not necessarily representative of the full population of offshore facilities in the Gulf of Mexico OCS Region.

2.1.1 Gulf of Mexico Regional Contingency Plan and Area Contingency Plan Strategies

There are two RCPs in the Gulf of Mexico OCS Region. The Region VI RCP covers the western portion of the Gulf of Mexico and includes the GOM coastline from the international border with Mexico on the Southwestern side to the Louisiana and Mississippi state line. Region VI contains five ACPs: Southwestern Texas Coastal Zone, Sector Corpus Christi, TX; Central Texas Coastal Zone, Sector Houston/Galveston, TX; Southeastern Texas/Southwestern Louisiana Coastal Zone, Marine Safety Unit (MSU) Port Arthur, TX; South Central Louisiana, MSU Morgan City, LA; and New Orleans, LA, Sector New Orleans, LA.

Region IV includes the eastern portion of the GOM from its western boundary at the Mississippi and Louisiana State line to the southwestern tip of Florida at Key West. In addition to the RRT, which guides response activities for all of Region IV through the Region IV RCP, there are three ACPs that guide response for specific areas of the Mississippi, Alabama and Western Florida Coastal Zones: Mississippi, Alabama and Northwest Florida Coastal Zone, Sector Mobile, AL; Central Western Florida Coast, Sector St. Petersburg, FL; and Southeastern/Southwestern Florida Coastal Zone, Sector Key West, FL.

All RCPs and ACPs in the Gulf of Mexico state that mechanical recovery is the preferred oil spill response option, and the Region VI RCP recommends the use of aerial surveillance to guide mechanical recovery efforts. The Federal On-Scene Coordinator is pre-approved to authorize the use of dispersants in Region VI, and IV in areas offshore more than 3 NM or 10 meter isobaths, whichever is farthest from shore, to 200 NM offshore, which is the Exclusive Economic Zone (EEZ) boundary. Region IV restricts the use of dispersants within three NM of other response operations.

In situ burning is pre-authorized in areas 3 NM offshore or greater, to the EEZ boundary. Permission must be obtained from the state of Florida before carrying out in situ burn in Florida state waters. Florida state waters extend nine NM offshore in western Florida.

The quantity and type of equipment available for protection and cleanup of shoreline areas in the Gulf of Mexico OCS Region was also assessed. The tactical plans developed for the Region VI ACPs had their pre-planned tactical approaches for GRPs removed from those plans in 2014 or earlier. Therefore, those resource numbers were not available. The BAH Team estimated the amount of resources that may be required for the environmental sites that were identified in the Region VI ACPs. Region IV ACPs do have GRPs that provide tactical booming strategies for protecting and enhancing shoreline recovery operations. These GRP charts were reviewed and evaluated to determine estimated amounts of boom and other resources that would be required to meet the goals of the ACP. Table 15 shows the estimates and information available from the GRPs.

Table 15: Summary of Region VI and Region IV Shoreline Protection and Cleanup Resource Requirements

ACP	Boom Stockpiles (ft)	Numbers of Skimming Devices	Numbers of Boats
Region VI Coastal Zone[22]	5,591,904	shoreline: 500	air boats, skiffs and jon boats: 500+
Sector Mobile	859,560	nearshore: 43 shoreline: 50+	skiffs and jon boats: 86+
Sector St. Petersburg	1,991,700	nearshore: 51 shoreline: 25	Air boats, skiffs and jon boats: 200+
Sector Key West	offshore boom: 107,000 shallow water boom: 52,000 harbor boom: 1,530,000 sorbent boom: 85,000+	shoreline: 236 unspecified type: 20	wave runners, skiffs, and jon boats: 140+
Totals	**10,217,164+**	**925+ (all types)**	**926 + (all types)**

Estimates of the number of personnel and other response resources that would be needed for shoreline cleanup are dependent upon the type of shoreline impacted and other physical factors such as weather that can influence the workforce. There are also numerous social, economic, and political variables that will have bearing on the numbers required.

[22] Estimated using ACP data from other regions.

2.1.2 Response Equipment Inventories

Stockpiles of oil spill response equipment currently available in the Gulf of Mexico OCS Region were calculated by surveying OSRO equipment stockpiles and searching a variety of publically available databases on equipment stockpiles (for more information on these methods, see Section 1.7). Total mechanical recovery equipment, in situ burning equipment, dispersant aircraft, and dispersant stockpiles are shown in Table 16. Mechanical recovery equipment is categorized by nearshore and offshore equipment. The aircraft shown in the table are stationed within the region; however, they could be cascaded to other regions for response efforts. Conversely, aircraft that are stationed in other OCS regions can be cascaded into the Gulf of Mexico OCS Region. The fire boom shown in the table is that which is readily available within the region. Most of this fire boom is staged within the region, and a smaller amount (1,000 feet) is staged in the Atlantic OCS Region and can readily cascade to the Gulf of Mexico.

Table 16: Total Response Equipment in the Gulf of Mexico OCS Region

Countermeasure Type	Type/Location	Quantity
Mechanical Recovery	Nearshore Equipment ERSP	104,450 bbl/day
	Offshore Equipment ERSP	547,313 bbl/day
	Total Mechanical Recovery ERSP	**651,763 bbl/day**
Fire Boom for In Situ Burning	Staged in the Gulf of Mexico OCS Region	20,000 ft
	Staged in the Atlantic OCS Region that can cascade in the GOM	1,000 ft
	Total Fire Boom	**21,000 ft**
Dispersant Aircraft	DC-3 in Houma, LA	2
	DC-4 in Houma, LA	1
	DC-6 in Opa-Locka, FL	1
	BT-67 in Houma, Louisiana	1
	C-130 in Stennis, Mississippi	1
	Total Number of Aircraft	**6**
Dispersants	**Total Dispersant Stockpile**	**387,200 gal**

2.1.2.1 *Scenario 1: Mississippi Canyon 807*

Scenario Site Information

Gulf of Mexico (GOM) Mississippi Canyon 807 (MC807) is an offshore (53 miles [46 nm] from shore), deepwater (3,030 ft) well in the Central Gulf of Mexico Planning Area. In the event of a worst case discharge at this site, there is a high probability for rapid, significant shoreline contact if spill response countermeasures are not immediately taken. Based on 100 stochastic model runs, the worst case release date for the GOM-MC807 WCD scenario was June 8, 2003.

Table 17: Scenario 1, GOM-MC807 – Well Information and Shoreline Contact Times

WCD Scenario Parameters	
Discharge Flow Rate	449,000 bbl/day
WCD Duration	182 days, Relief Well Only 45 days, Source Control
Total WCD Release Volume	81,718,000 bbl, Relief Well Only 20,205,000 bbl, Source Control
Simulation Duration (45 days following end of discharge)	227 days, Relief Well Only 90 days, Source Control
Oil Type	South Louisiana Crude
API Gravity	34.5
Viscosity @ 15^{o}C (cp)	10.1
Latitude, Longitude	28.157842^{o}N, 89.2156^{o}W
Depth to Sea Floor	3,030 ft
Distance to Shoreline	53 miles (46 nm)
SIMAP Model Results [a]	
Time for oil above 1 g/m^2 to reach shore [b]	4 days
Time for oil greater than 8 g/m^2 to reach shore [c]	4.5 days
[a] SIMAP model results presented in this table are based on the 100 stochastic model runs. [b] The 1 g/m^2 value is the threshold for socio-economic resource effects (e.g., closure of fisheries) (French-McCay et al. 2011; French McCay et al. 2012) [c] The 8 g/m^2 value is the minimum thickness of floating oil for which response equipment can be effectively used (NOAA 2010)	

Application of Source Control

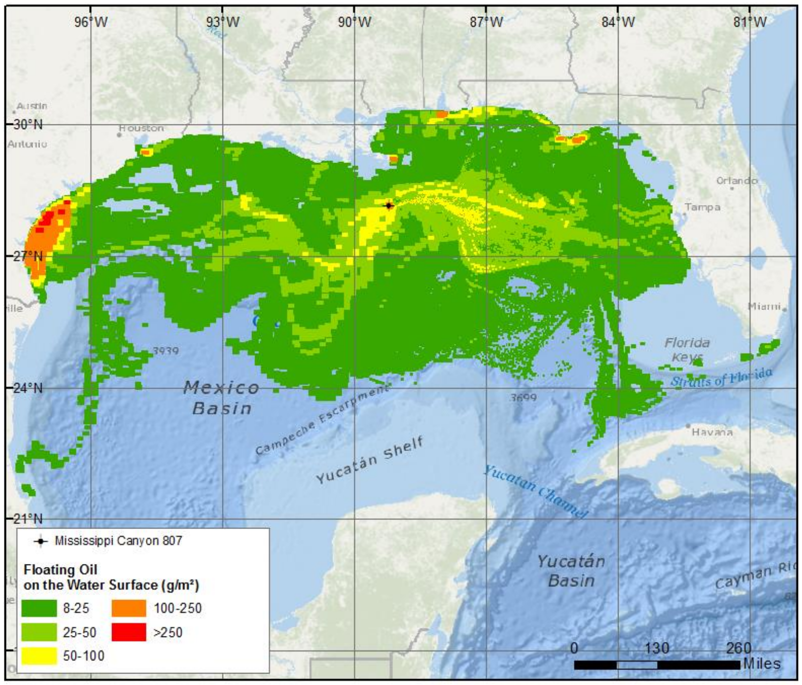
When a source control operation is modeled for the WCD GOM-MC807 scenario, the discharge period is reduced by 137 days, and the volume of oil released to the environment is reduced by 61,513,000 bbl. Table 18 compares discharge volume, shoreline-oiling volume, length of oiled shoreline, area of surface oiling, and the amount of oil biodegraded or in the sediments for the Relief Well Only and Source Control Only modeling simulations.

Table 18: Scenario 1, GOM-MC807 – Comparison of Relief Well Only and Source Control Response Scenarios

Scenario 1, GOM-MC807	Relief Well Only (182-day flow duration)	Source Control (45-day flow duration)	Reduction Due to Source Control	Percent Reduction Due to Source Control
Volume Discharged (bbl)	81,718,000 bbl	20,205,000 bbl	61,513,000 bbl	75 %
Volume Shoreline Oiling (bbl) any thickness	1,870,728 bbl	1,248,709 bbl	622,019 bbl	33 %
Total Length (mi) of Shoreline Oiled with $\geq 1 g/m^2$	4,528 mi	2,233 mi	2,295 mi	51 %
Cumulative Area (mi^2) of Surface Oiling $\geq 8 g/m^2$	11,715,947 mi^2	6,832,704 mi^2	4,883,243 mi^2	42 %
Amount Biodegraded or In Sediments (bbl) at the End of the Simulation	31,146,748 bbl	5,331,552 bbl	25,815,196 bbl	83 %

As shown in Table 18 and Figure 7, the volume and spread of oil spilled in this WCD scenario is greatly reduced by a source control intervention on day 45. However, even with source control intervention, there would be extensive shoreline contact and exposure to oil in the environment, especially along the eastern Gulf of Mexico U.S. coast. Application of additional response operations would be needed to remove or mitigate spilled oil on the surface.

182-Day Release of South Louisiana Crude at 449,000 bbl/day - Relief Well Only (WCD)



45-Day Release of South Louisiana Crude at 449,000 bbl/day - Source Control Only

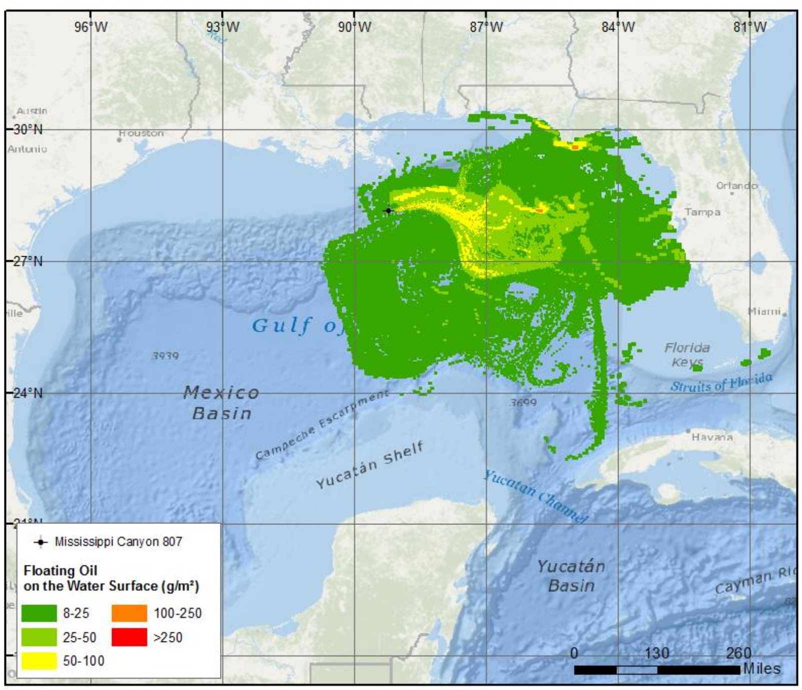


Figure 7: Scenario 1, GOM-MC807 – Comparison of Maximum Concentrations of Surface Oiling Experienced Throughout Simulation Periods for Relief Well Only (182-Day Discharge) and Source Control Only (45-Day Discharge)

Oil Discharge Behavior

Figure 8 shows the fate of oil for 90 days from the discharge (45-day discharge duration and 45 days following the source control). At the end of the simulation, 48% percent of the total oil had evaporated, 38% had either biodegraded or remained in the water column and sediments, 6% of the oil remained on the shoreline, and 6% of the oil remained floating on the surface. Note that, the model does not simulate potential photooxidation of floating oil.

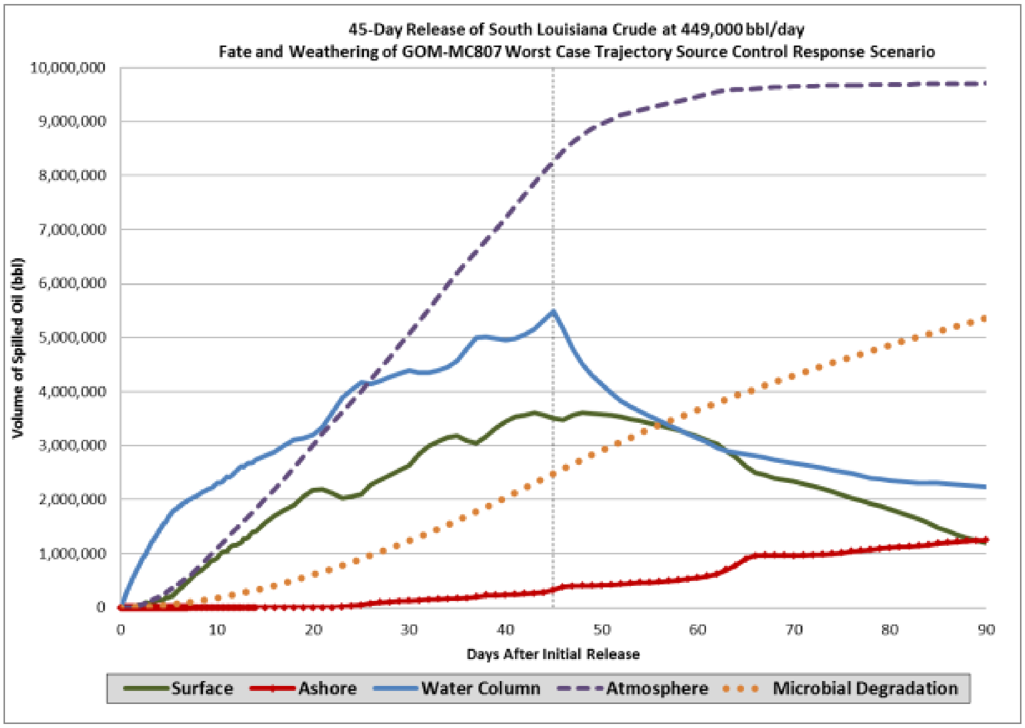


Figure 8: Scenario 1, GOM-MC807 Source Control, 45-Day Discharge – Oil Fate and Weathering (Dotted Vertical Line Indicates Source Control on Day 45)

In Scenario 1, GOM-MC807 Source Control, 63% of the total oil mass discharged from the blowout reached the surface, and 37% remained entrained within the water column. Due to the conditions present in the scenario at the point of discharge, the subsurface oil plume's behavior was somewhat unique from scenarios, in that oil droplet size was small and took nearly five days to rise to the surface, generally between 5 to 30 miles from the well site.

As with other WCD scenarios using South Louisiana Crude, the oil viscosity and thicknesses progressively change as the oil moves away from the discharge site. By the end of day 3, oil that was discharged at the beginning of the spill moved to the edge of the high volume recovery area and reached the upper limit (20,000 cST) for the mechanical recovery equipment being modeled in the simulation. By the end of day 4, the oil moved into the secondary recovery area and reached viscosities approaching 30,000 cST. Due to the variable nature of the winds, by the end of day 6, patchy areas of thick fresh oil had spread out in an easterly direction across a distance of over 100 miles from the well site. By day 9, viscosities of the older weathered oil approached 50,000 cST in the secondary recovery area.

As the GOM-MC807 plume moved across the ocean surface, the simulation demonstrates how surface expression of the fresh oil and the overall viscosity of the oil slick are closely tied to wind and sea state conditions. Figure 9 illustrates the effect of a high-wind weather event, which occurred on day 21 as the winds rose from 7 kts to a sustained 15-19 kts before subsiding on day 24. Fresh oil exposed to the surface during the high-wind period was entrained under the surface, dispersed by wave energy, or weathered into a higher viscosity category. Older oil that had already begun to weather significantly increased in its observed viscosities.

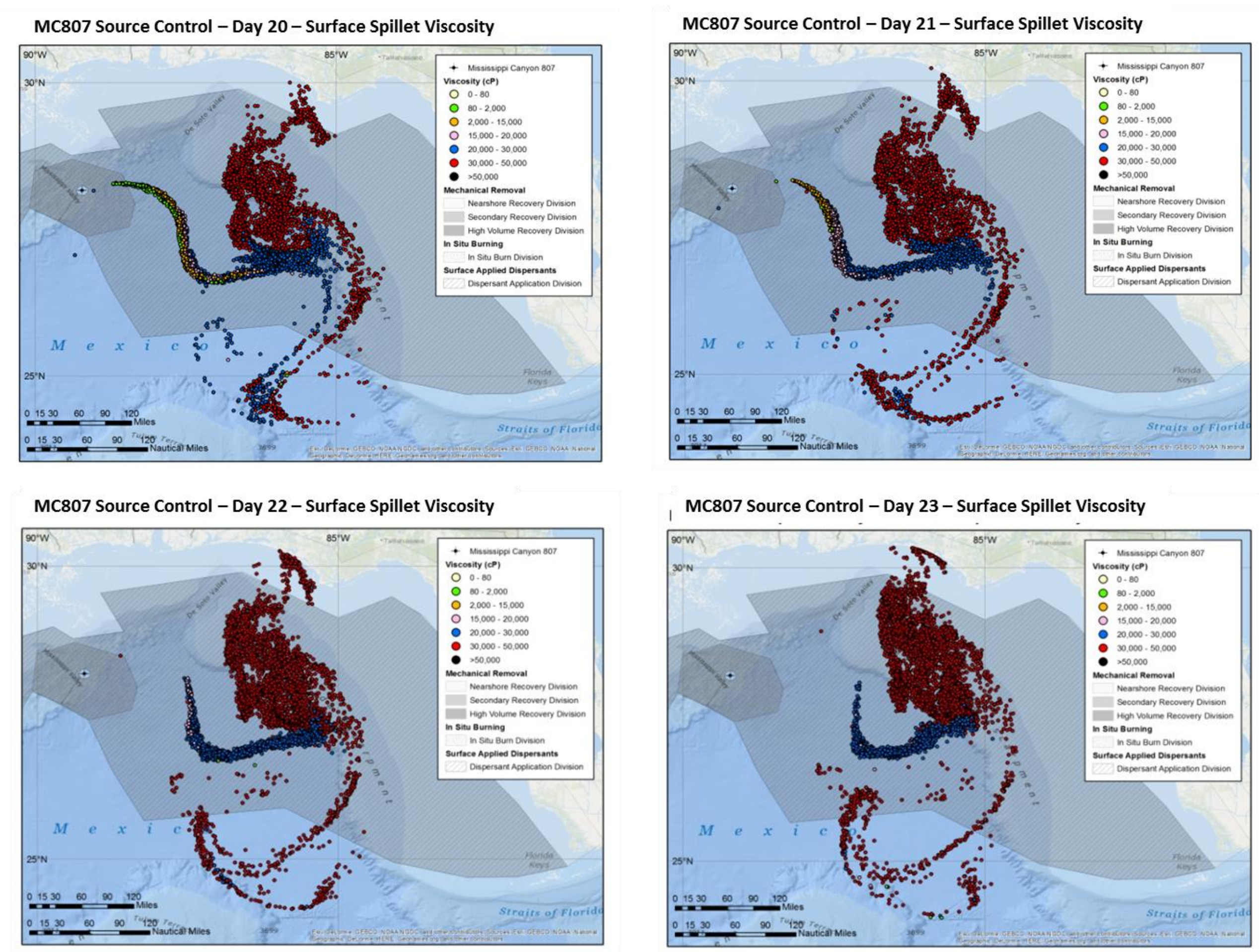


Figure 9: Scenario 1, GOM-MC807 Source Control, 45-Day Discharge – Surface Oil Viscosity during High-Wind Period

In the initial days of the GOM-MC807 scenario, oil moved generally eastward, and then spread out in both north and southerly directions. This appears to be the result of winds blowing mostly in a northerly direction and a current that is often moving entrained oil in a southeasterly direction. By day 17, the oil that moved in the northerly direction entered into nearshore recovery areas, but was generally less than 8 g/m^2 and heavily weathered. By day 21, low concentrations of heavily weathered oil made contact with shorelines in the Florida panhandle. By day 24, thicker volumes of weathered oil (30,000-50,000 cST) entered nearshore recovery areas and made shoreline contact, and large areas of thick oil (in 20,000-30,000 cST range) were in the secondary containment areas. Oil that had moved in a southeasterly direction entered several current eddies that circulate offshore in the southeastern Gulf of Mexico. Substantial shoreline oiling occurs along the eastern Gulf of Mexico coastline, including weathered tarballs in the Florida Keys.

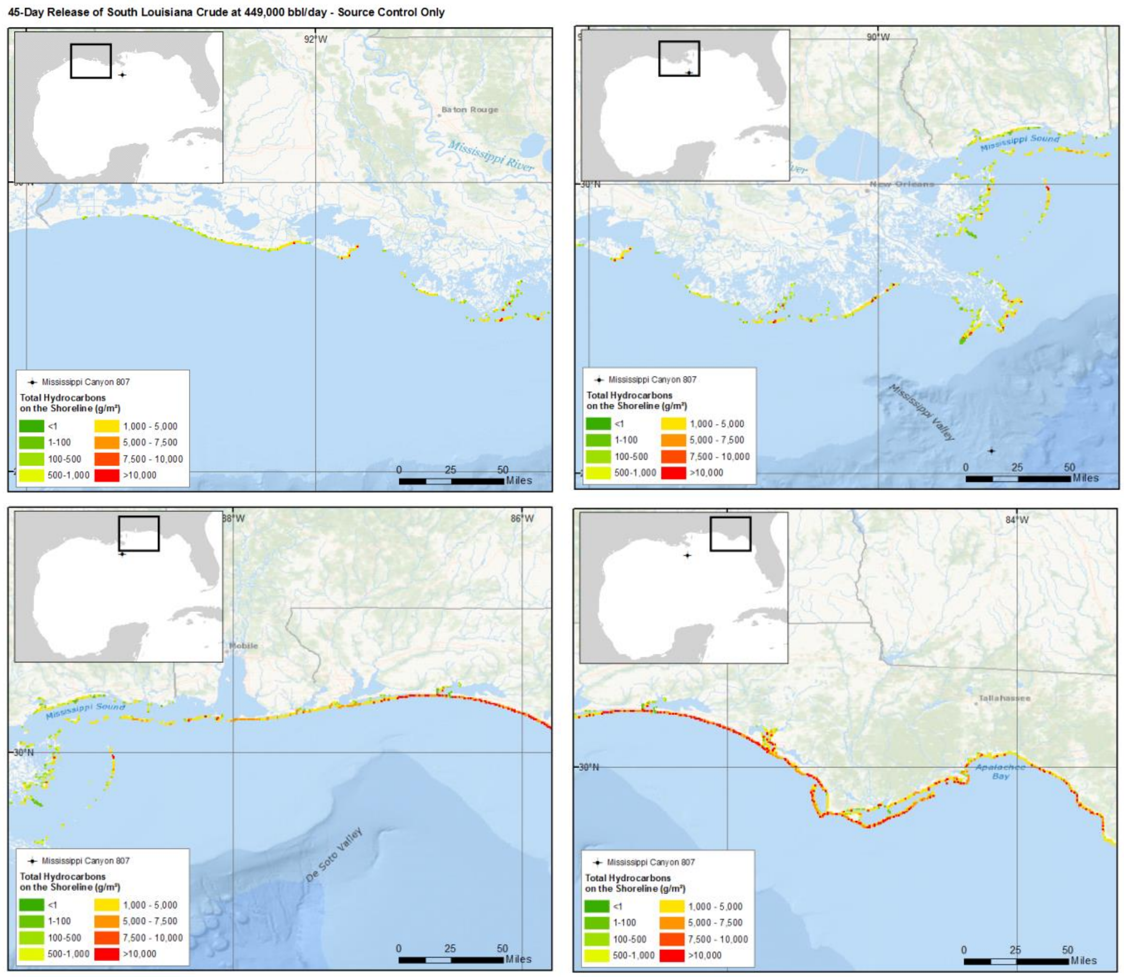


Figure 10: Scenario 1, GOM-MC807 Source Control, 45-Day Discharge – Shoreline Oil ≥1 g/m^2, including Weathered Tarballls (continued on Figure 11)

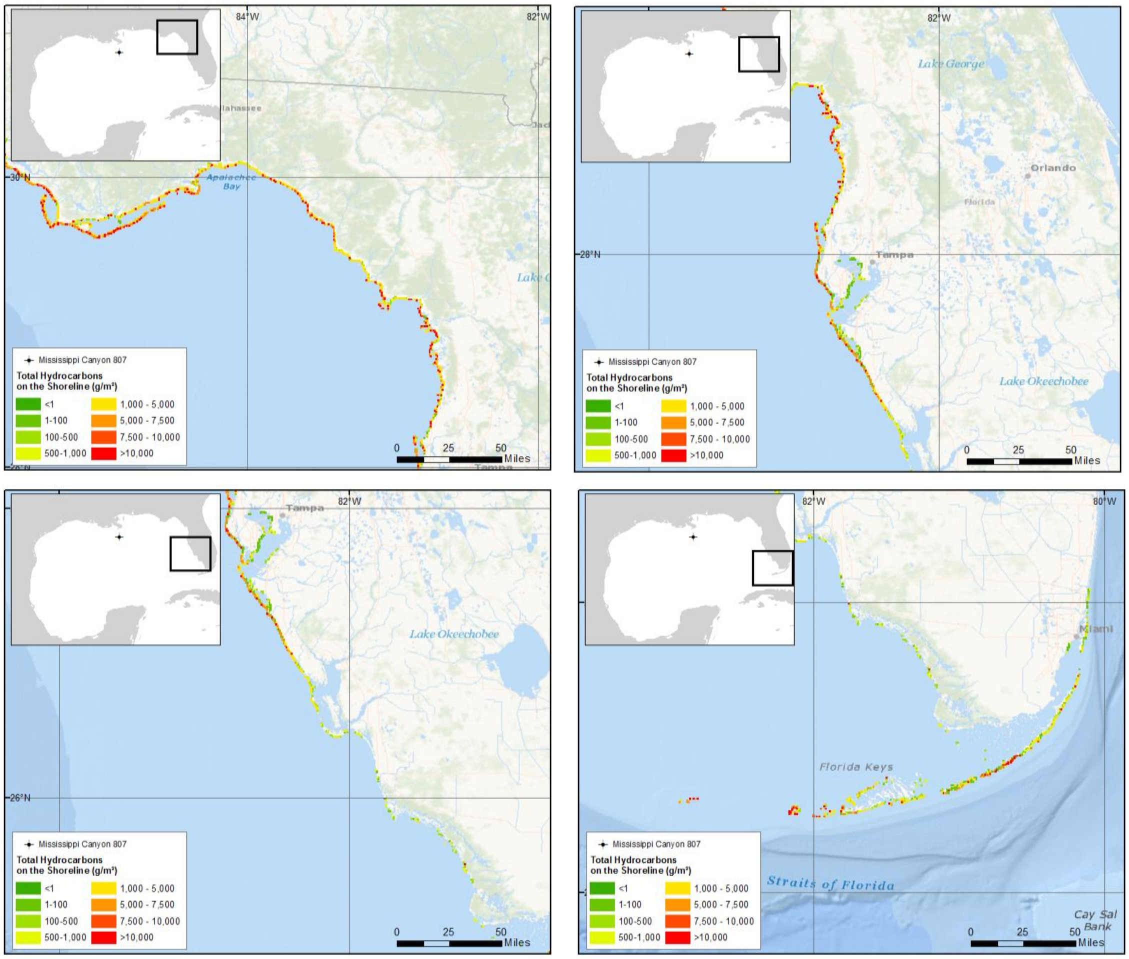


Figure 11: Scenario 1, GOM-MC807 Source Control, 45-Day Discharge – Shoreline Oil ≥1 g/m^2, including Weathered Tarball (continued from Figure 10)

Application of Response Countermeasures

Countermeasure Response Divisions

The following equipment types were employed in each of the following countermeasure response divisions, and are shown in Figure 12.

- High Volume Recovery Division – High volume mechanical recovery operations were employed beyond a 5.8 mile (5 nm) radius area established around the well for source control.
- In situ Burning Division – In situ burning operations were used in the same geographical area as the high volume mechanical recovery operations 5.8 mile (5 nm) away from the source control area.
- Secondary Recovery Division – Secondary mechanical recovery operations were used to remove oil that was not previously removed in the high volume recovery area.
- Nearshore Recovery Division – Nearshore mechanical recovery operations were used to remove oil from the surface of the water before it was washed onto shorelines.
- Dispersant Application Division – Surface applied dispersants were employed in the high volume and secondary recovery geographical areas as appropriate.

Subsurface dispersants, which were applied at the point of discharge in the vicinity of the wellhead, are not shown in Figure 12 or assigned to a geographic response division.

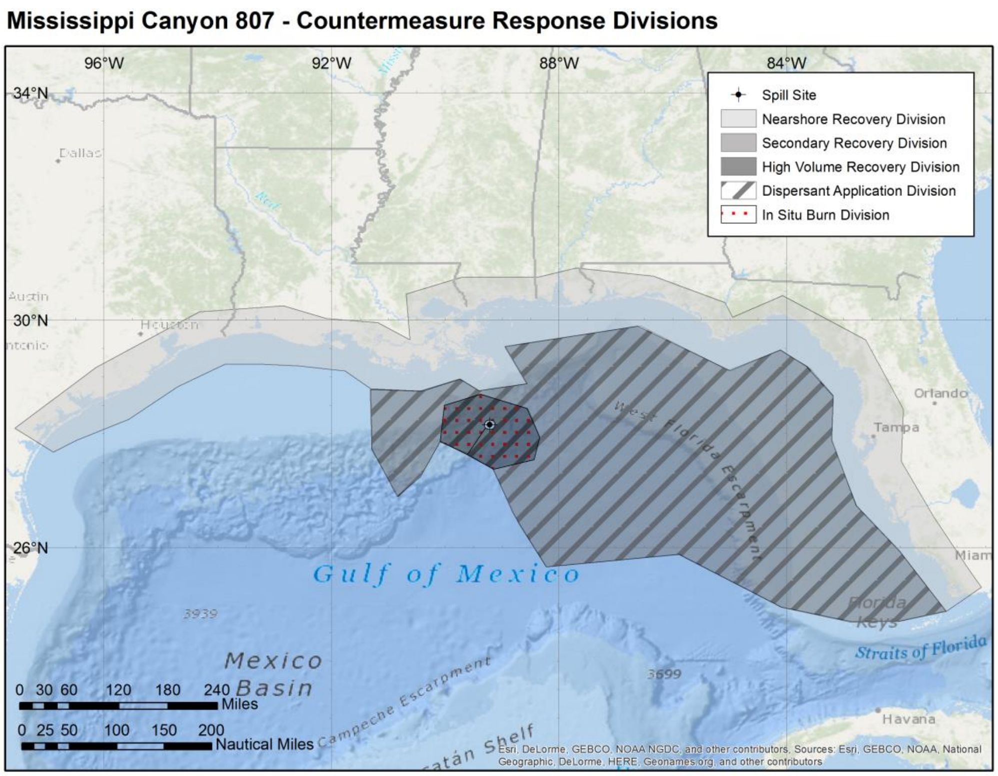


Figure 12: Scenario 1, GOM-MC807 – Geographic Coverage of Oil Countermeasure Response Divisions

The size and placement of the GOM-MC807 response divisions in the model were developed based on a review of the oil spill trajectories from the 45-day discharge in the Source Control simulation.

Countermeasure/Division Removal Rates (Model Inputs)

The removal rates by countermeasure type and response division that are shown in Table 19 represent the *maximum* potential rate that would be available at any point during the response operation.

As in an actual oil spill recovery operation, the model cascades response equipment into the response divisions as the assets arrive on the scene. The modeling reflects response equipment threshold values and limitations based on the availability of the response equipment (as determined to be in the stockpiles per OSRO response equipment survey) deployed in the appropriate divisions. As such, the model used oil removal rates for each division (i.e., SIMAP model polygon), based on the maximum potential daily removal rates (bbl/day) of the assigned asset (refer to Table 19), corrected by weather restrictions and daylight operations (as described in Section 1.8). Maximum removal rates are not realized in practice because of the limitations of weather delays, suspension of operations at night, the location of oil in relation to equipment, and performance thresholds, such as oil thickness on the water surface, sea state and currents, winds, and water content during oil emulsification.

Maximum oil removal rates are not necessarily applicable for the entire response period. This is because equipment cascades in at different times, and in some cases, resources are allocated to different applications. For example, because the MC807 scenario is simulating a high-volume WCD, the limiting factor for application of dispersant is the stockpile (not availability of application equipment). To maintain subsurface dispersant application throughout the duration of the blowout meant that surface dispersant application was limited by the stockpile. Dispersant application for this scenario is discussed further below.

Table 19: Maximum Potential Daily Oil Removal Rates for GOM-MC807 SC+MR+D+ISB+SubD Response Scenario [a]

Countermeasure Type	Response Division	Response System Category [b]	Removal Rate Applied [c]	Maximum Potential Daily Removal Rates (bbl/day)
Mechanical	**High-Volume**	Skimmer Group A	ERSP Day-1	123,233
		Skimmer Group B	ERSP Day-1	16,607
		Skimmer Group C	ERSP Day-1	99,152
	Secondary	Skimmer Group A	ERSP Day-3	7,950
		Skimmer Group B	ERSP Day-3	1,586
		Skimmer Group C	ERSP Day-3	34,005
	Nearshore	Skimmer Group A	ERSP Day-3	7,524
	Total	**All Mechanical Countermeasures**		**290,057**
In Situ Burning	**High-Volume In Situ Burning**	In Situ Burning	Based on ISB Calculator	16,452
Surface Dispersant	**High-Volume and Secondary**	Surface Dispersants	Based on DMP2	33,991
Subsurface Dispersant	**Wellhead**	Subsurface Dispersant	Based on a DOR of 1:100	75,429
Total		**All Countermeasures**		**415,929**

[a] GOM-MC807 SC+MR+D+ISB+SubD Response Scenario by countermeasure type and response division *without* application of weather restrictions.

[b] The characteristics of the different types of mechanical equipment and the specific pieces of equipment applied in this scenario are described in Section 2.1. The viscosity thresholds for different types of equipment are further described in Section 1.8.2.

[c] ERSP is described in Section 5.0. "ERSP Day-1" rates are the higher removal rates applied in the areas and times when the oil was flowing from the well and the oil is the thickest. "Day-1" does not necessarily indicate that this is only applied for the first day. "ERSP Day-3" rates are applied in the areas more distant from the well where the oil is thinner and more spread out making removal less efficient. "Day-3" does not necessarily indicate that this is the third day of the response.

For Scenario 1, GOM-MC807 response operation divisions were cascaded in over the course of the initial 18 days (as depicted in Figure 13). Oil began to rise to the surface at Hour 19, aerial surface dispersant application commenced on day 2 of the incident.

Maximum surface dispersant inventory use was achieved from day 2 through day 11 at over 71,380 gallons of surface dispersant applied daily. On day 12 of the event, the daily volume of surface application of dispersant was reduced to 18,250 gallons and further reduced to 16,250 gallons per day application on day 35. The surface dispersant application volume was reduced since simultaneous subsurface and surface dispersant operations for this high-volume WCD and 45-day duration incident would have resulted in an insufficient dispersant inventory and manufacturer resupply to continue both applications for the full period until well shutdown on day 45. The average daily dispersant use for the combined subsurface and surface application scenario was 57,733 gallons, versus 54,618 gallons for the surface only scenario. A total of 2,597,969 gallons of dispersant were applied for the combined subsurface and surface scenario and 2,457,800 gallons for the surface only scenario. Surface dispersants can treat oil at the rate of 1:20 dispersant to oil (i.e., 20 times as much oil is treated as dispersant applied). For subsurface dispersants, 100 times as much oil is treated as dispersant applied subsurface.

Subsurface dispersant operations commenced on day 5 to account for the mobilization and necessary logistics to arrive on scene and then deploy the equipment and commence subsurface application. Subsurface dispersant application was maintained continuously between day 5 and day 45, with an injection rate set at 22 gpm at 1:100 DOR.

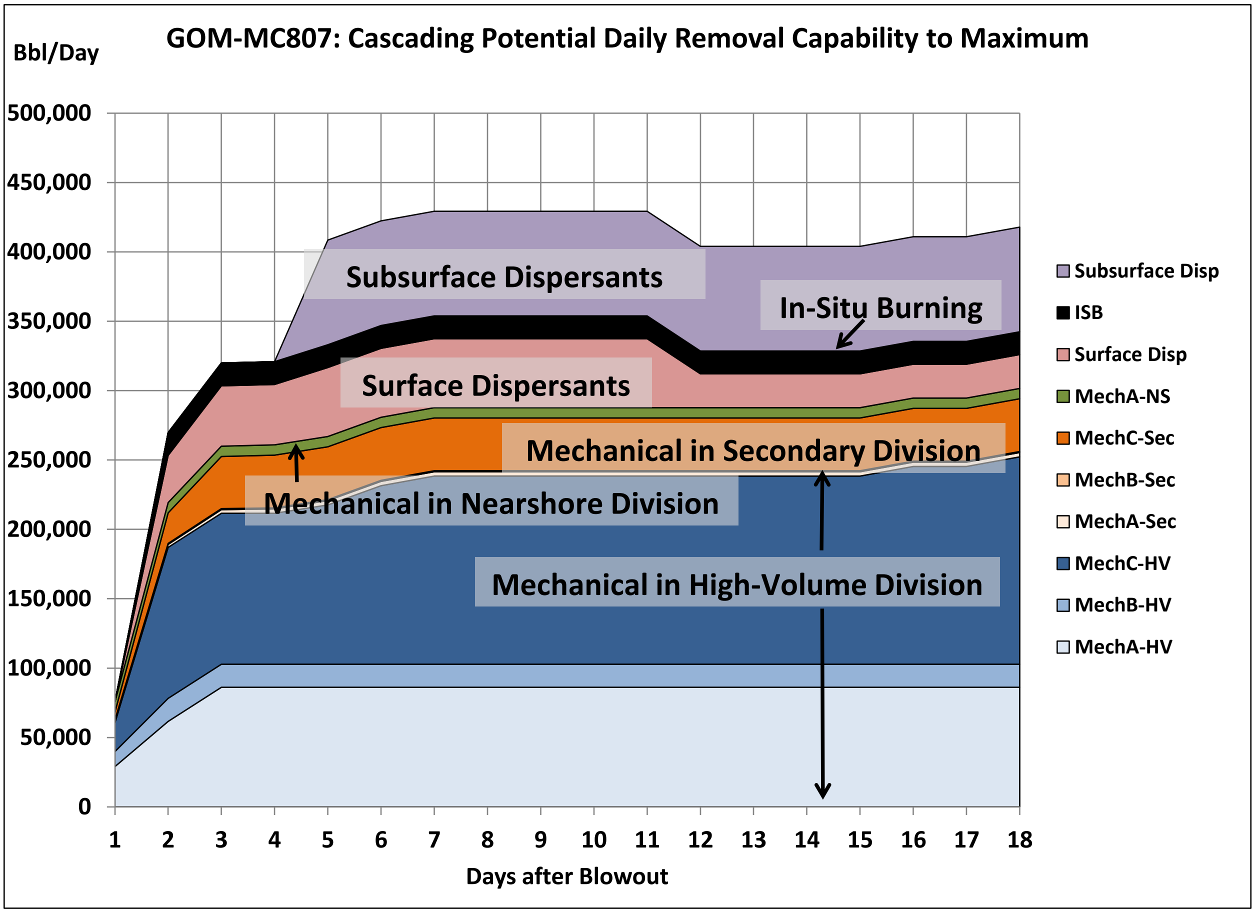


Figure 13: Scenario 2, GOM-MC807 – Cascading SC+MR+D+ISB+SubD Response Assets and Cumulative Potential Daily Removal Capacity

Countermeasure Simulation Results & Analysis

Achieved Removal versus Potential Equipment Capabilities

Maximum potential removal rates of oil removal systems are not achieved due to the limitations on countermeasures resulting from oil weathering and other environmental factors (such as increased sea state and darkness which often limited when the countermeasures could be applied). For the GOM-MC807 SC+MR+D+ISB+SubD simulation, weather restrictions were in effect for 21% of the time, and for most equipment, the operating period was limited to 12 hours of daylight (other equipment limitations applied are listed in Table 10, Table 12, and Table 13). Because of these thresholds and limitations, as well as the availability of recoverable, burnable, or dispersible oil in the response divisions, achieved oil removal was significantly less than the potential recovery capabilities (as shown in Table 20, Figure 14, and Figure 15 for the GOM-MC807 SC+MR+D+ISB+SubD simulation).

Table 20 shows the system potential with regard to barrels of oil that could be treated or removed based on the sum total of removal/treatments rates over the course of the entire response operation (i.e., during the release of oil from the well and for an additional 45 days after source control is achieved to stop the flow of oil). The "achieved" removal or treatment reflects the sum total of oil removed or treated over the course of the response operations. Figure 14 contrasts the sum total of potential removal/treatment over the course of the operations and the sum total of the achieved removal/treatment. The daily well flow is shown as a benchmark. The potential removal/treatment capability greatly exceeds the achieved removal/treatment due to the various environmental and logistical factors that limit performance.

Table 20: Scenario 1, MC807 – SC+MR+D+ISB+SubD Cumulative System Potential versus Achieved Oil Removal/Treatment over 90-Day Simulation

Response Type	Response Division	Response System Type	Total Removal/Treatment		
			System Potential (bbl)	Achieved (bbl)	% Potential [a]
Mechanical [b]	**High-Volume**	Skimmer Group A	6,717,479	356,469	5.3%
		Skimmer Group B	888,914	103,263	11.6%
		Skimmer Group C	4,953,313	780,310	15.8%
	Secondary	Skimmer Group A	704,932	74,268	10.5%
		Skimmer Group B	138,916	20,159	14.5%
		Skimmer Group C	3,018,723	340,933	11.3%
	Nearshore	Skimmer Group A	677,160	5,699	0.8%
	Mechanical Total	**-**	**17,099,437**	**1,681,100**	**9.8%**
In Situ Burning [c]	**High-Volume In Situ Burning**	-	1,075,290	376,422	35.0%
Surface Dispersants	**High-Volume/ Secondary**	-	643,391	463,219	72.0%
Subsurface Dispersants	**High-Volume/ Secondary**	-	3,092,589	1,134,407	36.7%
All Categories	**All Categories Total**	**-**	**21,910,707**	**3,655,148**	**16.7%**

[a] Achieved Total Recovery divided by System Potential Total Recovery as percentage.

[b] ERSP Day-1 rates assumed for High-Volume Division until well capping (source control); ERSP Day-3rates assumed for Secondary and Nearshore Divisions, and for High-Volume Division after day 45 source control.

[c] EBSP Day-1 rates assumed until day 45 source control, after which EBSP Day-3 rates were applied.

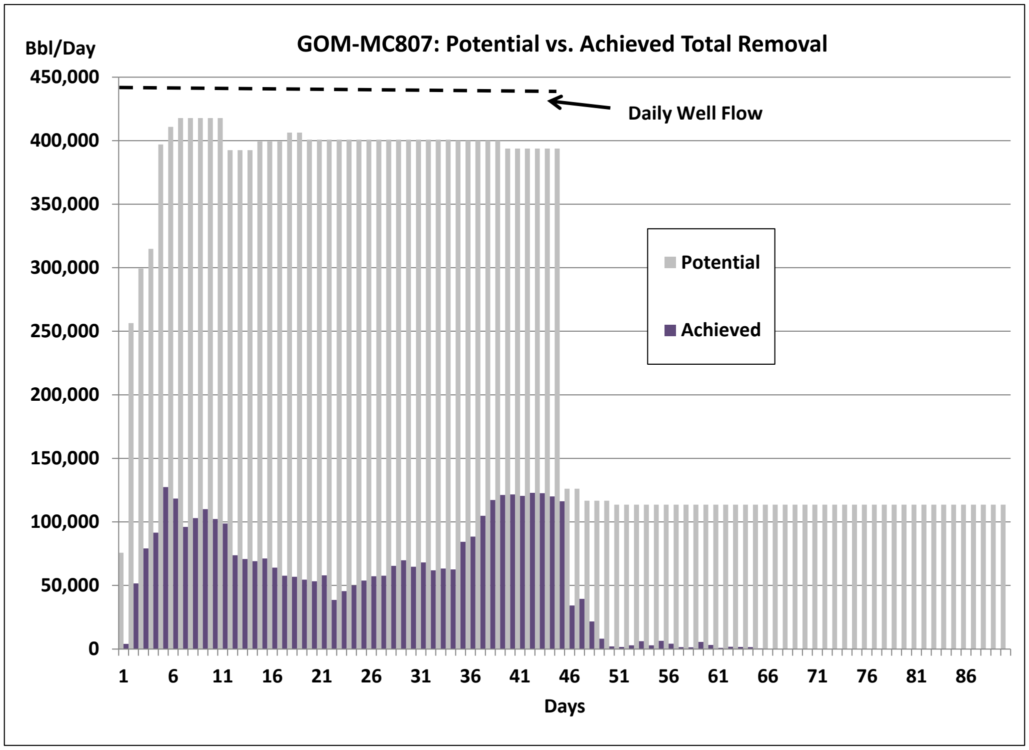


Figure 14: Scenario 1, GOM-MC807 – SC+MR+D+ISB+SubD Total Oil Removal System Potential and Achieved Total Daily Removal

Figure 15 contrasts the amount of oil flowing from the well on a daily basis along with the maximum potential daily capability per day, as well as the achieved average daily removal rate. The achieved average daily removal rate is considerably lower than the potential daily removal rate for each day of the scenario.

During the response period, some systems have very low or near-zero removal for some periods because of performance limitations due to environmental conditions, or because there is insufficient oil available, particularly in secondary and nearshore response areas where oil may not appear on the surface until after the oil has stopped flowing.

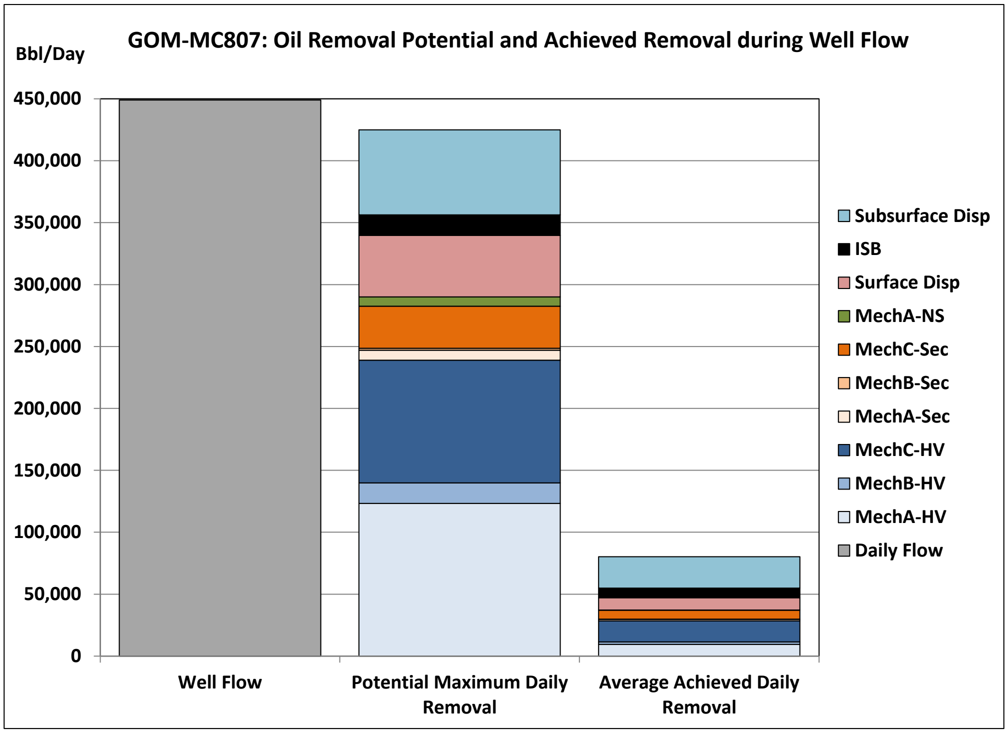


Figure 15: Scenario 1, GOM-MC807 – SC+MR+D+ISB+SubD Total Maximum Oil Removal System Potential and Achieved Removal Compared with Well Flow during 45-Day Discharge Period

Oil Removal by Countermeasure Type

Table 21 is a summary of model results for the various response countermeasures applied to the GOM-MC807 scenario. This table allows for comparison of the oiling and oil removal by each countermeasure across the various model simulations. Values within Table 21 represent the volume of oil present/removed at the completion of the response scenarios (90 days).

Table 21: Scenario 1, GOM-MC807 – Comparison of Shoreline Oiling and Oil Removal for the Relief Well Only, Source Control Only, and Response Countermeasure Simulations

Response Capability Simulations	Volume (bbl) of Discharge	Volume (bbl)/ Percent of Oil on Shoreline	Volume (bbl)/ Percent Removed by Skimming	Volume (bbl)/ Percent Dispersed	Volume (bbl)/ Percent Removed by Burning	Volume (bbl)/ Percent Bio-degraded or in Sediments
Relief Well Only 182 Day Discharge	81,718,000	1,870,675				31,146,748
Source Control (SC) Only, 45 Day Discharge	20,205,000	1,248,695 6%				5,331,552 26%
Source Control and Mechanical Recovery (SC+MR)		1,103,114 5%	2,164,794 11%			4,842,823 24%
Source Control, Mechanical Recovery and Surface Dispersant (SC+MR+D)		985,030 5%	2,156,497 11%	243,818 1%		4,928,899 24%
Source Control, Mechanical Recovery, Surface Dispersant and In Situ Burning (SC+MR+D+ISB)		977,390 5%	1,946,450 10%	207,277 1%	319,398 2%	4,906,685 24%
Source Control with Mechanical Recovery, Surface and Subsurface Dispersant, and In Situ Burning (SC+MR+D+ISB+SubD)		871,519 4%	1,781,130 9%	1,341,684 7%	376,428 2%	5,576,388 28%

Scenario 1, GOM-MC807 is a WCD from an offshore deep-water well where mechanical recovery was the primary tool that removed oil. When used without the aid of other response operations, mechanical recovery was able to remove up to 11% of the oil discharged. For this scenario, in which the oil plume surfaced many miles from the wellhead due to a small droplet size, distribution, and long rise time, the use of high volume mechanical recovery capabilities in the vicinity of where the oil first surfaces yields the best opportunity to remove oil before it spreads and weathers.

When surface applied dispersants were added, oil removed by mechanical recovery decreased slightly, but was still approximately 11%; however, an additional 1% of the oil was also dispersed into the water column thus causing less oil to reach the shoreline. When subsurface dispersants were added, oil removed by mechanical removal decreased to 9%; however, an additional 6% was dispersed into the water column. This is a significant increase in the oil "removed" from the water's surface (actually dispersed into the water column prior to surfacing), as an additional 1.1 million barrels of oil were dispersed. Subsurface dispersant application ultimately had the effect of decreasing the volume of oil on shorelines by over 100,000 bbl and reducing the overall surface oiling footprint by over half a million square miles.

In situ burning only accounted for 2% of the oil removed when used, which is likely a reflection of the limited area where burning could be applied (a small subarea of the High Volume Recovery Division) in this scenario. In situ burning in this scenario was limited by the availability of fireboom and other in situ burning equipment, and modeling equipment thresholds for wave height, wind, and viscosity and thickness of oil on the water surface.

Figure 16 displays the fate of oil at the end of the 90-day simulation for Scenario 1, GOM-MC807 involving source control, mechanical recovery, in situ burning, surface dispersants and subsurface dispersants (e.g., SC+MR+D+ISB+SubD).

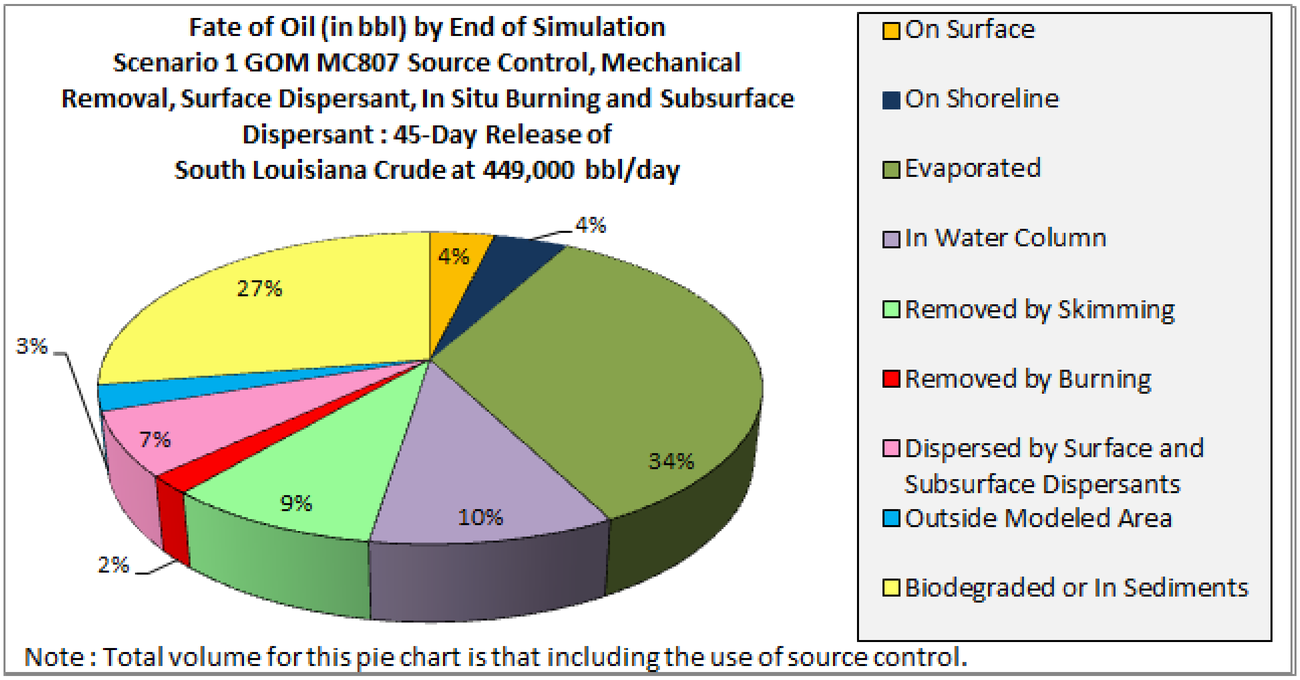


Figure 16: Scenario 1, GOM-MC807 – Fate of Oil at End of 90-Day Simulation (Scenario includes Source Control, Mechanical Recovery, Surface and Subsurface Dispersant, and In Situ Burning Countermeasures)

Reductions in Surface and Shoreline Oiling

Table 22 provides a comparison of the shoreline and water surface oiling results for each of the GOM-MC807 response countermeasure simulations.

Table 22: Scenario 1, GOM-MC807 – Comparison of Shoreline and Water Surface Oiling Above Equipment Threshold Values or Limitations

Scenario 1, GOM-MC807	Relief Well Only (WCD)	Source Control	Source Control and Mechanical Recovery	Source Control, Mechanical Recovery, and Surface Dispersant	Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning	Source Control with Mechanical Recovery, Surface and Subsurface Dispersant, and In Situ Burning
Volume (bbl) of Shoreline Oiling (to Any Degree)	1,870,728	1,248,709	1,103,124	985,038	977,398	871,526
Percent Reduction in Volume of Shoreline Oiled As Compared to Relief Well Only	-	33%	41%	47%	48%	53%
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	4,528	2,233	2,206	2,066	2,050	2,050
Percent Reduction in Shoreline Length Oiled with ≥1 g/m^2 As Compared to Relief Well Only	-	51%	51%	54%	55%	55%
Cumulative Area (mi^2) of Surface Affected by Oil ≥8g/m^2	11,715,947	6,832,704	6,269,404	5,614,293	5,561,852	4,948,193
Percent Reduction in Surface Affected by Oil ≥8g/m^2 As Compared to Relief Well Only	-	42%	46%	52%	53%	58%

Figure 17 is a visual depiction of the reduction in the surface area affected by ≥8.0 g/m^2 of oil over the 90-day period. The graphic directly compares the levels of maximum water surface oiling over time between the Source Control Only) simulation and the simulation that adds mechanical recovery, surface and subsurface dispersants, and in situ burning (SC+MR+D+ISB+SubD).

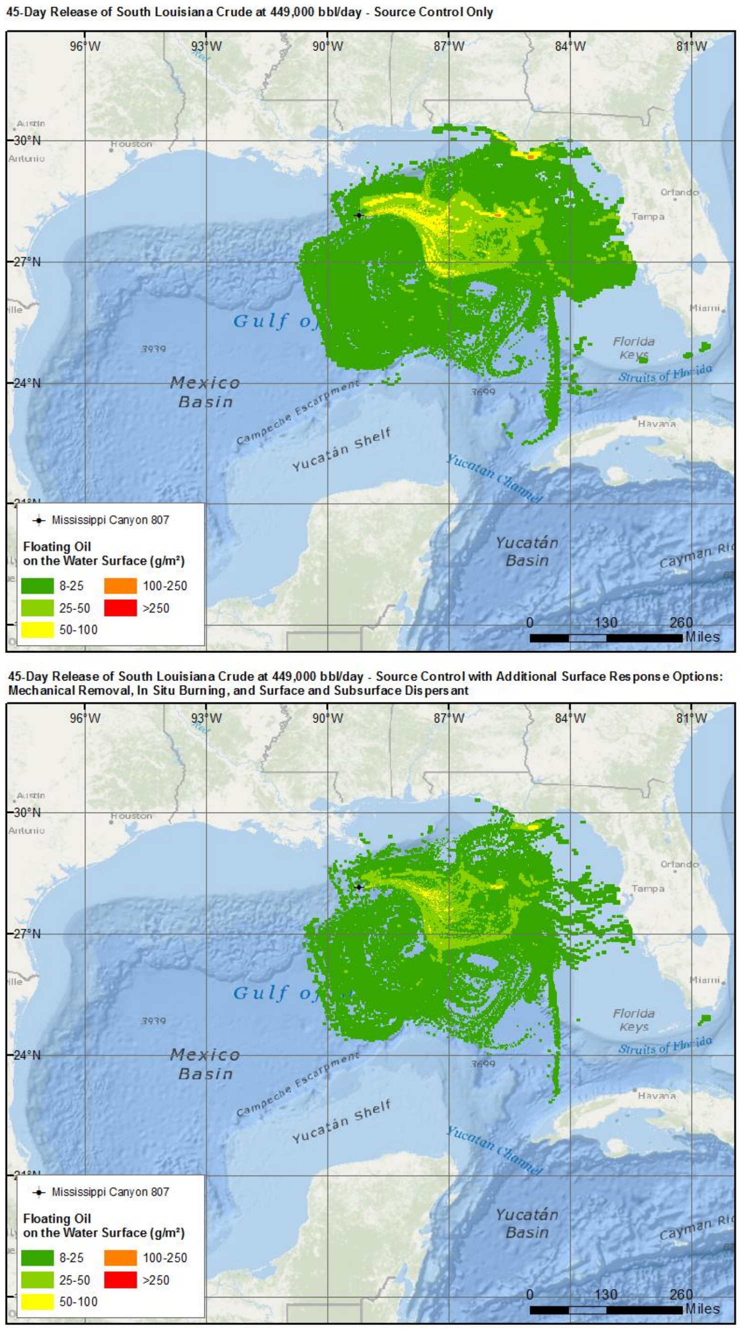


Figure 17: Scenario 1, GOM-MC807 – Comparison Floating Oil Concentration (≥8.0 g/m²) over 90-Day SIMAP Model Simulation, Top Panel: Source Control (SC), Bottom Panel: Source Control, Mechanical Recovery, Surface Dispersants, and In Situ Burning (SC+MR+D+ISB+SubD)

2.1.2.2 *Scenario 2: West Delta 28*

Scenario Site Information

Gulf of Mexico West Delta 28 (WD28) is a nearshore (6.4 miles [5.6 nm] from shore), shallow water (35 ft) well in the Central Gulf of Mexico Planning Area. In the event of a worst case discharge at this site, there is a high probability for rapid, significant shoreline contact (see Figure 18) if spill response countermeasures are not immediately taken. Based on 100 stochastic model runs, the worst case release date for the GOM-WD28 WCD scenario was August 22, 2005.

Table 23: Scenario 2, GOM-WD28 – Well Information and Shoreline Contact Times

WCD Scenario Parameters	
Discharge Flow Rate	97,000 bbl/day
WCD Duration	37 days, Relief Well Only 21 days, Source Control
Total WCD Release Volume	3,589,000 bbl, Relief Well Only 2,037,000 bbl, Source Control
Simulation Duration (45 days following end of discharge)	82 days, Relief Well Only 66 days, Source Control
Oil Type	South Louisiana Crude
API Gravity	34.5
Viscosity @ 15°C (cp)	10.1
Latitude, Longitude	29.13848°N / 89.563623°W
Depth to Sea Floor	35 ft
Distance to Shoreline	6.4 miles (5.6 nm)
SIMAP Model Results [a]	
Time for oil above 1 g/m^2 to reach shore [b]	1 day
Time for oil greater than 8 g/m^2 to reach shore [c]	1 day, Figure 18
[a] SIMAP model results presented in this table are based on the 100 stochastic model runs. [b] The 1 g/m^2 value is the threshold for socio-economic resource effects (e.g., closure of fisheries) (French-McCay et al. 2011; French McCay et al. 2012) [c] The 8 g/m^2 value is the minimum thickness of floating oil for which response equipment can be effectively used (NOAA 2010)	

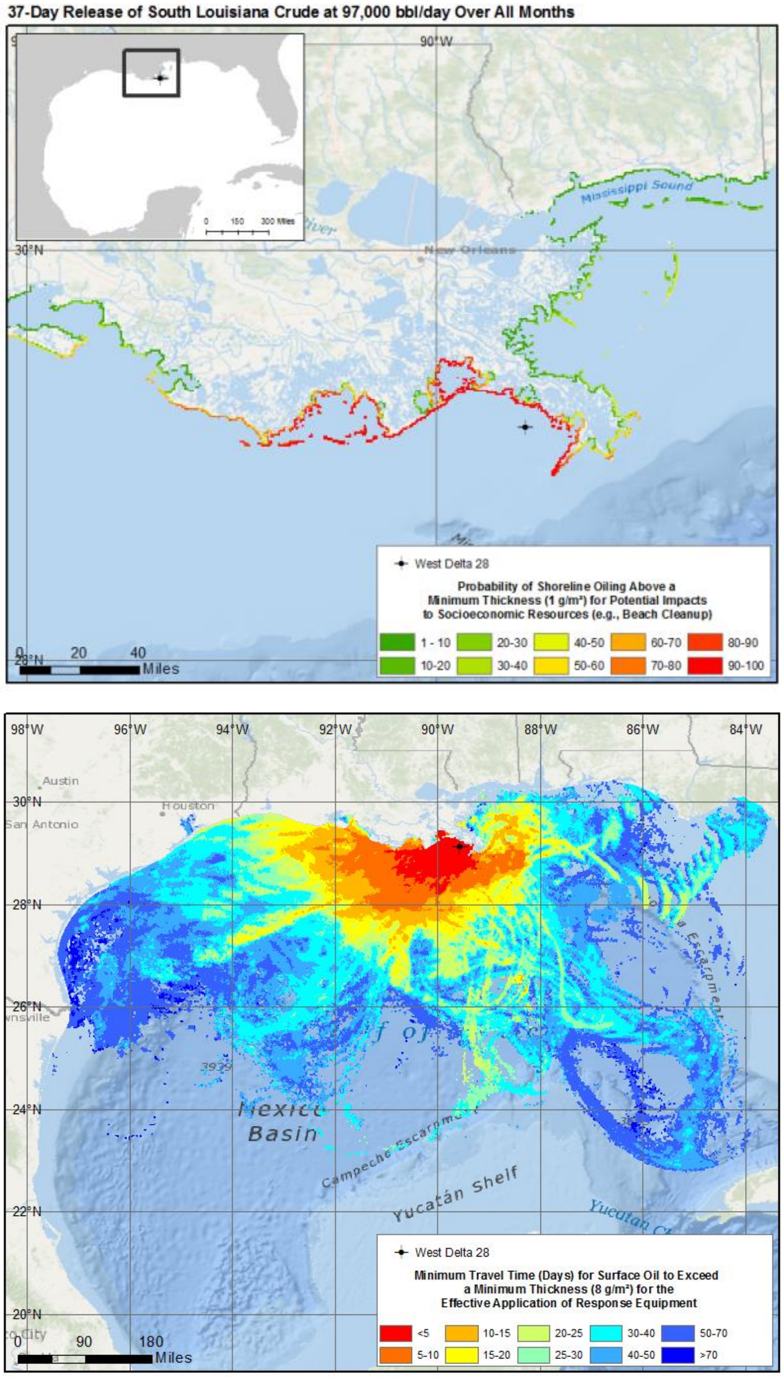


Figure 18: Scenario 2, GOM-WD28 Relief Well Only Scenario, 37-Day Discharge – Probability of Shoreline Oiling and Minimum Travel Times for Surface Oiling

Application of Source Control

When a source control operation is modeled for the WCD GOM-WD28 scenario, the discharge period is reduced by 16 days, and the volume of oil released to the environment is reduced by 1,552,000 bbl. Correspondingly, source control results in substantially less impact to the water column and shoreline in comparison to the Relief Well Only simulation.

Table 24 and Figure 19 compare discharge volume, shoreline-oiling volume, length of oiled shoreline, area of surface oiling, and the amount of oil biodegraded or in the sediments for the Relief Well Only and Source Control Only modeling simulations.

Table 24: Scenario 2, GOM-WD28 – Comparison of Relief Well Only and Source Control Response Scenarios

Scenario 2, GOM-WD28	Relief Well Only (37-day flow duration)	Source Control (21-day flow duration)	Reduction Due to Source Control	Percent Reduction Due to Source Control
Volume Discharged (bbl)	3,589,000 bbl	2,037,000 bbl	1,552,000 bbl	43 %
Volume Shoreline Oiling (bbl) any thickness	460,091 bbl	338,605 bbl	121,486 bbl	26 %
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	1,430 mi	1,266 mi	164 mi	12 %
Cumulative Area (mi^2) of Surface Oiling ≥8g/m^2	1,814,749 mi^2	1,367,833 mi^2	446,916 mi^2	25 %
Amount Biodegraded or In Sediments (bbl) at the End of the Simulation	870,703 bbl	450,132 bbl	420,571 bbl	48 %

As shown in Figure 19, the volume and spread of oil spilled from this WCD is greatly reduced by Source Control; however, without the application of additional response operations to remove or mitigate spilled oil on the surface, the expected contact and exposure to oil in the environment is still quite extensive.

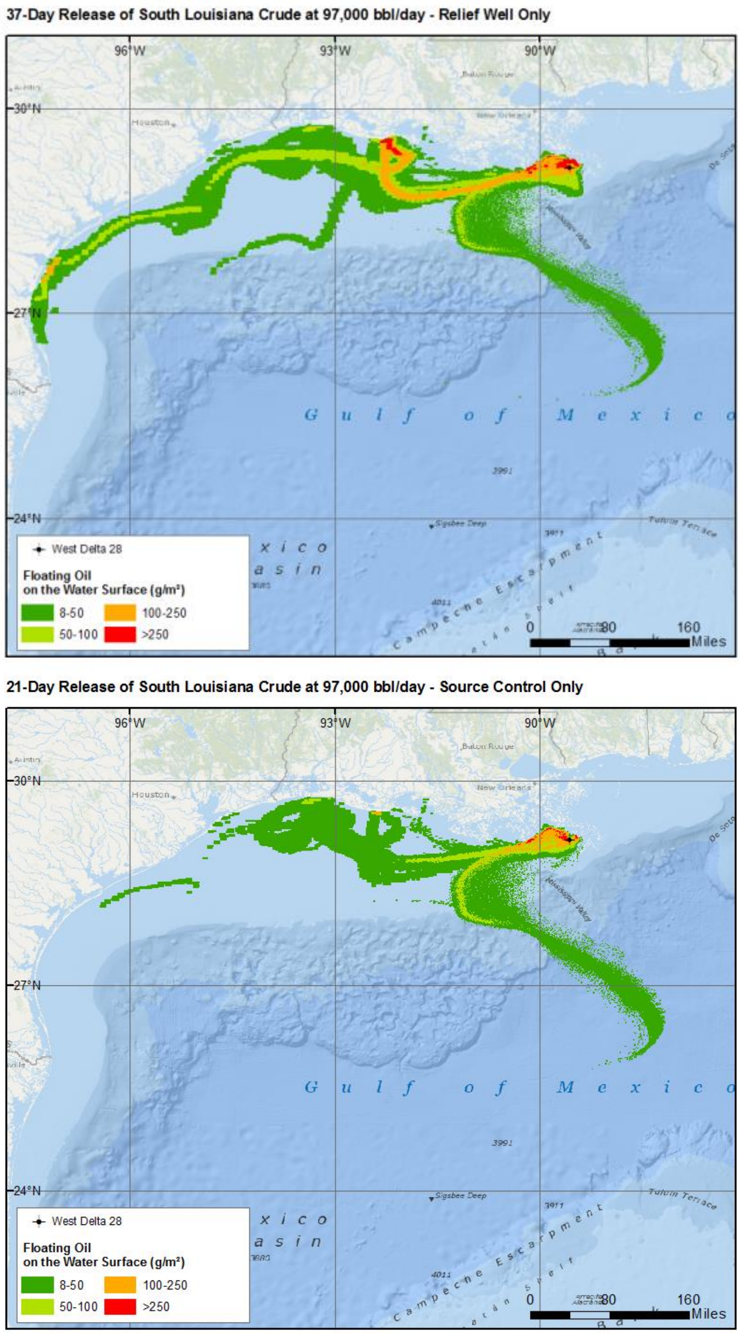


Figure 19: Scenario 2, GOM-WD28 – Comparison of Maximum Concentrations of Surface Oiling Experienced Throughout Simulation Periods for Relief Well Only (37-Day Discharge) and Source Control (21-Day Discharge)

Oil Discharge Behavior

Figure 20 shows the fate of oil for 66 days from the discharge (21-day discharge duration and 45 days following the source control). At the end of the simulation, 49% percent of the total oil had evaporated, 34% had either biodegraded or remained in the water column and sediments, 17% of the oil remained on the shoreline, and <1% of the oil remained floating on the surface. Note that the model does not simulate potential photooxidation of floating oil.

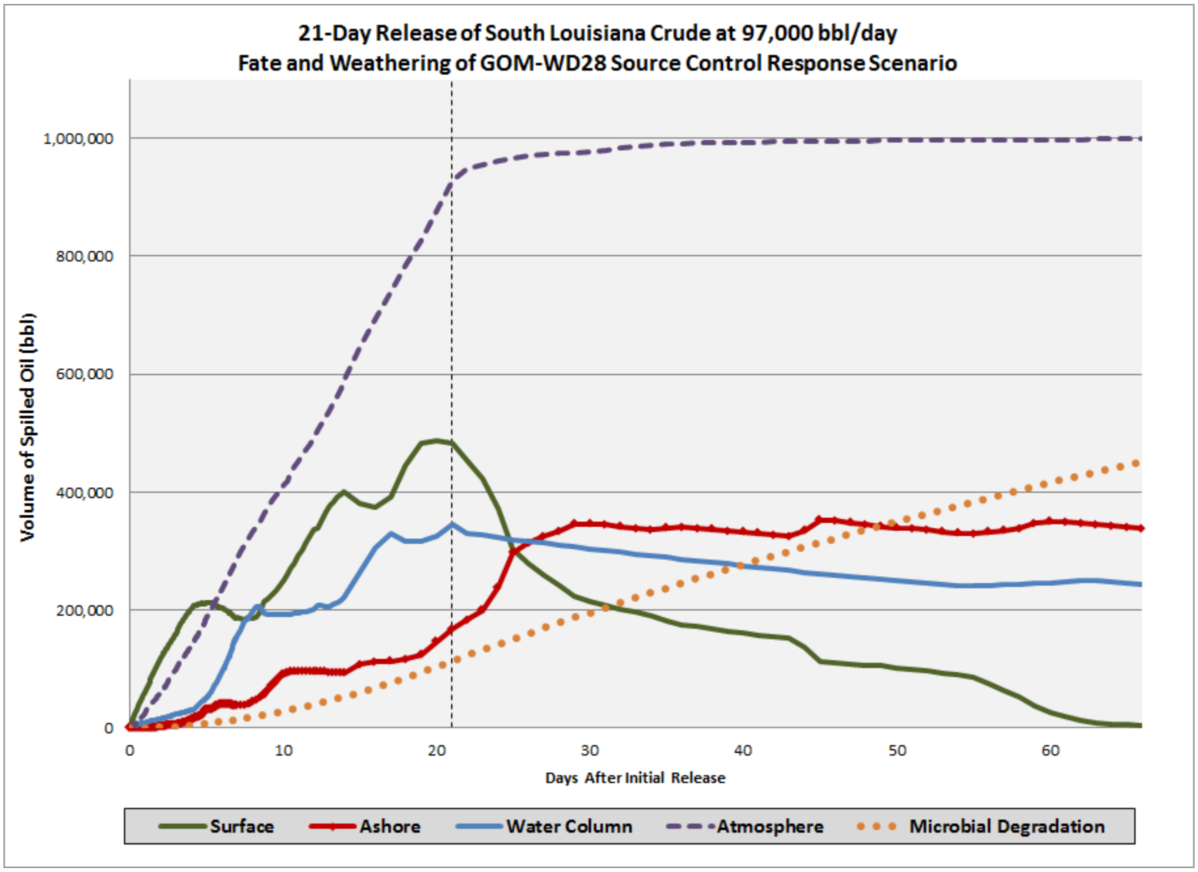


Figure 20: Scenario 2, GOM-WD28 Source Control, 21-Day Discharge – Oil Fate and Weathering (Dotted Vertical Line Indicates Source Control on Day 21)

In Scenario 2, GOM-WD28 Source Control, 93% of the total oil mass discharged from the blowout will reach the surface, while 7% remains entrained within the water column. Upon release from the blowout, oil droplets take less than 1 hour to reach the surface, with most surfacing in the immediate vicinity of the well location. As the oil slick spreads, the surface oil remained thick (> 8 g/m^2) and fresh enough to be recovered or treated (< 20,000 cST) for extended periods (up to 6 days) in calm conditions (Figure 21 and Figure 22), in both the high volume and secondary/nearshore recovery divisions. As winds increased, the surface oil weathered and became unrecoverable and non-dispersible. Figure 21 and Figure 22 display model results at day 6, showing the oil movements and weathering that occurred over the a relatively calm first five days of the discharge. As the winds became stronger from day 6 and beyond, the viscosity of the discharged oil changed more quickly and the effectiveness of response countermeasures was degraded.

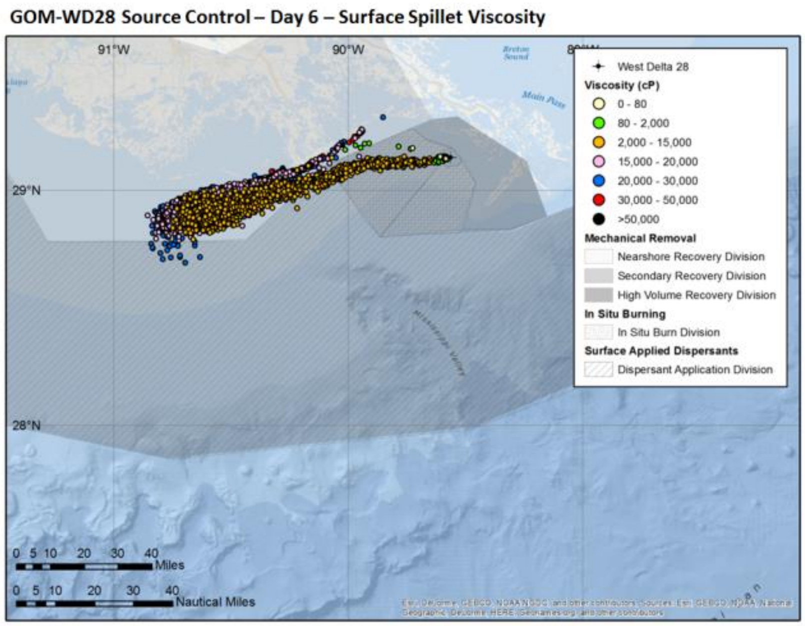


Figure 21: Scenario 2, GOM-WD28 Source Control – Surface Spillet Viscosity (cp) at Day 6

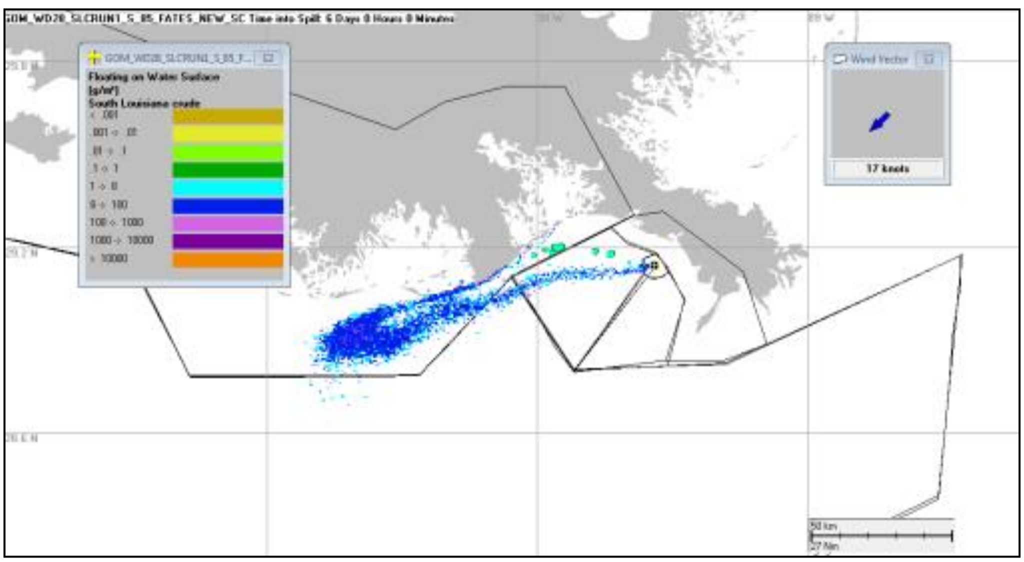


Figure 22: Scenario 2, GOM-WD28 Source Control - Floating Oil on Water Surface (g/m^2) at Day 6

The path of the plume varies over time, but travels in a generally westerly longshore direction. Some oil is entrained in the Gulf of Mexico Loop Current and travels to the southeast. Minimum travel time for contact to shorelines is 0.5 hours, with substantial shoreline impacts beginning within 12 hours of the start of the discharge. At the end of the simulation, the majority of the shoreline oiling over 1 g/m^2 is along the Louisiana and Texas coasts (Figure 23). Shoreline oil in the Florida Keys was transported through the Loop Current and washed ashore as weathered tarballs.

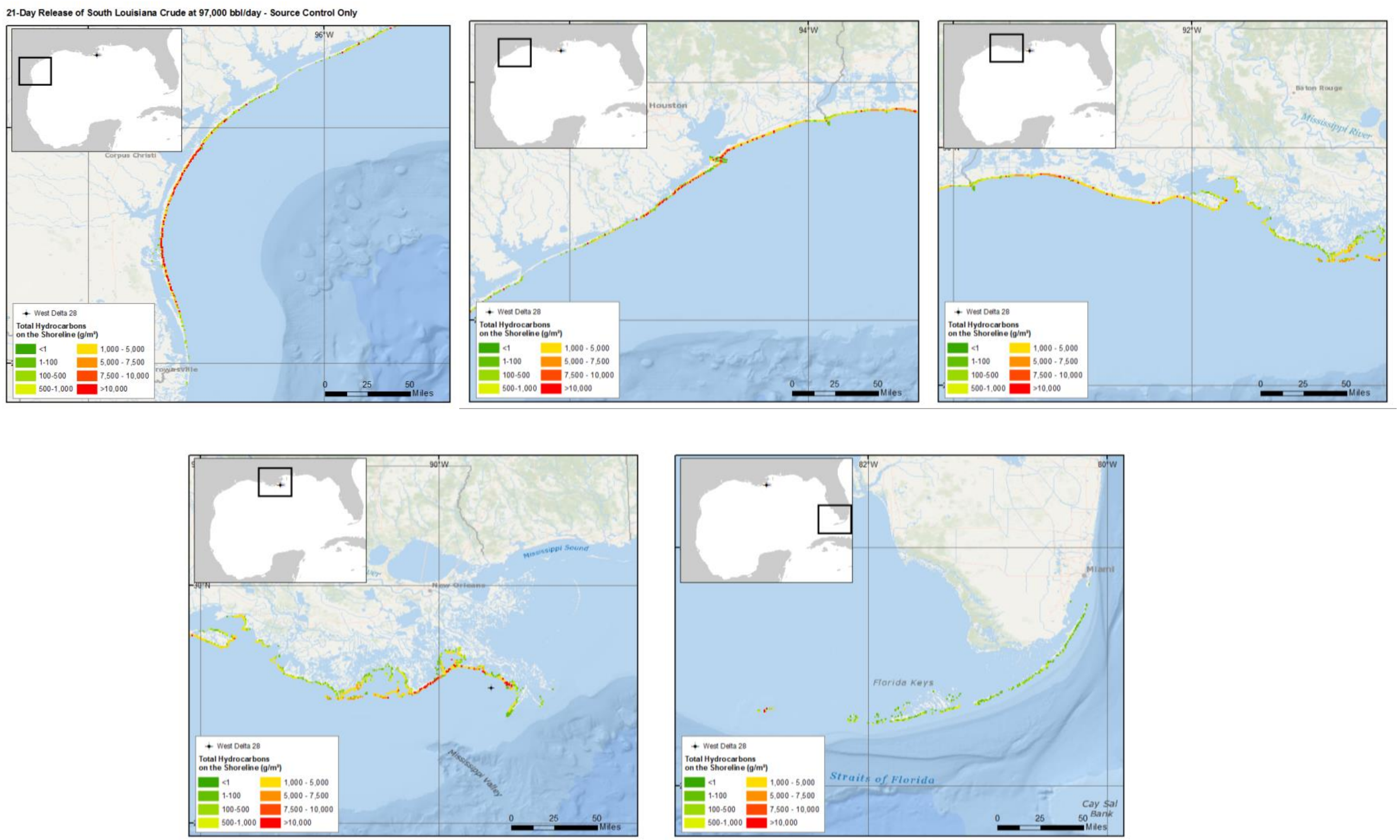


Figure 23: Scenario 2, GOM-WD28 Source Control, 21-Day Discharge – Shoreline Oil ≥1 g/m2, including Weathered Tarballls

Application of Response Countermeasures

Countermeasure Response Divisions

The following equipment types were employed in each of the following countermeasure response divisions, and are shown in Figure 24.

- High Volume Recovery Division – High volume mechanical recovery operations were employed beyond a 0.6 mile (0.5 nm) radius area established around the well for source control.
- In situ Burning Division – In situ burning operations were used in the same geographical area as the high volume mechanical recovery operations (2.9 mile [2.5 nm]) away from the source control area.
- Secondary Recovery Division – Secondary mechanical recovery operations were used to remove oil that was not previously removed in the high volume recovery area.
- Nearshore Recovery Division – Nearshore mechanical recovery operations were used to remove oil from the surface of the water before it was washed onto shorelines.
- Dispersant Application Division – Surface applied dispersants were employed in the high volume and secondary recovery geographical areas beyond a 2.9 mile (2.5 nm) radius area established around the well for source control, as appropriate.

No subsurface dispersants were applied in the GOM-WD28 scenario.

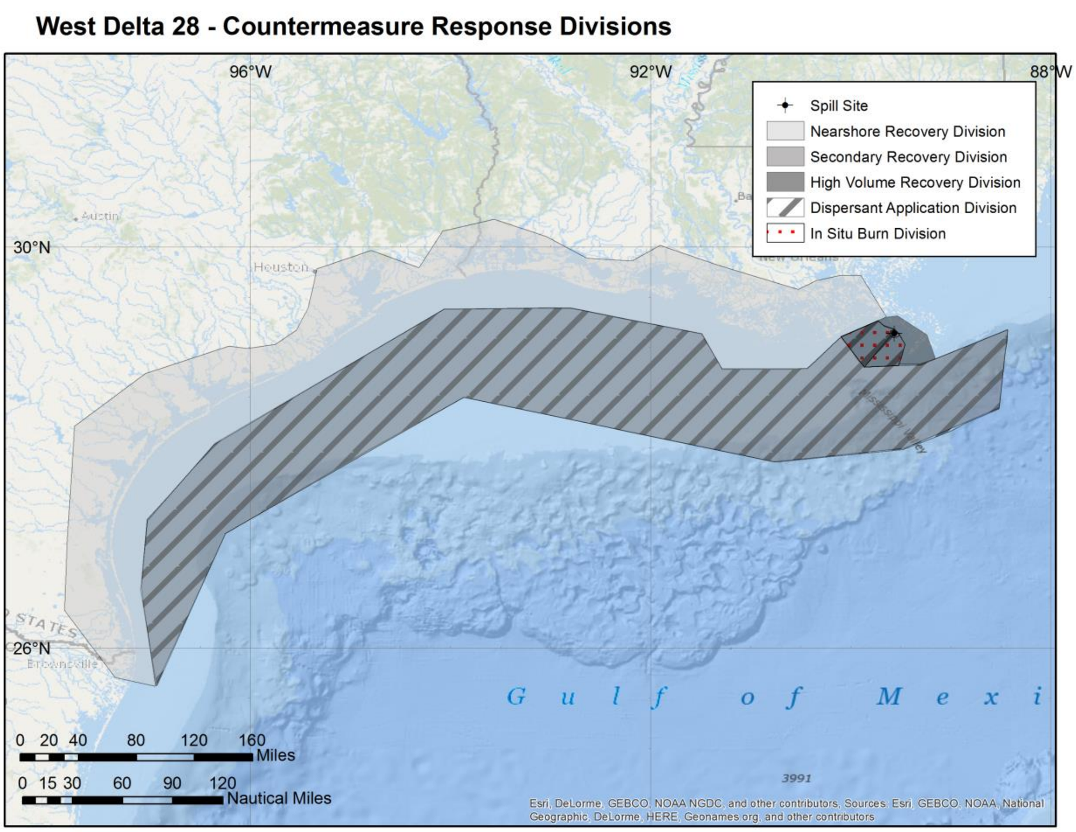


Figure 24: Scenario 2, GOM-WD28 – Geographic Coverage of Oil Countermeasure Response Divisions

The size and placement of the GOM-WD28 response operation divisions in the model were developed based on a review of the oil spill trajectories from the 21-day discharge in the Source Control Only simulation.

Countermeasure/Division Removal Rates (Model Inputs)

The removal rates by countermeasure type and response division that are shown in Table 25 represent the *maximum* potential rate that would be available at any point during the response operation.

As in an actual oil spill recovery operation, the model cascades response equipment into the response divisions as the assets arrive on the scene. The modeling reflects response equipment threshold values and limitations based on the availability of the response equipment to be deployed to the location of the appropriate divisions. As such, the model used oil removal rates for each division (i.e., SIMAP model polygon), based on the maximum potential daily removal rates (bbl/day) of the assigned asset (refer to Table 25), corrected by weather restrictions and daylight operations (as described in Section 1.8). Maximum removal rates are not realized in practice because of the limitations of weather delays, suspension of operations at night, the location of oil in relation to equipment, and performance thresholds, such as oil thickness on the water surface, sea state and currents, winds, and water content during oil emulsification.

These maximum rates are not necessarily applicable for the entire response period. This is because equipment cascades in at different times, and in some cases, resources are allocated to different applications. For example, in this WCD scenario, in situ burning could be conducted in a relatively small area only and was limited by both availability of fireboom and other equipment, as well as thresholds for wave height, winds, viscosity, and thickness of oil on the water surface were reached.

Table 25: Maximum Potential Daily Oil Removal Rates for GOM-WD28 SC+MR+D+ISB Response Scenario [a]

Countermeasure Type	Response Division	Response System Category [b]	Removal Rate Applied [c]	Maximum Potential Daily Removal Rates (bbl/day)
Mechanical	**High-Volume**	Skimmer Group A	ERSP Day-1	86,185
		Skimmer Group B	ERSP Day-1	16,607
		Skimmer Group C	ERSP Day-1	149,513
	Secondary	Skimmer Group A	ERSP Day-3	3,104
		Skimmer Group B	ERSP Day-3	756
		Skimmer Group C	ERSP Day-3	38,030
	Nearshore	Skimmer Group A	ERSP Day-3	7,428
	Total	**All Mechanical Countermeasures**		**301,623**
In Situ Burning	**High-Volume In Situ Burning**	In Situ Burning	Based on ISB Calculator	16,452
Surface Dispersant	**High-Volume and Secondary**	Surface Dispersants	Based on DMP 2	46,962
	Total	**All Countermeasures**		**365,037**

[a] GOM-WD28 SC+MR+D+ISB Response Scenario by countermeasure type and response division *without* application of weather restrictions.

[b] The characteristics of the different types of mechanical equipment and the specific pieces of equipment applied in this scenario are described in Section 2.1. The viscosity thresholds for different types of equipment are further described in Section 1.8.2.

[c] ERSP is described in Section 5.0. "ERSP Day-1" rates are the higher removal rates applied in the areas and times when the oil was flowing from the well and the oil is the thickest. "Day-1" does not necessarily indicate that this is only applied for the first day. "ERSP Day-3" rates are applied in the areas more distant from the well where the oil is thinner and more spread out making removal less efficient. "Day-3" does not necessarily indicate that this is the third day of the response.

For Scenario 2, GOM-WD28 response operation divisions are cascaded in over the course of the initial 18 days (as depicted in Figure 25). Oil began to arrive on the surface after approximately one hour. Commencement of the aerial surface dispersant application occurred on day one of the incident and continued at various daily volumes throughout the 21 days until well shutdown.

Maximum daily application and inventory use was achieved at over 101,000 gallons/day from day 2 through day 15, and then slightly reduced on day 16 to almost 99,000 daily gallons, with an average daily application of 93,575 gallons over the 21-day event for a total of 1,965,080 gallons aerially applied.

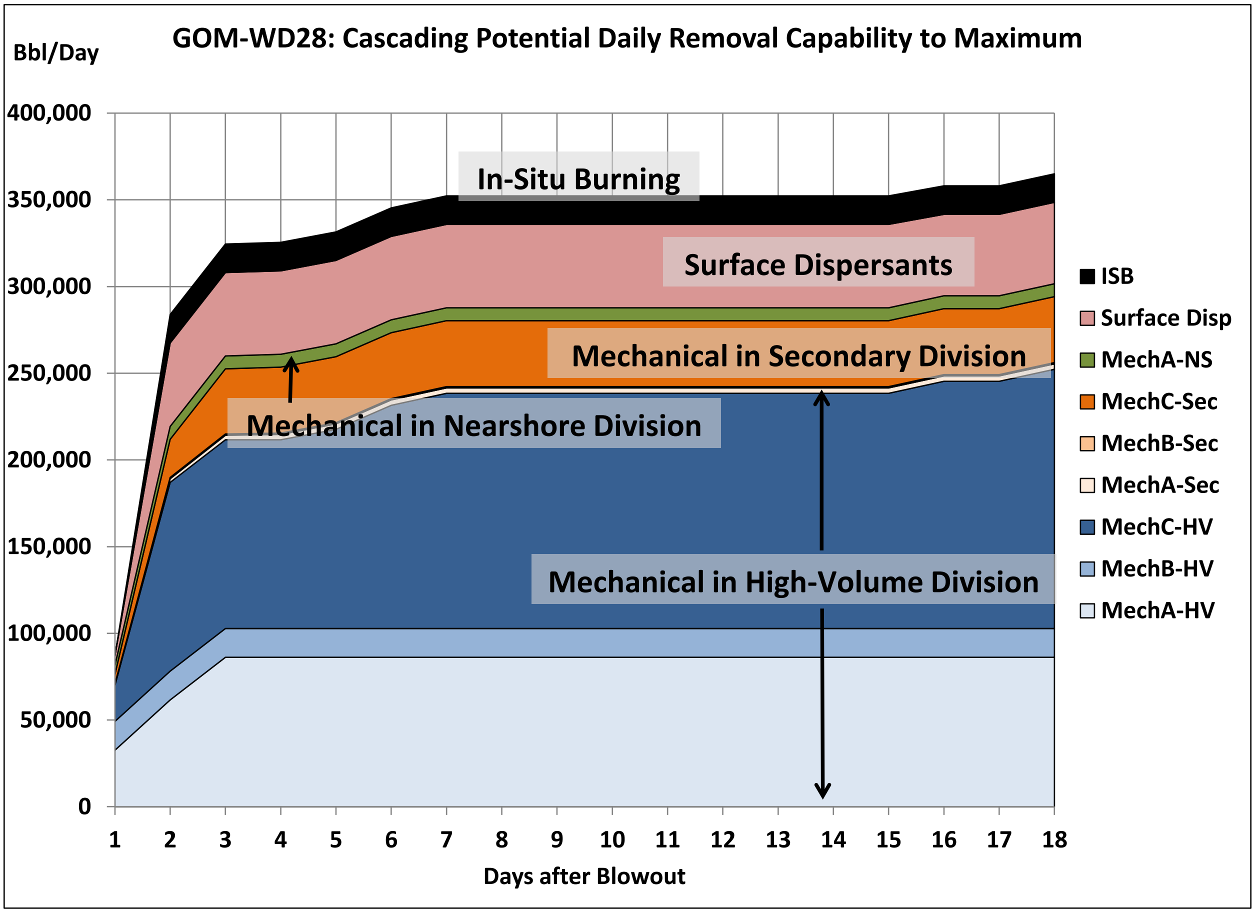


Figure 25: Scenario 2, GOM-WD28 – Cascading SC+MR+D+ISB Response Assets and Cumulative Potential Daily Removal Capacity

Countermeasure Simulation Results & Analysis

Achieved Removal versus Potential Equipment Capabilities

Maximum potential removal rates of oil removal systems are not achieved due to the limitations on countermeasures resulting from oil weathering and other environmental factors (such as increased sea state and darkness which often limited when the countermeasures could be applied). For the GOM-WD28 SC+MR+D+ISB simulation, weather restrictions were in effect for 21% of the time, and for most equipment, the operating period was limited to 12 hours of daylight (other equipment limitations applied are listed in Table 10 , Table 12 , and Table 13). Because of these thresholds and limitations, as well as the availability of recoverable, burnable, or dispersible oil in the response divisions, achieved oil removal was significantly less than the potential recovery capabilities (as shown in Table 26, Figure 26, and Figure 27 for the GOM-WD28 SC+MR+D+ISB simulation).

Table 26 shows the system potential with regard to barrels of oil that could be treated or removed based on the sum total of removal/treatments rates over the course of the entire response operation (i.e., during the release of oil from the well and for an additional 45 days after source control is achieved to stop the flow of oil). The "achieved" removal or treatment reflects the sum total of oil removed or treated over the course of the response operations. Figure 26 contrasts the sum total of potential removal/treatment over the course of the operations and the sum total of the achieved removal/treatment. The daily well flow is shown as a benchmark. The potential removal/treatment capability greatly exceeds the achieved removal/treatment due to the various environmental and logistical factors that limit performance.

Table 26: Scenario 2, GOM-WD28 – SC+MR+D+ISB Cumulative System Potential Oil Recovery versus Achieved Oil Recovery over 66-Day Simulation

Response Type	Response Division	Response System Type	Total Recovery		
			System Potential (bbl)	Achieved (bbl)	% Potential [a]
Mechanical [b]	**High-Volume**	Skimmer Group A	2,775,505	151,585	5%
		Skimmer Group B	496,122	49,712	10%
		Skimmer Group C	3,902,956	683,305	18%
	Secondary	Skimmer Group A	201,038	1,517	1%
		Skimmer Group B	49,140	361	1%
		Skimmer Group C	2,460,921	0	0%
	Nearshore	Skimmer Group A	488,147	7,820	2%
	Mechanical Total	**All**	**10,373,829**	**894,301**	**9%**
In Situ Burning [c]	**High-Volume In Situ Burning**	-	811,914	18,962	2%
Dispersants	**High-Volume/Secondary**	-	934,776	139,893	15%
All Categories	**All Categories Total**	**All**	**19,718,843**	**1,053,156**	**5%**

[a] Achieved Total Recovery divided by System Potential Total Recovery as percentage.

[b] ERSP Day-1 rates assumed for High-Volume Division until well capping (source control); ERSP Day-3rates assumed for Secondary and Nearshore Divisions, and for High-Volume Division after day 21 source control.

[c] EBSP Day-1 rates assumed until day 21 source control, after which EBSP Day-3 rates were applied.

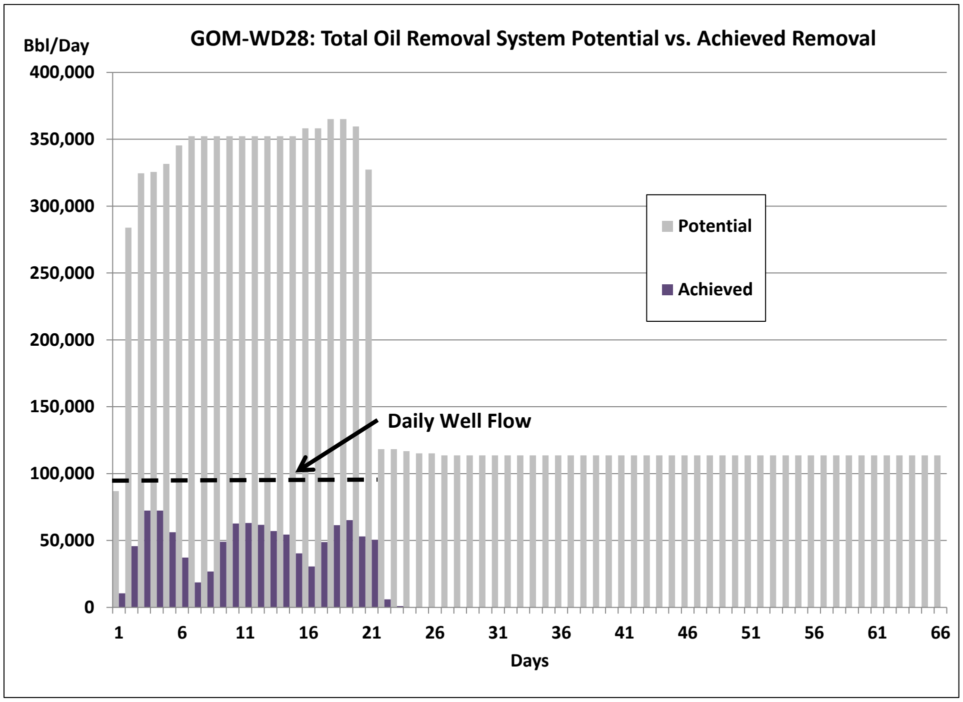


Figure 26: Scenario 2, GOM-WD28 – SC+MR+D+ISB Total Oil Removal System Potential and Achieved Total Daily Removal

Figure 27 contrasts the amount of oil flowing from the well on a daily basis along with the maximum potential daily capability per day, as well as the achieved average daily removal rate. The achieved average daily removal rate is lower than the potential daily removal rate for each day of the scenario.

During the response period, some systems have very low or near-zero removal for some periods because of performance limitations due to environmental conditions, or because there is insufficient oil available, particularly in secondary and nearshore response areas where oil may not appear on the surface until after the oil has stopped flowing.

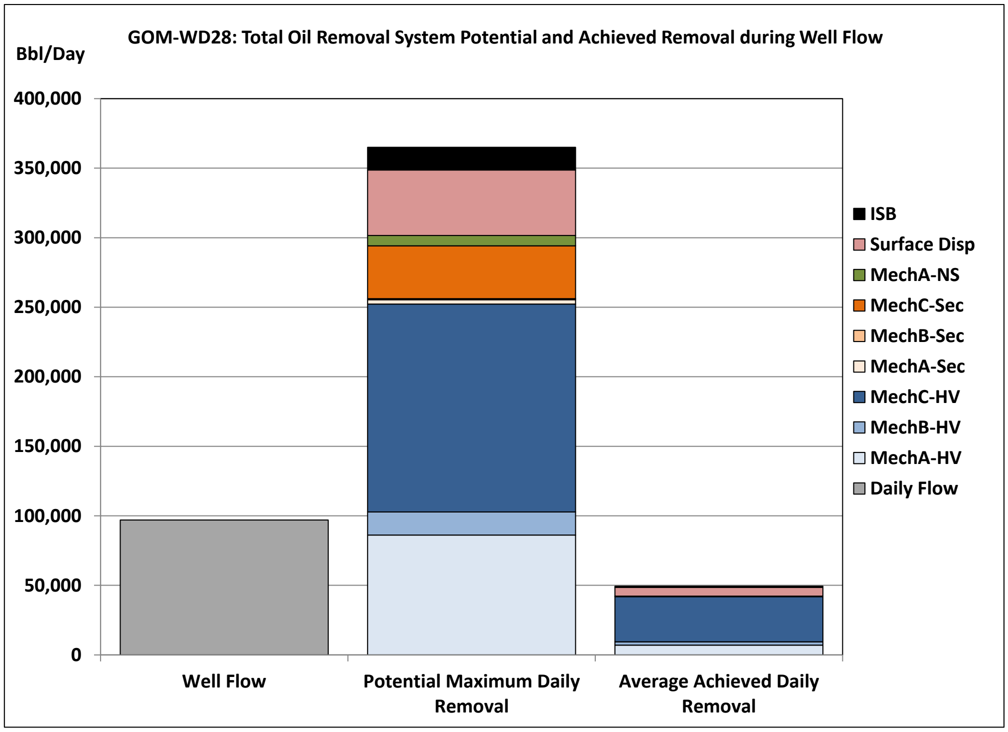


Figure 27: Scenario 2, GOM-WD28 – SC+MR+D+ISB Total Maximum Oil Removal System Potential and Achieved Removal Compared with Well Flow during 21-Day Discharge Period

Oil Removal by Countermeasure Type

Table 27 is a summary of model results for the various response countermeasures applied to the GOM-WD28 scenario. This table allows for comparison of the oiling and oil removal by each countermeasure across the various model simulations. Values within Table 27 represent the volume of oil present/removed at the completion of the response scenarios (66 days).

Scenario 2, GOM-WD28 is a WCD from a nearshore shallow-water well where mechanical recovery was the primary tool that removed oil. When used without the aid of other response operations, mechanical recovery was able to remove up to 47% of the oil discharged in this scenario. These results highlight the efficiency of deploying high-volume mechanical recovery as close to the point of discharge onto the water's surface as possible, before the oil has widely spread out and becomes too thin to remove from the environment.

When surface applied dispersants were added, oil removed by mechanical recovery decreased to 44%; however, an additional 7% of the oil was also dispersed into the water column thus causing less oil to reach the shoreline.

In situ burning only accounted for 1% of the oil removed when used, which is likely a reflection of the limited area where burning could be applied (a small subarea of the High Volume Recovery Division) in this nearshore scenario. As discussed in the earlier Methods section, in situ burning is limited by availability of fireboom and other equipment, and modeling equipment thresholds for wave height, wind, and viscosity and thickness of oil on the water surface.

Figure 28 displays the fate of oil at the end of the 66-day simulation for Scenario 2, GOM-WD28 involving source control, mechanical recovery, in situ burning, and surface dispersants (e.g., SC+MR+D+ISB).

Table 27: Scenario 2, GOM-WD28 – Comparison of Shoreline Oiling and Oil Removal for the Relief Well Only Scenario and Four Response Scenarios at the End of the Model Simulations

Scenario	Volume (bbl) of Discharge	Volume (bbl)/ Percent of Oil on Shoreline	Volume (bbl)/ Percent Removed by Skimming	Volume (bbl)/ Percent Dispersed	Volume (bbl)/ Percent Removed by Burning	Volume (bbl)/ Percent Bio-degraded or in Sediments
Relief Well Only, 37 Day Discharge	3,589,000	460,091				870,703
Source Control (SC), 21 Day Discharge	2,037,000	338,605 17%				450,132 22%
Source Control and Mechanical Recovery (SC+MR)	2,037,000	83,674 4%	947,315 46%			202,893 10%
Source Control, Mechanical Recovery and Surface Dispersant (SC+MR+D)	2,037,000	19,026 1%	899,892 44%	142,491 7%		254,394 12%
Source Control, Mechanical Recovery, Surface Dispersant and In Situ Burning (SC+MR+D+ISB)	2,037,000	16,157 1%	894,315 44%	139,895 7%	18,962 1%	249,229 12%

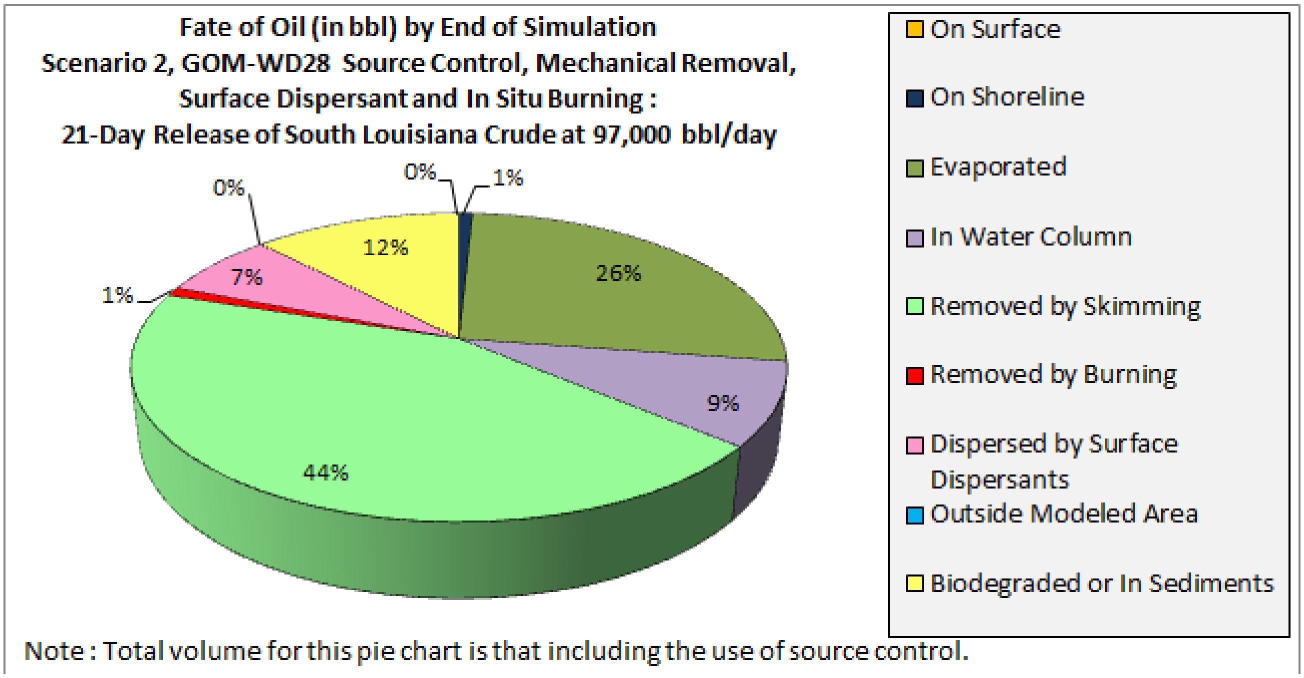


Figure 28: Scenario 2, GOM-WD28 – Fate of Oil at End of 66-Day Simulation (Scenario includes Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning Response Operations)

Reductions in Surface and Shoreline Oiling

Table 28 provides a comparison of the shoreline and water surface oiling results for each of the GOM-WD28 response countermeasure simulations.

Table 28: Scenario 2, GOM-WD28 – Comparison of Shoreline and Water Surface Oiling Above Equipment Threshold Values or Limitations

Scenario 2, GOM-WD28	Relief Well Only (WCD)	Source Control	Source Control and Mechanical Recovery	Source Control, Mechanical Recovery, and Surface Dispersant	Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning
Volume (bbl) of Shoreline Oiling (to Any Degree)	460,094	338,606	83,674	19,026	16,157
Percent Reduction in Volume of Shoreline Oiled As Compared to Relief Well Only	-	26%	82%	96%	97%
Total Length (mi) of Shoreline Oiled with ≥1g/m²	1,430	1,266	815	263	189
Percent Reduction in Shoreline Length Oiled with ≥1 g/m² As Compared to Relief Well Only	-	12%	43%	82%	87%
Cumulative Area (mi²) of Surface Affected by Oil ≥8g/m²	1,814,749	1,367,833	406,291	33,870	26,301
Percent Reduction in Surface Affected by Oil ≥8g/m² As Compared to Relief Well Only	-	25%	78%	98%	99%

Figure 29 is a visual depiction of the reduction in the surface area affected by ≥8.0 g/m² of oil over the 66-day period. The graphic directly compares the levels of maximum water surface oiling over time between the Source Control Only simulation and the simulation that adds mechanical recovery, dispersants, and burning (SC+ MR+D+ISB).

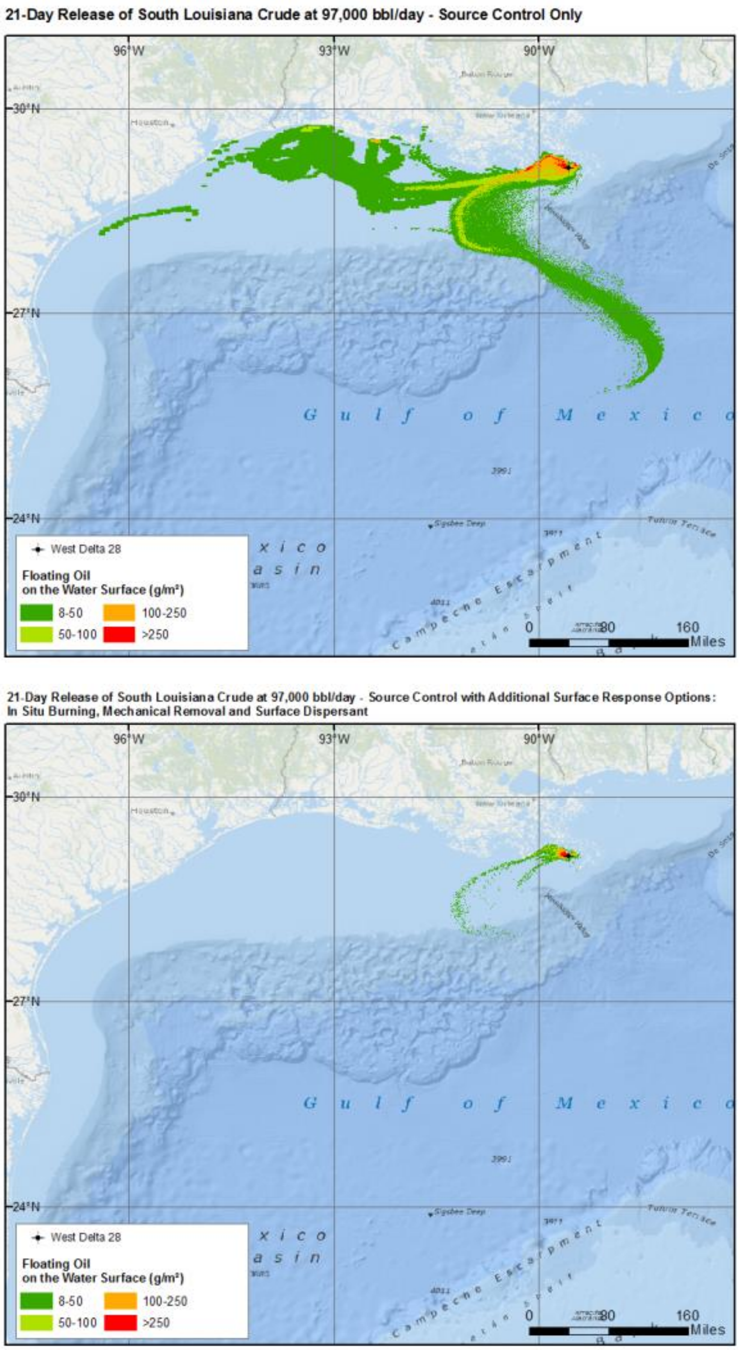


Figure 29: Scenario 2, GOM-WD28 – Comparison Floating Oil Concentration (≥8.0 g/m^2) over 66-Day SIMAP Model Simulation, Top Panel: Source Control (SC), Bottom Panel: Source Control, Mechanical Recovery, Surface Dispersants, and In Situ Burning (SC+MR+D+ISB)

2.1.2.3 *Scenario 3: West Cameron 168*

Scenario Site Information

West Cameron 168 (WC168) is an oil condensate well 29 miles [25 nm] from shore with a water depth of 42 ft in the Central Gulf of Mexico Planning Area. Based on 100 stochastic model runs, the worst case release date for the GOM-WC168 WCD scenario was December 21, 2006.

Table 29: Scenario 3, GOM-WC168 – Well Information and Shoreline Contact Times

WCD Scenario Parameters	
Discharge Flow Rate	26,400 bbl/day
WCD Duration	76 days, Relief Well Only 21 days, Source Control
Total WCD Release Volume	2,006,400 bbl, Relief Well Only 554,400 bbl, Source Control
Simulation Duration (45 days following end of discharge)	121 days, Relief Well Only 66 days, Source Control
Oil Type	Condensate (South Louisiana)
API Gravity	57.5
Viscosity @ 25°C (cp)	2.0
Latitude, Longitude	29.388171°N / 93.406424°W
Depth to Sea Floor	42 ft
Distance to Shoreline	29 miles (25 nm)
SIMAP Model Results [a]	
Time for oil above 1 g/m² to reach shore [b]	2 days
Time for oil greater than 8 g/m² to reach shore [c]	5.5 days (Figure 30)

[a] SIMAP model results presented in this table are based on the 100 stochastic model runs.

[b] The 1 g/m² value is the threshold for socio-economic resource effects (e.g., closure of fisheries) (French McCay et al. 2011; French McCay et al. 2012)

[c] The 8 g/m² value is the minimum thickness of floating oil for which response equipment can be effectively used (NOAA 2010)

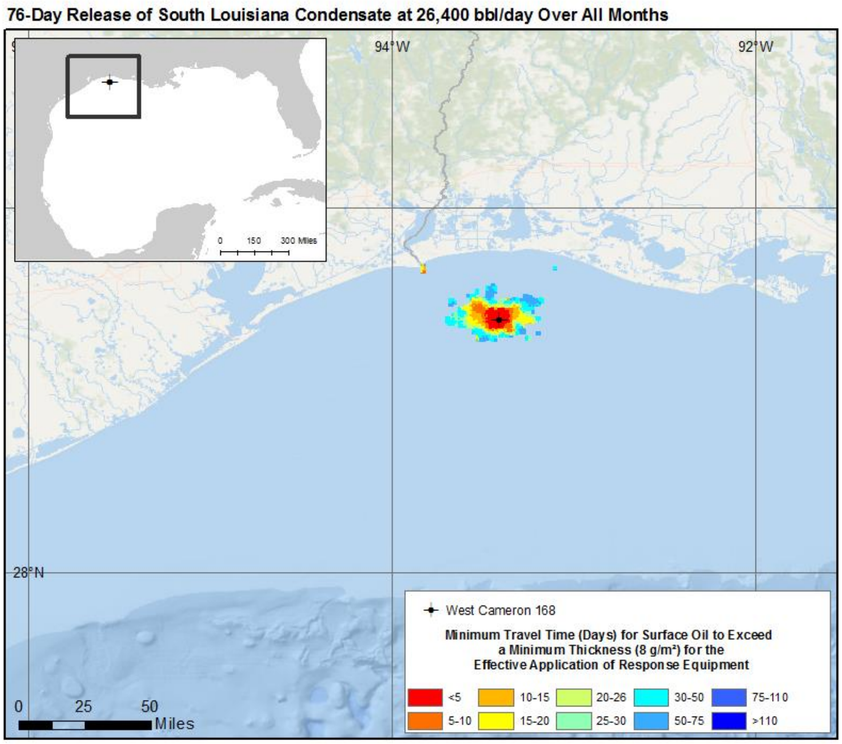


Figure 30: Scenario 3, GOM-WC168 Relief Well Only Scenario, 76-Day Discharge –Minimum Travel Times for Surface Oiling

Application of Source Control

When a source control operation is modeled for the WCD GOM-WC168 scenario, the discharge period is reduced by 55 days, and the volume of oil released to the environment is reduced by 1,452,000 bbl. Correspondingly, source control results in substantially less oil contact with the water column and shoreline in comparison to the Relief Well Only simulation. Table 30 compares discharge volume, shoreline-oiling volume, length of oiled shoreline, area of surface oiling, and the amount of oil biodegraded or in the sediments for the Relief Well Only and Source Control Only modeling simulations.

Table 30: Scenario 3, GOM-WC168 – Comparison of Relief Well Only and Source Control Response Scenarios

Scenario 3, GOM-WC168	Relief Well Only (76-day flow duration)	Source Control (21-day flow duration)	Reduction Due to Source Control	Percent Reduction Due to Source Control
Volume Discharged (bbl)	2,006,400 bbl	554,400 bbl	1,452,000 bbl	72 %
Volume Shoreline Oiling (bbl) any thickness	15,150 bbl	4,272 bbl	10,878 bbl	72 %
Total Length (mi) of Shoreline Oiled with ≥1g/m²	539 mi	122 mi	417 mi	77 %
Cumulative Area (mi²) of Surface Oiling ≥8g/m²	62,073 mi²	9,375 mi²	52,698 mi²	85 %
Amount Biodegraded or In Sediments (bbl) at the End of the Simulation	152,084 bbl	33,060 bbl	119,024 bbl	78 %

While the cumulative area of surface oiling ≥8g/m² is reduced by nearly 53,000 mi² (Table 30) with the use of source control, the geographic extent of surface oil spilled does not vary significantly between the two simulations (Figure 31).

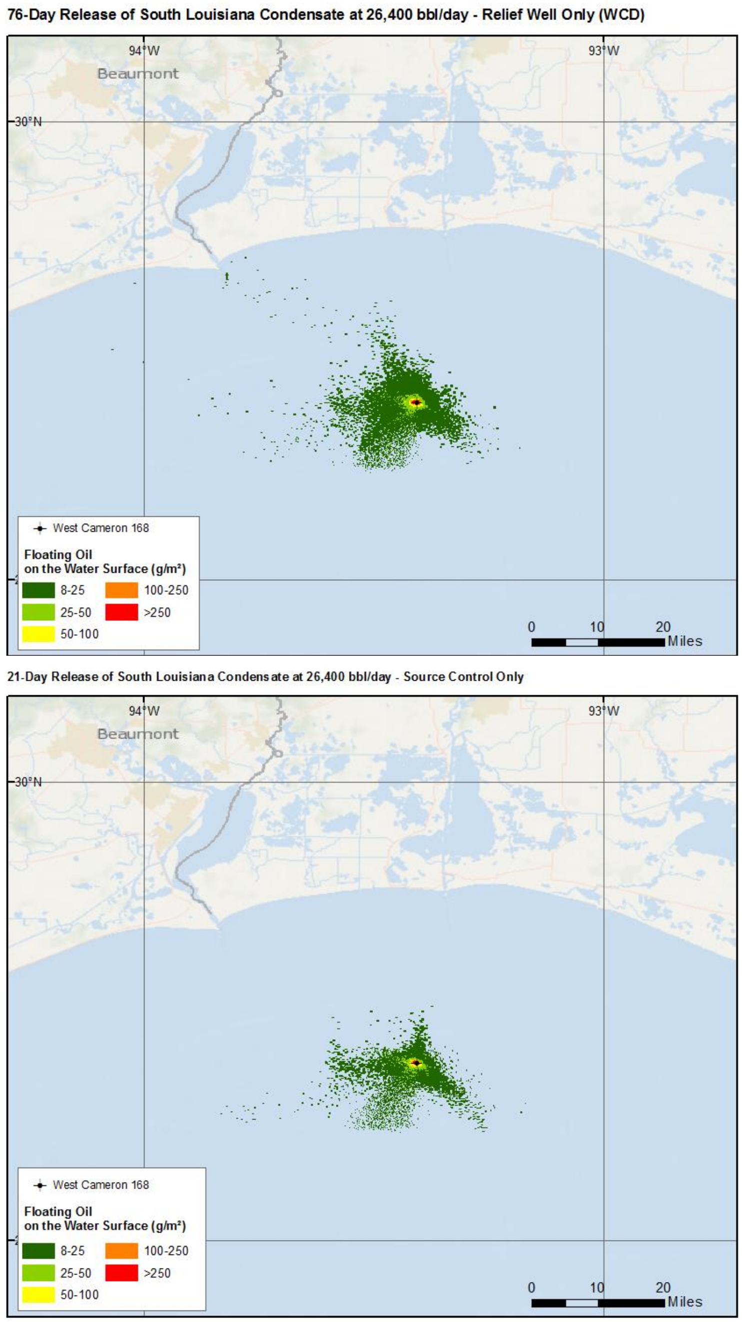


Figure 31: Scenario 3, GOM-WC168 – Comparison of Maximum Concentrations of Surface Oiling Experienced Throughout Simulation Periods for Relief Well Only (76-Day Discharge) and Source Control (21-Day Discharge)

Oil Discharge Behavior

Figure 32 shows the fate of oil for 66 days from the discharge (21-day discharge duration and 45 days following the source control). At the end of the simulation, 86% percent of the total oil had evaporated, 13% had either biodegraded or remained in the water column and sediments, 1% of the oil remained on the shoreline, and <1% of the oil remained floating on the surface. Note that the model does not simulate potential photooxidation of floating oil.

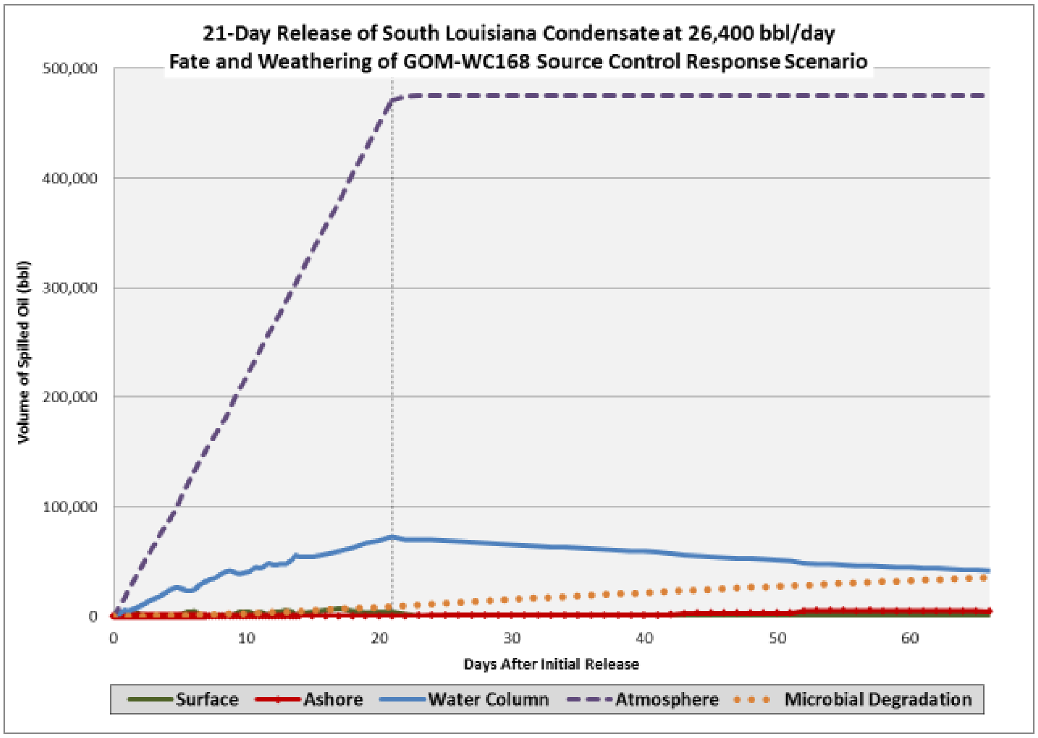


Figure 32: Scenario 3, GOM-WC168 Source Control, 21-Day Discharge – Oil Fate and Weathering (Dotted vertical line indicates source control on Day 21)

In GOM-WC168 Source Control simulation, 93% of the total oil mass discharged from the blowout reached the surface, while 7% remained entrained within the water column. Upon release from the wellhead, oil droplets took less than 1 hour to surface, with most surfacing in the immediate vicinity of the well location. As the oil slick spread, the surface oil remained thick (> 8 g/m^2) enough to be recovered mechanically in the high volume response division; however, surface oil thickness reduced relatively quickly because of the highly volatile nature of the discharged condensate. The oil remained fresh enough to be recovered or treated (< 20,000 cST with a maximum of 2,000 cST) for the entire period of the discharge (Figure 33) across both the high volume and secondary/nearshore response divisions. Correspondingly, the surface oil became too thin (< 8 g/m^2) for recovery outside of the high volume response division (Figure 34). Figure 33 and Figure 34 demonstrate these results by showing the movement of the oil plume across the high volume and secondary response divisions in the 1-8 g/m^2 and 0.01-1 g/m^2 thickness ranges, and the tendency for the oil to evaporate, spread, and dissipate on the surface.

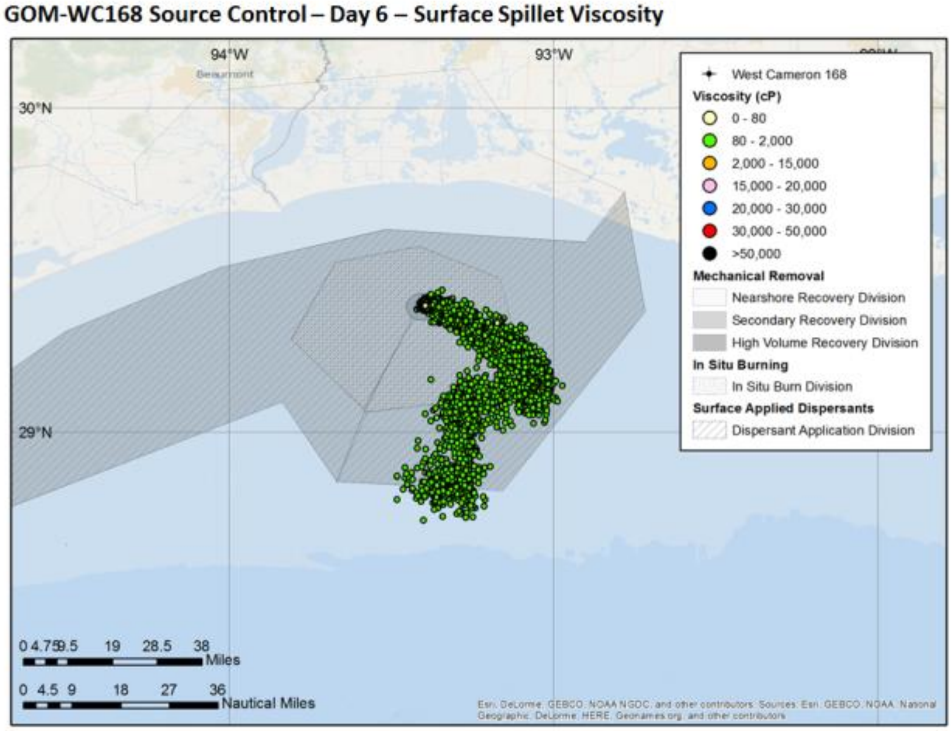


Figure 33: Scenario 3, GOM-WC168 Source Control – Surface Spillet Viscosity (cp) at Day 6

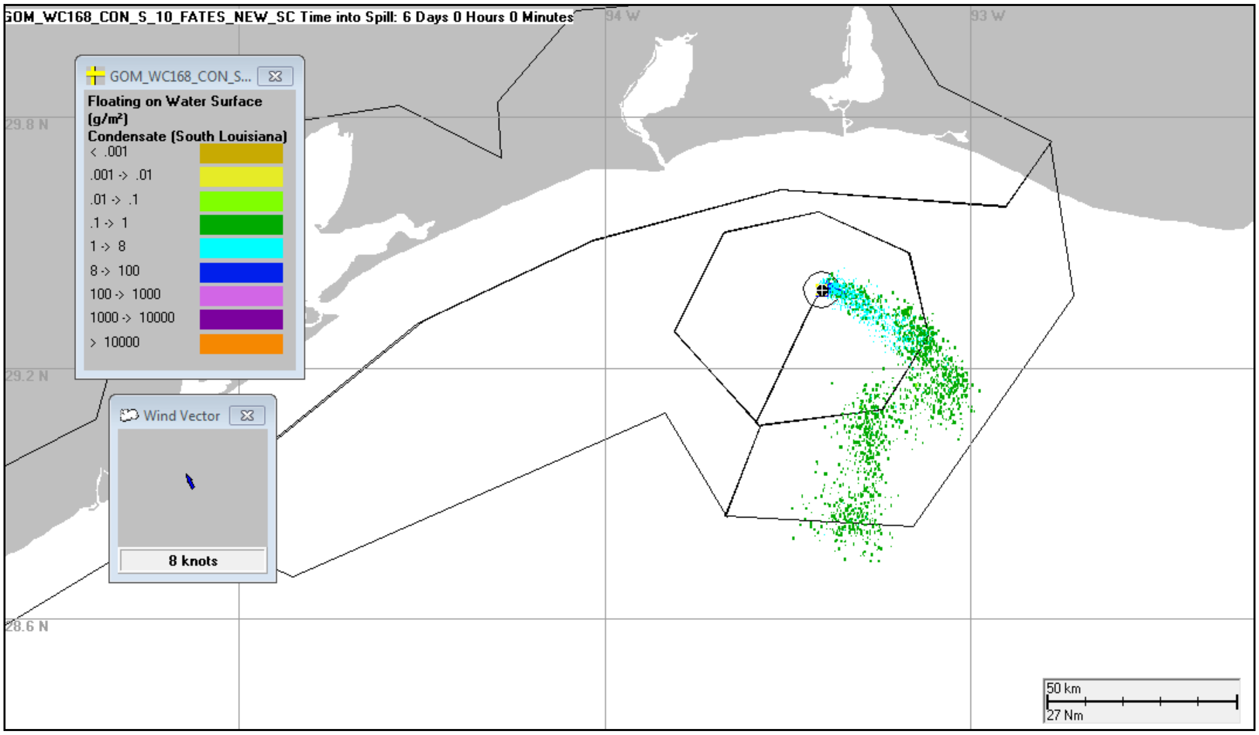


Figure 34: Scenario 3, GOM-WC168 Source Control – Floating Oil on Water Surface (g/m^2) at Day 6

The path of the plume varied significantly over time as the winds shifted several times between northerly and southerly flows. The oil plume tended to spread out over a larger area during periods of low winds, and substantially decreased in size during higher wind conditions as the oil dissipated due to increases in evaporation and mixing energy in the water column.

Minimum travel time for contact with shorelines was 23 days, with substantial shoreline impacts beginning only after Day 24. At the end of the simulation, the majority of the shoreline oiling over 1 g/m^2 was along the southern Texas coast with a very small area also occurring in Louisiana directly adjacent to the Texas border (Figure 35). For this simulation, the currents transport tarballs to southern Texas to the Brownsville area, as shown in Figure 36. While this is ultimately dependent upon the hydrodynamics, there have been many observations of this potential pile-up of tarballs in this general vicinity in previous oil spills because of currents generally moving materials west towards Texas in the Gulf of Mexico. In general, the transport of the model is primarily being driven by the currents in this simulation, since the majority of the spillets were entrained in the water column during the course of the spill. Ultimately, in this simulation, only about 0.5% of the total volume of the spilled oil is on the beach in southern Texas.

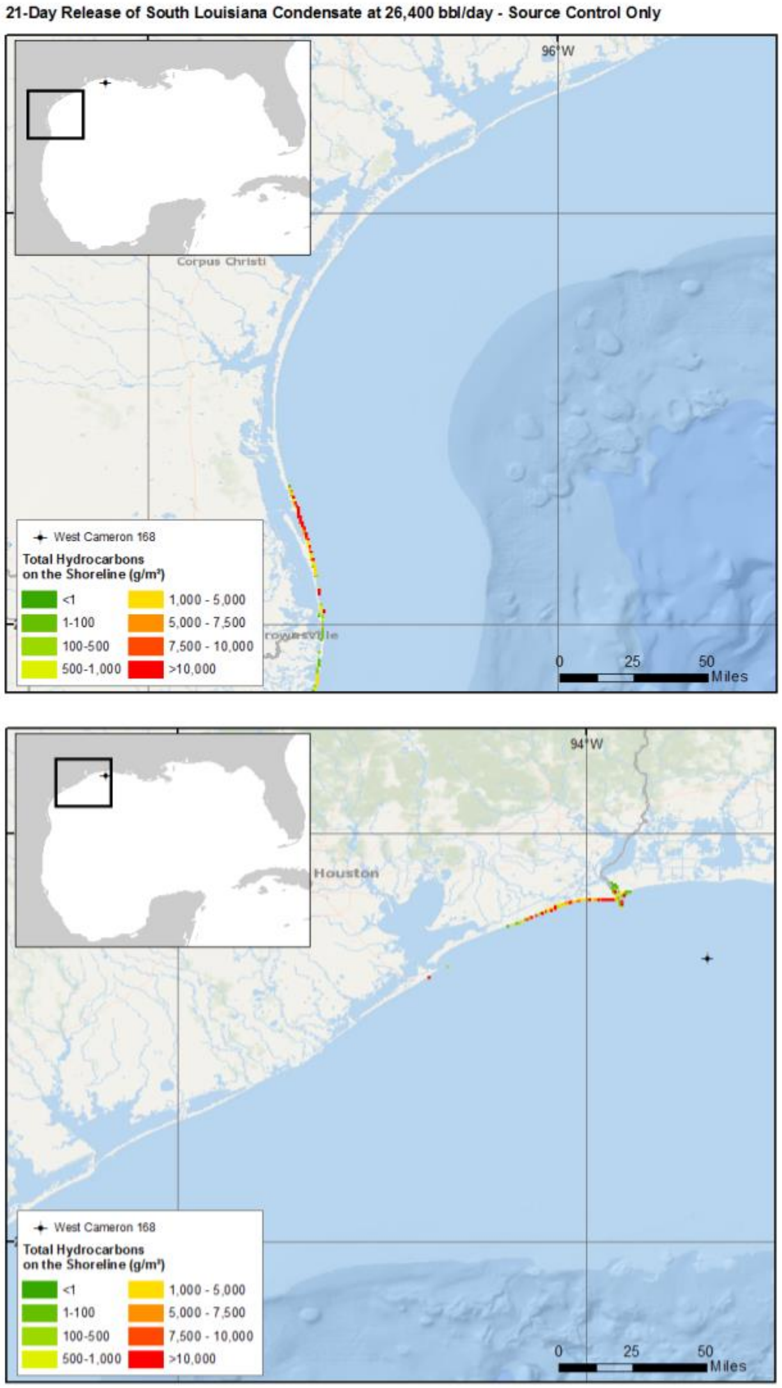


Figure 35: Scenario 3, GOM-WC168 Source Control, 21-Day Discharge – Shoreline Oil ≥1 g/m^2, including Weathered Tarballs

21-Day Release of South Louisiana Condensate at 26,400 bbl/day - Source Control Only

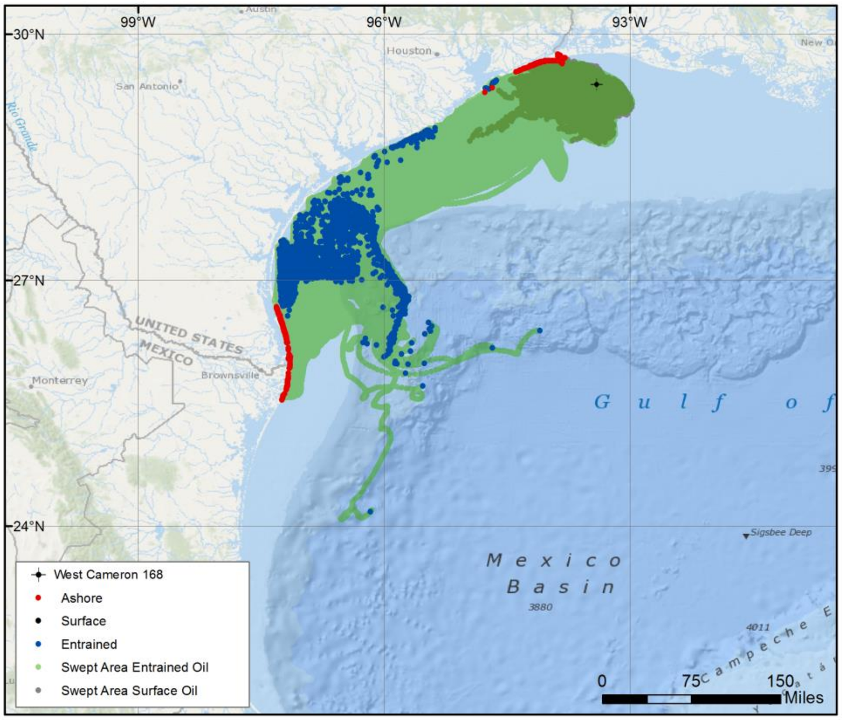


Figure 36: Scenario 3, GOM-WC168 Source Control, 21-Day Discharge – Hydrocarbon Particle Trajectory Showing Swept Area of Surface and Subsurface Oil Over the Course of the Spill (Figure Is a Cumulative Image of the Different Particles Present Throughout the 66-day Model Simulation)

Application of Response Countermeasures

Countermeasure Response Divisions

The following equipment types were employed in each of the following countermeasure response divisions, and are shown in Figure 37.

- High Volume Recovery Division – High volume mechanical recovery operations were employed beyond a 0.6 mile (0.5 nm) radius area established around the well for source control.
- In situ Burning Division – In situ burning operations were used in the same geographical area as the high volume mechanical recovery operations (2.9 mile [2.5 nm]) away from the source control area.
- Secondary Recovery Division – Secondary mechanical recovery operations were used to remove oil that was not previously removed in the high volume recovery area.
- Nearshore Recovery Division – Nearshore mechanical recovery operations were used to remove oil from the surface of the water before it was washed onto shorelines.
- Dispersant Application Division – Surface applied dispersants were employed in the high volume and secondary recovery geographical areas beyond a 2.9 mile (2.5 nm) radius area established around the well for source control, as appropriate.

No subsurface dispersants were applied in the GOM-WC168 scenario.

West Cameron 168 - Countermeasure Response Divisions

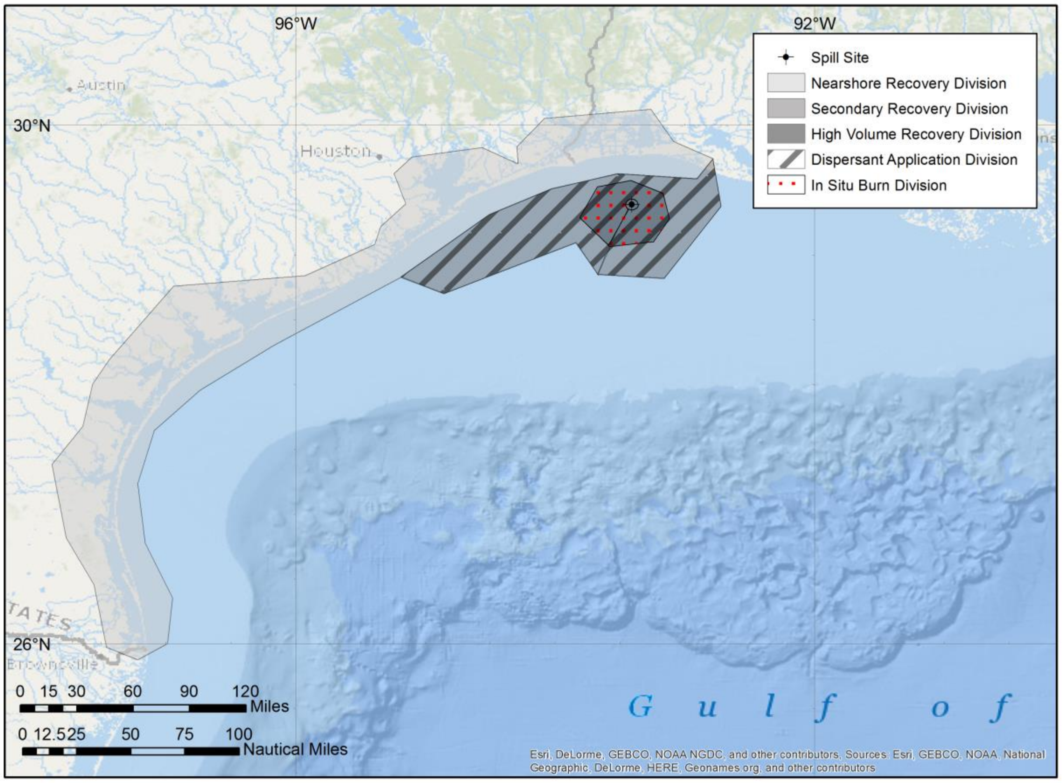


Figure 37: Scenario 3, GOM-WC168 – Geographic Coverage of Countermeasure Response Divisions

The size and placement of the GOM-WC168 response divisions in the model were developed based on a review of the oil spill trajectories from the 21-day discharge in the Source Control Only simulation.

Countermeasure/Division Removal Rates (Model Inputs)

The removal rates by countermeasure type and response division that are shown in Table 19 represent the *maximum* potential rate that would be available at any point during the response operation.

As in an actual oil spill recovery operation, the model cascades response equipment into the response divisions as the assets arrive on the scene. The modeling reflects response equipment threshold values and limitations based on the availability of the response equipment (as determined to be in the stockpiles per OSRO response equipment survey) deployed in the appropriate divisions. As such, the model used oil removal rates for each division (i.e., SIMAP model polygon), based on the maximum potential daily removal rates (bbl/day) of the assigned asset (refer to Table 31), corrected by weather restrictions and daylight operations (as described in Section 1.8). Maximum removal rates are not realized in practice because of the limitations of weather delays, suspension of operations at night, the location of oil in relation to equipment, and performance thresholds, such as oil thickness on the water surface, sea state and currents, winds, and water content during oil emulsification.

Maximum oil removal rates are not necessarily applicable for the entire response period. This is because equipment cascades in at different times, and in some cases, resources are allocated to different applications.

Table 31: Maximum Potential Daily Oil Removal Rates for GOM-WC168 SC+MR+D+ISB Response Scenario [a]

Countermeasure Type	Response Division	Response System Category [b]	Removal Rate Applied [c]	Maximum Potential Daily Removal Rates (bbl/day)
Mechanical	**High-Volume**	Skimmer Group A	ERSP Day-1	109,692
		Skimmer Group B	ERSP Day-1	16,607
		Skimmer Group C	ERSP Day-1	125,281
	Secondary	Skimmer Group A	ERSP Day-3	8,664
		Skimmer Group B	ERSP Day-3	756
		Skimmer Group C	ERSP Day-3	32,567
	Nearshore	Skimmer Group A	ERSP Day-3	6,323
		Skimmer Group B	ERSP Day-3	N/A
		Skimmer Group C	ERSP Day-3	1,079
	Total	**All Mechanical Countermeasures**		**300,969**
In Situ Burning	**High-Volume In Situ Burning**	In Situ Burning	Based on ISB Calculator	16,452
Surface Dispersant	**High-Volume and Secondary**	Surface Dispersants	Based on DMP 2	24,605
	Total	**All Countermeasures**		**342,026**

[a] GOM-WC168 SC+MR+D+ISB Response Scenario by countermeasure type and response division *without* application of weather restrictions.

[b] The characteristics of the different types of mechanical equipment and the specific pieces of equipment applied in this scenario are described in Section 2.1. The viscosity thresholds for different types of equipment are further described in Section 1.8.2.

[c] ERSP is described in Section 5.0. "ERSP Day-1" rates are the higher removal rates applied in the areas and times when the oil was flowing from the well and the oil is the thickest. "Day-1" does not necessarily indicate that this is only applied for the first day. "ERSP Day-3" rates are applied in the areas more distant from the well where the oil is thinner and more spread out making removal less efficient. "Day-3" does not necessarily indicate that this is the third day of the response.

For Scenario 3, GOM-WC168 response divisions are cascaded in over the course of the initial 18 days (as depicted in Figure 38). Oil began to arrive on the surface after approximately one hour. Commencement of the surface dispersant application began on day 1 of the incident.

Maximum daily dispersant application was achieved on day 2 (approx. 52,000 gallons/day), with an average daily application of 50,283 gallons and 1,055,950 gallons applied over the 21-day event.

It should be noted that the oil modeled in WC168 is an oil condensate. The significant volume of surface dispersant applied resulted, pursuant to the modeling, in 0% of the condensate being dispersed, therefore for this specific scenario, the modeling results indicate the need for re-evaluating the advisability of applying dispersants on this type of oil. Decisions to apply surface dispersants on condensate, may necessitate an FOSC decision based upon specific scenarios of well location, other environmental factors and the availability of other response resources, that would go into the determination on the advisability of using dispersant response methodologies on this type of oil.

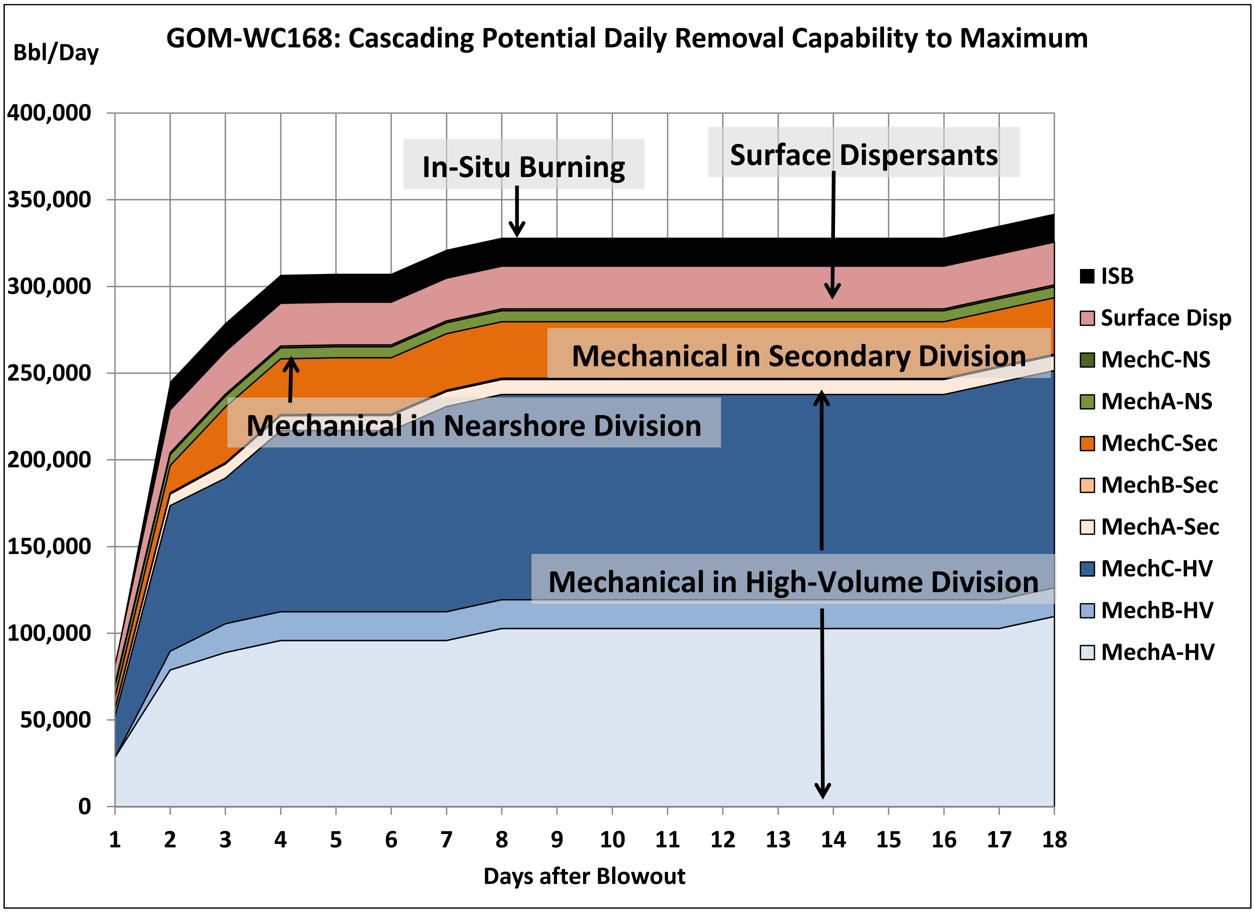


Figure 38: Scenario 2, GOM-WC168 – Cascading SC+MR+D+ISB Response Assets and Cumulative Potential Daily Removal Capacity

Countermeasure Simulation Results & Analysis

Achieved Removal versus Potential Equipment Capabilities

Maximum potential removal rates of oil removal systems are not achieved due to the limitations on countermeasures resulting from oil weathering, amounts of oil available for removal and other environmental factors (such as increased sea state and darkness which often limited when the countermeasures could be applied). For the GOM-WD-168 SC+MR+D+ISB simulation, weather restrictions were in effect for 21% of the time, and for most equipment, the operating period was limited to 12 hours of daylight (other equipment limitations applied are listed in Table 10 , Table 12 , and Table 13). Because of these thresholds and limitations, as well as the availability of recoverable, burnable, or dispersible oil in the response divisions, achieved oil removal was significantly less than the potential recovery capabilities (as shown in Table 32, Figure 39, and Figure 40) for the GOM-WC168 SC+MR+D+ISB simulation). In fact, no oil was removed in any division except the High Volume Recovery Division, and no oil was dispersed.

Table 32 shows the system potential with regard to barrels of oil that could be treated or removed based on the sum total of removal/treatments rates over the course of the entire response operation (i.e., during the release of oil from the well and for an additional 45 days after source control is achieved to stop the flow of oil). The "achieved" removal or treatment reflects the sum total of oil removed or treated over the course of the response operations. Figure 39 contrasts the sum total of potential removal/treatment over the course of the operations and the sum total of the achieved removal/treatment. The daily well flow is shown as a benchmark. The potential removal/treatment capability greatly exceeds the achieved removal/treatment due to the various environmental and logistical factors that limit performance.

Table 32: Scenario 3, GOM-WC168 – SC+MR+D+ISB Cumulative System Potential versus Achieved Oil Removal/Treatment over 66-Day Simulation

Response Type	Response Division	Response System Type	Total Removal/Treatment		
			System Potential (bbl)	Achieved (bbl)	% Potential [a]
Mechanical [b]	**High-Volume**	Skimmer Group A	3,219,398	6,149	0.2%
		Skimmer Group B	473,739	21,518	4.5%
		Skimmer Group C	3,389,924	13,671	0.4%
	Secondary	Skimmer Group A	564,567	0	0%
		Skimmer Group B	49,392	0	0%
		Skimmer Group C	2,105,797	0	0%
	Nearshore	Skimmer Group A	417,318	0	0%
		Skimmer Group C	71,214	0	0%
	Mechanical Total	**All**	**10,291,349**	**41,338**	**0.4%**
In Situ Burning [c]	**High-Volume In Situ Burning**	-	811,914	2,733	0.3%
Dispersants	**High-Volume/Secondary**	-	518,315	0	0%
All Categories	**All Categories Total**	**All**	**11,621,578**	**44,111**	**0.4%**

[a] Achieved Total Recovery divided by System Potential Total Recovery as percentage.

[b] ERSP Day-1 rates assumed for High-Volume Division until well capping (source control); ERSP Day-3rates assumed for Secondary and Nearshore Divisions, and for High-Volume Division after day 21 source control.

[c] EBSP Day-1 rates assumed until day 21 source control, after which EBSP Day-3 rates were applied.

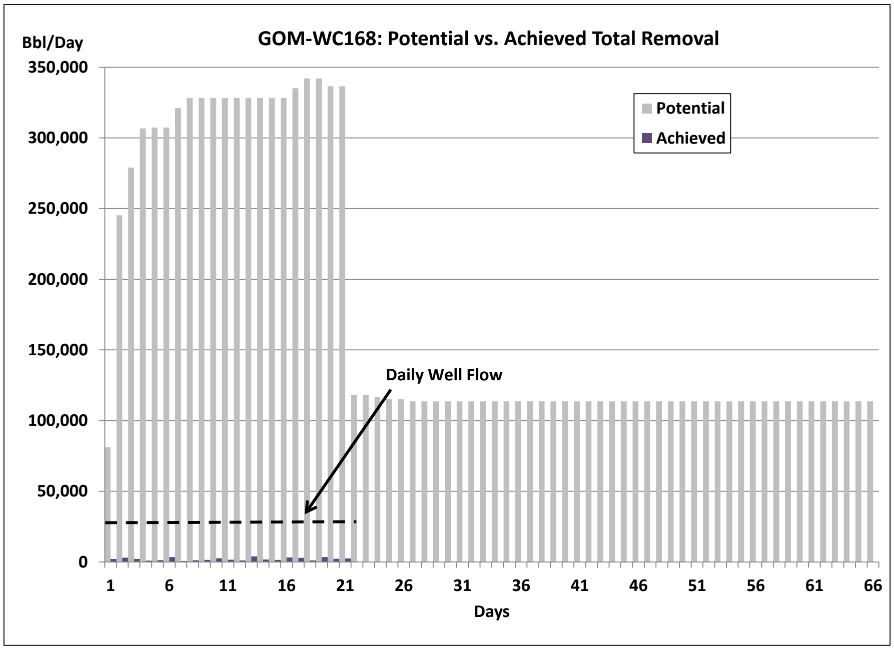


Figure 39: Scenario 3, GOM-WC168 SC+MR+D+ISB Total Oil Removal System Potential and Achieved Total Daily Removal

Figure 40 contrasts the amount of oil flowing from the well on a daily basis along with the maximum potential daily capability per day, as well as the achieved average daily removal rate. The achieved average daily removal rate is lower than the potential daily removal rate for each day of the scenario.

During the response period, some systems have very low or near-zero removal for some or all periods because of performance limitations due to environmental conditions, or because there is insufficient oil available, particularly in secondary and nearshore response areas where oil may not appear on the surface until after the oil has stopped flowing.

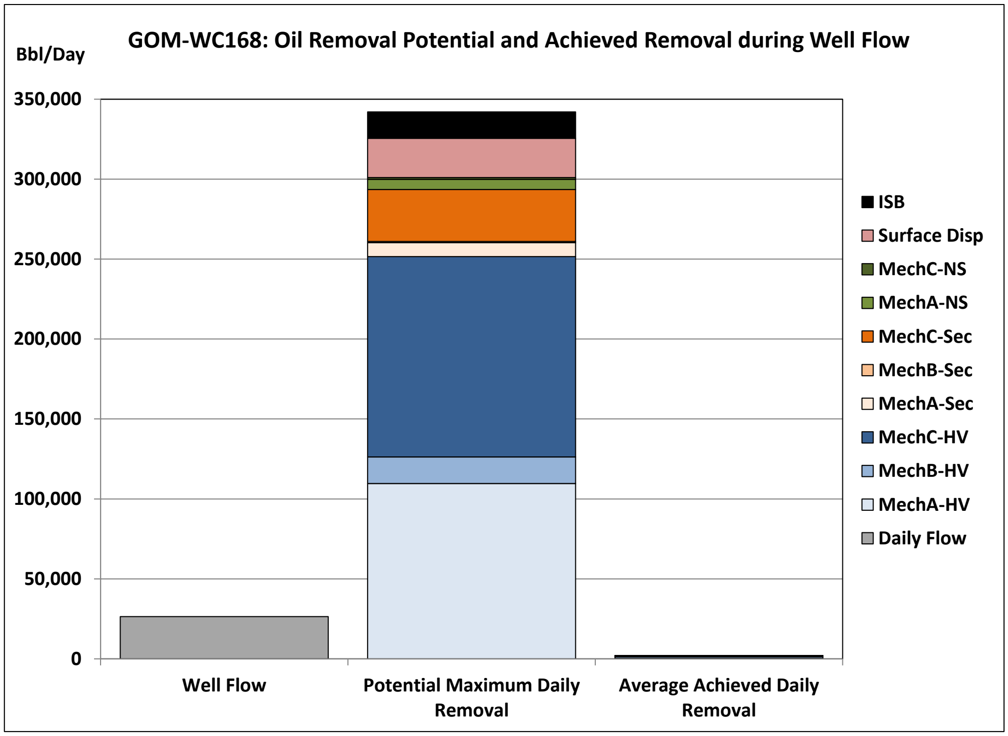


Figure 40: Scenario 3, GOM-WC168 SC+MR+D+ISB Total Maximum Oil Removal System Potential and Achieved Removal Compared with Well Flow during 21-Day Discharge Period

Oil Removal by Countermeasure Type

Table 33 is a summary of model results for the various response countermeasures applied to the GOM-WC168 scenario. This table allows for comparison of the oiling and oil removal by each countermeasure across the various model simulations. Values within Table 33 represent the volume of oil present/removed at the completion of the response scenarios (66 days).

Table 33: Scenario 3, GOM-WC168 – Comparison of Shoreline Oiling and Oil Removal for the Relief Well Only, Source Control Only, and Response Countermeasure Simulations

Response Capability Simulations	Volume (bbl) of Discharge	Volume (bbl)/ Percent of Oil on Shoreline	Volume (bbl)/ Percent Removed by Skimming	Volume (bbl)/ Percent Dispersed	Volume (bbl)/ Percent Removed by Burning	Volume (bbl)/ Percent Bio-Degraded or in Sediments
Relief Well Only, 76 Day Discharge	2,006,400	15,149				152,084
Source Control (SC), 21 Day Discharge	554,400	4,272 1%				33,060 6%
Source Control and Mechanical Recovery (SC+MR)		2,100 0.4%	44,756 8%			28,678 5%
Source Control, Mechanical Recovery and Surface Dispersant (SC+MR+D)		2,112 0.4%	44,496 8%	0 0%		28,600 5%
Source Control, Mechanical Recovery, Surface Dispersant and In Situ Burning (SC+MR+D+ISB)		2,083 0.4%	41,335 7.5%	0 0%	2,732 0.5%	28,461 5%

Mechanical recovery was able to remove up to 8% of the oil discharged in this scenario. These results highlight the limited utility of deploying mechanical recovery systems anywhere but in the immediate vicinity of the discharge site for an offshore spill involving volatile oil condensates. As can be seen in the following section, the use of mechanical recovery was effective in significantly reducing the surface area oiling footprint (reduced from 9,375 to 2,276 square miles) and the volume of oil washing ashore (reduced by 50%; see Table 34). In this scenario, the lack of oil effectively dispersed by surface dispersants as oil >8 g/m^2 thick is due to both the method in which oil recovery/treatment is applied in the model and the fate of condensate in the environment. Since the model applies the response operations in the order of (1) in situ burning, (2) mechanical removal and (3) surface dispersant, due to the high volatile content and low viscosity (and therefore a fast spreading rate) of condensate, and oil not being present on the surface for sufficiently long periods for treatment, there was no oil left on the surface to treat with dispersants. Similarly, in situ burning only accounted for 0.5% of the oil removed.

Figure 41 displays the fate of oil at the end of the 66-day simulation for Scenario 3, GOM-WC168 involving source control, mechanical recovery, in situ burning, and surface dispersants (e.g., SC+MR+D+ISB).

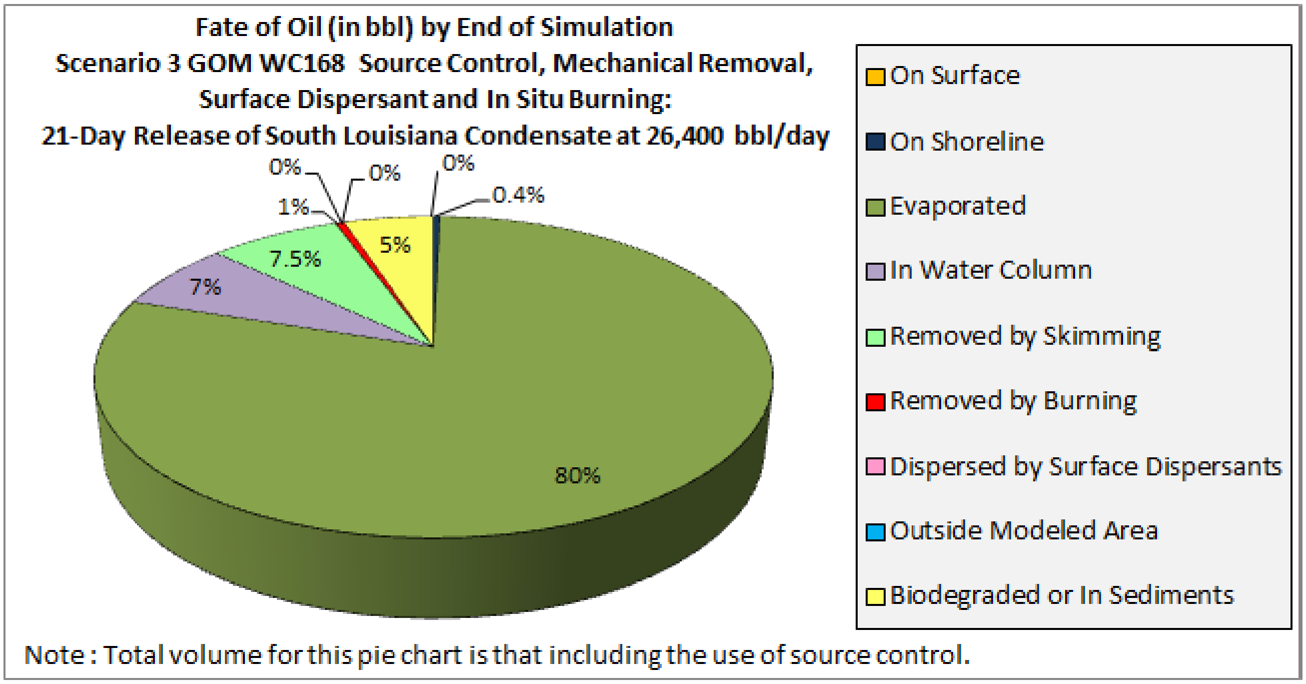


Figure 41: Scenario 3, GOM-WC168 – Fate of Oil at End of 66-Day Simulation (Scenario includes Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning Response Operations)

Reductions in Surface and Shoreline Oiling

Table 34 provides a comparison of the shoreline and water surface oiling results for each of the GOM-WC168 response countermeasure simulations.

Table 34: Scenario 3, GOM-WC168 – Comparison of Shoreline and Water Surface Oiling Above Equipment Threshold Values or Limitations

Scenario 3, GOM-WC168	Relief Well Only (WCD)	Source Control	Source Control and Mechanical Recovery	Source Control, Mechanical Recovery, and Surface Dispersant	Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning
Volume (bbl) of Shoreline Oiling (to Any Degree)	15,150	4,272	2,100	2,112	2,083
% Reduction in Volume of Shoreline Oiled As Compared to Relief Well Only	-	72%	86%	86%	86%
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	539	122	115	116	118
% Reduction in Shoreline Length Oiled with ≥1 g/m^2 As Compared to Relief Well Only	-	77%	79%	78%	78%
Cumulative Area (mi^2) of Surface Affected by Oil ≥8g/m^2	62,073	9,375	2,276	2,250	2,252
Percent Reduction in Surface Affected by Oil ≥8g/m^2 As Compared to Relief Well Only	-	85%	96%	96%	96%

Figure 42 is a visual depiction of the reduction in the surface area affected by ≥8.0 g/m^2 of oil over the 66-day period. The graphic directly compares the levels of maximum water surface oiling over time between the Source Control Only simulation and the simulation that adds mechanical recovery, dispersants, and burning (SC+MR+D+ISB).

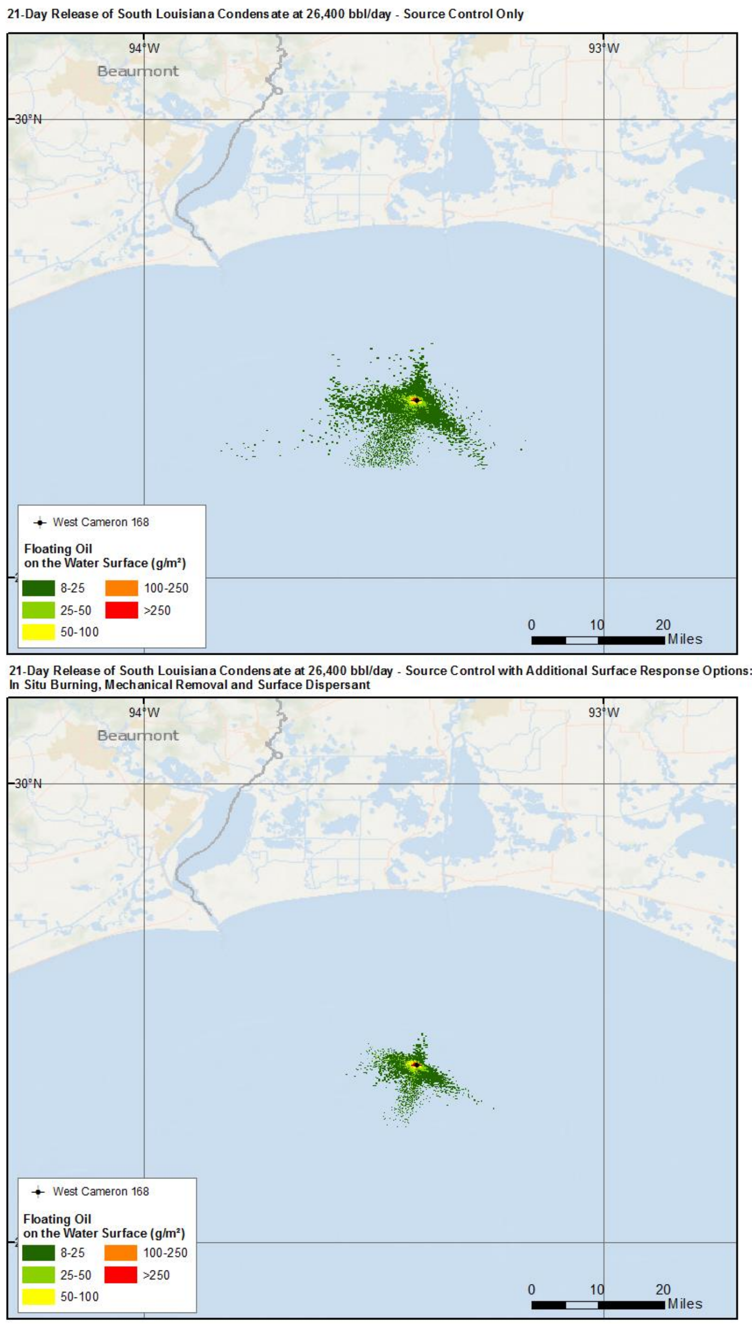


Figure 42: Scenario 3, GOM-WC168 – Comparison Floating Oil Concentration ($\geq$8.0 g/m^2) over 66-Day SIMAP Model Simulation, Top Panel: Source Control (SC), Bottom Panel: Source Control, Mechanical Recovery, Surface Dispersants, and In Situ Burning (SC+MR+D+ISB)

2.1.2.4 *Scenario 4: High Island 376*

Scenario Site Information

High Island 376 (HIA376) is an offshore (129 miles [112 nm] from shore), mid-depth continental shelf (334 ft) well in the Western Gulf of Mexico Planning Area. In the event of a worst case discharge at this site, there is a medium probability for significant shoreline contact along western Louisiana and eastern Texas (see Figure 43) if spill response countermeasures are not immediately taken. Based on 100 stochastic model runs, the worst case release date for the GOM-HIA376 WCD scenario was July 14, 2000.

Table 35: Scenario 4, GOM-HIA376 – Well Information and Shoreline Contact Times

WCD Scenario Parameters	
Discharge Flow Rate	77,000 bbl/day
WCD Duration	50 days, Relief Well Only 21 days, Source Control
Total WCD Release Volume	3,850,000 bbl, Relief Well Only 1,617,000 bbl, Source Control
Simulation Duration (45 days following end of discharge)	95 days, Relief Well Only 66 days, Source Control
Oil Type	South Louisiana Crude
API Gravity	34.5
Viscosity @ 15^{0}C (cp)	10.1
Latitude, Longitude	27.943209^{0}N / 93.667917^{0}W
Depth to Sea Floor	334 ft
Distance to Shoreline	129 miles (112 nm)
SIMAP Model Results [a]	
Time for oil above 1 g/m^2 to reach shore [b]	6 days
Time for oil greater than 8 g/m^2 to reach shore [c]	6.5 days, Figure 43

[a] SIMAP model results presented in this table are based on the 100 stochastic model runs.

[b] The 1 g/m^2 value is the threshold for socio-economic resource effects (e.g., closure of fisheries) (French-McCay et al. 2011; French McCay et al. 2012)

[c] The 8 g/m^2 value is the minimum thickness of floating oil for which response equipment can be effectively used (NOAA 2010)

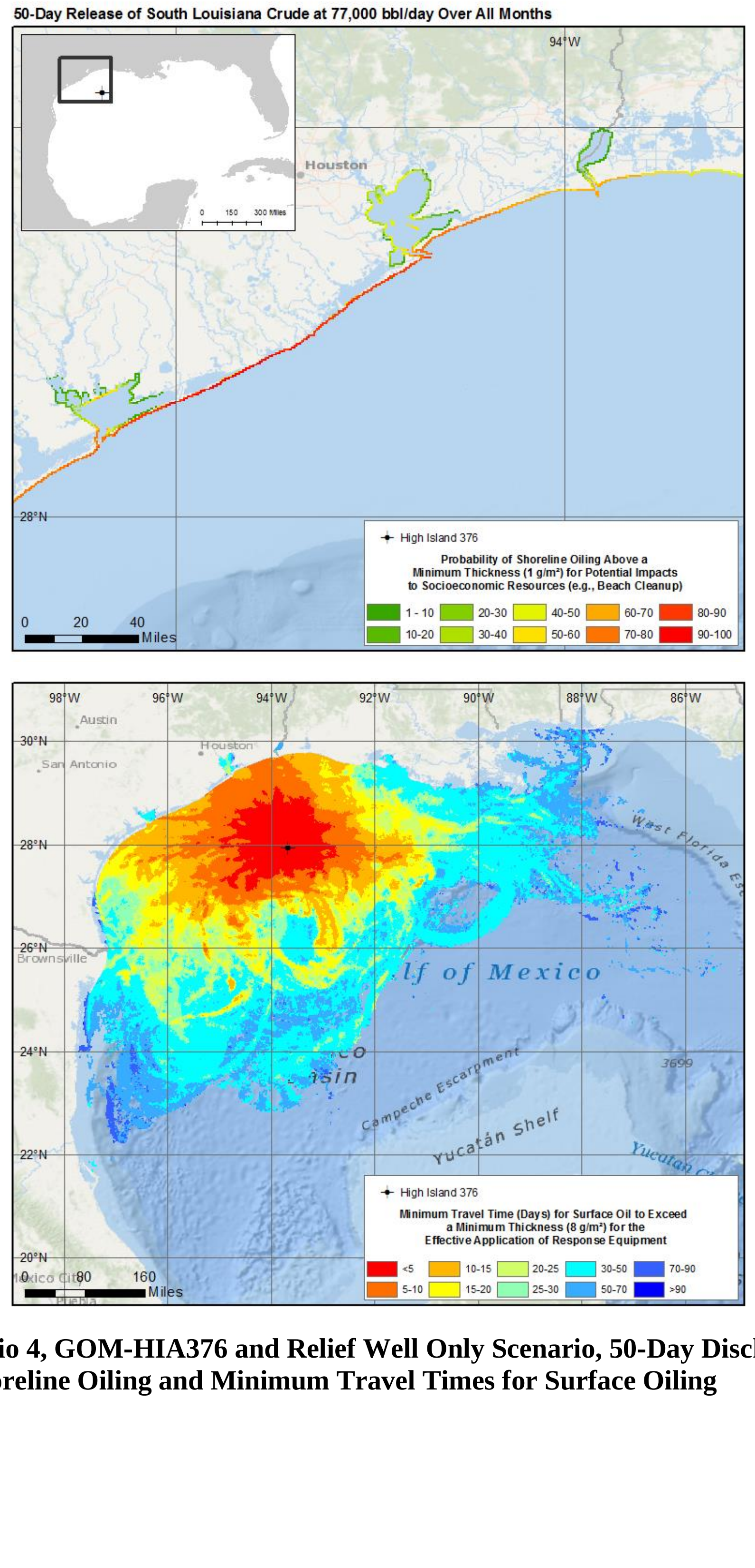


Figure 43: Scenario 4, GOM-HIA376 and Relief Well Only Scenario, 50-Day Discharge – Probability of Shoreline Oiling and Minimum Travel Times for Surface Oiling

Application of Source Control

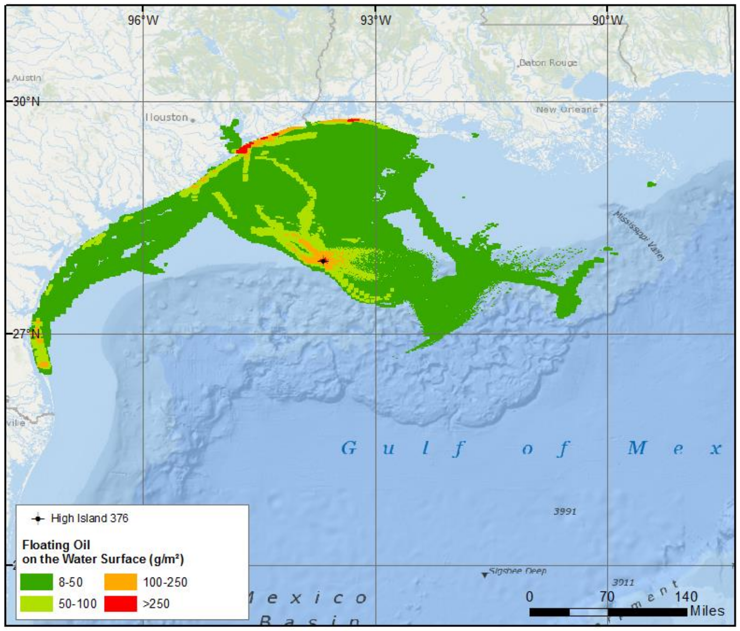
When a source control operation is modeled for the WCD GOM-HIA376 scenario, the discharge period is reduced by 29 days, and the volume of oil released to the environment is reduced by 2,233,000 bbl. Correspondingly, source control results in substantially less impact with the water column and shoreline in comparison to the Relief Well Only simulation. Table 36 and Figure 44 compare discharge volume, shoreline-oiling volume, length of oiled shoreline, area of surface oiling, and the amount of oil biodegraded or in the sediments for the Relief Well Only and Source Control Only modeling simulations.

Table 36: Scenario 4, GOM-HIA376 – Comparison of Relief Well Only and Source Control Response Scenarios

Scenario 4, GOM-HIA376	Relief Well Only (50-day flow duration)	Source Control (21-day flow duration)	Reduction Due to Source Control	Percent Reduction Due to Source Control
Volume Discharged (bbl)	3,850,000 bbl	1,617,000 bbl	2,233,000 bbl	58 %
Volume Shoreline Oiling (bbl) any thickness	535,495 bbl	256,740 bbl	278,755 bbl	52 %
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	1,452 mi	851 mi	601 mi	41 %
Cumulative Area (mi^2) of Surface Oiling ≥8g/m^2	2,283,530 mi^2	1,544,640 mi^2	738,890 mi^2	32 %
Amount Biodegraded and In Sediments (bbl) at the End of the Simulation	799,033 bbl	290,581 bbl	508,452 bbl	64 %

As shown in Table 36 and Figure 44, the volume and spread of oil spilled from this WCD is greatly reduced by source control, particularly to the west; however, without the application of additional response operations to remove or mitigate spilled oil on the surface, the expected contact and exposure to oil in the environment is still quite extensive.

50-Day Release of South Louisiana Crude at 77,000 bbl/day - Relief Well Only (WCD)



21-Day Release of South Louisiana Crude at 77,000 bbl/day - Source Control Only

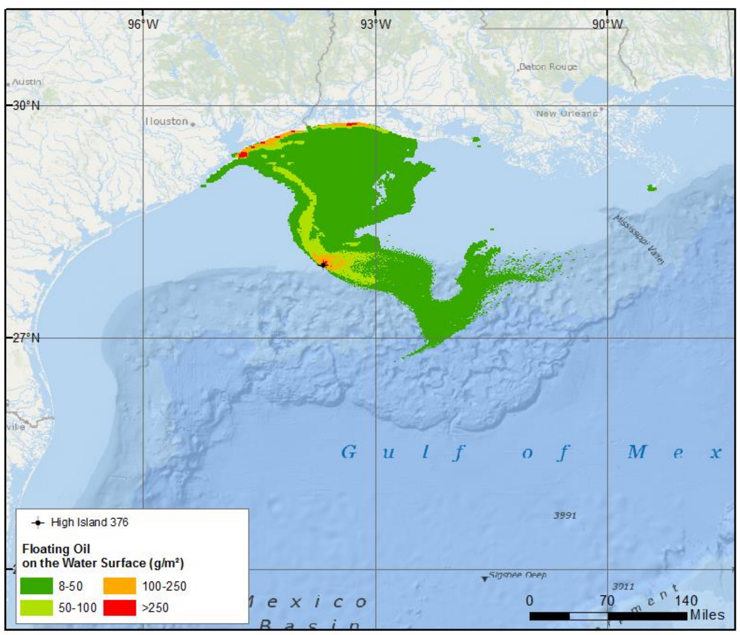


Figure 44: Scenario 4, GOM-HIA376 – Comparison of Maximum Concentrations of Surface Oiling Experienced Throughout Simulation Periods for Relief Well Only (50-Day Discharge) and Source Control (21-Day Discharge)

Oil Discharge Behavior

Figure 45 shows the fate of oil for 66 days from the discharge (21-day discharge duration and 45 days following the use of source control). At the end of the simulation, 60% percent of the total oil had evaporated, 18% had either biodegraded or remained in the water column and sediments, 16% of the oil remained on the shoreline, and 6% of the oil remained floating on the surface. Note that, the model does not simulate potential photooxidation of floating oil.

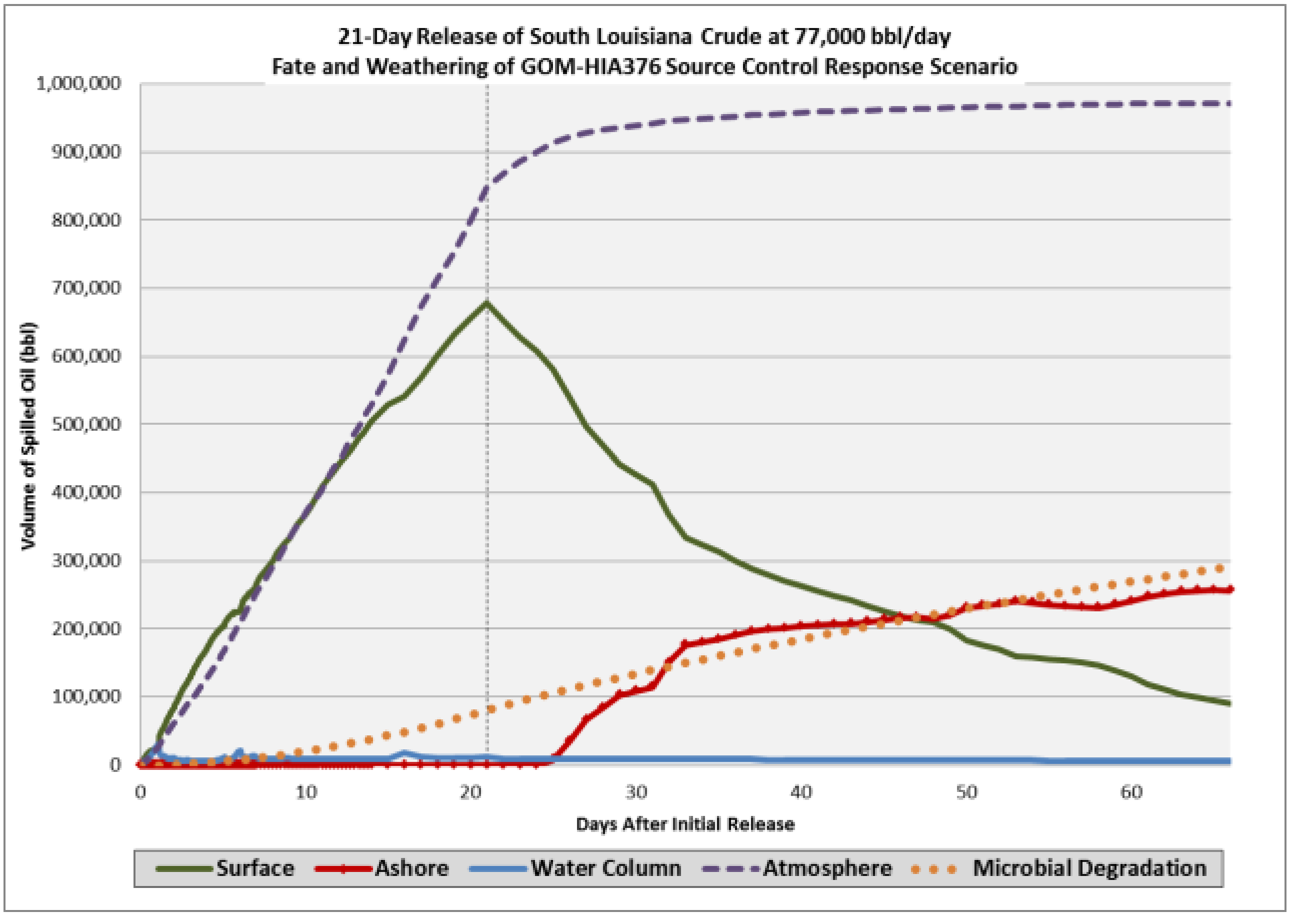


Figure 45: Scenario 4, GOM-HIA376 Source Control, 21-Day Discharge – Oil Fate and Weathering (Dotted Vertical Line Indicates Source Control on Day 21)

In the GOM-HIA376 Source Control Only simulation, 100% of the total oil mass discharged from the blowout reached the surface. Upon release from the blowout, oil droplets took less than 1 hour to reach the surface, with most surfacing in the immediate vicinity of the well location. As the oil slick spread, the surface oil remained thick (> 8 g/m^2) and fresh enough to be recovered or treated (< 20,000 cST) for up to a five day period in calm conditions (Figure 46 and Figure 47), in both the high volume and secondary/nearshore response divisions.

Figure 46 and Figure 47 display model results at day 4, showing the oil movements and weathering that occurred over the a relatively calm first four days of the discharge.

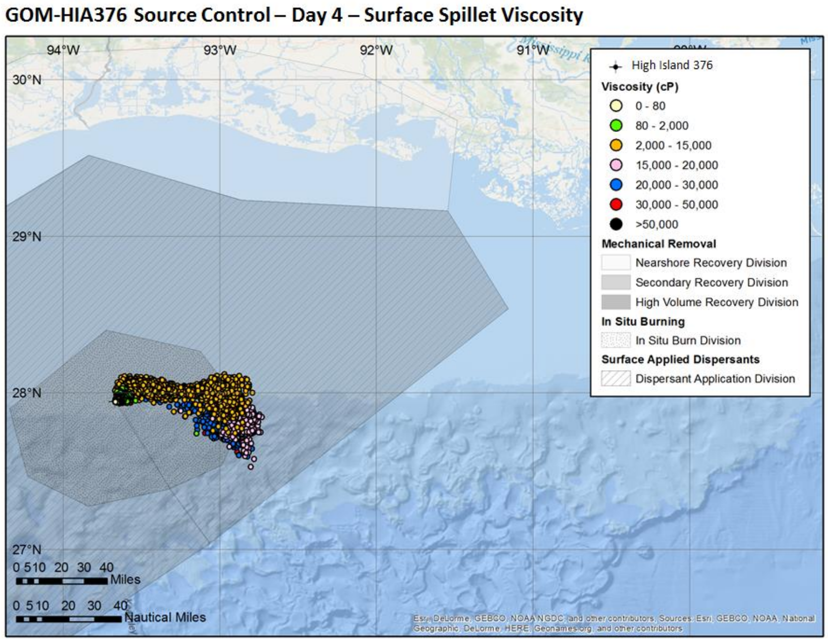


Figure 46: Scenario 4, GOM-HIA376 Source Control – Surface Spillet Viscosity (cp) at Day 4

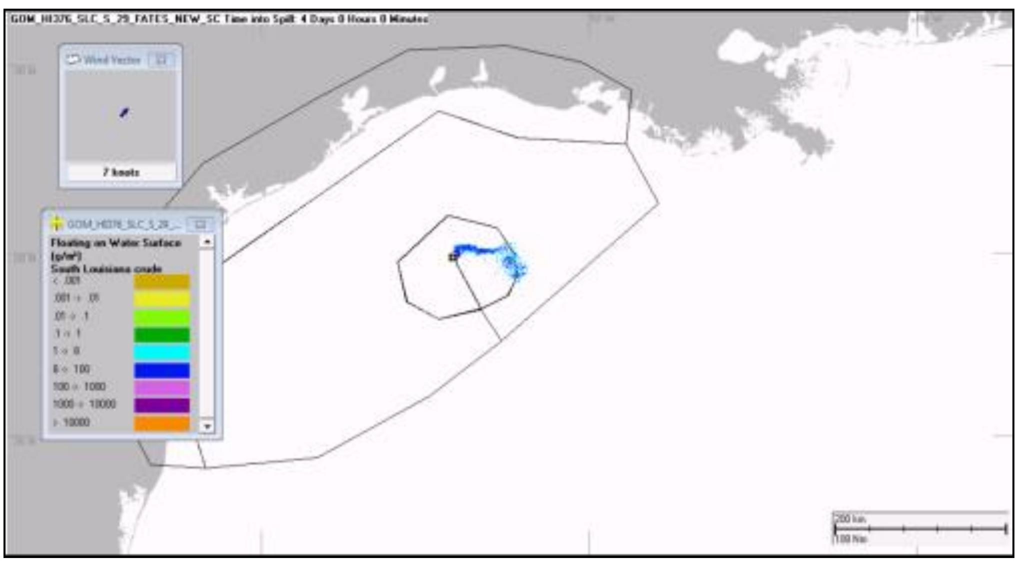


Figure 47: Scenario 4, GOM-HIA376 Source Control – Floating Oil on Water Surface (g/m^2) at Day 4

The path of the plume varies over time, but travels in a generally easterly direction. At day 13, oil appears to get entrained in adjoining warm and cold core eddies, resulting in eastward transport of a portion of oil and southwest transport of a separate portion of the oil. Minimum travel time for contact to shorelines is 21 days, with substantial shoreline impacts beginning within 25 days of the start of the discharge. At the end of the simulation, the majority of the shoreline oiling over 1 g/m^2 is along the Louisiana and eastern Texas coastline (Figure 48).

21-Day Release of South Louisiana Crude at 77,000 bbl/day - Source Control Only

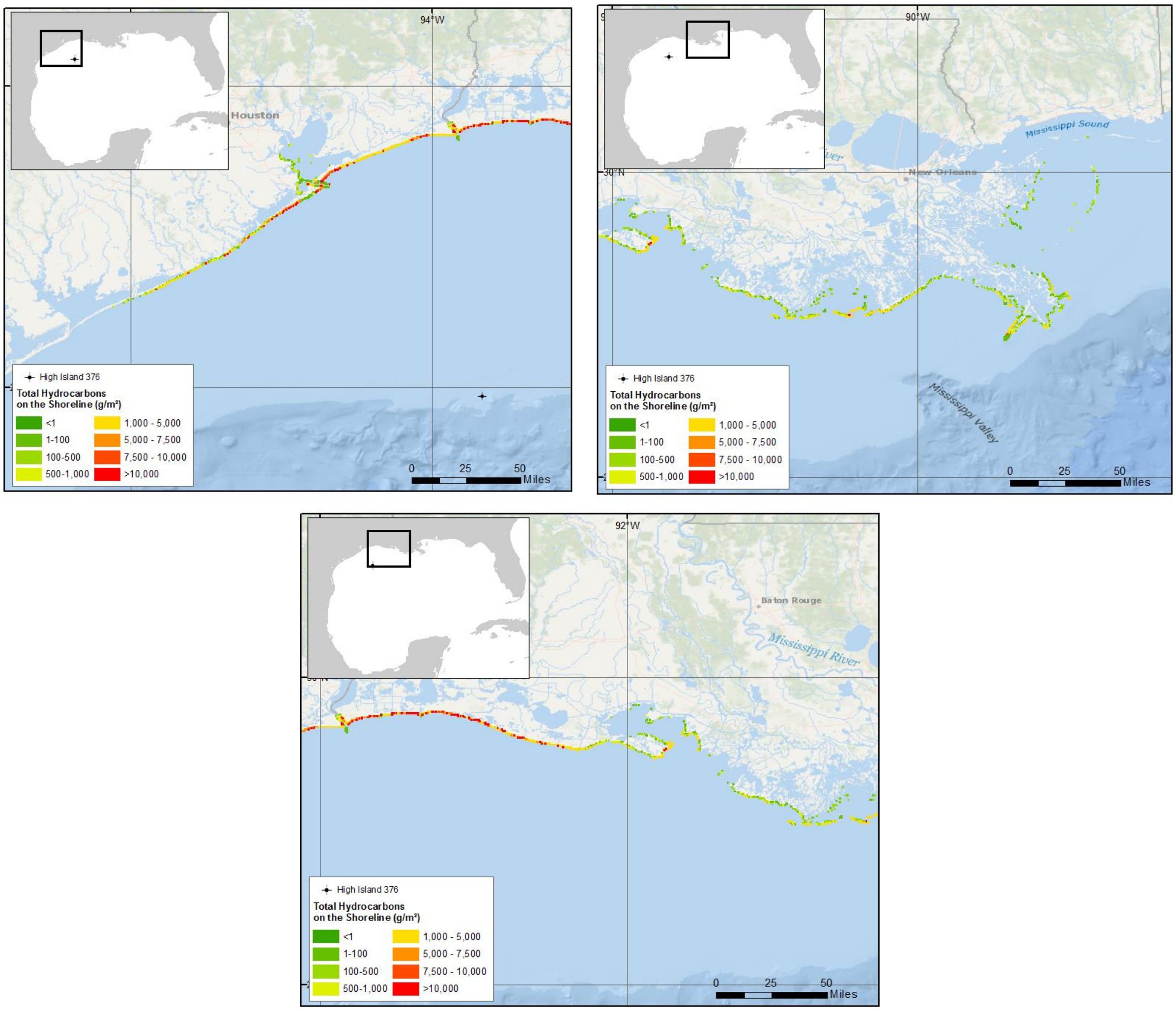


Figure 48: Scenario 4, GOM-HIA376 Source Control, 21-Day Discharge – Shoreline Oil ≥1 g/m², including Weathered Tarballs

Application of Response Countermeasures

Countermeasure Response Divisions

The following equipment types were employed in each of the following countermeasure response divisions, and are shown in Figure 49.

- High Volume Recovery Division – High volume mechanical recovery operations were employed beyond a 0.6 mile (0.5 nm) radius area established around the well for source control.
- In situ Burning Division – In situ burning operations were used in the same geographical area as the high volume mechanical recovery operations (2.9 mile [2.5 nm]) away from the source control area.
- Secondary Recovery Division – Secondary mechanical recovery operations were used to remove oil that was not previously removed in the high volume recovery area.
- Nearshore Recovery Division – Nearshore mechanical recovery operations were used to remove oil from the surface of the water before it was washed onto shorelines.
- Dispersant Application Division – Surface applied dispersants were employed in the high volume and secondary recovery geographical areas beyond a 2.9 mile (2.5 nm) radius area established around the well for source control, as appropriate.

No subsurface dispersants were applied in the GOM-HIA376 scenario.

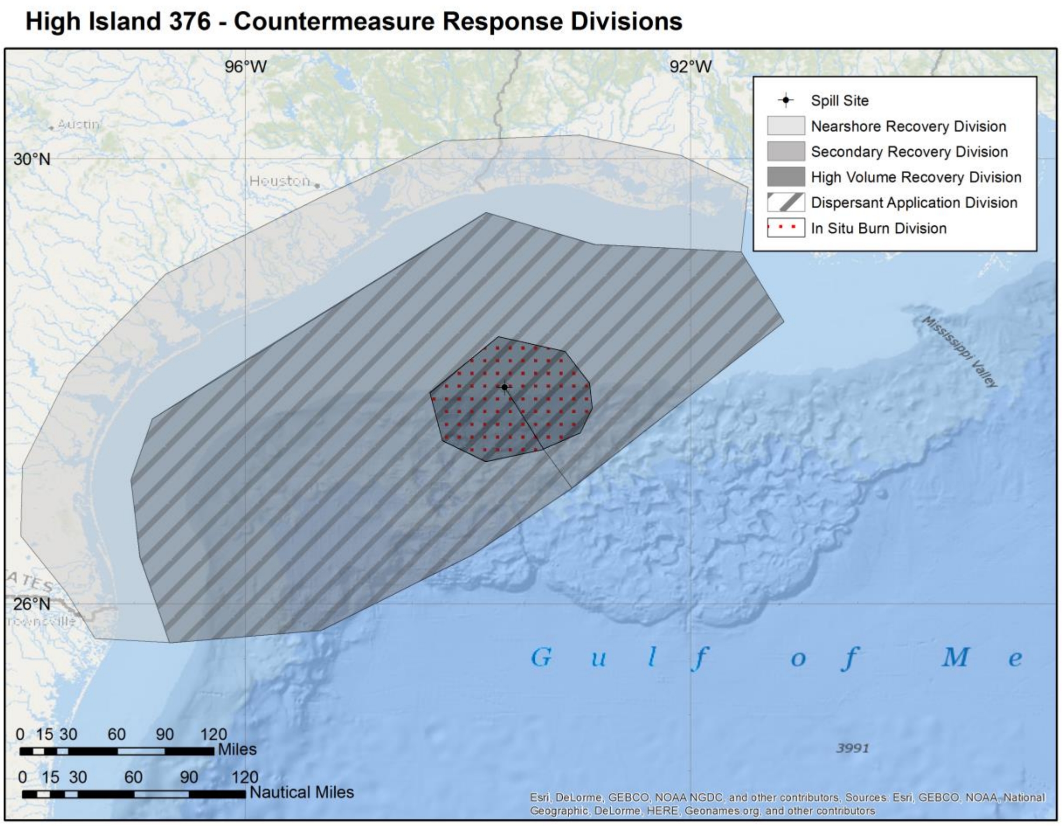


Figure 49: Scenario 4, GOM-HIA376 – Geographic Coverage of Oil Countermeasure Response Divisions

The size and placement of the GOM-HIA376 response operation divisions in the model were developed based on a review of the oil spill trajectories from the 21-day discharge in the Source Control Only simulation.

Countermeasure/Division Removal Rates (Model Inputs)

The removal rates by countermeasure type and response division that are shown in Table 37 represent the *maximum* potential rate that would be available at any point during the response operation.

As in an actual oil spill response operation, the model cascades response equipment into the response divisions as the assets arrive on the scene. The modeling reflects response equipment threshold values and limitations based on the availability of the response equipment to be deployed to the location of the appropriate divisions. As such, the model used oil removal rates for each division (i.e., SIMAP model polygon), based on the maximum potential daily removal rates (bbl/day) of the assigned asset (refer to Table 37), corrected by weather restrictions and daylight operations (as described in Section 1.8). Maximum removal rates are not realized in practice because of the limitations of weather delays, suspension of operations at night, the location of oil in relation to equipment, and performance thresholds, such as oil thickness on the water surface, sea state and currents, winds, and water content during oil emulsification.

These maximum rates are not necessarily applicable for the entire response period. This is because equipment cascades in at different times, and in some cases, resources are allocated to different applications. For example, in this WCD scenario, in situ burning could be conducted in a relatively small area only and was limited by both availability of fireboom and other equipment, as well as thresholds for wave height, winds, viscosity, and thickness of oil on the water surface were reached.

Table 37: Maximum Potential Daily Oil Removal Rates for GOM-HIA376 SC+MR+D+ISB Response Scenario [a]

Countermeasure Type	Response Division	Response System Category [b]	Removal Rate Applied [c]	Maximum Potential Daily Removal Rates (bbl/day)
Mechanical	**High-Volume**	Skimmer Group A	ERSP Day-1	128,099
		Skimmer Group C	ERSP Day-1	114,863
	Secondary	Skimmer Group A	ERSP Day-3	1,418
		Skimmer Group B	ERSP Day-3	302
		Skimmer Group C	ERSP Day-3	1,989
	Nearshore	Skimmer Group A	ERSP Day-3	6,353
		Skimmer Group C	ERSP Day-3	1,049
	Total	**All Mechanical Countermeasures**		**254,073**
In Situ Burning	**High-Volume In Situ Burning**	In Situ Burning	Based on ISB Calculator	16,452
Surface Dispersant	**High-Volume and Secondary**	Surface Dispersants	Based on DMP 2	36,562
	Total	**All Countermeasures**		**307,087**

[a] GOM-HI376 SC+MR+D+ISB Response Scenario by countermeasure type and response division *without* application of weather restrictions.

[b] The characteristics of the different types of mechanical equipment and the specific pieces of equipment applied in this scenario are described in Section 2.1. The viscosity thresholds for different types of equipment are further described in Section 1.8.2.

[c] ERSP is described in Section 5.0. "ERSP Day-1" rates are the higher removal rates applied in the areas and times when the oil was flowing from the well and the oil is the thickest. "Day-1" does not necessarily indicate that this is only applied for the first day. "ERSP Day-3" rates are applied in the areas more distant from the well where the oil is thinner and more spread out making removal less efficient. "Day-3" does not necessarily indicate that this is the third day of the response.

For Scenario 4, GOM-HI376 response divisions are cascaded in over the course of the initial 18 days (as depicted in Figure 50). Oil began to arrive on the surface after approximately one hour. Aerial surface dispersant application began on day 1.

Maximum daily surface dispersant application was achieved on day 2 with almost 77,000 gallons/day for the duration of the 21-day event, with a total of 1,553,900 gallons applied over the course of the scenario.

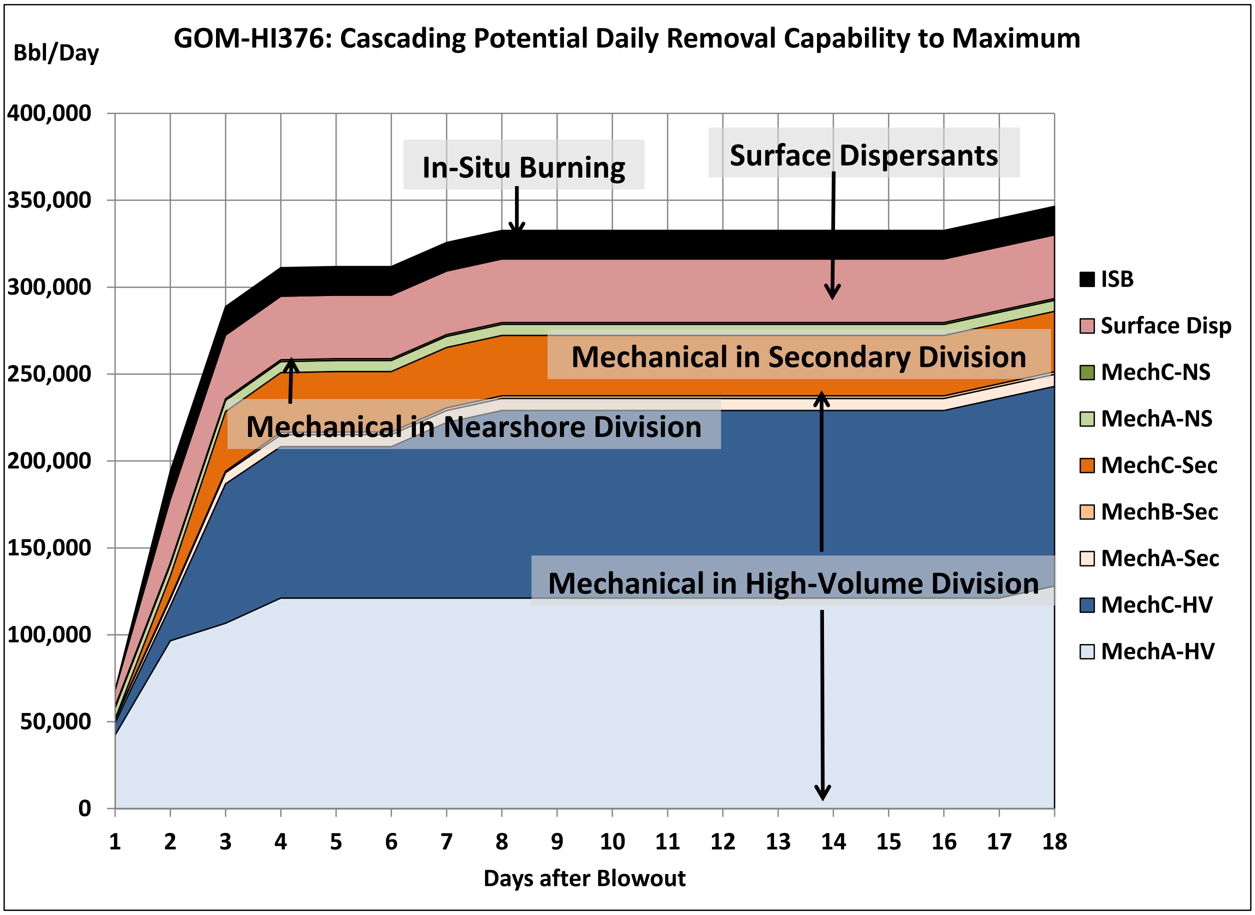


Figure 50: Scenario 4, GOM-HIA376 – Cascading SC+MR+D+ISB Response Assets and Cumulative Potential Daily Removal Capacity

Countermeasure Simulation Results & Analysis

Achieved Removal versus Potential Equipment Capabilities

Maximum potential removal rates of oil removal systems are not achieved due to the limitations on countermeasures resulting from oil weathering and other environmental factors (such as increased sea state and darkness which often limited when the countermeasures could be applied). For the GOM-HIA376 SC+MR+D+ISB simulation, weather restrictions were in effect for 21% of the time, and for most equipment, the operating period was limited to 12 hours of daylight (other equipment limitations applied are listed in Table 10 , Table 12 , and Table 13). Because of these thresholds and limitations, as well as the availability of recoverable, burnable, or dispersible oil in the response divisions, achieved oil removal was significantly less than the potential response capabilities (as shown in Table 38, Figure 51, and Figure 52) for the GOM-HIA376 SC+MR+D+ISB simulation.

Table 38 shows the system potential with regard to barrels of oil that could be treated or removed based on the sum total of removal/treatments rates over the course of the entire response operation (i.e., during the release of oil from the well and for an additional 45 days after source control is achieved to stop the flow of oil). The "achieved" removal or treatment reflects the sum total of oil removed or treated over the course of the response operations. Figure 51 contrasts the sum total of potential removal/treatment over the course of the operations and the sum total of the achieved removal/treatment. The daily well flow is shown as a benchmark. The potential removal/treatment capability greatly exceeds the achieved removal/treatment due to the various environmental and logistical factors that limit performance.

Table 38: Scenario 4, GOM-HIA376 – SC+MR+D+ISB Cumulative System Potential Oil Recovery versus Achieved Oil Recovery over 66-Day Simulation

Response Type	Response Division	Response System Type	Total Recovery		
			System Potential (bbl)	Achieved (bbl)	% Potential [a]
Mechanical [b]	**High-Volume**	Skimmer Group A	3,863,716	234,628	6%
		Skimmer Group C	2,923,170	609,892	21%
	Secondary	Skimmer Group A	480,076	0	0%
		Skimmer Group B	97,134	0	0%
		Skimmer Group C	2,235,725	0	0%
	Nearshore	Skimmer Group A	419,298	0	0%
		Skimmer Group C	69,234	0	0%
	Mechanical Total	**All**	**10,088,353**	**844,520**	**8%**
In Situ Burning [c]	**High-Volume In Situ Burning**	-	**811,914**	**18,963**	**2%**
Dispersants	**High-Volume/Secondary**	-	**755,908**	**157,360**	**21%**
All Categories	**All Categories Total**	**All**	**11,656,175**	**1,020,843**	**9%**

[a] Achieved Total Recovery divided by System Potential Total Recovery as percentage.

[b] ERSP Day-1 rates assumed for High-Volume Division until well capping (source control); ERSP Day-3rates assumed for Secondary and Nearshore Divisions, and for High-Volume Division after day 21 source control.

[c] EBSP Day-1 rates assumed until day 21 source control, after which EBSP Day-3 rates were applied.

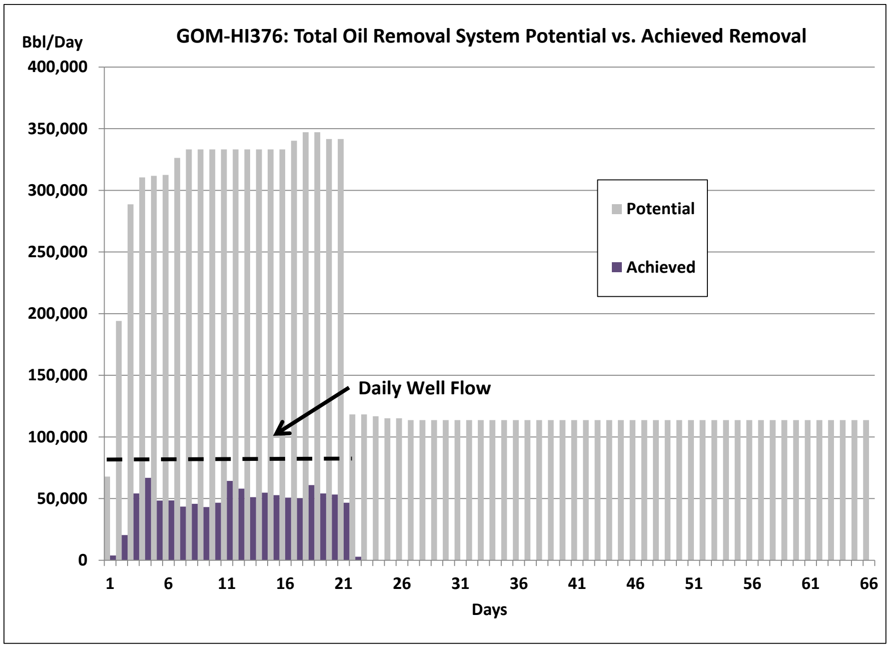


Figure 51: Scenario 4, GOM-HIA376 SC+MR+D+ISB Total Oil Removal System Potential and Achieved Total Daily Removal

Figure 52 contrasts the amount of oil flowing from the well on a daily basis along with the maximum potential daily capability per day, as well as the achieved average daily removal rate. The achieved average daily removal rate is lower than the potential daily removal rate for each day of the scenario.

During the response period, some systems have very low or near-zero removal for some periods because of performance limitations due to environmental conditions, or because there is insufficient oil available, particularly in secondary and nearshore response areas where oil may not appear on the surface until after the oil has stopped flowing.

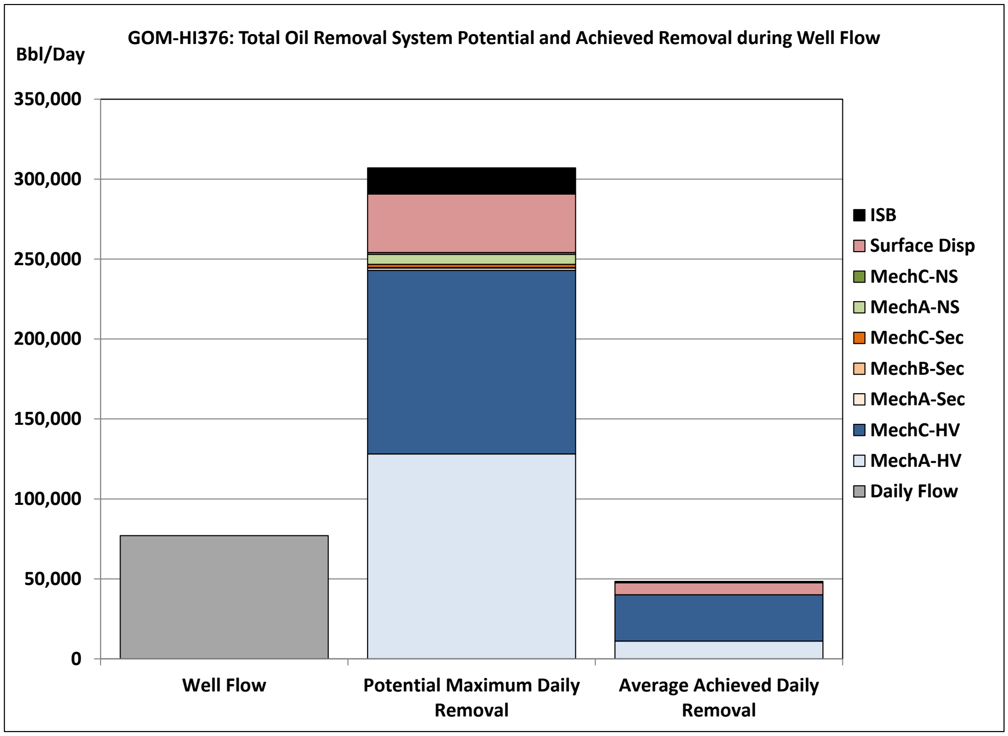


Figure 52: Scenario 4, GOM-HIA376 SC+MR+D+ISB Total Maximum Oil Removal System Potential and Achieved Removal Compared with Well Flow during 21-Day Discharge Period

Oil Removal by Countermeasure Type

Table 39 is a summary of model results for the various response countermeasures applied to the GOM-HIA376 scenario. This table allows for comparison of the oiling and oil removal by each countermeasure across the various model simulations. Values within Figure 53 represent the volume of oil present/removed at the completion of the response scenarios (66 days).

Table 39: Scenario 4, GOM-HIA376 – Comparison of Shoreline Oiling and Oil Removal for the Relief Well Only Scenario and Four Response Scenarios at the End of the Model Simulations

Scenario	Volume (bbl) of Discharge	Volume (bbl)/ Percent of Oil on Shoreline	Volume (bbl)/ Percent Removed by Skimming	Volume (bbl)/ Percent Dispersed	Volume (bbl)/ Percent Removed by Burning	Volume (bbl)/ Percent Bio-Degraded or in Sediments
Relief Well Only, 50 Day Discharge	3,850,000	535,490				799,033
Source Control (SC), 21 Day Discharge	1,617,000	256,737 16%				290,581 18%
Source Control and Mechanical Recovery (SC+MR)	1,617,000	59,371 4%	898,386 56%			67,169 4%
Source Control, Mechanical Recovery and Surface Dispersant (SC+MR+D)	1,617,000	4,825 0.3%	854,907 53%	154,990 10%		130,170 8%
Source Control, Mechanical Recovery, Surface Dispersant and In Situ Burning (SC+MR+D+ISB)	1,617,000	4,657 0.3%	844,533 52%	151,534 9.4%	18,427 1%	127,644 8%

Scenario 4, GOM-HIA376 is a WCD from a continental shelf well where mechanical recovery was the primary tool that removed oil. This scenario, more than all the others, demonstrates the potential efficiencies that can be realized by deploying high-volume mechanical recovery as close to the point of discharge onto the water's surface as possible. In this case, due to the rapid rise of the oil to the surface in close proximity to the well site, and persistent calm weather conditions, the percentage of oil recovered by mechanical recovery equipment was very high. Wind remained under 10-12 knots for the entire period of the simulation, and as a result the oil was less likely to entrain and was more available for mechanical removal on the water surface. Additionally, due to these calm weather conditions, the oil did not weather as quickly as it did in the other scenarios, with more oil staying in the high recovery division (Figure 47) with viscosities remaining below the maximum threshold (15,000 cST) for mechanical recovery for a longer period. When used without the aid of other response operations, mechanical recovery was able to remove up to 56% of the oil discharged in this scenario.

When surface applied dispersants were added, oil removed by mechanical recovery decreased to 53%; however, an additional 10% of the oil was also dispersed into the water column thus causing less oil to reach the shoreline.

In situ burning only accounted for 1% of the oil removed when used, which is likely a reflection of the limited area where burning could be applied (e.g., restricted to the High Volume Recovery Division) in this scenario. As discussed in the earlier Methods section, in situ burning is limited by availability of fireboom and other equipment, and modeling equipment thresholds for wave height, wind, and viscosity and thickness of oil on the water surface.

Figure 53 displays the fate of oil at the end of the 66-day simulation for Scenario 4, GOM-HIA376 involving source control, mechanical recovery, in situ burning, and surface dispersants (e.g., SC+MR+D+ISB).

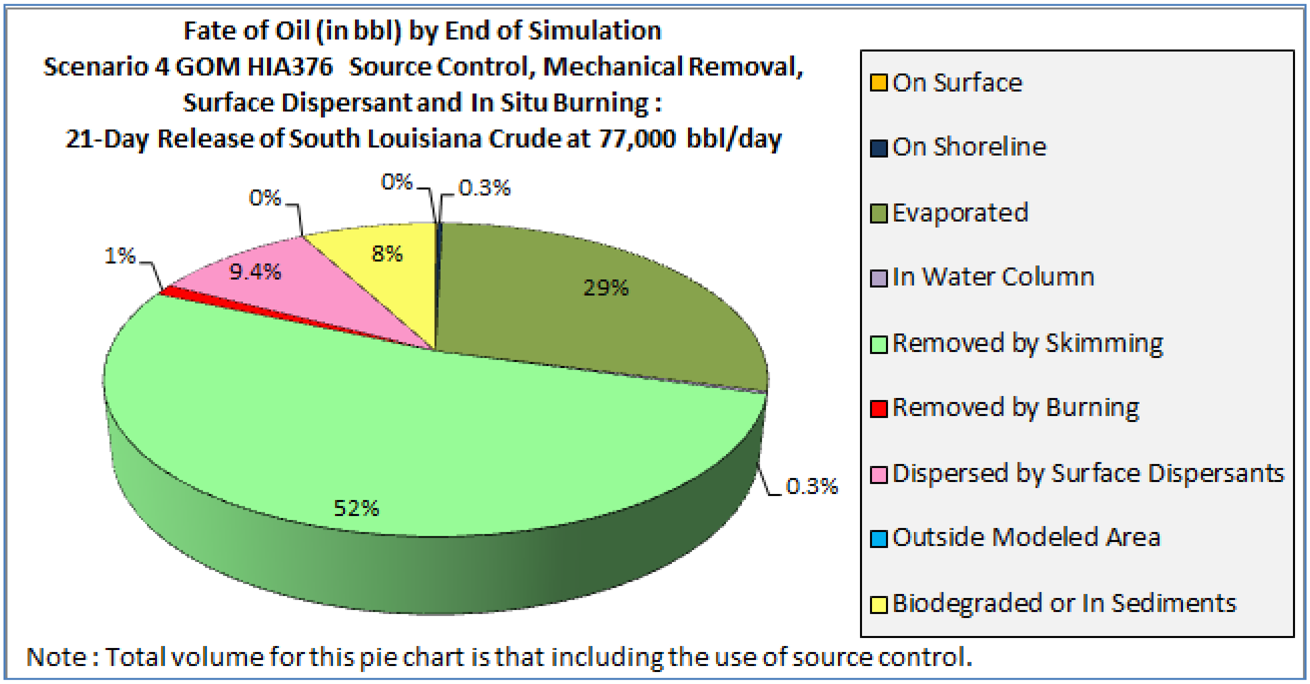


Figure 53: Scenario 4, GOM-HIA376 – Fate of Oil at End of 66-Day Simulation (Scenario includes Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning Response Operations)

Reductions in Surface and Shoreline Oiling

Table 40 provides a comparison of the shoreline and water surface oiling results for each of the GOM-HIA376 response countermeasure simulations.

Table 40: Scenario 4, GOM-HIA376 – Comparison of Shoreline and Water Surface Oiling Above Equipment Threshold Values or Limitations

Scenario 4, GOM-HIA376	Relief Well Only (WCD)	Source Control	Source Control and Mechanical Recovery	Source Control, Mechanical Recovery, and Surface Dispersant	Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning
Volume (bbl) of Shoreline Oiling (to Any Degree)	535,495	256,740	59,371	4,825	4,657
Percent Reduction in Volume of Shoreline Oiled As Compared to Relief Well Only	-	52%	89%	99%	99%
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	1,452	851	613	237	218
Percent Reduction in Shoreline Length Oiled with ≥1 g/m^2 As Compared to Relief Well Only	-	41%	58%	84%	85%
Cumulative Area (mi^2) of Surface Affected by Oil ≥8g/m^2	2,283,530	1,544,640	469,034	69,855	70,583
Percent Reduction in Surface Affected by Oil ≥8g/m^2 As Compared to Relief Well Only	-	32%	79%	97%	97%

Figure 54 is a visual depiction of the reduction in the surface area affected by ≥8.0 g/m^2 of oil over the 66-day period. The graphic directly compares the levels of maximum water surface oiling over time between the Source Control Only simulation and the simulation that adds mechanical recovery, dispersants, and burning (SC+MR+D+ISB).

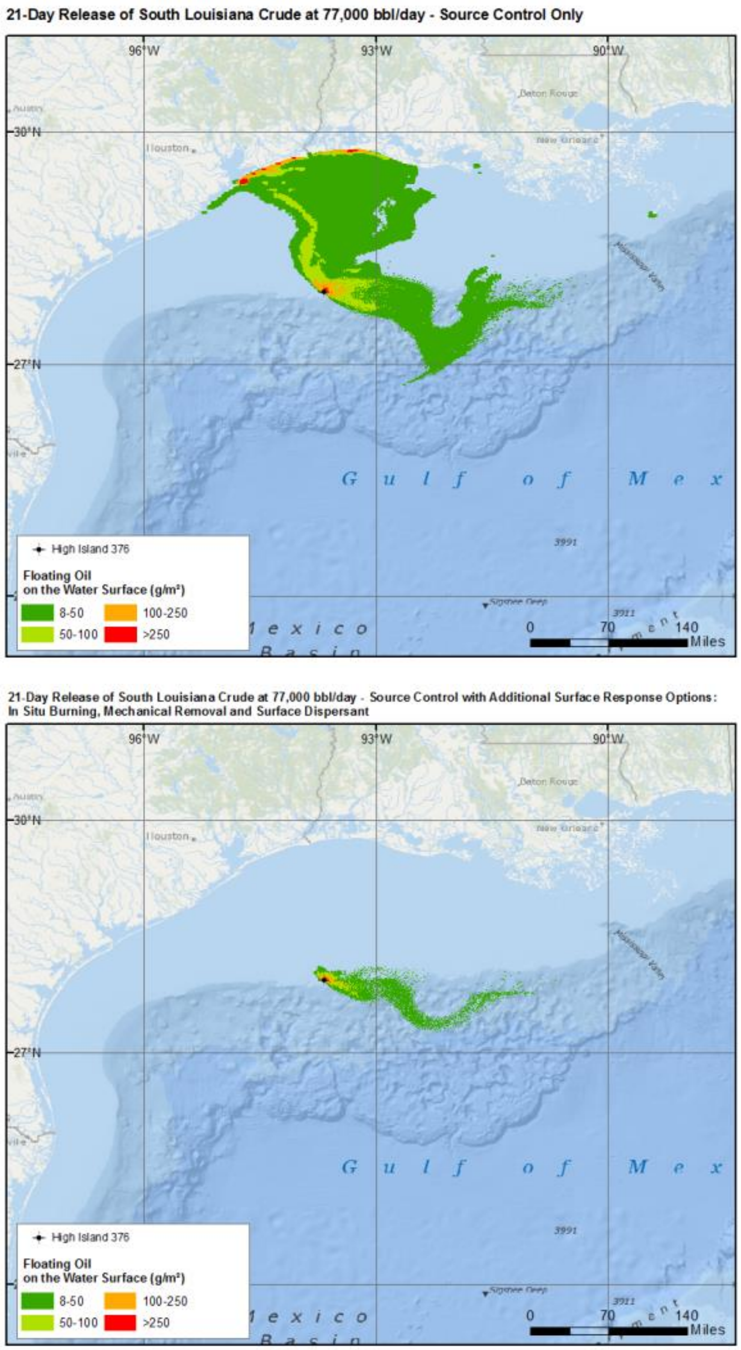


Figure 54: Scenario 4, GOM-HIA376 – Comparison Floating Oil Concentration (≥8.0 g/m^2) over 66-Day SIMAP Model Simulation, Top Panel: Source Control (SC), Bottom Panel: Source Control, Mechanical Recovery, Surface Dispersants, and In Situ Burning (SC+MR+D+ISB)

2.1.2.5 *Scenario 5: Keathley Canyon 919*

Scenario Site Information

Keathley Canyon 919 (KC919) is an offshore (250 miles [217 nm] from shore), deepwater (6,490 ft) well in the Central Gulf of Mexico Planning Area. Based on 100 stochastic model runs, the worst case release date for the GOM-KC919 WCD scenario was December 7, 2001.

Table 41: Scenario 5, GOM-KC919 – Well Information and Shoreline Contact Times

WCD Scenario Parameters	
Discharge Flow Rate	252,000 bbl/day
WCD Duration	120 days, Relief Well Only 45 days, Source Control
Total WCD Release Volume	30,240,000 bbl, Relief Well Only 11,340,000 bbl, Source Control
Simulation Duration (45 days following end of discharge)	165 days, Relief Well Only 90 days, Source Control
Oil Type	South Louisiana Crude
API Gravity	34.5
Viscosity @ 15^{0}C (cp)	10.1
Latitude, Longitude	26.080171 °N / 92.037507 °W
Depth to Sea Floor	6,490 ft
Distance to Shoreline	250 miles (217 nm)
SIMAP Model Results [a]	
Time for oil above 1 g/m^2 to reach shore [b]	12 days
Time for oil greater than 8 g/m^2 to reach shore [c]	15 days, Figure 55

[a] SIMAP model results presented in this table are based on the 100 stochastic model runs.

[b] The 1 g/m^2 value is the threshold for socio-economic resource effects (e.g., closure of fisheries) (French-McCay et al. 2011; French McCay et al. 2012)

[c] The 8 g/m^2 value is the minimum thickness of floating oil for which response equipment can be effectively used (NOAA 2010)

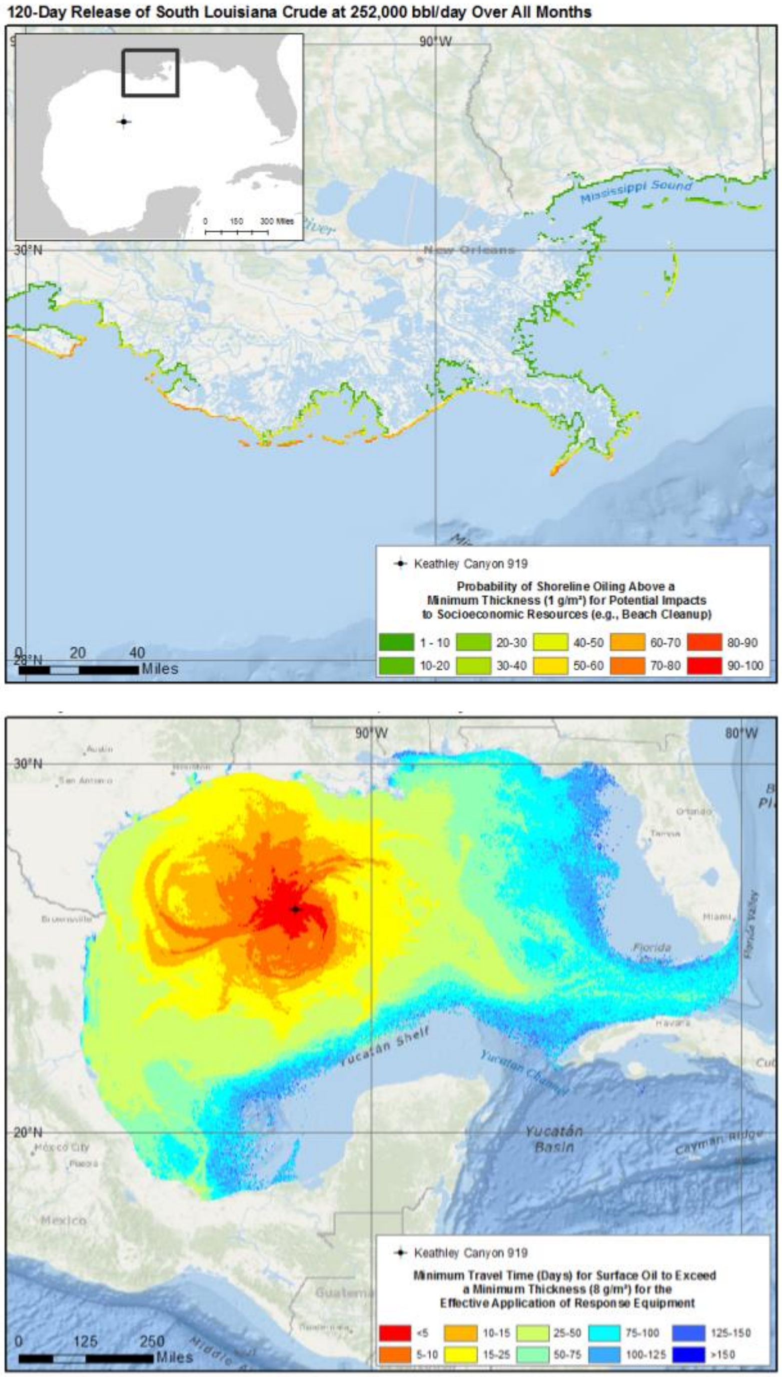


Figure 55: Scenario 5, GOM-KC919 Relief Well Only Scenario, 120-Day Discharge – Probability of Shoreline Oiling and Minimum Travel Times for Surface Oiling

Application of Source Control

When a successful source control operation is modeled for the WCD GOM-KC919 scenario, the discharge period is reduced by 75 days and the volume of oil released to the environment is reduced by 18,900,000 bbl. Correspondingly, source control results in substantially less impact with the water column and shoreline in comparison to the Relief Well Only simulation. However, due to the time estimated necessary to deploy the source control measure in this case (45 days), the oil spill footprint for this incident remains quite large in size and volume.

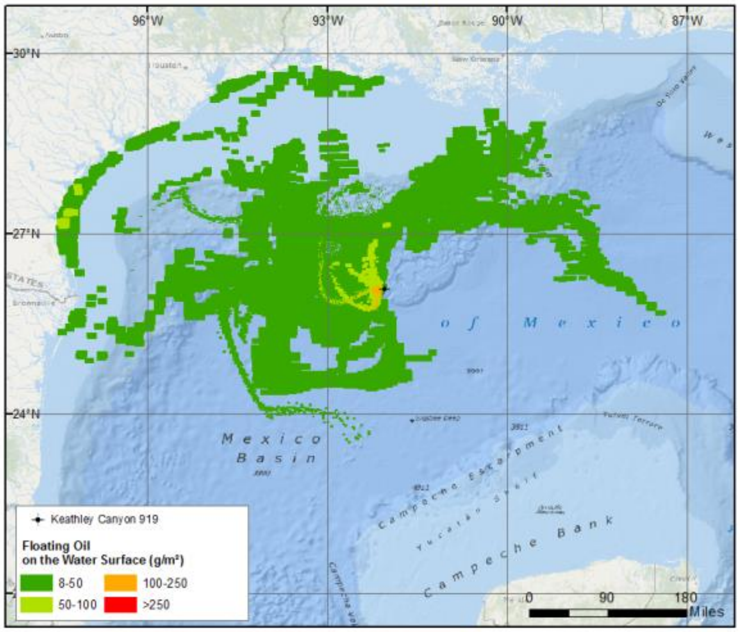
Table 42 and Figure 56 compare discharge volume, shoreline-oiling volume, length of oiled shoreline, area of surface oiling, and the amount of oil biodegraded or in the sediments for the Relief Well Only and Source Control Only modeling simulations.

Table 42: Scenario 5, GOM-KC919 – Comparison of Relief Well Only and Source Control Response Scenarios

Scenario 5, GOM-KC919	Relief Well Only (120-day flow duration)	Source Control (45-day flow duration)	Reduction Due to Source Control	Percent Reduction Due to Source Control
Volume Discharged (bbl)	30,240,000 bbl	11,340,000 bbl	18,900,000 bbl	63 %
Volume Shoreline Oiling (bbl) any thickness	877,530 bbl	186,362 bbl	691,168 bbl	79 %
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	2,602 mi	1,135 mi	1,467 mi	56 %
Cumulative Area (mi^2) of Surface Oiling ≥8g/m^2	5,247,021 mi^2	2,588,459 mi^2	2,658,562 mi^2	51 %
Amount Biodegraded or In Sediments (bbl) at the End of the Simulation	10,539,001 bbl	3,267,619 bbl	7,271,382 bbl	69 %

As shown in Figure 56, the volume and spread of oil spilled from this WCD is greatly reduced by source control; however, without the application of additional response operations to remove or mitigate spilled oil on the surface, the expected contact and exposure to oil in the environment is still quite extensive.

120-Day Release of South Louisiana Crude at 252,000 bbl/day - Relief Well Only (WCD)



45-Day Release of South Louisiana Crude at 252,000 bbl/day - Source Control Only

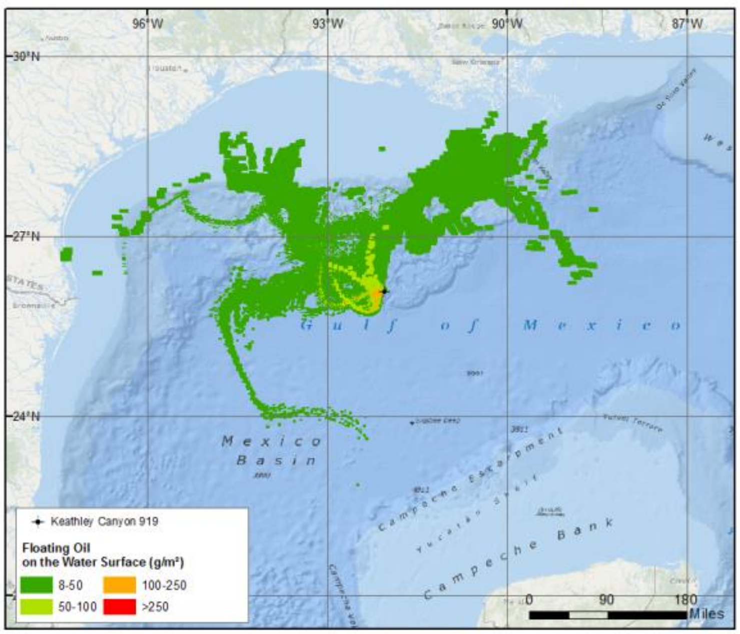


Figure 56: Scenario 5, GOM-KC919 – Comparison of Maximum Concentrations of Surface Oiling Experienced Throughout Simulation Periods for Relief Well Only (120-Day Discharge) and Source Control Only (45-Day Discharge)

Oil Discharge Behavior

Figure 57 shows the fate of oil for 90 days from the discharge (45-day discharge duration and 45 days following the source control). At the end of the simulation, 41% percent of the total oil had evaporated, 49% had either biodegraded or remained in the water column and sediments, 2% of the oil remained on the shoreline, and 3% of the oil remained floating on the surface. Note that, the model does not simulate potential photooxidation of floating oil.

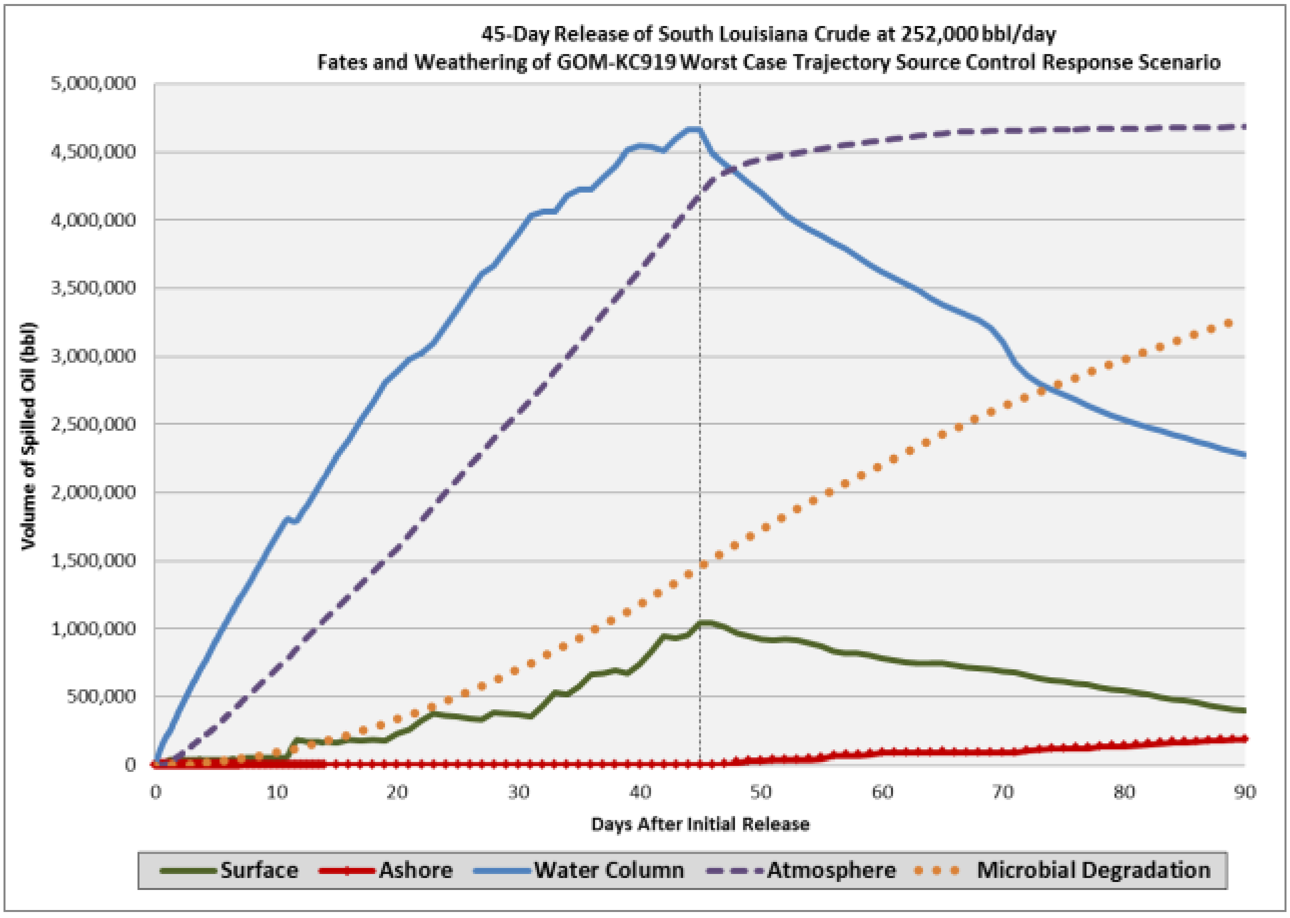


Figure 57: Scenario 5, GOM-KC919 Source Control, 45-Day Discharge – Oil Fate and Weathering (Dotted vertical line indicates source control on Day 45)

Scenario 5, GOM-KC919 Source Control, is notable in that only 55% of the total oil mass discharged from the blowout reached the surface, and the remaining 45% stay entrained within the water column, entered into the bottom sediments or biodegraded. While oil first appeared on the surface within 12-18 hours of being discharged from the well, the entire amount of oil discharged that eventually rose to the surface took approximately 28 hours. The oil rising during calm conditions surfaced in the immediate vicinity of the well location. Due to the relatively persistent strong winds associated with most of the discharge period for this simulation, less fresh, thick oil was available on the water's surface. Figure 58 and Figure 59 display model results at day 2, showing the oil movements, and weathering that occurred over the relatively calm first two days of the discharge. Stronger winds after day 2 increased the viscosity of floating oil, which made response countermeasures less effective.

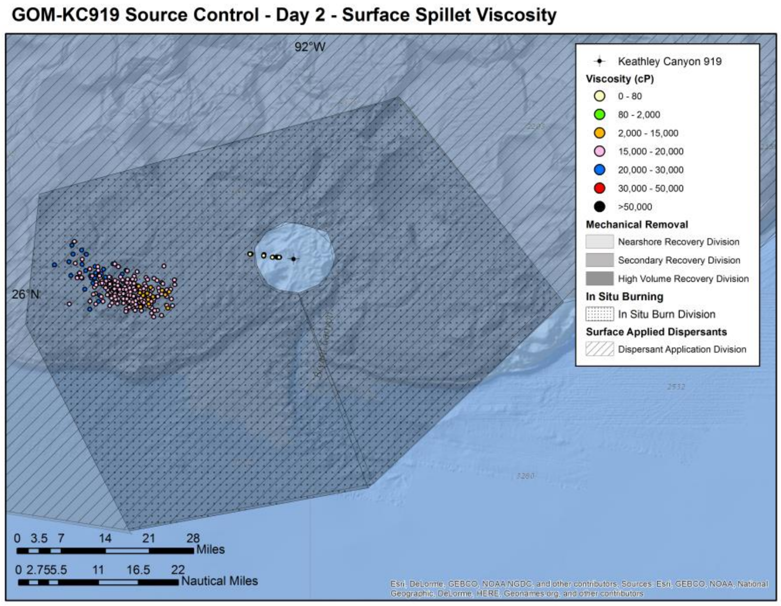


Figure 58: KC919 Source Control – Surface Spillet Viscosity (cp) at Day 2

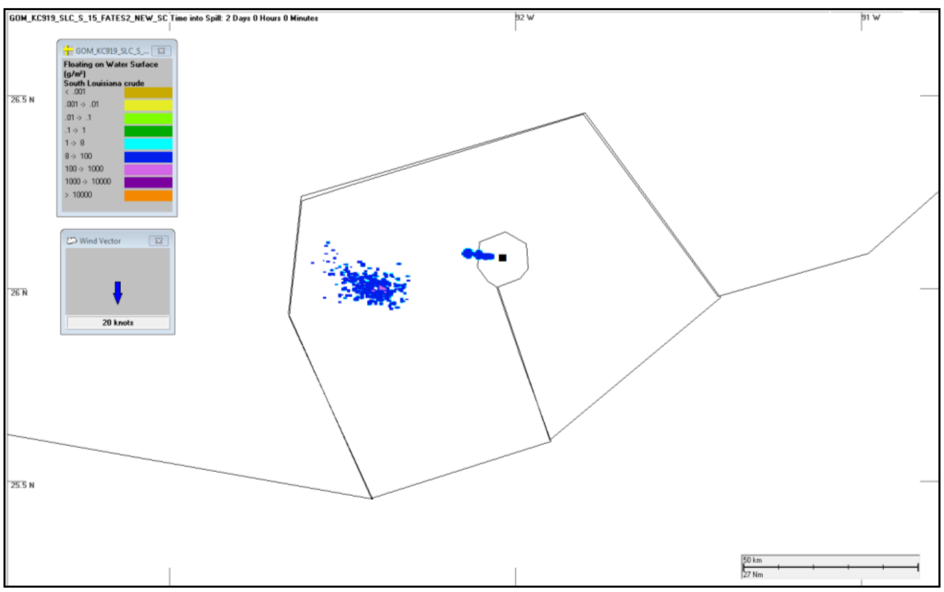


Figure 59: Scenario 5, GOM-KC919 Source Control – Floating Oil on Water Surface (g/m^2) at Day 2

The path of the plume varied over time, but the oil moved in a generally northerly direction before enter the Loop Current and spreading throughout the entire Gulf of Mexico. Minimum travel time for contact to shorelines was 43 days, with substantial shoreline impacts beginning after 47 days from the start of the discharge. The extended time for oil to reach shorelines is a function of the distance offshore and the prevailing wind conditions during the discharge period. At the end of the simulation, the majority of the shoreline oiling over 1 g/m^2 was along the coastline of southeastern Louisiana and western Texas (Figure 60). Oil that washed ashore in the Florida Keys was weathered tarballs.

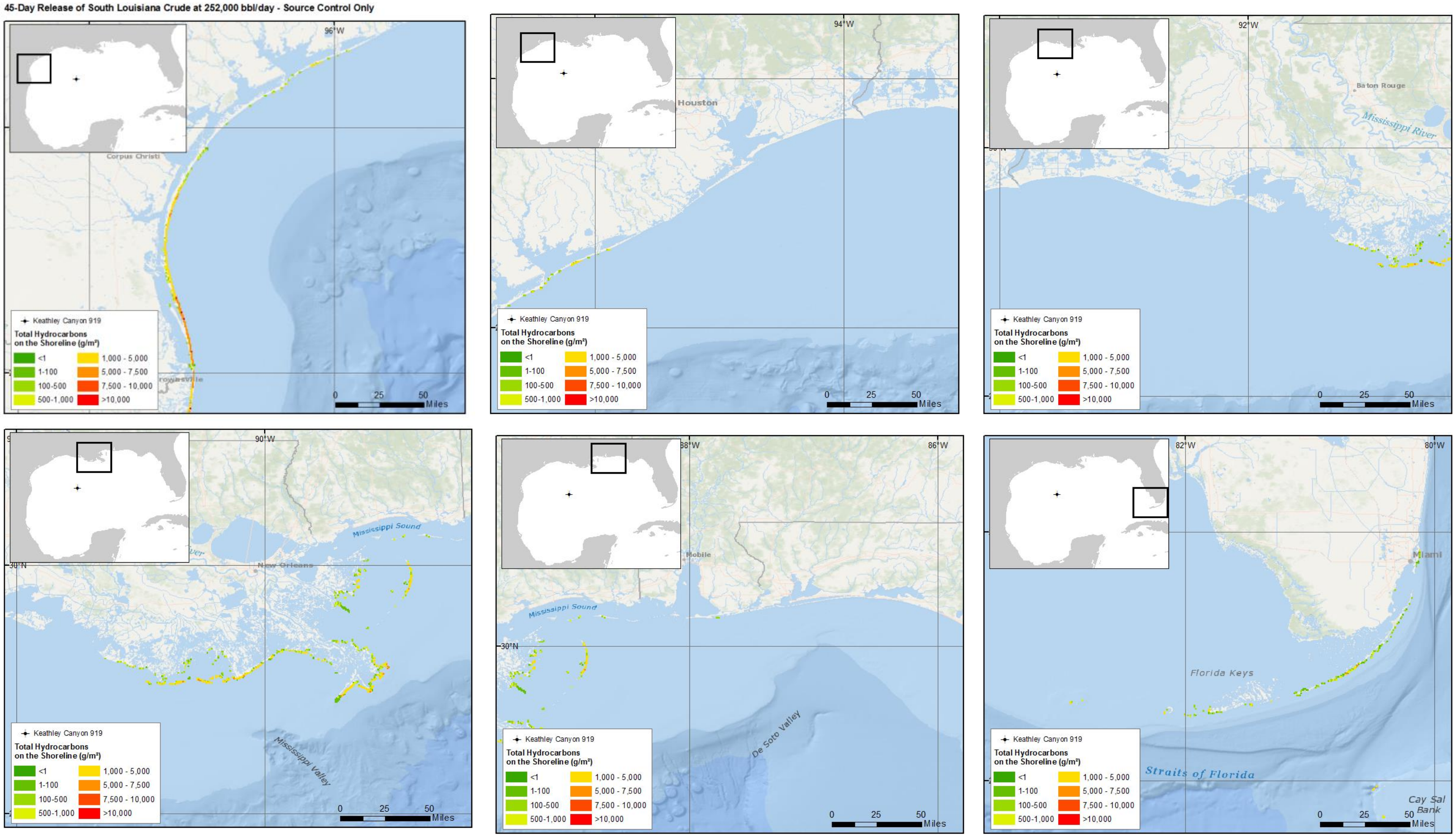


Figure 60: Scenario 5, GOM-KC919 Source Control, 45-Day Discharge – Shoreline Oil ≥1 g/m2, including Weathered Tarballs

Application of Response Countermeasures

Countermeasure Response Divisions

The following equipment types were employed in each of the following countermeasure response divisions, and are shown in Figure 61.

- High Volume Recovery Division – High volume mechanical recovery operations were employed beyond a 5.8 mile (5 nm) radius area established around the well for source control.
- In situ Burning Division – In situ burning operations were used in the same geographical area as the high volume mechanical recovery operations 5.8 mile (5 nm) away from the source control area.
- Secondary Recovery Division – Secondary mechanical recovery operations were used to remove oil that was not previously removed in the high volume recovery area.
- Nearshore Recovery Division – Nearshore mechanical recovery operations were used to remove oil from the surface of the water before it was washed onto shorelines.
- Dispersant Application Division – Surface applied dispersants were employed in the high volume and secondary recovery geographical areas as appropriate.

Subsurface dispersants, which were applied at the point of discharge in the vicinity of the wellhead, are not shown in Figure 61 or assigned to a geographic response division.

Keathley Canyon 919 - Countermeasure Response Divisions

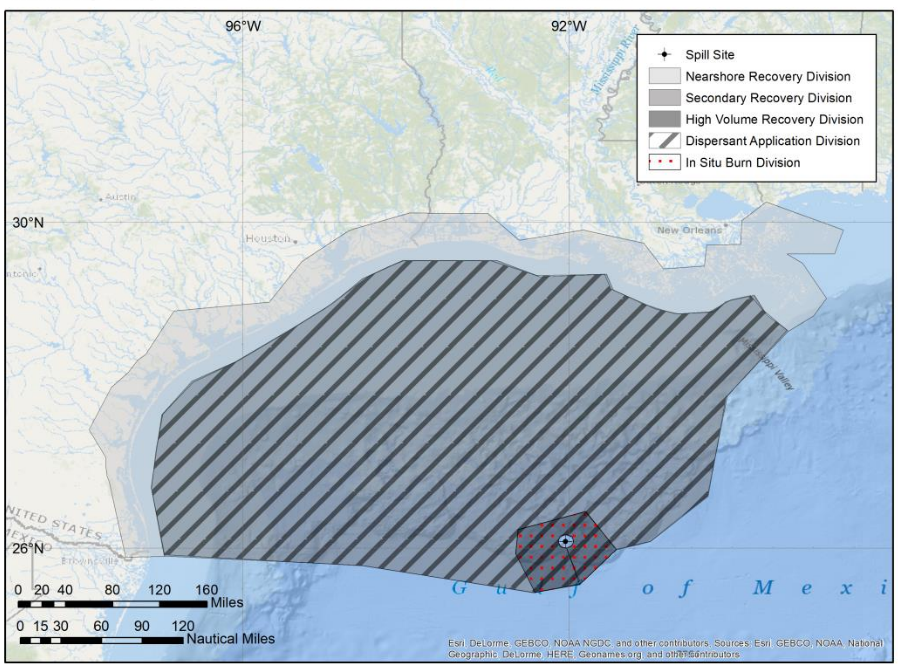


Figure 61: Scenario 5, GOM-KC919 – Geographic Coverage of Oil Countermeasure Response Divisions

The size and placement of the GOM-KC919 response divisions in the model were developed based on a review of the oil spill trajectories from the 45-day discharge in the Source Control Only simulation.

Countermeasure/Division Removal Rates (Model Inputs)

The removal rates by countermeasure type and response division that are shown in Table 19 represent the *maximum* potential rate that would be available at any point during the response operation.

As in an actual oil spill recovery operation, the model cascades response equipment into the response divisions as the assets arrive on the scene. The modeling reflects response equipment threshold values and limitations based on the availability of the response equipment (as determined to be in the stockpiles per OSRO response equipment survey) deployed in the appropriate divisions. As such, the model used oil removal rates for each division (i.e., SIMAP model polygon), based on the maximum potential daily removal rates (bbl/day) of the assigned asset (refer to Table 43), corrected by weather restrictions and daylight operations (as described in Section 1.8). Maximum removal rates are not realized in practice because of the limitations of weather delays, suspension of operations at night, the location of oil in relation to equipment, and performance thresholds, such as oil thickness on the water surface, sea state and currents, winds, and water content during oil emulsification.

Maximum oil removal rates are not necessarily applicable for the entire response period. This is because equipment cascades in at different times, and in some cases, resources are allocated to different applications. For example, because the KC919 scenario is simulating a high-volume WCD, the limiting factor for application of dispersant is the stockpile (not availability of application equipment). To maintain subsurface dispersant application throughout the duration of the blowout meant that surface dispersant application was limited by the stockpile. Dispersant application for this scenario is discussed further below.

Table 43: Maximum Potential Daily Oil Removal Rates for GOM-KC919 SC+MR+D+ISB+SubD Response Scenario [a]

Countermeasure Type	Response Division	Response System Category [b]	Removal Rate Applied [c]	Maximum Potential Daily Removal Rates (bbl/day)
Mechanical	**High-Volume**	Skimmer Group A	ERSP Day-1	174,050
		Skimmer Group C	ERSP Day-1	76,313
	Secondary	Skimmer Group A	ERSP Day-3	6,712
		Skimmer Group B	ERSP Day-3	460
		Skimmer Group C	ERSP Day-3	35,387
	Nearshore	Skimmer Group A	ERSP Day-3	5,258
		Skimmer Group B		470
		Skimmer Group C		1,674
	Total	**All Mechanical Countermeasures**		**300,324**
In Situ Burning	**High-Volume In Situ Burning**	In Situ Burning	Based on ISB Calculator	16,452
Surface Dispersant	**High-Volume and Secondary**	Surface Dispersants	Based on DMP2	21,638
Subsurface Dispersant	**Wellhead**	Subsurface Dispersant	Based on a DOR of 1:100	92,571
Total		**All Countermeasures**		**430,985**

[a] GOM-KC919 SC+MR+D+ISB+SubD Response Scenario by countermeasure type and response division *without* application of weather restrictions.

[b] The characteristics of the different types of mechanical equipment and the specific pieces of equipment applied in this scenario are described in Section 2.1. The viscosity thresholds for different types of equipment are further described in Section 1.8.2.

[c] ERSP is described in Section 5.0. "ERSP Day-1" rates are the higher removal rates applied in the areas and times when the oil was flowing from the well and the oil is the thickest. "Day-1" does not necessarily indicate that this is only applied for the first day. "ERSP Day-3" rates are applied in the areas more distant from the well where the oil is thinner and more spread out making removal less efficient. "Day-3" does not necessarily indicate that this is the third day of the response.

For Scenario 5, GOM-KC919 response operation divisions were cascaded in over the course of the initial 18 days (as depicted in Figure 62). Oil reached the surface after approximately twenty-eight (28) hours. Commencement of the surface dispersant application began on day 2 of the 45-day incident.

For the surface dispersant only simulation (no subsurface dispersant application), daily dispersant use was 60,000 gallons/day between day 4 and day 12; 56,000 gallons/day between day 12 and day 33, and 60,000 gallons/day between day 33 and day 45. The total dispersant volume for the surface only scenario used a total of 2,528,560 gallons, with an average daily rate of 56,190 gallons.

Subsurface dispersant operations commenced on day 5. For the surface and subsurface dispersant simulation, daily surface dispersant application was 45,000 gallons/day between day 2 and day 12; 17,000 gallons/day between day 12 and day 35, and 13,000 gallons/day between day 35 and day 45. The total dispersant volume used for the subsurface and surface simulation was 2,532,530 gallons, with an average daily rate of 56,278 gallons.

The subsurface dispersant application rate was 22 gpm (31,680 gallons/day) from day 5 to day 12, and 27 gpm (38,880 gallons/day) from day 12 and until well shutdown on day 45. Higher subsurface dispersant application is possible with use of high-volume systems or the use of multiple systems. However, higher subsurface dispersant application would exhaust the limited dispersant inventory (i.e., the available dispersant stockpile is a limiting factor in the KC919 scenario).

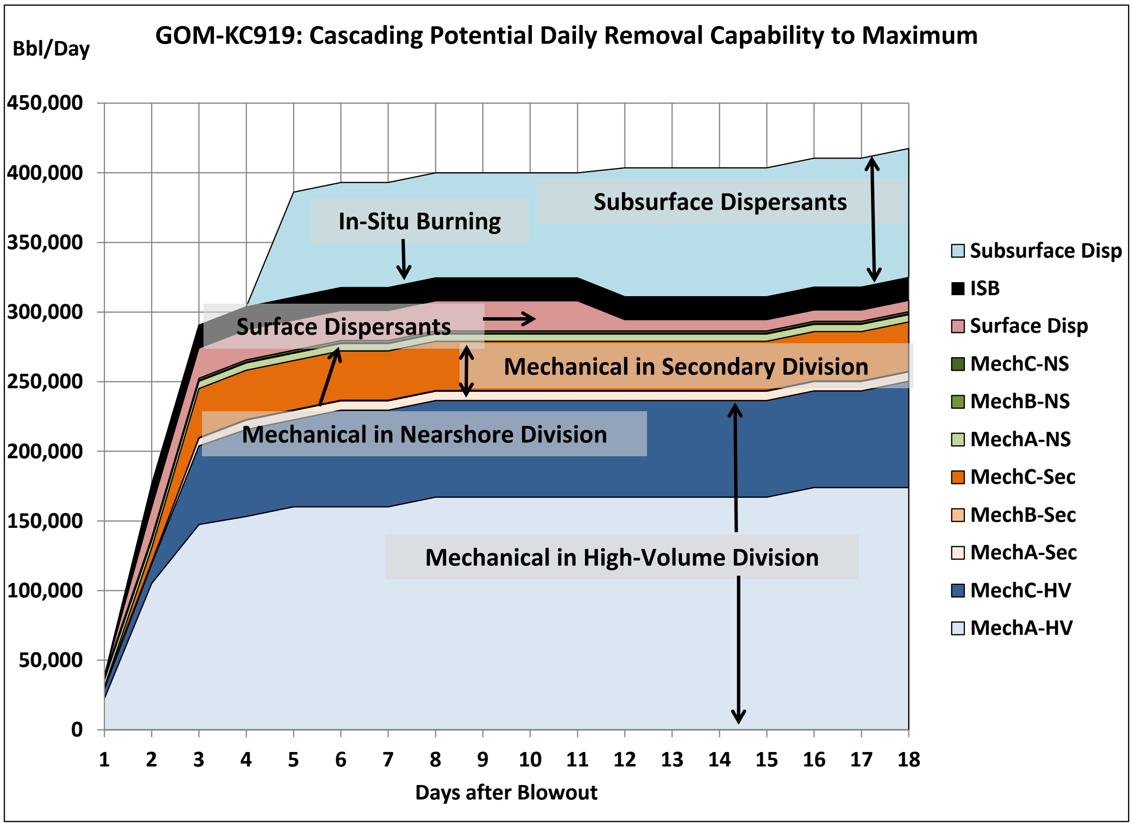


Figure 62: Scenario 5, GOM- KC919 – Cascading SC+MR+D+ISB+SubD Response Assets and Cumulative Potential Daily Removal Capacity

Countermeasure Simulation Results & Analysis

Achieved Removal versus Potential Equipment Capabilities

Maximum potential removal rates of oil removal systems are not achieved due to the limitations on countermeasures resulting from oil weathering (viscosity increases), and other environmental factors (such as increased sea state and darkness which often limited when the countermeasures could be applied). For the GOM- KC919 SC+MR+D+ISB+SubD simulation, weather restrictions were in effect for 21% of the time, and for most equipment, the operating period was limited to 12 hours of daylight (other equipment limitations applied are listed in Table 10, Table 12, and Table 13). Because of these thresholds and limitations, as well as the lack of recoverable, burnable, or dispersible oil in the response divisions (45% of the oil remaining entrained in the water column due to the deepwater subsurface release and weather conditions, and 33% of the oil evaporated), achieved oil removal was significantly less than the potential recovery capabilities (as shown in Figure 63 and Figure 64) for the GOM-KC919 SC+MR+D+ISB+SubD simulation).

Countermeasure limitations were especially noticeable in the very low efficiency of Skimmer Group C systems in the secondary recovery area, and for all skimming systems in the nearshore area. Also observed is that in situ burning was a relatively effective countermeasure (achieving 21% of it available removal potential) in the high volume area of this scenario. These results indicate that in situ burning could be well suited for remote offshore locations where secondary storage may be a logistical constraint. Surface applied dispersants were comparably effective, achieving 25% of its removal/mitigating potential. In general, dispersant spraying aircraft with large payloads are also well suited for scenarios involving remote offshore locations.

Table 44 shows the system potential with regard to barrels of oil that could be treated or removed based on the sum total of removal/treatments rates over the course of the entire response operation (i.e., during the release of oil from the well and for an additional 45 days after source control is achieved to stop the flow of oil). The "achieved" removal or treatment reflects the sum total of oil removed or treated over the course of the response operations. Figure 63 contrasts the sum total of potential removal/treatment over the course of the operations and the sum total of the achieved removal/treatment. The daily well flow is shown as a benchmark. The potential removal/treatment capability greatly exceeds the achieved removal/treatment due to the various environmental and logistical factors that limit performance.

Table 44: Scenario 5, GOM- KC919 – SC+MR+D+ISB+SubD Cumulative System Potential Oil Recovery versus Achieved Oil Recovery over 90-Day Simulation

Response Type	Response Division	Response System Type	Total Removal/Treatment		
			System Potential (bbl)	Achieved (bbl)	% Potential [a]
Mechanical [b]	**High-Volume**	Skimmer Group A	9,256,673	615,466	6.6%
		Skimmer Group C	3,805,008	741,917	19.5%
	Secondary	Skimmer Group A	598,800	40,408	6.7%
		Skimmer Group B	40,940	4,601	11.2%
		Skimmer Group C	3,159,541	1,104	0.03%
	Nearshore	Skimmer Group A	478,478	0	0.0%
		Skimmer Group B	42,770	0	0.0%
		Skimmer Group C	152,334	0	0.0%
	Mechanical Total	**All**	**17,534,544**	**1,403,497**	**8.0%**
In Situ Burning [c]	**High-Volume In Situ Burning**	-	1,075,290	276,912	25.8%
Surface Dispersants	**High-Volume/Secondary**	-	487,692	176,365	36.2%
Subsurface Dispersants	**High-Volume/Secondary**	-	3,675,417	1,197,304	32.6%
All Categories	**All Categories Total**	**All**	**22,772,943**	**3,054,078**	**13.4%**

[a] Achieved Total Recovery divided by System Potential Total Recovery as percentage.

[b] ERSP Day-1 rates assumed for High-Volume Division until well capping (source control); ERSP Day-3rates assumed for Secondary and Nearshore Divisions, and for High-Volume Division after day 45 source control.

[c] EBSP Day-1 rates assumed until day 45 source control, after which EBSP Day-3 rates were applied.

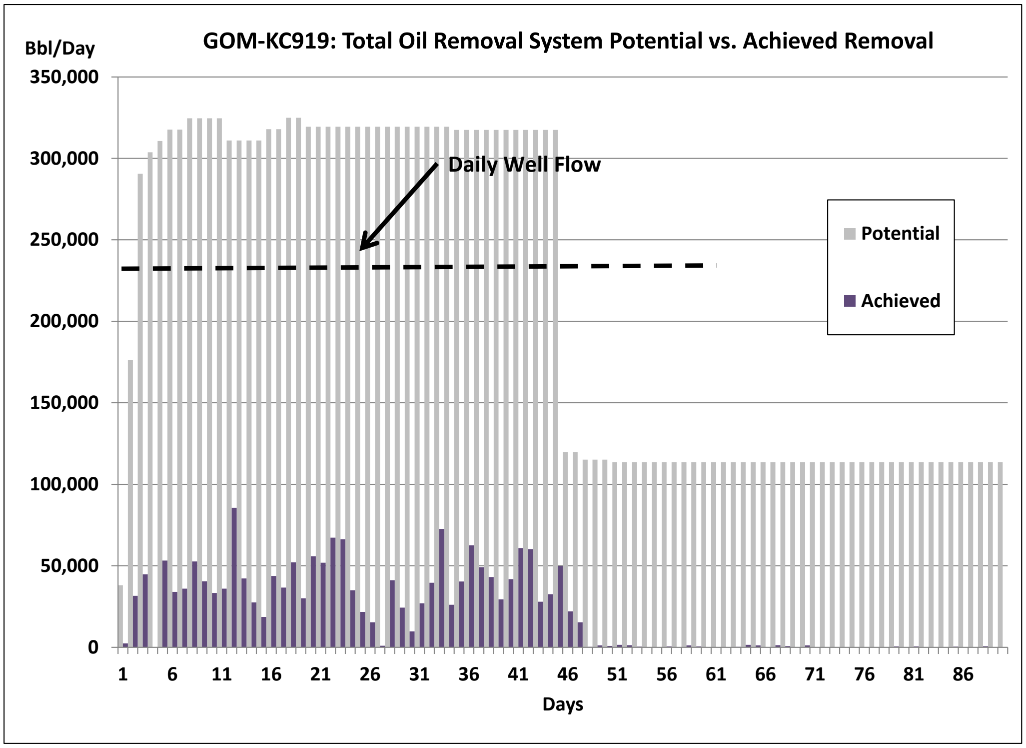


Figure 63: Scenario 5, GOM- KC919 SC+MR+D+ISB+SubD Total Oil Removal System Potential and Achieved Total Daily Removal

Figure 63 contrasts the amount of oil flowing from the well on a daily basis along with the maximum potential daily capability per day, as well as the achieved average daily removal rate. The achieved average daily removal rate is lower than the potential daily removal rate for each day of the scenario.

During the response period, some systems have very low or near-zero removal for some periods because of performance limitations due to environmental conditions, or because there is insufficient oil available, particularly in secondary and nearshore response areas where oil may not appear on the surface until after the oil has stopped flowing.

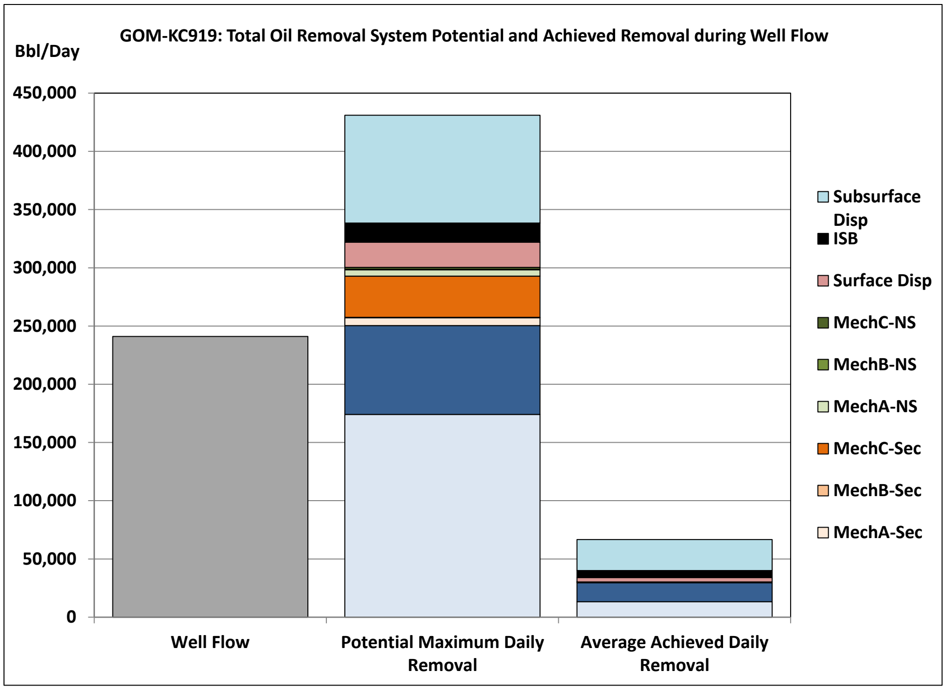


Figure 64: Scenario 5, GOM- KC919 SC+MR+D+ISB+SubD Total Maximum Oil Removal System Potential and Achieved Removal Compared with Well Flow During 21-Day Discharge Period

Oil Removal by Countermeasure Type

Table 45 is a summary of model results for the various response countermeasures applied to the GOM-KC919 scenario. This table allows for comparison of the oiling and oil removal by each countermeasure across the various model simulations. Values within Table 45 represent the volume of oil present/removed at the completion of the response scenarios (90 days).

Table 45: Scenario 5, GOM-KC919 – Comparison of Shoreline Oiling and Oil Removal for the Relief Well Only Scenario and Four Response Scenarios at the End of the Model Simulations

Scenario	Volume (bbl) of Discharge	Volume (bbl)/ Percent of Oil on Shoreline	Volume (bbl)/ Percent Removed by Skimming	Volume (bbl)/ Percent Dispersed	Volume (bbl)/ Percent Removed by Burning	Volume (bbl)/ Percent Bio-degraded or in Sediments
Relief Well Only, 37 Day Discharge	30,240,000	877,513				10,539,001
Source Control (SC), 45 Day Discharge	11,340,000	186,361 2%				3,267,619 29%
Source Control and Mechanical Recovery (SC+MR)	11,340,000	109,040 1%	1,893,749 17%			2,721,935 24%
Source Control, Mechanical Recovery and Surface Dispersant (SC+MR+D)	11,340,000	83,821 1%	1,864,240 16%	141,249 1%		2,781,594 25%
Source Control, Mechanical Recovery, Surface Dispersant and In Situ Burning (SC+MR+D+ISB)	11,340,000	77,045 1%	1,675,916 15%	136,128 1%	237,624 2%	2,768,726 24%
Source Control with Mechanical Recovery, Surface and Subsurface Dispersant, and In Situ Burning (SC+MR+D+ISB+SubD)	11,340,000	37,352 0.3%	1,403,519 12%	1,133,432 10%	276,917 2%	3,517,769 31%

Scenario 5, GOM-KC919 is a WCD from an offshore deep-water well where mechanical recovery was the primary tool that removed oil. When used without the aid of other response operations, mechanical recovery was able to remove up to 17% of the oil discharged in this scenario. These results highlight the efficiency of deploying high-volume mechanical recovery as close to the point of discharge onto the water's surface as possible, before the oil has widely spread out and becomes too thin to remove from the environment.

When surface applied dispersants were added, oil removed by mechanical recovery decreased to 16%; however, an additional 1% of the oil was also dispersed into the water column; the overall result was a slight decrease in the overall volume of oil to reach the shoreline. When subsurface dispersants were added, oil removed by mechanical removal decreased to 12%; however, the oil was dispersed into the water column increased to 10%. This resulted in a 1 million barrel decrease in oil reaching the water surface and a decrease of approximately a half a million square miles of surface waters oiled > 8 g/m2, as well as decrease in 240 miles of shoreline oiled, and a nearly 40,000 bbl decrease in the amount of oil stranding on the shoreline.

In situ burning only accounted for 2% of the oil removed when used, which is likely a reflection of the limited area where burning could be applied (a small subarea of the High Volume Recovery Division) in this nearshore scenario. As discussed in the earlier Methods section, in situ burning is limited by availability of fireboom and other equipment, and modeling equipment thresholds for wave height, wind, and viscosity and thickness of oil on the water surface.

Figure 65 displays the fate of oil at the end of the 90-day simulation for Scenario 5, GOM-KC919 involving source control, mechanical recovery, in situ burning, surface dispersants and subsurface dispersants (e.g., SC+MR+D+ISB+SubD).

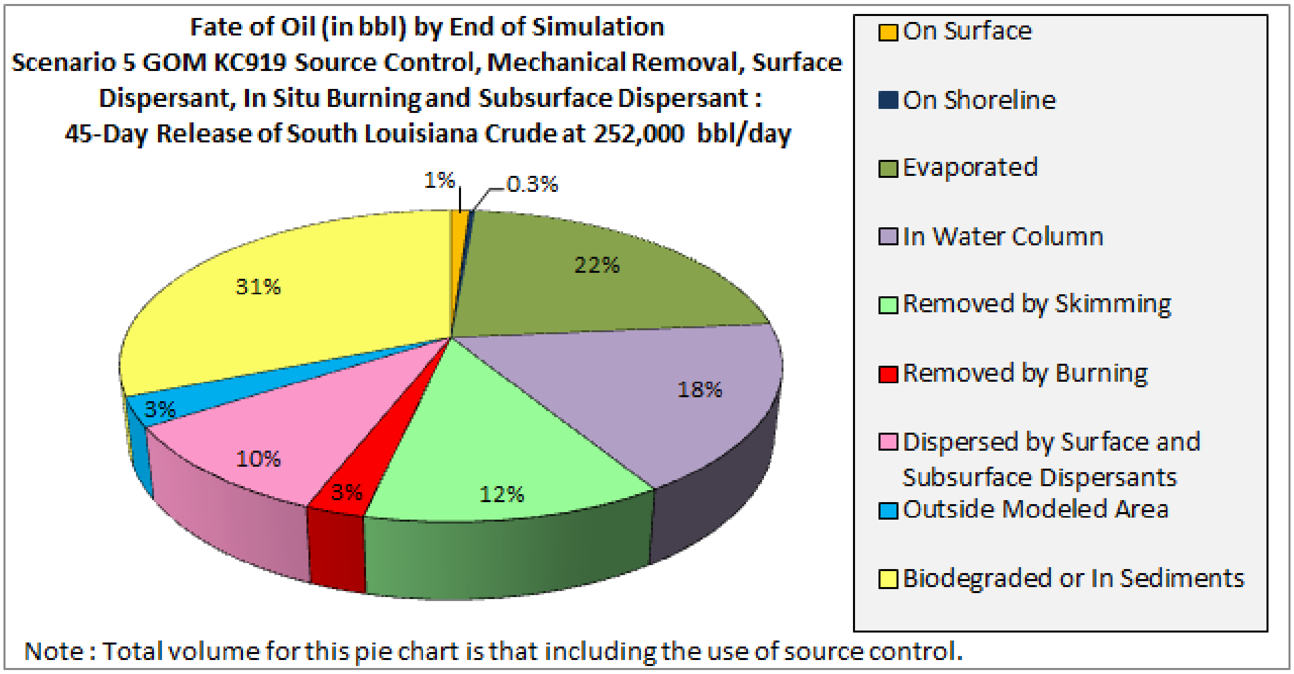


Figure 65: Scenario 5, GOM-KC919 – Fate of Oil at End of 90-Day Simulation (Scenario includes Source Control, Mechanical Recovery, Surface and Subsurface Dispersant, and In Situ Burning Countermeasures)

Reductions in Surface and Shoreline Oiling

Table 46 provides a comparison of the shoreline and water surface oiling results for each of the GOM-KC919 response countermeasure simulations. While from a mass balance perspective, the addition of spill countermeasures did not remove large percentages of the gross volume of oil discharged due to the large amounts of oil that were naturally entrainment or evaporated, the combination of applied spill countermeasures did an effective job at significantly decreasing the overall oiling footprint of the remaining oil spill on the water's surface and on the shoreline.

Table 46: Scenario 5, GOM-KC919 – Comparison of Shoreline and Water Surface Oiling Above Equipment Threshold Values or Limitations

Scenario 5, GOM-KC919	Relief Well Only (WCD)	Source Control	Source Control and Mechanical Recovery	Source Control, Mechanical Recovery, and Surface Dispersant	Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning	Source Control with Mechanical Recovery, Surface and Subsurface Dispersant, and In Situ Burning
Volume (bbl) of Shoreline Oiling (to Any Degree)	877,530	186,362	109,041	83,821	77,045	37,352
Percent Reduction in Volume of Shoreline Oiled As Compared to Relief Well Only	-	79%	88%	90%	91%	96%
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	2,602	1,135	899	719	693	459
Percent Reduction in Shoreline Length Oiled with ≥1 g/m^2 As Compared to Relief Well Only	-	56%	65%	72%	73%	82%
Cumulative Area (mi^2) of Surface Affected by Oil ≥8g/m^2	5,247,021	2,588,459	1,670,216	1,114,463	1,083,719	591,849
Percent Reduction in Surface Affected by Oil ≥8g/m^2 As Compared to Relief Well Only	-	51%	68%	79%	79%	89%

Figure 66 is a visual depiction of the reduction in the surface area affected by ≥8.0 g/m^2 of oil over the 90-day period. The graphic directly compares the levels of maximum water surface oiling over time between the Source Control Only simulation that adds mechanical recovery, surface and subsurface dispersants, and in situ burning (SC+MR+D+ISB+SubD).

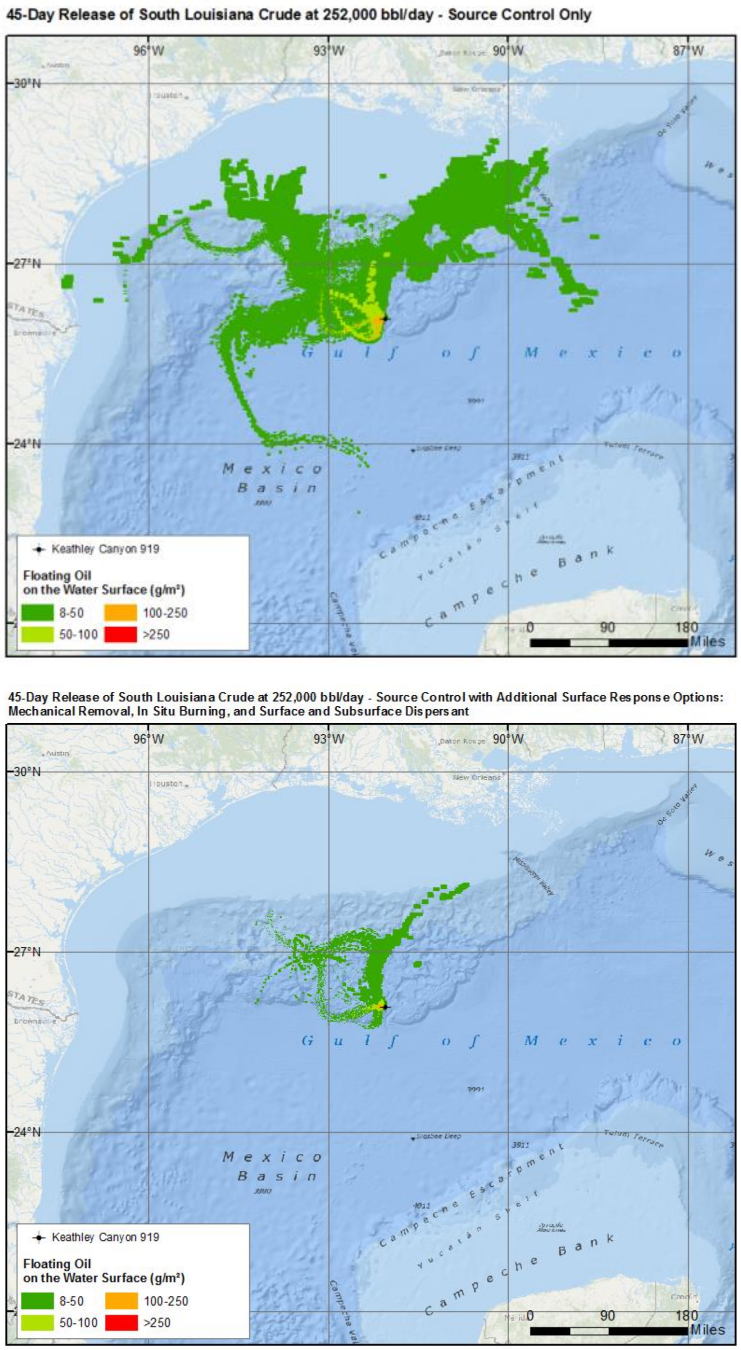


Figure 66: Scenario 5, GOM-KC919 – Comparison Floating Oil Concentration (≥8.0 g/m^2) over 90-Day SIMAP Model Simulation, Top Panel: Source Control (SC), Bottom Panel: Source Control, Mechanical Recovery, Surface Dispersants, and In Situ Burning (SC+MR+D+ISB+SubD)

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2.1.2.6 *Scenario 6: DeSoto Canyon 187*

Scenario Site Information

Gulf of Mexico De Soto Canyon 187 (DC187) is an offshore (116 miles [101 nm] from shore), deepwater (4,490 ft) well in the Central Gulf of Mexico Planning Area. In the event of a worst case discharge at this site, there is a high probability for significant shoreline contact (see Figure 67) if spill response countermeasures are not immediately taken. Based on 100 stochastic model runs, the worst case release date for the GOM-DC187 WCD scenario was December 27, 2002.

Table 47: Scenario 6, GOM-DC187 – Well Information and Shoreline Contact Times

WCD Scenario Parameters	
Discharge Flow Rate	241,000 bbl/day
WCD Duration	106 days, Relief Well Only 45 days, Source Control
Total WCD Release Volume	25,546,000 bbl, Relief Well Only 10,845,000 bbl, Source Control
Simulation Duration (45 days following end of discharge)	151 days, Relief Well Only 90 days, Source Control
Oil Type	South Louisiana Crude
API Gravity	34.5
Viscosity @ 15^{o}C (cp)	10.1
Latitude, Longitude	28.785337^{0}N, 87.39878^{0}W
Depth to Sea Floor	4,490 ft
Distance to Shoreline	116 miles (101 nm)
SIMAP Model Results [a]	
Time for oil above 1 g/m^2 to reach shore [b]	5 days
Time for oil greater than 8 g/m^2 to reach shore [c]	7.5 days, Figure 67

[a] SIMAP model results presented in this table are based on the 100 stochastic model runs.

[b] The 1 g/m^2 value is the threshold for socio-economic resource effects (e.g., closure of fisheries) (French-McCay et al. 2011; French McCay et al. 2012)

[c] The 8 g/m^2 value is the minimum thickness of floating oil for which response equipment can be effectively used (NOAA 2010)

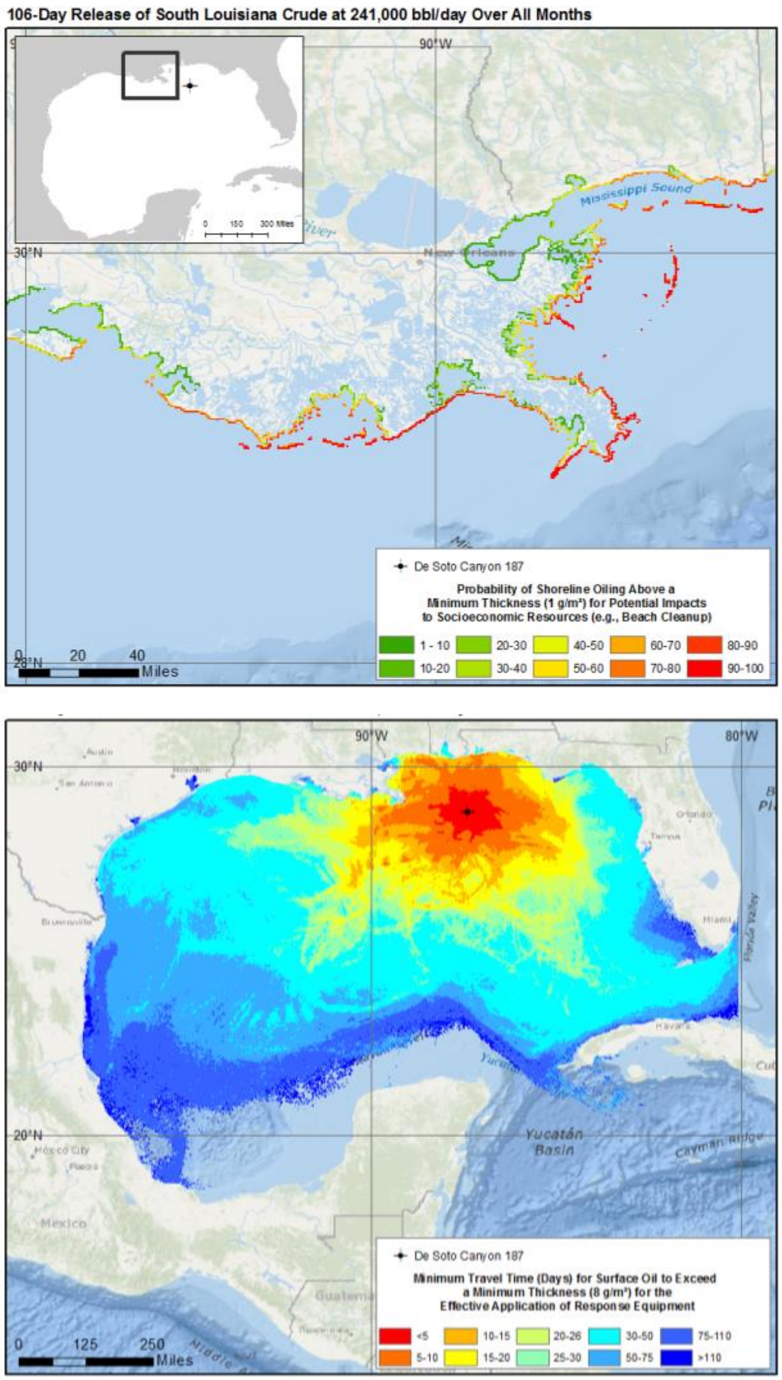


Figure 67: Scenario 6, GOM-DC187 Relief Well Only Scenario, 106-Day Discharge – Probability of Shoreline Oiling and Minimum Travel Times for Surface Oiling

Application of Source Control

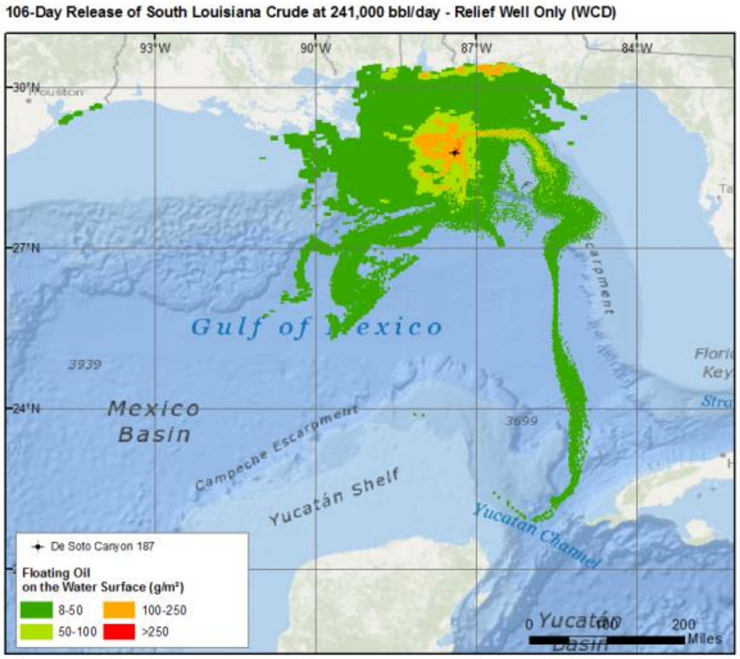
When a source control operation is modeled for the WCD GOM-DC187 scenario, the discharge period is reduced by 61 days, and the volume of oil released to the environment is reduced by 14,701,000 bbl. Correspondingly, source control results in substantially less impact to the water column and shoreline in comparison to the Relief Well Only simulation.

Table 48 and Figure 68 compare discharge volume, shoreline-oiling volume, length of oiled shoreline, area of surface oiling, and the amount of oil biodegraded or in the sediments for the Relief Well Only and Source Control Only modeling simulations.

Table 48: Scenario 6, GOM-DC187 – Comparison of Relief Well Only and Source Control Response Scenarios

Scenario 6, GOM-DC187	Relief Well Only (106-day flow duration)	Source Control (45-day flow duration)	Reduction Due to Source Control	Percent Reduction Due to Source Control
Volume Discharged (bbl)	25,546,000 bbl	10,845,000 bbl	14,701,000 bbl	58 %
Volume Shoreline Oiling (bbl) any thickness	1,494,337 bbl	244,277 bbl	1,250,060 bbl	84 %
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	2,990 mi	1,075 mi	1,915 mi	64 %
Cumulative Area (mi^2) of Surface Oiling ≥8g/m^2	4,485,334 mi^2	2,088,673 mi^2	2,396,661 mi^2	53 %
Amount Biodegraded or In Sediments (bbl) at the End of the Simulation	8,760,015 bbl	3,160,324 bbl	5,599,691 bbl	64 %

As shown in Figure 68, the volume and spread of oil spilled from this WCD is greatly reduced by source control; however, without the application of additional response operations to remove or mitigate spilled oil on the surface, the expected contact and exposure to oil in the environment is still quite extensive.



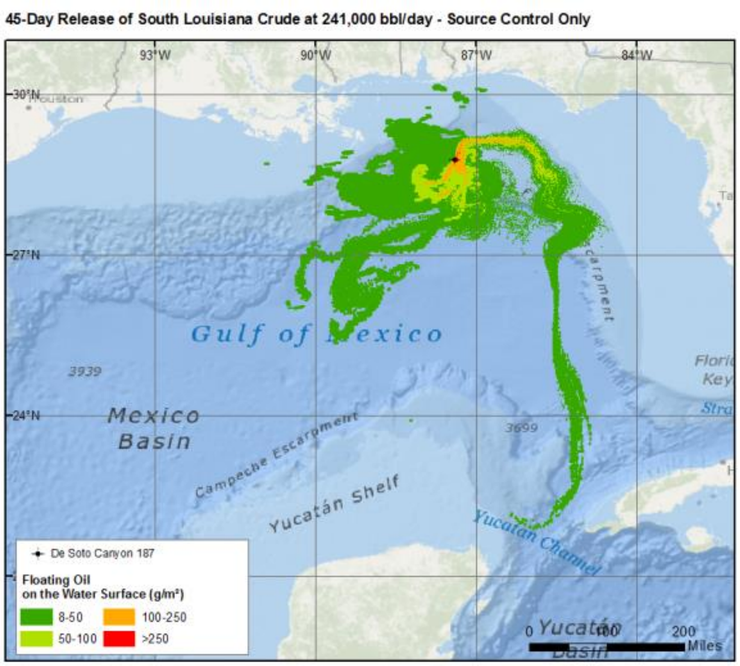


Figure 68: Scenario 6, GOM-DC187 – Comparison of Maximum Concentrations of Surface Oiling Experienced Throughout Simulation Periods for Relief Well Only (106-Day Discharge) and Source Control (45-Day Discharge)

Oil Discharge Behavior

Figure 69 shows the fate of oil for 90 days from the discharge (45-day discharge duration and 45 days following the source control). At the end of the simulation, 42% percent of the total oil had evaporated, 52% had either biodegraded or remained in the water column and sediments, 2% of the oil remained on the shoreline, and 4% of the oil remained floating on the surface. Note that, the model does not simulate potential photooxidation of floating oil.

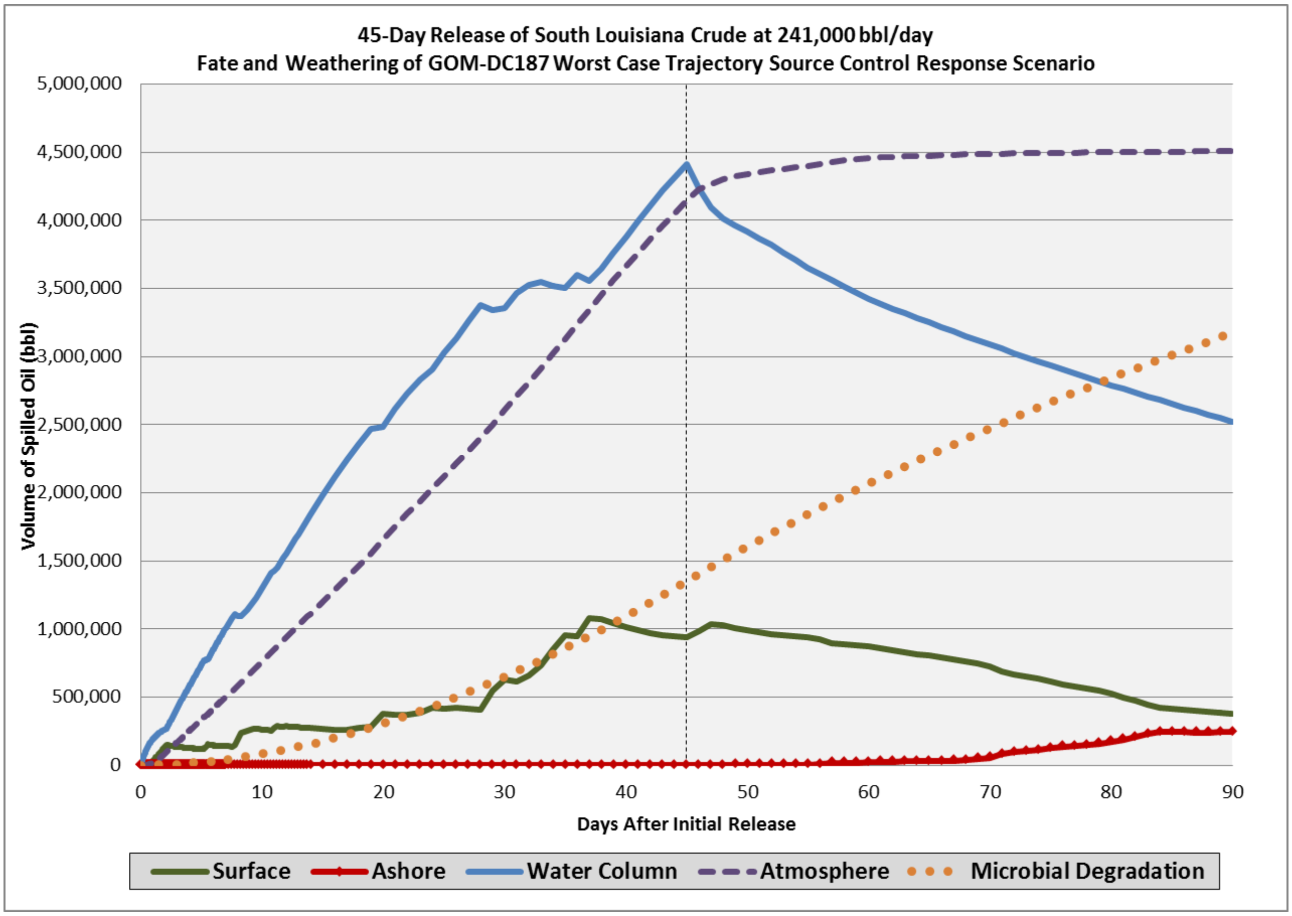


Figure 69: Scenario 6, GOM-DC187 Source Control, 45-Day Discharge – Oil Fate and Weathering (Dotted Vertical Line Indicates Source Control on Day 45)

In Scenario 6, GOM-DC187 Source Control, 63% of the total oil mass discharged from the blowout will reach the surface, while 37% remains entrained within the water column. While oil first appeared on the surface within 18 hours of being discharged from the well, the entire amount of oil discharged that eventually rose to the surface took approximately 26 hours. The oil rising during calm conditions surfaced in the immediate vicinity of the well location. As the oil slick spreads, the surface oil remained thick (> 8 g/m^2) and fresh enough to be recovered or treated (< 20,000 cST) and stayed in the High Volume Recovery Division for approximately 3 days in calm conditions (Figure 70 and Figure 71). As winds increased after day 3, thick patches of oil still remained in the secondary division, but become weathered and mostly non-recoverable or treatable.

Figure 70 and Figure 71 display model results at day 3, showing the oil movements and weathering that occurred over the a relatively calm first two days of the discharge. After day 3, the winds were stronger, viscosity of the discharged oil changed, and effectiveness of response countermeasures was degraded.

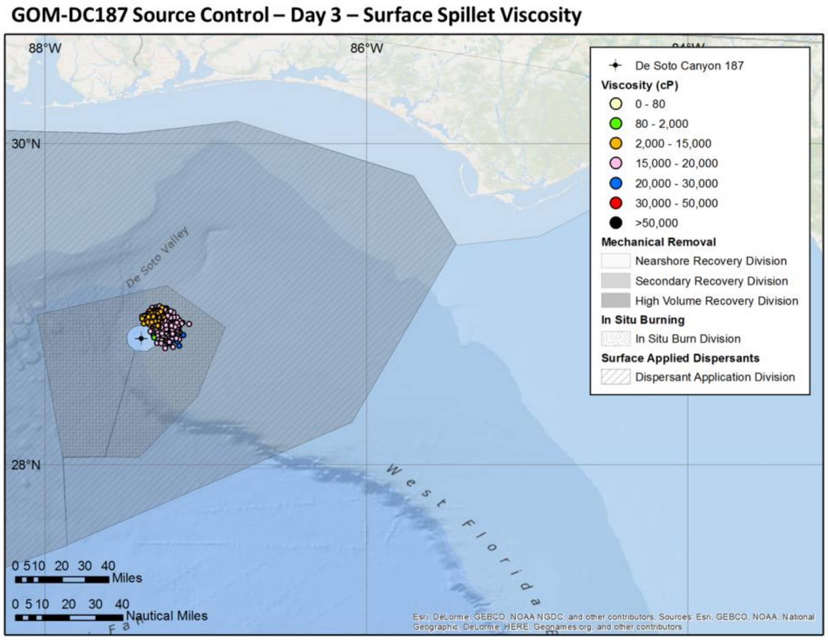


Figure 70: Scenario 6, GOM-DC187 Source Control – Surface Spillet Viscosity (cp) at Day 3

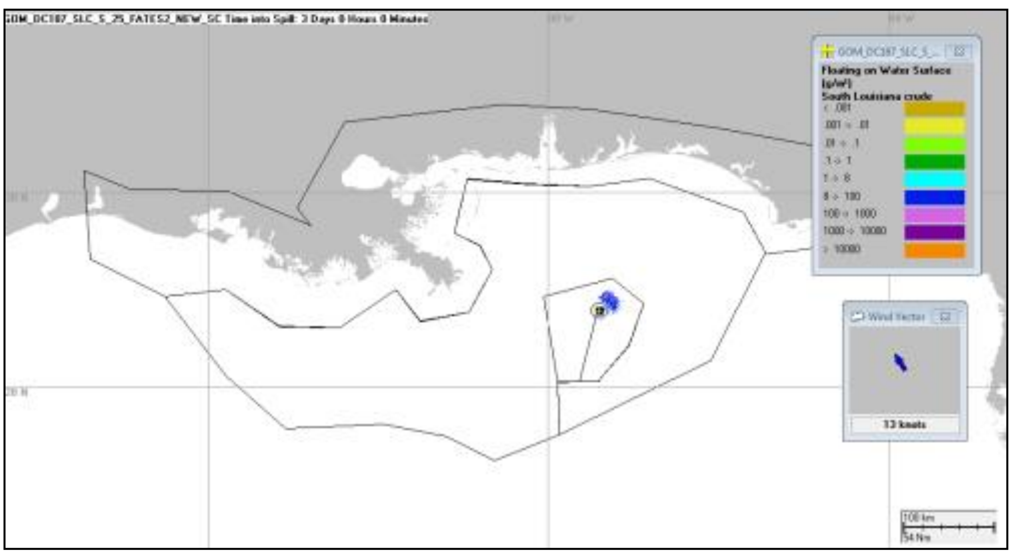


Figure 71: Scenario 6, GOM-DC187 Source Control- Floating Oil on Water Surface (g/m^2) at Day 3

The path of the GOM-DC187 plume varies over time, but the oil traveled generally in an easterly/southeasterly direction, before becoming entrained in the Gulf of Mexico Loop Current. Minimum travel time for contact to shorelines is 37 days, with substantial shoreline impacts beginning after 47 days from the start of the discharge. At the end of the simulation, the majority of the shoreline oiling over 1 g/m^2 is along the Louisiana and Texas coasts (Figure 72).

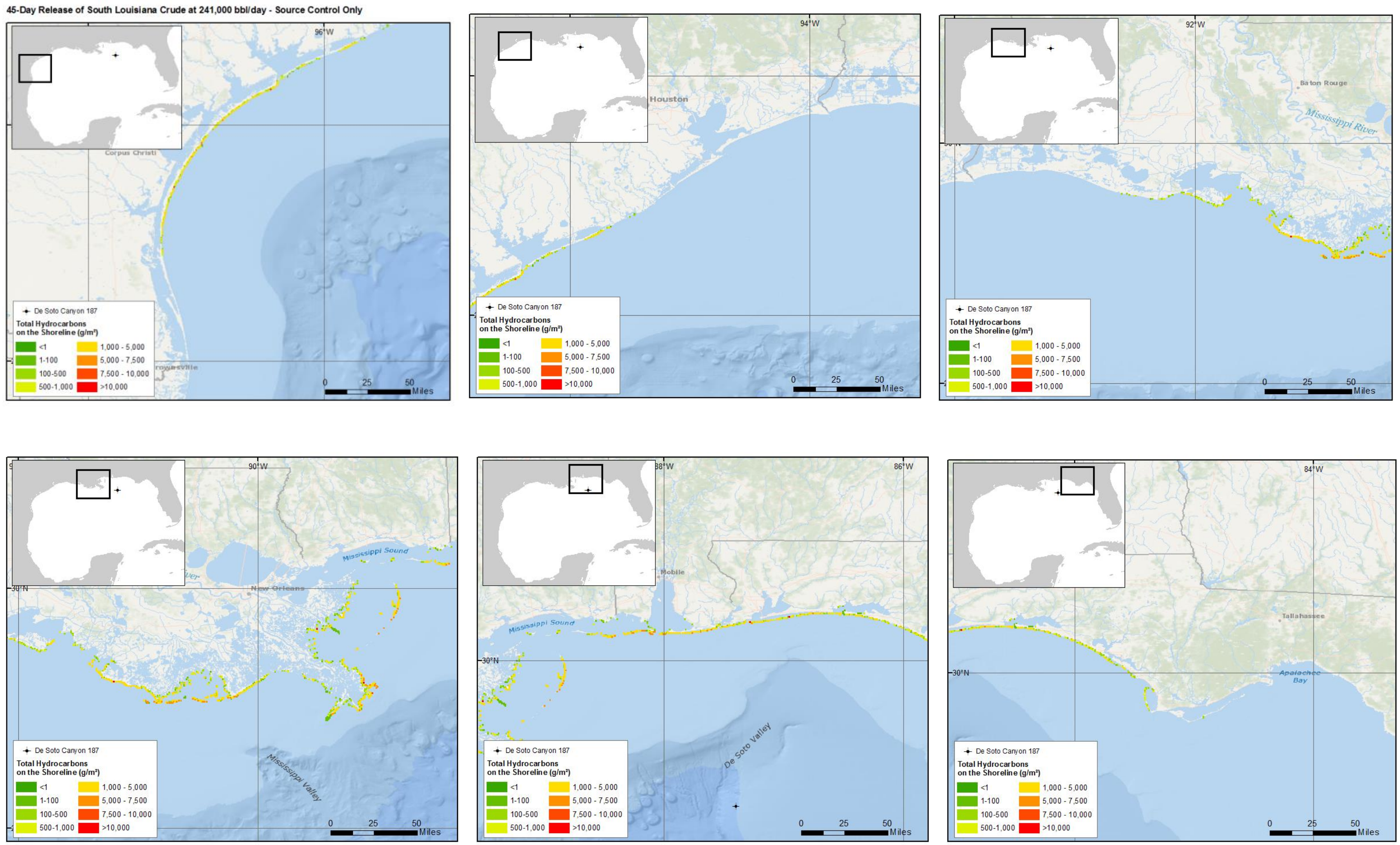


Figure 72: Scenario 6, GOM-DC187 Source Control, 45-Day Discharge – Shoreline Oil ≥1 g/m², including Weathered Tarball

Application of Response Countermeasures

Countermeasure Response Divisions

The following equipment types were employed in each of the following countermeasure response divisions, and are shown in Figure 73.

- High Volume Recovery Division – High volume mechanical recovery operations were employed beyond a 5.8 mile (5 nm) radius area established around the well for source control.
- In situ Burning Division – In situ burning operations were used in the same geographical area as the high volume mechanical recovery operations 5.8 mile (5 nm) away from the source control area.
- Secondary Recovery Division – Secondary mechanical recovery operations were used to remove oil that was not previously removed in the high volume recovery area.
- Nearshore Recovery Division – Nearshore mechanical recovery operations were used to remove oil from the surface of the water before it was washed onto shorelines.
- Dispersant Application Division – Surface applied dispersants were employed in the high volume and secondary recovery geographical areas as appropriate.

Subsurface dispersants, which were applied at the point of discharge in the vicinity of the wellhead, are not shown in Figure 73 or assigned to a geographic response division.

De Soto Canyon 187 - Countermeasure Response Divisions

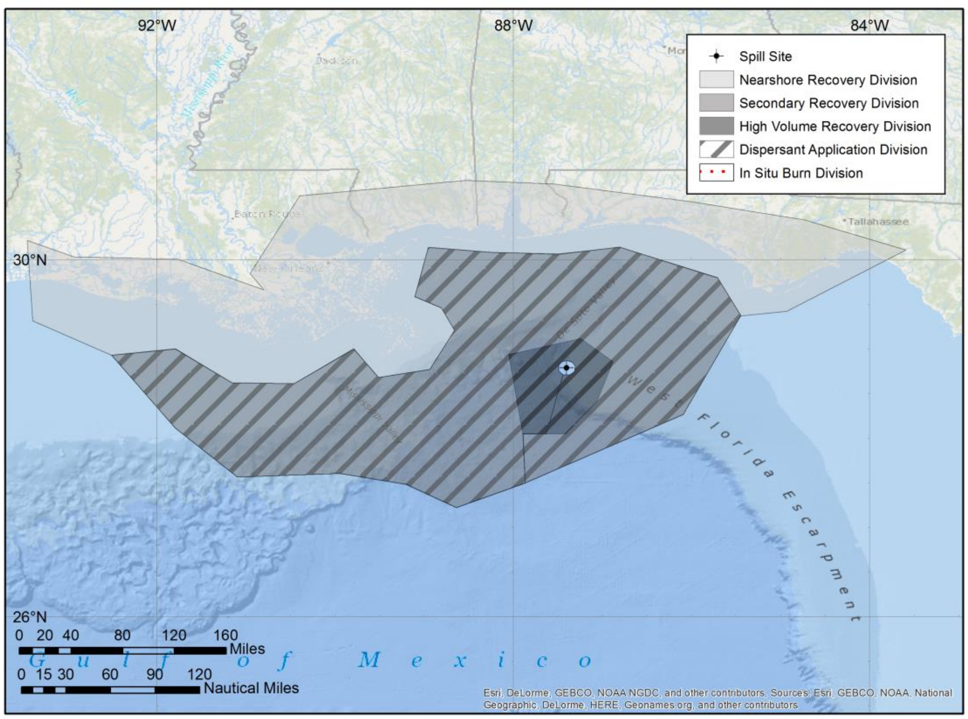


Figure 73: Scenario 6, GOM-DC187 – Geographic Coverage of Oil Countermeasure Response Divisions

The size and placement of the GOM-DC187 response operation divisions in the model were developed based on a review of the oil spill trajectories from the 45-day discharge in the Source Control Only simulation.

Countermeasure/Division Removal Rates (Model Inputs)

The removal rates by countermeasure type and response division that are shown in Table 19 represent the *maximum* potential rate that would be available at any point during the response operation.

As in an actual oil spill recovery operation, the model cascades response equipment into the response divisions as the assets arrive on the scene. The modeling reflects response equipment threshold values and limitations based on the availability of the response equipment (as determined to be in the stockpiles per OSRO response equipment survey) deployed in the appropriate divisions. As such, the model used oil removal rates for each division (i.e., SIMAP model polygon), based on the maximum potential daily removal rates (bbl/day) of the assigned asset (refer to Table 49), corrected by weather restrictions and daylight operations (as described in Section 1.8).

Maximum oil removal rates are not necessarily applicable for the entire response period. This is because equipment cascades in at different times, and in some cases, resources are allocated to different applications. For example, because the DC187 scenario is simulating a high-volume WCD, the limiting factor for application of dispersant is the stockpile (not availability of application equipment). To maintain subsurface dispersant application throughout the duration of the blowout meant that surface dispersant application was limited by the stockpile. Dispersant application for this scenario is discussed further below.

Table 49: Maximum Potential Daily Oil Removal Rates for GOM-DC187 SC+MR+D+ISB+SubD Response Scenario [a]

Countermeasure Type	Response Division	Response System Category [b]	Removal Rate Applied [c]	Maximum Potential Daily Removal Rates (bbl/day)
Mechanical	**High-Volume**	Skimmer Group A	ERSP Day-3	124,198
		Skimmer Group B	ERSP Day-3	10,831
		Skimmer Group C	ERSP Day-3	107,933
	Secondary	Skimmer Group A	ERSP Day-3	8,420
		Skimmer Group B	ERSP Day-3	1,406
		Skimmer Group C	ERSP Day-3	33,904
	Nearshore	Skimmer Group A	ERSP Day-3	6,371
		Skimmer Group C	ERSP Day-3	1,031
	Total	**All Mechanical Countermeasures**		**294,094**
In Situ Burning	**High-Volume In Situ Burning**	In Situ Burning	Based on ISB Calculator	16,452
Surface Dispersant	**High-Volume and Secondary**	Surface Dispersants	Based on DMP2	38,619
Subsurface Dispersant	**Wellhead**	Subsurface Dispersant	Based on a DOR of 1:100	75,428
Total		**All Countermeasures**		**424,593**

[a] GOM-DC187 SC+MR+D+ISB+SubD Response Scenario by countermeasure type and response division *without* application of weather restrictions.

[b] The characteristics of the different types of mechanical equipment and the specific pieces of equipment applied in this scenario are described in Section 2.1. The viscosity thresholds for different types of equipment are further described in Section 1.8.2.

[c] ERSP is described in Section 5.0. "ERSP Day-1" rates are the higher removal rates applied in the areas and times when the oil was flowing from the well and the oil is the thickest. "Day-1" does not necessarily indicate that this is only applied for the first day. "ERSP Day-3" rates are applied in the areas more distant from the well where the oil is thinner and more spread out making removal less efficient. "Day-3" does not necessarily indicate that this is the third day of the response.

For Scenario 6, GOM- DC187 response operation divisions are cascaded in over the course of the initial 18 days (as depicted in Figure 74). Oil arrived on the surface after approximately twenty-six (26) hours. Aerial surface dispersant application began on day 2.

For the surface dispersant only simulation (no subsurface dispersant application), dispersant use was as follows:

- Day 2 to day 4: 81,000 gallons/day
- Day 4 to day 14: 111,000 gallons/day
- Day 14 to day 45: approx. 36,500 gallons/day

For the surface and subsurface dispersant simulation, aerial (surface) dispersant use was as follows:

- Day 2 to day 12: 45,000 gallons/day

- Day 12 to day 35: 17,000 gallons/day
- Day 35 to day 45: 13,000 gallons/day
- Total aerial dispersant volume: 2,528,560 gallons
- Average daily rate: 56,190 gallons

Subsurface dispersant application rate was as follows:

- Day 5 to day 12: 22 gpm, 31,680 gallons/day
- Day 12 to day 45: 27 gpm, 38,880 gallons/day

For both the surface dispersant simulation and the surface and subsurface dispersant simulation, a total of 2,528,560 gallons was applied, for an average daily rate of 56,190 gallons.

Higher dispersant application would have been feasible with use of higher volume application systems or the use of multiple systems. However, higher subsurface dispersant application would have exhausted the limited dispersant inventory (i.e., the available dispersant stockpile is a limiting factor in the DC187 scenario).

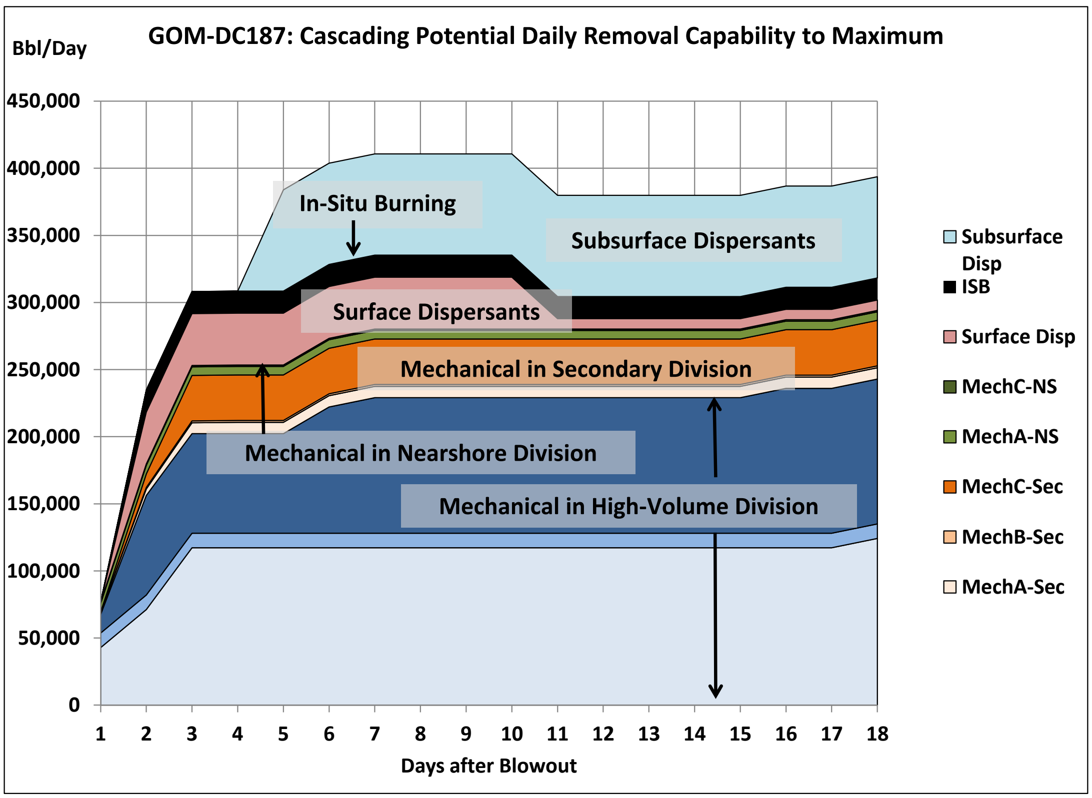


Figure 74: Scenario 6, GOM- DC187 – Cascading SC+MR+D+ISB Response Assets and Cumulative Potential Daily Removal Capacity

Countermeasure Simulation Results & Analysis

Achieved Removal versus Potential Equipment Capabilities

Maximum potential removal rates of oil removal systems are not achieved due to the limitations on countermeasures resulting from oil weathering and other environmental factors (such as increased sea state and darkness which often limited when the countermeasures could be applied). For the GOM-DC187 SC+MR+D+ISB+SubD simulation, weather restrictions were in effect for 21% of the time, and for most equipment, the operating period was limited to 12 hours of daylight (other equipment limitations applied are listed in Table 10 , Table 12 , and Table 13). Because of these thresholds and limitations, as well as the availability of recoverable, burnable, or dispersible oil in the response divisions, achieved oil removal was significantly less than the potential recovery capabilities (as shown in Table 50, Figure 75, and Figure 15 for the GOM-DC187 SC+MR+D+ISB simulation).

Table 50 shows the system potential with regard to barrels of oil that could be treated or removed based on the sum total of removal/treatments rates over the course of the entire response operation (i.e., during the release of oil from the well and for an additional 45 days after source control is achieved to stop the flow of oil). The "achieved" removal or treatment reflects the sum total of oil removed or treated over the course of the response operations. Figure 75 contrasts the sum total of potential removal/treatment over the course of the operations and the sum total of the achieved removal/treatment. The daily well flow is shown as a benchmark. The potential removal/treatment capability greatly exceeds the achieved removal/treatment due to the various environmental and logistical factors that limit performance.

Table 50: Scenario 6, GOM- DC187 – SC+MR+D+ISB+SubD Cumulative System Potential Oil Recovery versus Achieved Oil Recovery over 90-Day Simulation

Response Type	Response Division	Response System Type	Total Removal/Treatment		
			System Potential (bbl)	Achieved (bbl)	% Potential [a]
Mechanical [b]	**High-Volume**	Skimmer Group A	6,702,024	398,058	5.9%
		Skimmer Group B	605,520	46,938	7.8%
		Skimmer Group C	5,399,775	100,681	1.9%
	Secondary	Skimmer Group A	747,205	60,594	8.1%
		Skimmer Group B	124,882	8,593	6.9%
		Skimmer Group C	2,993,650	0	0.0%
	Nearshore	Skimmer Group A	573,390	68	0.0%
		Skimmer Group C	92,790	0	0.0%
	Mechanical Total	**All**	**17,239,236**	**614,934**	**3.6%**
In Situ Burning [c]	**High-Volume In Situ Burning**	-	1,234,170	141,051	11.4%
Surface Dispersants	**High-Volume/Secondary**	-	604,487	289,722	47.9%
Subsurface Dispersants	**High-Volume/Secondary**	-	3,092,548	430,087	13.9%
All Categories	**All Categories Total**	**All**	**22,170,441**	**1,475,794**	**6.7%**

[a] Achieved Total Recovery divided by System Potential Total Recovery as percentage.

[b] ERSP Day-1 rates assumed for High-Volume Division until well capping (source control); ERSP Day-3rates assumed for Secondary and Nearshore Divisions, and for High-Volume Division after day 45 source control.

[c] EBSP Day-1 rates assumed until day 45 source control, after which EBSP Day-3 rates were applied.

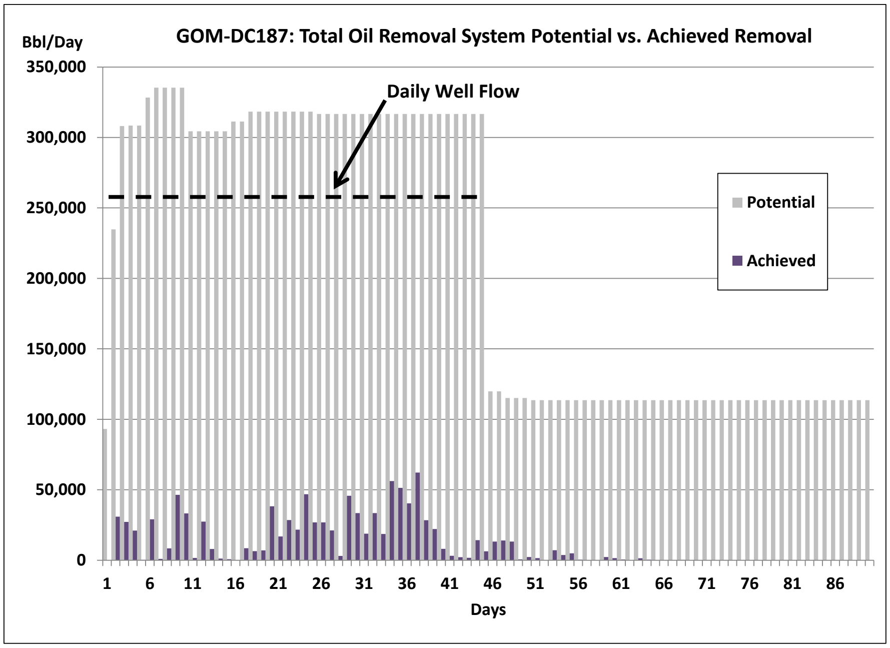


Figure 75: Scenario 6, GOM-DC187 SC+MR+D+ISB Total Oil Removal System Potential and Achieved Total Daily Removal

Figure 15 contrasts the amount of oil flowing from the well on a daily basis along with the maximum potential daily capability per day, as well as the achieved average daily removal rate. The achieved average daily removal rate is lower than the potential daily removal rate for each day of the scenario.

During the response period, some systems have very low or near-zero removal for some periods because of performance limitations due to environmental conditions, or because there is insufficient oil available, particularly in secondary and nearshore response areas where oil may not appear on the surface until after the oil has stopped flowing.

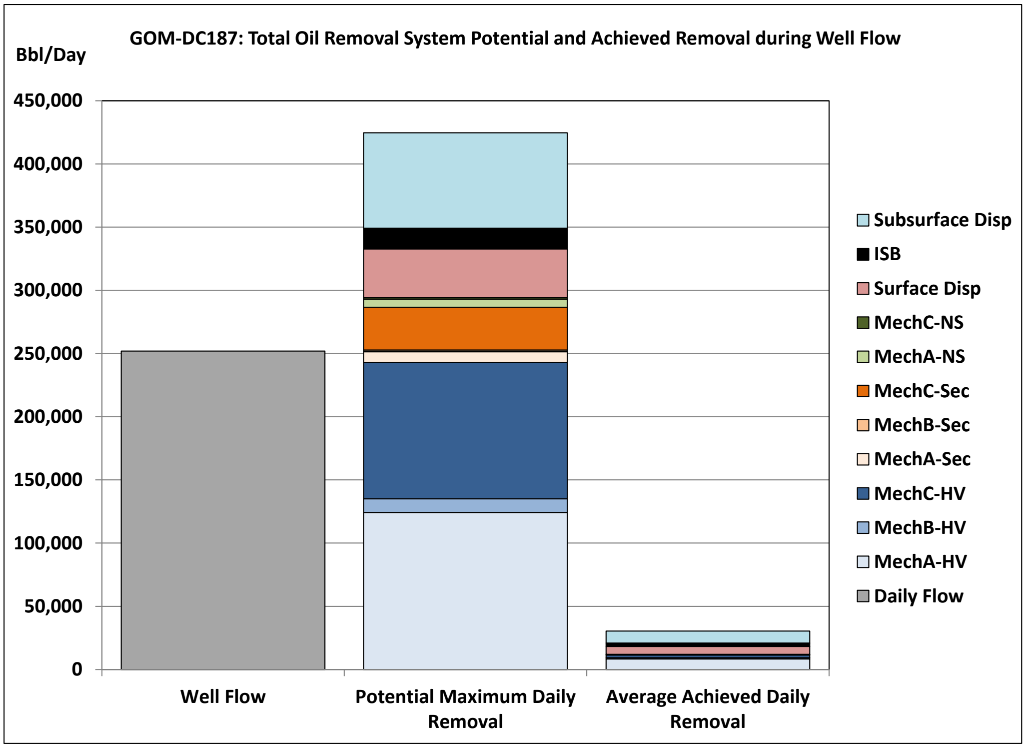


Figure 76: Scenario 1, GOM-DC187 – SC+MR+D+ISB+SubD Total Maximum Oil Removal System Potential and Achieved Removal Compared with Well Flow during 45-Day Discharge Period

Oil Removal by Countermeasure Type

Table 51 is a summary of model results for the various response countermeasures applied to the GOM-DC187 scenario. This table allows for comparison of the oiling and oil removal by each countermeasure across the various model simulations. Values within Table 51 represent the volume of oil present/removed at the completion of the response scenarios (90 days).

Table 51: Scenario 6, GOM-DC187 – Comparison of Shoreline Oiling and Oil Removal for the Relief Well Only Scenario and Four Response Scenarios at the End of the Model Simulations

Scenario	Volume (bbl) of Discharge	Volume (bbl)/ Percent of Oil on Shoreline	Volume (bbl)/ Percent Removed by Skimming	Volume (bbl)/ Percent Dispersed	Volume (bbl)/ Percent Removed by Burning	Volume (bbl)/ Percent Bio-degraded or in Sediments
Relief Well Only, 106 Day Discharge	25,546,000	1,494,315				8,760,015
Source Control (SC), 45 Day Discharge	10,845,000	244,275 2%				3,160,324 29%
Source Control and Mechanical Recovery (SC+MR)	10,845,000	168,067 2%	712,343 7%			2,925,279 27%
Source Control, Mechanical Recovery and Surface Dispersant (SC+MR+D)	10,845,000	126,490 1%	689,618 6%	233,384 2%		2,998,536 28%
Source Control, Mechanical Recovery, Surface Dispersant and In Situ Burning (SC+MR+D+ISB)	10,845,000	121,158 1%	619,490 6%	237,896 2%	131,860 1%	2,978,152 27%
Source Control with Mechanical Recovery, Surface and Subsurface Dispersant, and In Situ Burning (SC+MR+D+ISB+SubD)	10,845,000	101,992 1%	614,943 6%	667,983 6%	141,053 1%	3,488,473 32%

Scenario 6, GOM-DC187 is a WCD from an offshore deep-water well where mechanical recovery was the primary tool that removed oil. When used without the aid of other response operations, mechanical recovery was able to remove up to 7% of the oil discharged in this scenario. These results highlight the efficiency of deploying high-volume mechanical recovery as close to the point of discharge onto the water's surface as possible, before the oil has widely spread out and becomes too thin to remove from the environment.

When surface applied dispersants were added, oil removed by mechanical recovery decreased to 6%; however, an additional 2% of the oil was also dispersed into the water column thus causing less oil to reach the shoreline. When subsurface dispersants were added, oil removed by mechanical removal remained at 6%; however, 6% was also dispersed into the water column causing less oil to surface, reach the shoreline, or evaporate.

In situ burning only accounted for 1% of the oil removed when used, which is likely a reflection of the limited area where burning could be applied (restricted to the High Volume Recovery Division) in this scenario. As discussed in the earlier Methods section, in situ burning is limited by availability of fireboom and other equipment, and modeling equipment thresholds for wave height, wind, and viscosity and thickness of oil on the water surface.

Figure 77displays the fate of oil at the end of the 90-day simulation for Scenario 6, GOM-DC187 involving source control, mechanical recovery, in situ burning, and surface dispersants (e.g., SC+MR+D+ISB+SubD).

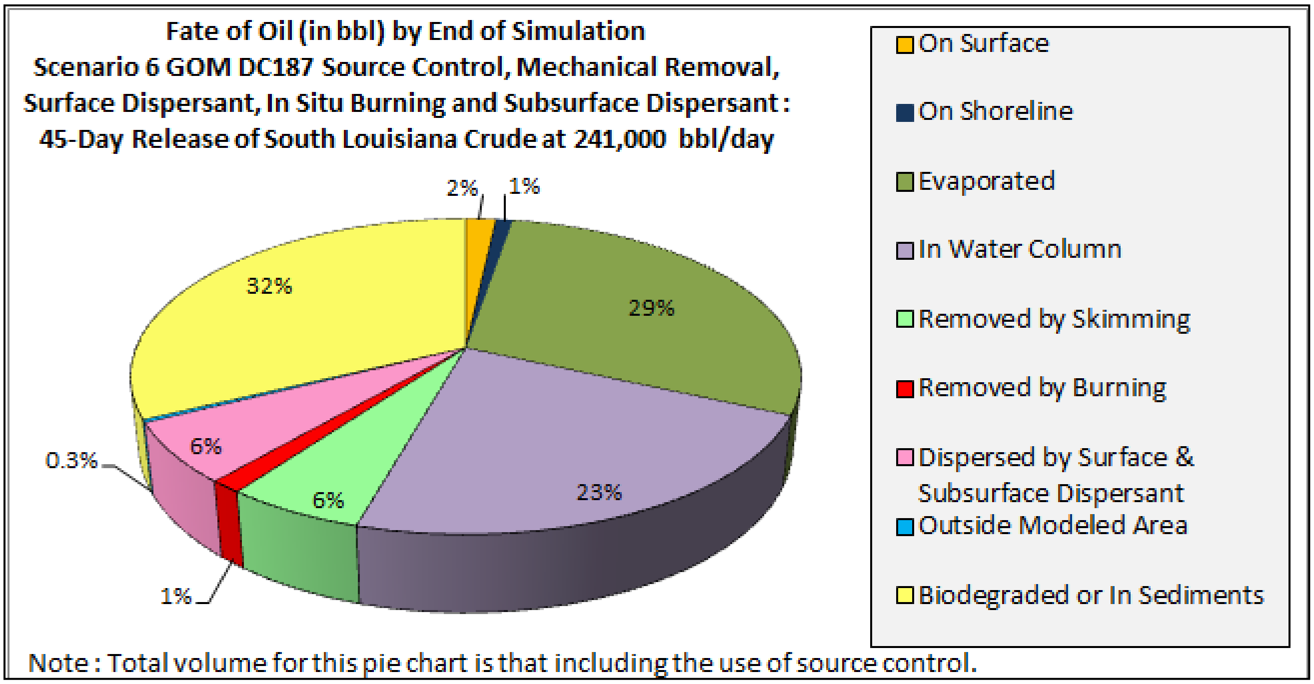


Figure 77: Scenario 6, GOM-DC187 – Fate of Oil at End of 90-Day Simulation (Scenario includes Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning Response Operations)

Reductions in Surface and Shoreline Oiling

Table 52 provides a comparison of the shoreline and water surface oiling results for each of the GOM-DC187 response countermeasure simulations.

Table 52: Scenario 6, GOM-DC187 – Comparison of Shoreline and Water Surface Oiling Above Equipment Threshold Values or Limitations

Scenario 6, GOM-DC187	Relief Well Only (WCD)	Source Control	Source Control and Mechanical Recovery	Source Control, Mechanical Recovery, and Surface Dispersant	Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning	Source Control with Mechanical Recovery, Surface and Subsurface Dispersant, and In Situ Burning
Volume (bbl) of Shoreline Oiling (to Any Degree)	1,494,337	244,277	168,068	126,491	121,159	101,992
Percent Reduction in Volume of Shoreline Oiled As Compared to Relief Well Only	-	84%	89%	92%	92%	93%
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	2,990	1,075	935	800	757	715
Percent Reduction in Shoreline Length Oiled with ≥1 g/m^2 As Compared to Relief Well Only	-	64%	69%	73%	75%	76%
Cumulative Area (mi^2) of Surface Affected by Oil ≥8g/m^2	4,485,334	2,088,673	1,723,599	1,001,506	930,706	762,543
Percent Reduction in Surface Affected by Oil ≥8g/m^2 As Compared to Relief Well Only	-	53%	62%	78%	79%	83%

Figure 78 is a visual depiction of the reduction in the surface area affected by ≥8.0 g/m^2 of oil over the 90-day period. The graphic directly compares the levels of maximum water surface oiling over time between the Source Control Only simulation and the simulation that adds mechanical recovery, dispersants, and burning (SC+MR+D+ISB+SubD).

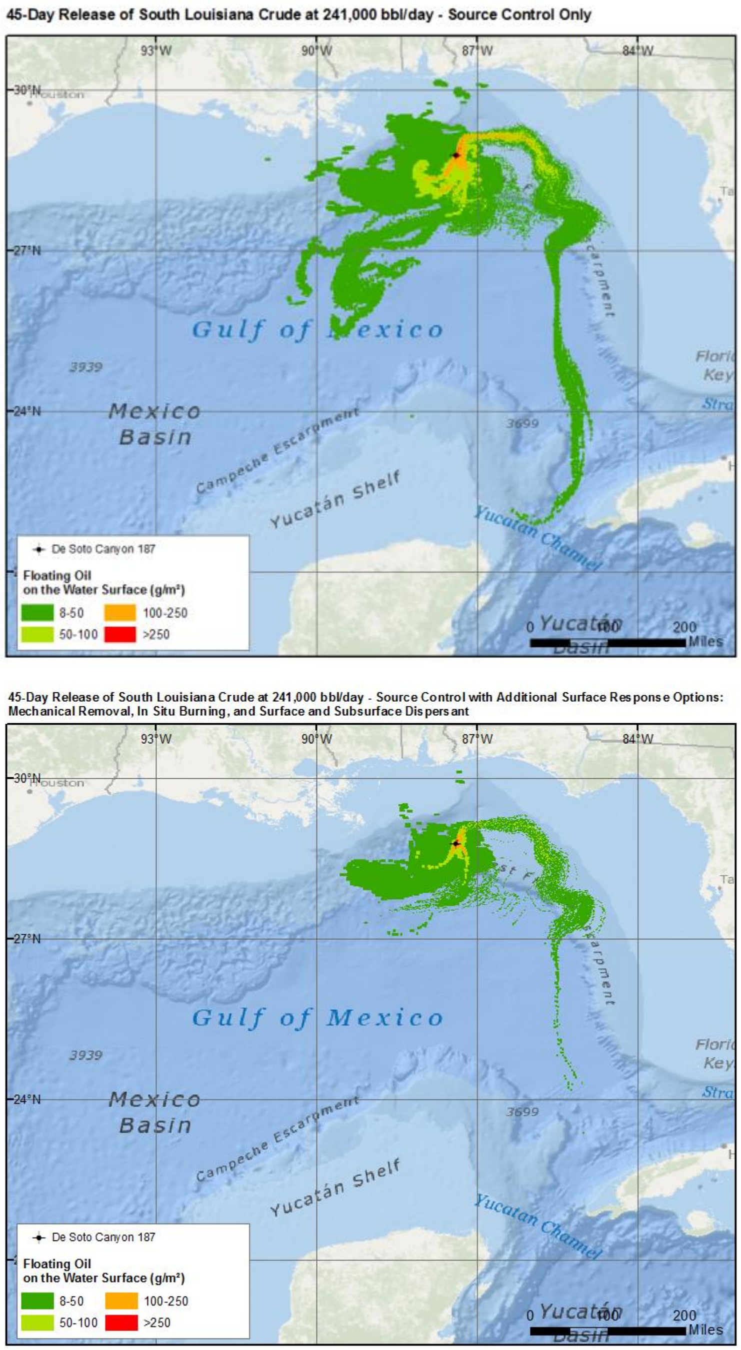


Figure 78: Scenario 6, GOM-DC187 – Comparison Floating Oil Concentration (≥8.0 g/m^2) over 90-Day SIMAP Model Simulation, Top Panel: Source Control (SC), Bottom Panel: Source Control, Mechanical Recovery, Surface Dispersants, and In Situ Burning (SC+MR+D+ISB+SubD)

2.2 WCD PROFILES AND RESPONSE COUNTERMEASURES MODELING FOR PACIFIC OCS REGION

The Pacific OCS Region produces about 61,100 barrels of oil per day, a small fraction of what the Gulf of Mexico produces. The OCS Region is divided into the Washington/Oregon, Northern California, Central California, and Southern California Planning areas. Currently, all offshore oil and gas activities in the Pacific OCS Region are within the Southern California Planning Area, which is home to 1,386 wells on 23 platforms according to data collected in December 2013.

Water depths of wells in the Pacific OCS Region are relatively shallow compared to those in the Gulf of Mexico and range from 95 to 1,198 feet with an average depth of 406 feet. The facilities in the Pacific OCS Region are 4 to 13 miles offshore. Most of the platforms in the area are within a few miles of the Chanel Islands National Marine Sanctuary and Channel Islands National Park, both sensitive environmental endpoints that would likely be priorities for protection during a WCD scenario, and could also restrict the use of certain response methods such as dispersants.

Figure 81 shows WCD sizes and locations in the Pacific OCS Region based on data from OSRPs collected on December 12, 2014. While this is not an exhaustive representation of all WCDs in the region, it gives an informative overview of WCD sizes and locations in the region (for more information on the how these data were collected, see Section 4.1 of Volume I of this study). WCD volumes range from 121 to 12,036 bbl/day, with an average of 3,262 bbl/day.

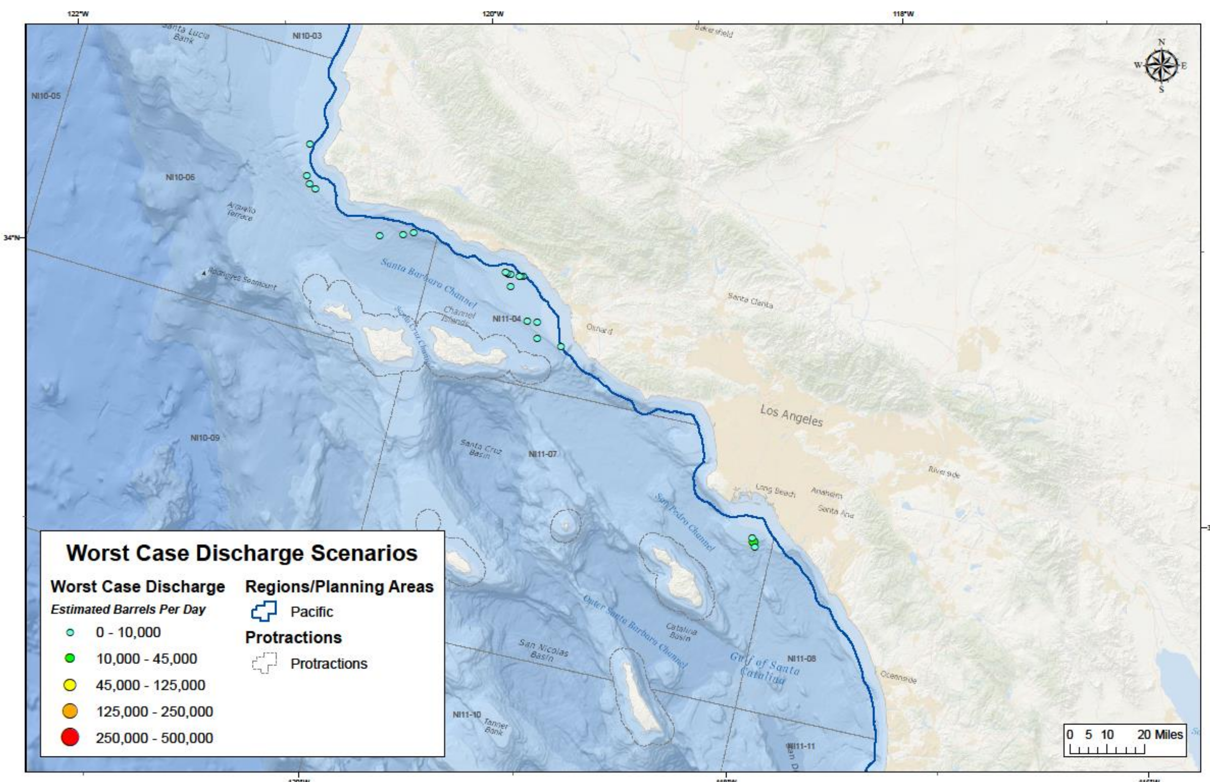


Figure 79: Worst Case Discharge Volumes (bbl/day) Specified in the OSRP Locations in Pacific OCS Region

One model scenario was selected for the Pacific OCS region. The scenario was named for the lease block in which it is located, Santa Maria 6683 (SM6683), and the discharge was simulated in the exact center of the lease block. This scenario was not necessarily intended to be representative of the total population of offshore facilities in the Pacific OCS Region.

2.2.1 Pacific Regional Contingency Plan and Area Contingency Plan Strategies

The oil spill trajectories modeled for the Santa Maria 6683 WCD scenario all fall within the Region IX RCP. The Region IX RCP covers coastal oil spills from the U.S. border with Mexico to the California and Oregon state boundary. The trajectory of the Santa Maria 6683 Scenario fall within the Los Angeles/Long Beach ACP and Southern California ACP. These ACPs and the Region IX RCP state that mechanical recovery is the preferred response option in these jurisdictions. The use of surface-applied dispersants is pre-approved for the FOSC in waters from three to 200 NM offshore except for areas within the boundaries of National Marine Sanctuaries or within three NM of the Mexico border or Oregon state boundary. The FOSC is pre-approved to authorize the use of in situ burning from 35 to 200 NM offshore; however, there is currently no offshore oil activity in this area. Consultation with the Region IX RRT is required for the use of in situ burning in all other areas.

The Geographic Response Plans developed by Area Committees for the Central and Southern California Coasts provide detailed descriptions of the strategies recommended for each identified environmentally sensitive site. These strategies are documented on map or chart excerpts in the ACP. In addition to the strategic and tactical approach being outlined, the site information also provides the amount of boom considered to be needed for carrying out the strategy as well as boats, skimmers where appropriate and even heavy equipment that might be needed for building berms or other structures for protecting the shoreline. Geographic Response Plan (GRP) maps/charts in both the Central and Southern Coastal ACPs were reviewed and evaluated to determine estimated amounts of boom and other resources that would be required to meet the goals of the ACP (Table 53).

Table 53: Pacific Region, Central California and Southern California ACP Shoreline Protection and Cleanup Resource Summary[23]

ACP	Boom (ft)	Numbers of Skimming Devices	Numbers of Boats	Other Resources
Sector LA/LB	ocean: 2,500 18 inch: 41,600 swamp: 48,000 sorbent: 49,000	shoreline: 91	skiffs: 57 boom boats: 58	heavy equipment such as bulldozers, backhoes and front end loaders: 29
Sector San Diego	hard: 82,600 snare/sorbent: 4,800	unspecified type: 8	boom boats: 78 skiffs: 20	front end loaders: 2 bulldozers: 12 fencing material, steel posts and sorbents for filter fences: 500 ft.
Totals	**228,500 (all types)**	**99 (all types)**	**213 (all types)**	**heavy equipment: 43 units** **fencing: 500 ft**

2.2.2 Response Equipment Inventories

Stockpiles of oil spill response equipment currently available in the Pacific OCS Region were calculated by surveying OSRO equipment stockpiles and searching a variety of publically available databases on equipment stockpiles (for more information on these methods, see Section 1.7). Total response equipment in the Pacific OCS Region is shown in Table 54. Mechanical recovery equipment is

[23] Some boats and heavy equipment can be used in both ACP areas, and therefore may be double-counted in this table.

categorized by nearshore and offshore equipment. The aircraft shown in the table are stationed within the region; however, they could be cascaded to other regions for response efforts. Conversely, aircraft that are stationed in other OCS regions can be cascaded into the Pacific OCS Region. The fire boom shown in the table is that which is readily available for oil spill response in the Pacific OCS Region. Most of this fire boom is staged within the Pacific OCS Region, and a smaller amount (500 feet) is staged in Hawaii and can readily cascade to the Pacific OCS Region.

Table 54: Response Equipment in the Pacific OCS Region

Countermeasure Type	Type/Location	In Pacific Region[a]	In Southern CA
Mechanical Recovery	Nearshore Equipment ERSP	78,707 bbl/day	17,869 bbl/day
	Offshore Equipment ERSP	295,102 bbl/day	46,540 bbl/day
	Total Mechanical Recovery ERSP	**373,809 bbl/day**	**64,409 bbl/day**
Fire Boom for In Situ Burning	Fire Boom staged in California	1,500 ft	
	Fire Boom staged in Washington	1,000 ft	
	Fire Boom staged in Hawaii that can cascade into the Pacific OCS Region	500 ft	
	Total Fire Boom	**3,000 ft**	
Dispersant Aircraft	DC-4 in Atwater, California	1	
	C-130 in Mesa, AZ	1	
	Total Number of Aircraft	**2**	
Dispersants	**Total Dispersant Stockpile**	**77,195 gal**	

[a] Totals include equipment contained in Southern CA as well as other selected equipment in the greater Pacific Region.

For the Pacific Region WCD scenario, due to its volume, only two (2) dispersant aircraft platforms were utilized. The first is the NRC DC-4 located in Atwater, California which would transit to and stage out of Camarillo, CA. The second aircraft was MSRC's C-130, located in Mesa, AZ which would transit to and stage out of Santa Barbara, CA. In California alone, there is approximately 41,975 gallons of dispersants in various inventories, additional inventories if ever needed could be transported to CA from other US locations.

2.2.2.1 *Scenario 7: Santa Maria 6683*

Scenario Site Information

Pacific Santa Maria 6683 (SM6683) is a nearshore (9.2 miles [8 nm] from shore), deepwater (1,075 ft) well in the Southern California Planning Area. In the event of a worst case discharge at this site, there is a high probability for rapid, significant shoreline contact (see Figure 80) if spill response countermeasures are not immediately taken. Based on 100 stochastic model runs, the worst case release date for the Pacific-SM6683 WCD scenario was June 26, 2009.

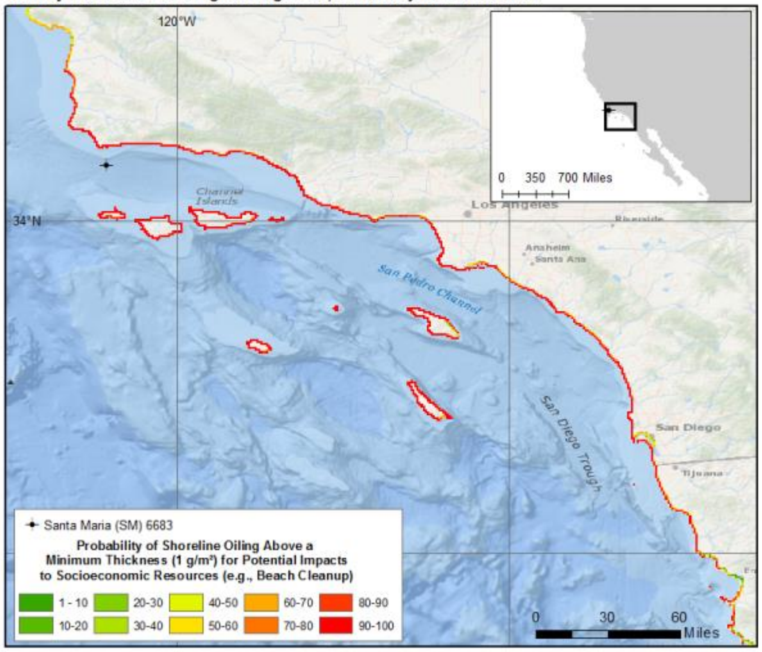
Table 55: Scenario 7, Pacific -SM6683 – Well Information, and Shoreline Contact Times

WCD Scenario Parameters	
Discharge Flow Rate	5,200 bbl/day
WCD Duration	170 days, Relief Well Only 10 days, Source Control
Total WCD Release Volume	884,000 bbl, Relief Well Only 52,000 bbl, Source Control
Simulation Duration (45 days following end of discharge)	215 days, Relief Well Only 55 days, Source Control
Oil Type	Point Arguello Light
API Gravity	30.3
Viscosity @ 15^{o}C (cp)	22
Latitude, Longitude	34.33732^{o}N / 120.4209^{o}W
Depth to Sea Floor	1,075 ft
Distance to Shoreline	9.2 miles (8 nm)
SIMAP Model Results [a]	
Time for oil above 1 g/m^2 to reach shore [b]	1 day
Time for oil greater than 8 g/m^2 to reach shore [c]	3.5 days, Figure 80

[a] SIMAP model results presented in this table are based on the 100 stochastic model runs.

[b] The 1 g/m^2 value is the threshold for socio-economic resource effects (e.g., closure of fisheries) (French-McCay et al. 2011; French McCay et al. 2012)

[c] The 8 g/m^2 value is the minimum thickness of floating oil for which response equipment can be effectively used (NOAA 2010)



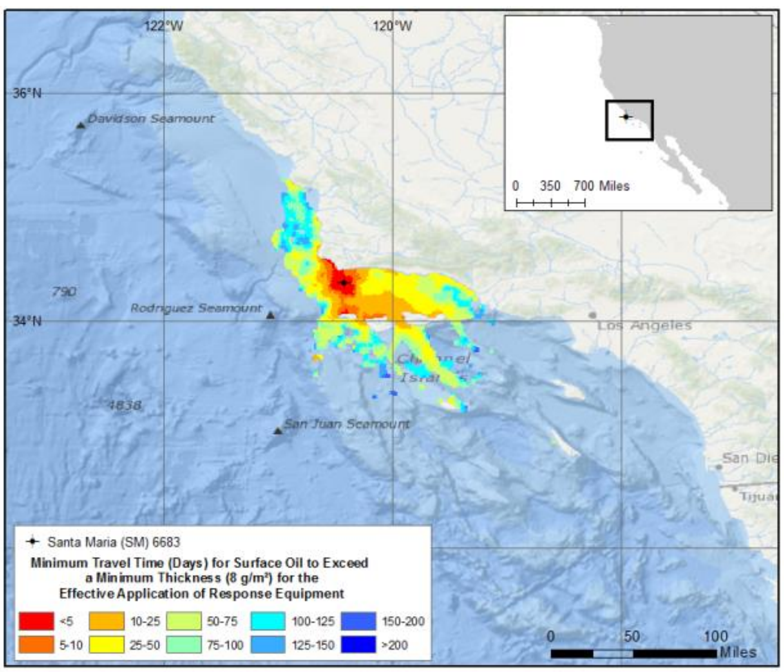


Figure 80: Scenario 7, Pacific-SM6683 Relief Well Only Scenario, 170-Day Discharge – Probability of Shoreline Oiling and Minimum Travel Times for Surface Oiling

Application of Source Control

As there are no drilling rigs operating on the continental U.S. West Coast, the Relief Well Only scenario runs for an extremely long period, which reflects the time necessary for a drilling rig to mobilize and deploy to the area. As a result, the ability to implement interim source control activities that secure the discharge is an extremely critical capability for the region. When a source control operation is modeled for the WCD Pacific-SM6683 scenario, the discharge period is reduced by 160 days, and the volume of oil released to the environment is reduced by 832,000 bbl. Correspondingly, source control results in substantially less impact to the water column and shoreline in comparison to the Relief Well Only simulation. As there are no drilling rigs operating on the continental U.S. West Coast, the relief well only scenario runs for an extremely long period, which reflects the time necessary for a drilling rig to mobilize and deploy to the area. As a result, the ability to implement interim source control activities that secure the discharge is an extremely critical capability for the region.

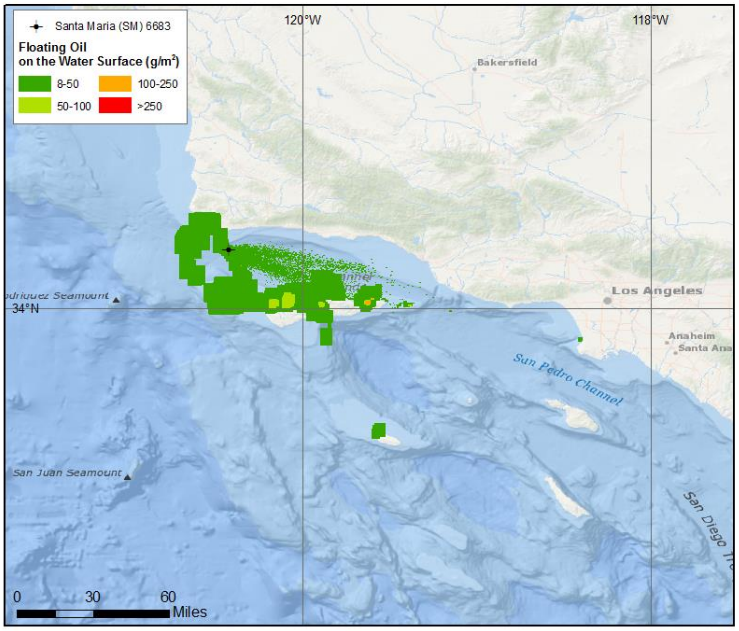
Table 56 and Figure 81 compare discharge volume, shoreline-oiling volume, length of oiled shoreline, area of surface oiling, and the amount of oil biodegraded or in the sediments for the Relief Well Only and Source Control Only modeling simulations.

Table 56: Scenario 7, Pacific -SM6683 – Comparison of Relief Well Only, and Source Control Response Scenarios

Scenario 7, PACIFIC-SM6683	Relief Well Only (170-day flow duration)	Source Control (10-day flow duration)	Reduction Due to Source Control	Percent Reduction Due to Source Control
Volume Discharged (bbl)	884,000 bbl	52,000 bbl	832,000 bbl	94 %
Volume Shoreline Oiling (bbl) any thickness	51,566 bbl	14,082 bbl	37,484 bbl	73 %
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	1,620 mi	620 mi	1,000 mi	62 %
Cumulative Area (mi^2) of Surface Oiling ≥8g/m^2	56,173 mi^2	4,958 mi^2	51,215 mi^2	91 %
Amount Biodegraded or In Sediments (bbl) at the End of the Simulation	370,169 bbl	12,294 bbl	357,875 bbl	97 %

As shown in Figure 81, the volume and spread of oil spilled from this WCD is reduced by source control; however, without the application of additional response operations to remove or mitigate spilled oil on the surface, the expected contact and exposure to oil in the environment still occurs in sensitive regions.

170-Day Release of Point Arguello Light at 5,200 bbl/day - Relief Well Only (WCD)



10-Day Release of Point Arguello Light at 5,200 bbl/day - Source Control Only

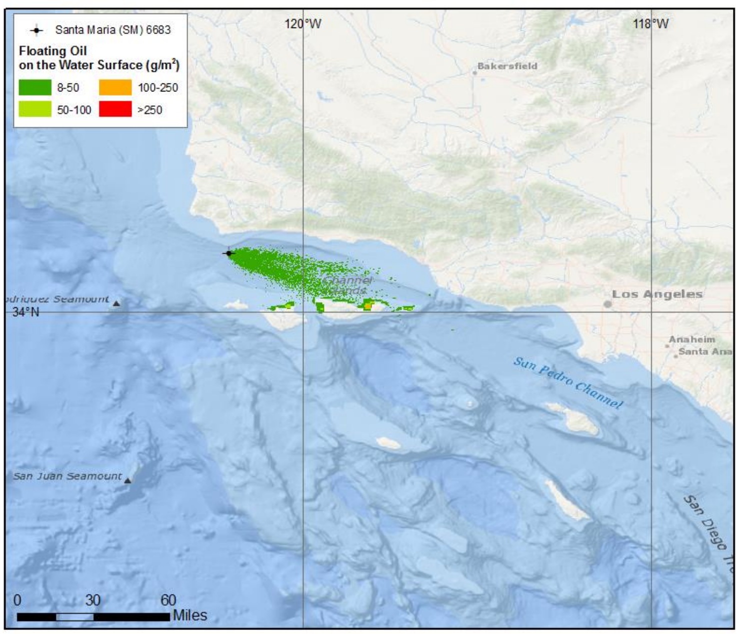


Figure 81: Scenario 7, Pacific-SM6683 – Comparison of Maximum Concentrations of Surface Oiling Experienced Throughout Simulation Periods for Relief Well Only (170-Day Discharge) and Source Control (10-Day Discharge)

Oil Discharge Behavior

Figure 82 shows the fate of oil for 55 days from the discharge (10-day discharge duration and 45 days following the source control). At the end of the simulation, 39% percent of the total oil had evaporated, 30% had either biodegraded or remained in the water column and sediments, 27% of the oil remained on the shoreline, and 4% of the oil remained floating on the surface. Note that, the model does not simulate potential photooxidation of floating oil.

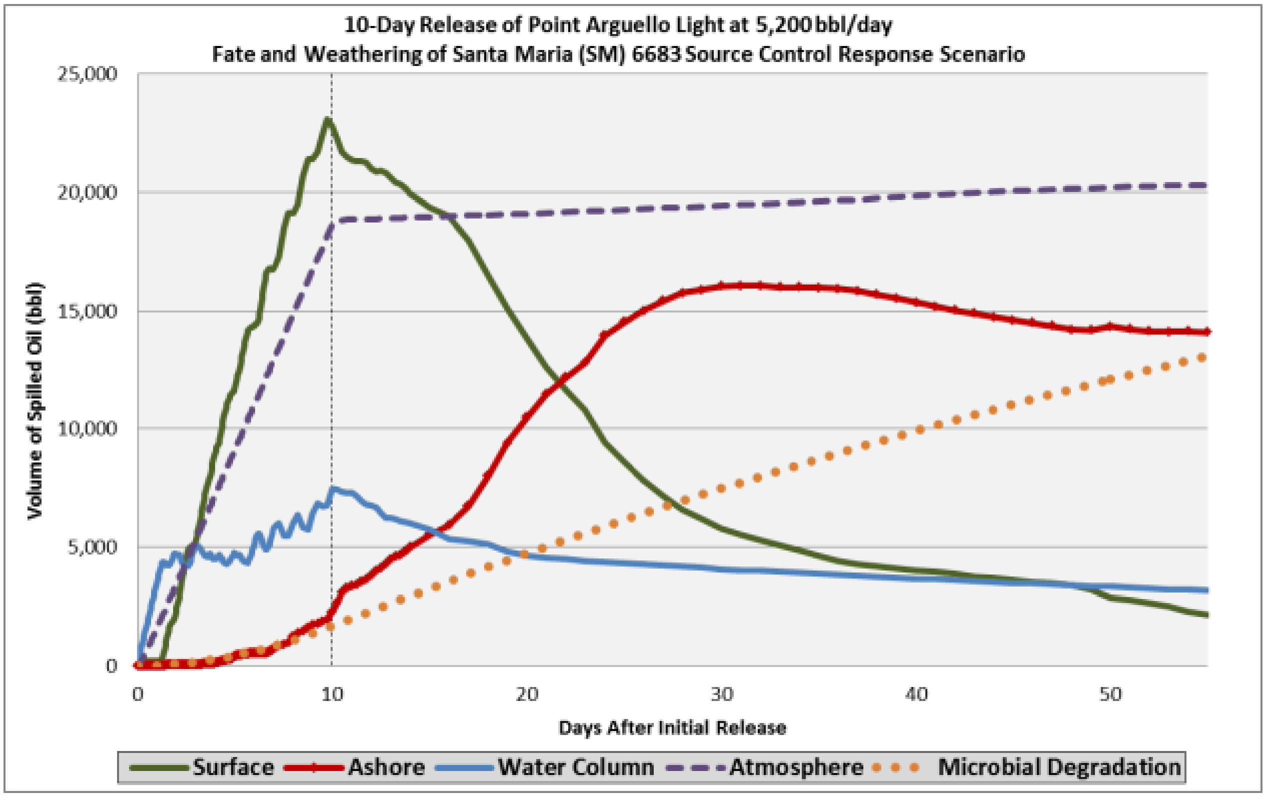


Figure 82: Scenario 7, Pacific-SM6683 Source Control, 10-Day Discharge – Oil Fate and Weathering (Dotted vertical line indicates source control on Day 10)

In Scenario 7, Pacific-SM6683 Source Control, 97% of the total oil mass discharged from the blowout will reach the surface, while 3% remains entrained in the water column. Upon release from the blowout, oil droplets take approximately 7 hours to reach the surface, with most surfacing in the immediate vicinity of the well location. As the oil slick spreads, the surface oil remained thick (> 8 g/m^2) and fresh enough to be recovered or treated (< 20,000 cST) for only very short periods (up to 1-2 days) even in calm conditions (Figure 83 and Figure 84). Conditions suitable for recovery were mainly in the high volume recovery divisions; however, some recovery in the secondary recovery area is possible on some days. As winds increased, the surface oil weathered rapidly and became unrecoverable and non-dispersible. Figure 83 and Figure 84 display model results at day 4, showing the oil movements and weathering that occurred over the a relatively calm first four days of the discharge. As the winds became stronger from day 8 and beyond, the viscosity of the discharged oil changed more quickly and the effectiveness of response countermeasures was degraded.

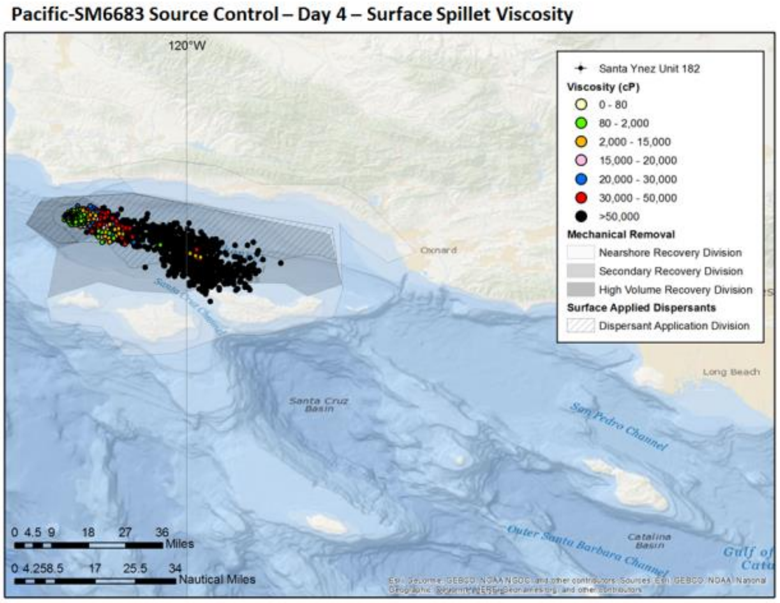


Figure 83: Scenario 7, Pacific-SM6683 Source Control – Surface Spillet Viscosity (cp) at Day 4

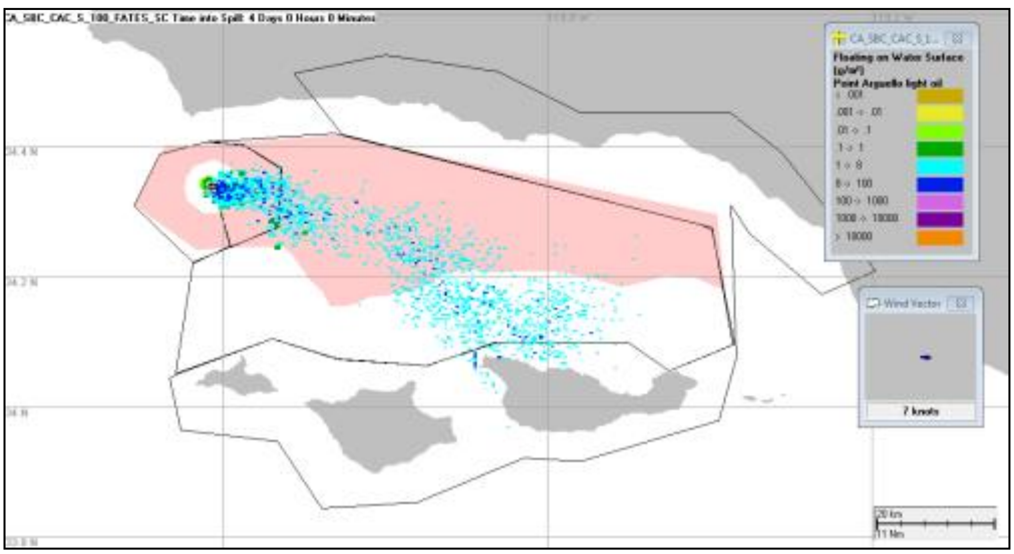


Figure 84: Scenario 7, Pacific-SM6683 Source Control – Floating Oil on Water Surface (g/m^2) at Day 4

The SM6683 plume moved in a southeasterly direction towards Santa Cruz Island, as the oil was entrained in the summer southerly flow of the California current. Minimum travel time for contact to shorelines was 30 hours, with substantial shoreline impacts beginning within 4 days of the start of the discharge. At the end of the simulation, the majority of the shoreline oiling over 1 g/m^2 was along the Channel Islands and the southern California coasts (Figure 85). The California current also transported a small amount of oil to northern Baja Mexico.

10-Day Release of Point Arguello Light at 5,200 bbl/day - Source Control Only

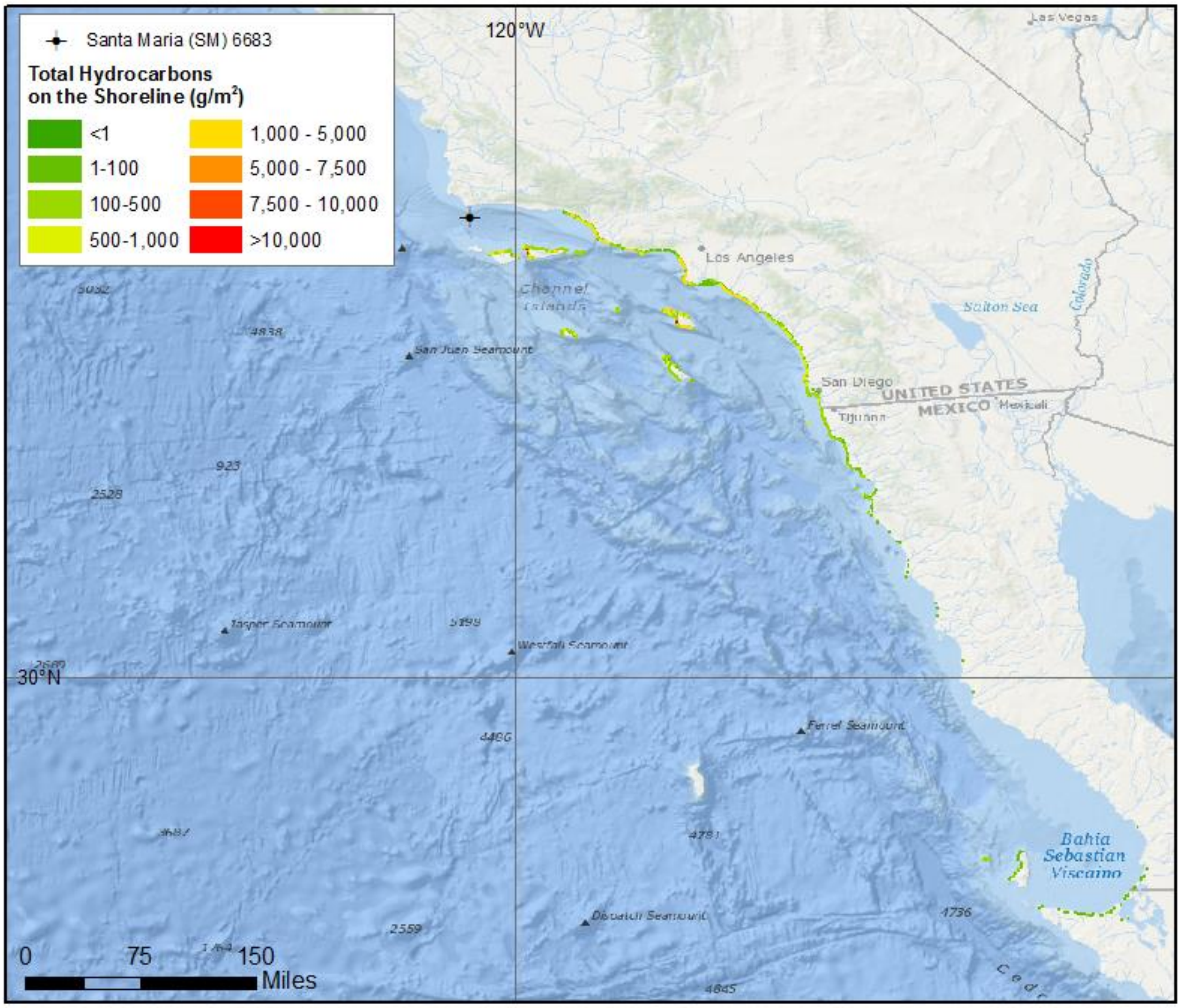


Figure 85: Scenario 7, Pacific-SM6683 Source Control, 10-Day Discharge – Shoreline Oil ≥1 g/m², including Weathered Tarballs

Application of Response Countermeasures

Countermeasure Response Divisions

The following equipment types were employed in each of the following countermeasure response divisions, and are shown in Figure 86.

- High Volume Recovery Division – High volume mechanical recovery operations were employed beyond a 0.6 mile (0.5 nm) radius area established around the well for source control.
- Secondary Recovery Division – Secondary mechanical recovery operations were used to remove oil that was not previously removed in the high volume recovery area.
- Nearshore Recovery Division – Nearshore mechanical recovery operations were used to remove oil from the surface of the water before it was washed onto shorelines.

- Dispersant Application Division – Surface applied dispersants were employed in the high volume and secondary recovery geographical areas beyond a 2.9 mile (2.5 nm) radius area established around the well for source control, as appropriate.

No subsurface dispersants were applied in the Pacific-SM6683 scenario.

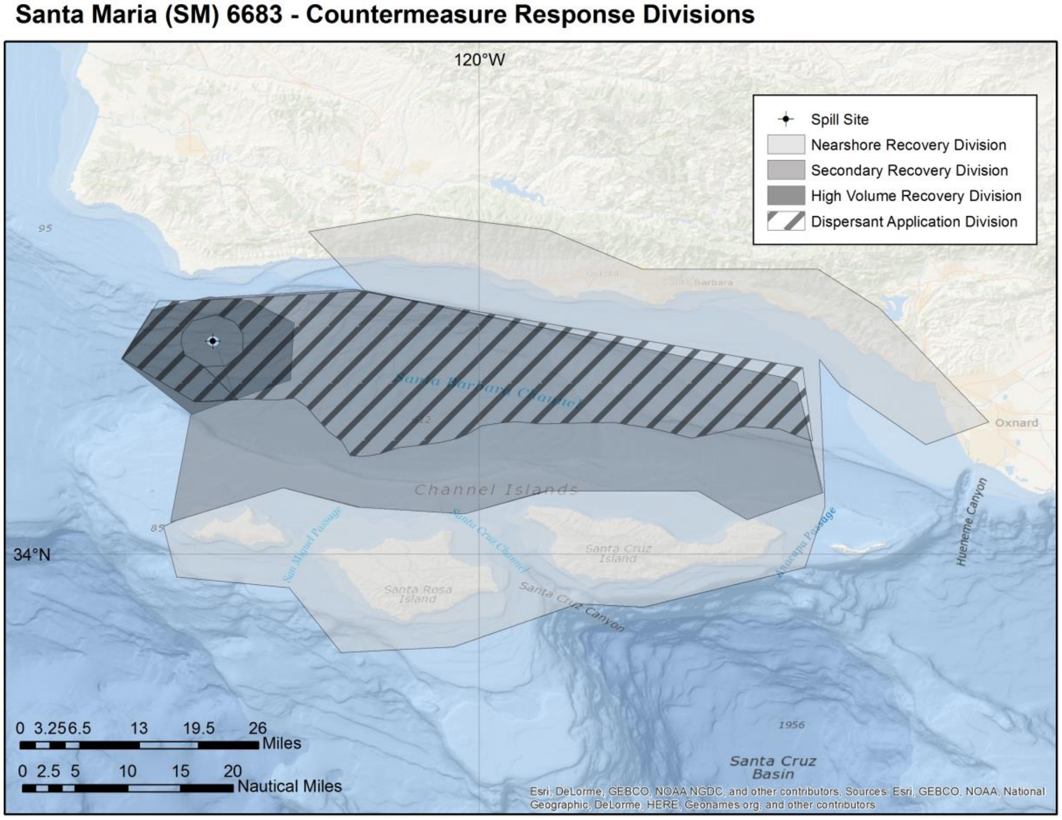


Figure 86: Scenario 7, Pacific-SM6683 – Geographic Coverage of Oil Countermeasure Response Divisions

The size and placement of the CA-SM6683 response operation divisions in the model were developed based on a review of the oil spill trajectories from the 10-day discharge in the Source Control Only simulation.

Countermeasure/Division Removal Rates (Model Inputs)

The removal rates by countermeasure type and response division that are shown in Table 57 represent the *maximum* potential rate that would be available at any point during the response operation.

As in an actual oil spill recovery operation, the model cascades response equipment into the response divisions as the assets arrive on the scene. For this scenario, only the ERSP for recovery systems located in the Pacific Region were used for the model. The modeling reflects response equipment threshold values and limitations based on the availability of the response equipment (as determined to be in the stockpiles per OSRO response equipment survey) deployed in the appropriate divisions. As such, the model used oil removal rates for each division (i.e., SIMAP model polygon), based on the maximum potential daily removal rates (bbl/day) of the assigned asset (refer to Table 57), corrected by weather restrictions and daylight operations (as described in Section 1.8). Maximum removal rates are not realized in practice because of the limitations of weather delays, suspension of operations at night, the location of oil in relation to equipment, and performance thresholds, such as oil thickness on the water surface, sea state and currents, winds, and water content during oil emulsification.

Maximum oil removal rates are not necessarily applicable for the entire response period. This is because equipment cascades in at different times, and in some cases, resources are allocated to different applications.

Table 57: Maximum Potential Daily Oil Removal Rates for Pacific-SM6683 SC+MR+D Response Scenario [a]

Countermeasure Type	Response Division	Response System Category [b]	Removal Rate Applied [c]	Maximum Potential Daily Removal Rates (bbl/day)
Mechanical	**High-Volume**	Skimmer Group A	ERSP Day-1	31,065
		Skimmer Group C	ERSP Day-1	31,363
	Secondary	Skimmer Group A	ERSP Day-3	8,787
	Nearshore	Skimmer Group A	ERSP Day-3	390
	Total	All		**71,605**
Surface Dispersant	**High-Volume and Secondary**	Surface Dispersants	Based on DMP 2	33,333
	Total	**All**		**104,398**

[a] Pacific-SM6683 SC+MR+D Response Scenario by countermeasure type and response division *without* application of weather restrictions.

[b] The characteristics of the different types of mechanical equipment and the specific pieces of equipment applied in this scenario are described in Section 2.1. The viscosity thresholds for different types of equipment are further described in Section 1.8.2.

[c] ERSP is described in Section 5.0. "ERSP Day-1" rates are the higher removal rates applied in the areas and times when the oil was flowing from the well and the oil is the thickest. "Day-1" does not necessarily indicate that this is only applied for the first day. "ERSP Day-3" rates are applied in the areas more distant from the well where the oil is thinner and more spread out making removal less efficient. "Day-3" does not necessarily indicate that this is the third day of the response.

For Scenario 7, Pacific-SM6683 SC+MR+D, response operation divisions are cascaded in over the course of the initial 18 days (as depicted in Figure 87). Oil reaches the surface after approximately seven hours. Commencement of the surface dispersant application began on day 1 of the incident.

Maximum daily application and inventory use was achieved on day 2 at 10,500 gallons/day with an average daily surface application of 9,975 gallons for a total of 99,750 gallons of dispersants applied for the 10-day duration of the event.

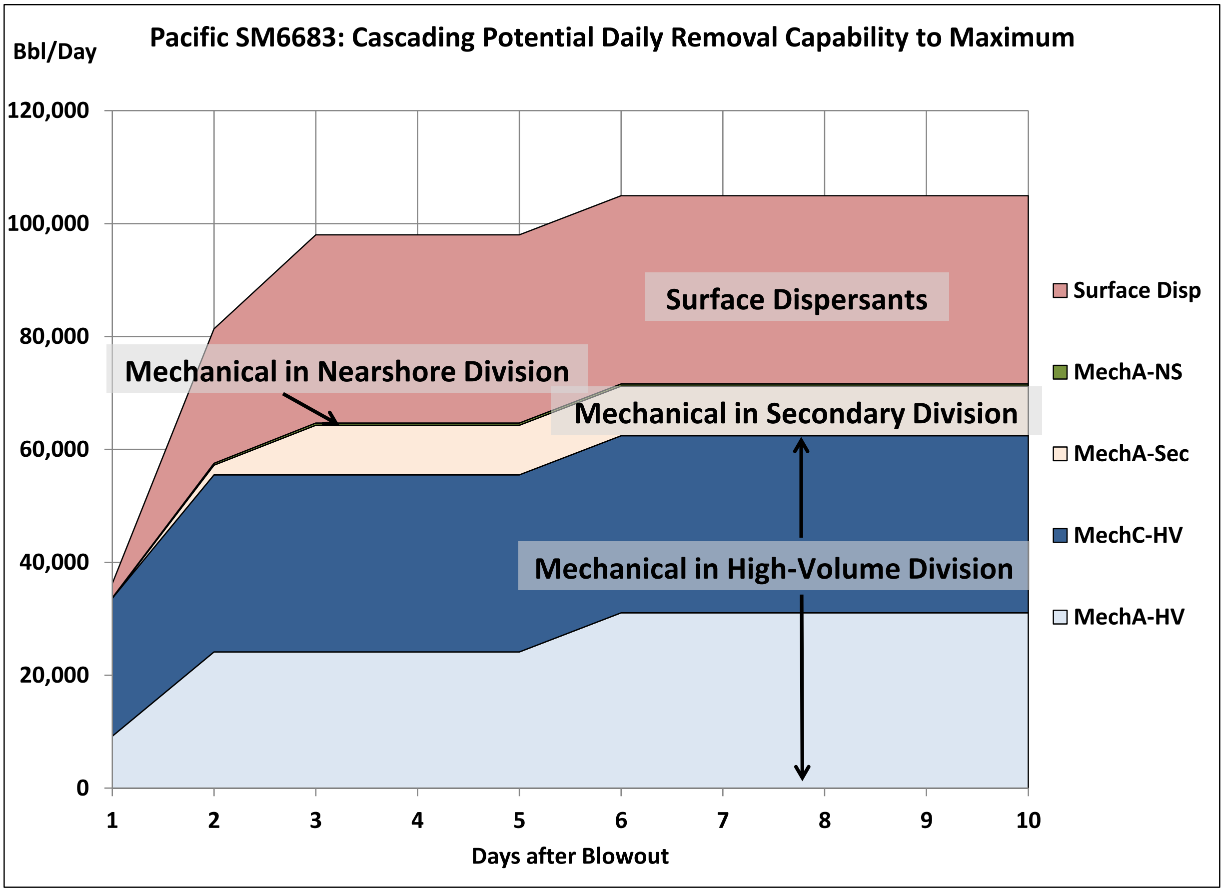


Figure 87: Scenario 7, Pacific-SM6683 – Cascading SC+MR+D Response Assets and Cumulative Potential Daily Removal Capacity

Countermeasure Simulation Results & Analysis

Achieved Removal versus Potential Equipment Capabilities

Maximum potential removal rates of oil removal systems are not achieved due to the limitations on countermeasures resulting from oil weathering and other environmental factors (such as increased sea state and darkness which often limited when the countermeasures could be applied). For the Pacific-SM6683 SC+MR+D simulation, weather restrictions were in effect for 21% of the time, and for most equipment, the operating period was limited to 12 hours of daylight (other equipment limitations applied are listed in Table 10 , Table 12 , and Table 13). Because of these thresholds and limitations, as well as the availability of recoverable, burnable, or dispersible oil in the response divisions, achieved oil removal was significantly less than the potential recovery capabilities (as shown in Table 58, Figure 88, and Figure 89) for the Pacific-SM6683 SC+MR+D simulation.

Table 58 shows the system potential with regard to barrels of oil that could be treated or removed based on the sum total of removal/treatments rates over the course of the entire response operation (i.e., during the release of oil from the well and for an additional 45 days after source control is achieved to stop the flow of oil). The "achieved" removal or treatment reflects the sum total of oil removed or treated over the course of the response operations. Figure 88 contrasts the sum total of potential removal/treatment over the course of the operations and the sum total of the achieved removal/treatment. The daily well flow is shown as a benchmark. The potential removal/treatment capability greatly exceeds the achieved removal/treatment due to the various environmental and logistical factors that limit performance.

Table 58: Scenario 7, Pacific-SM6683 SC+MR+D Cumulative System Potential Oil Recovery versus Achieved Oil Recovery over 55-Day Simulation

Response Type	Response Division	Response System Type	Total Recovery		
			System Potential (bbl)	Achieved (bbl)	% Potential [a]
Mechanical [b]	High-Volume	Skimmer Group A	487,802	8,545	2%
		Skimmer Group C	530,306	0	0%
	Secondary	Skimmer Group A	476,215	1,491	0.3%
	Nearshore	Skimmer Group A	21,468	909	4%
	Mechanical Total	**All**	**1,515,791**	**10,945**	**0.7%**
Dispersants	**High-Volume/Secondary**	-	306,903	353	0.1%
All Categories	**All Categories Total**	**All**	**1,822,694**	**11,298**	**0.6%**

[a] Achieved Total Recovery divided by System Potential Total Recovery as percentage.

[b] ERSP Day-1 rates assumed for High-Volume Division until well capping (source control); ERSP Day-3rates assumed for Secondary and Nearshore Divisions, and for High-Volume Division after Day 10 source control.

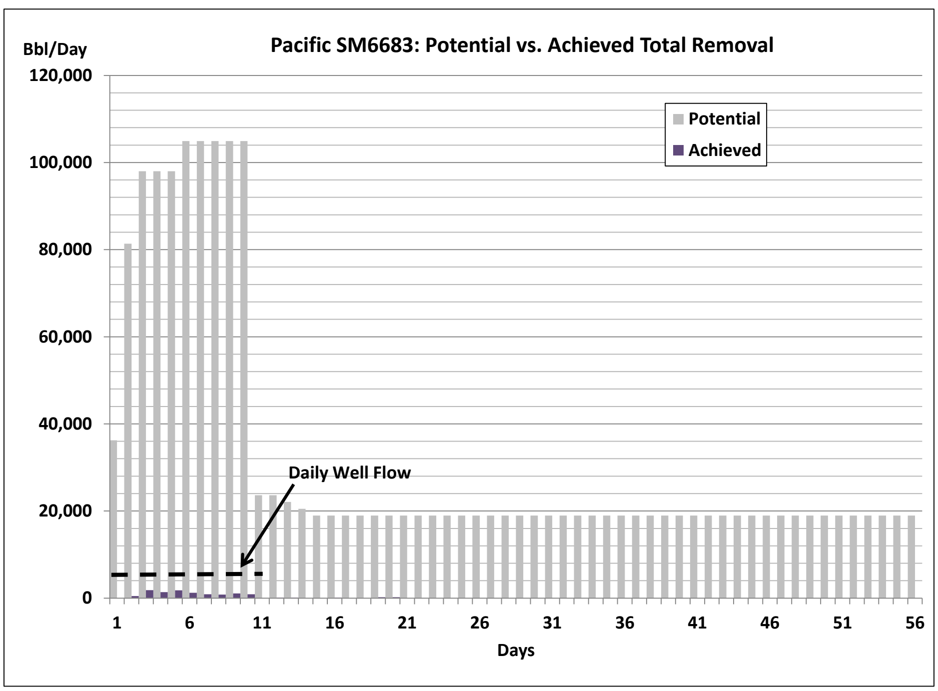


Figure 88: Scenario 7, Pacific-SM6683 SC+MR+D Total Oil Removal System Potential and Achieved Total Daily Removal

Figure 89 contrasts the amount of oil flowing from the well on a daily basis along with the maximum potential daily capability per day, as well as the achieved average daily removal rate. The achieved average daily removal rate is lower than the potential daily removal rate for each day of the scenario.

During the response period, some systems have very low or near-zero removal for some periods because of performance limitations due to environmental conditions, or because there is insufficient oil available, particularly in secondary and nearshore response areas where oil may not appear on the surface until after the oil has stopped flowing.

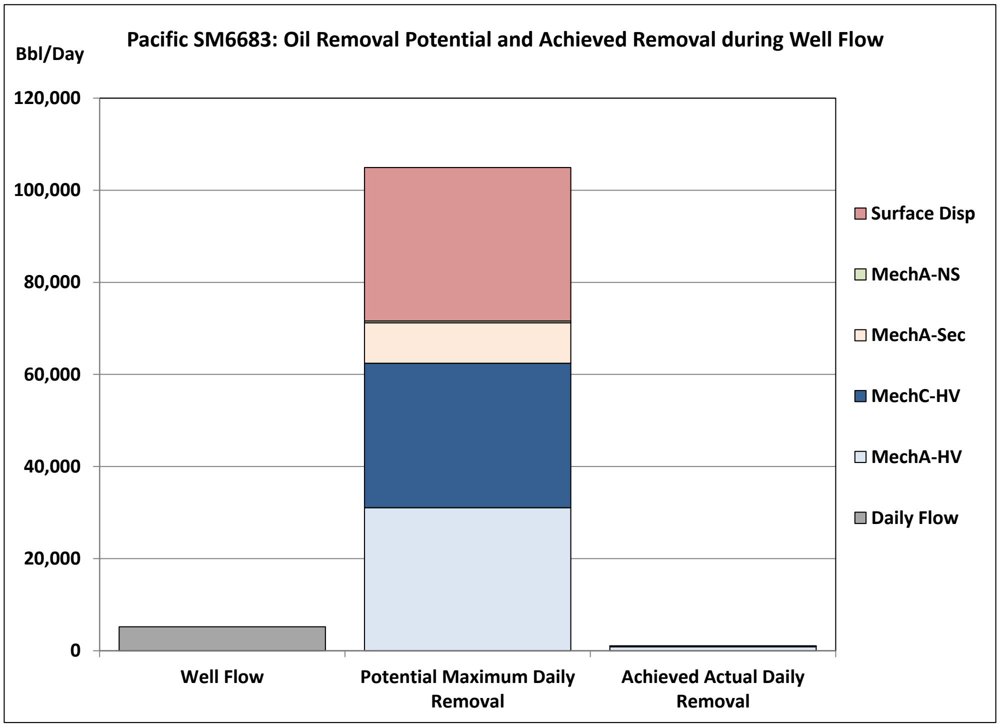


Figure 89: Scenario 7, Pacific-SM6683 SC+MR+D Total Maximum Oil Removal System Potential and Achieved Removal Compared with Well Flow during 10-Day Discharge Period

Oil Removal by Countermeasure Type

Table 59 is a summary of model results for the various response countermeasures applied to the Pacific-SM6683 scenario. This table allows for comparison of the oiling and oil removal by each countermeasure across the various model simulations. Values within Table 59 represent the volume of oil present/removed at the completion of the response scenarios (55 days).

Table 59: Scenario 7, Pacific-SM6683 – Comparison of Shoreline Oiling and Oil Removal for the Relief Well Only Scenario and Three Response Scenarios at the End of the Model Simulations

Scenario	Volume (bbl) of Discharge	Volume (bbl)/ Percent of Oil on Shoreline	Volume (bbl)/ Percent Removed by Skimming	Volume (bbl)/ Percent Dispersed	Volume (bbl)/ Percent Bio-degraded or in Sediments
Relief Well Only, 170 Day Discharge	884,000	51,565			370,169
Source Control (SC), 10 Day Discharge	52,000	14,082 27%			12,294 24%
Source Control and Mechanical Recovery (SC+MR)		8,565 16%	11,306 22%		8,036 15%
Source Control, Mechanical Recovery and Surface Dispersant (SC+MR+D)		8,360 16%	10,945 21%	346 0.7%	8,173 16%

When used without the aid of other response operations, mechanical recovery at SM6683 was able to remove up to 22% of the oil discharged in this scenario. As shown in Table 60, through the use of mechanical recovery response, the amounts of water surface area and shorelines that were oiled were significantly reduced by an additional 10% and 4%, respectively, as compared to with source control only. Due to the rapid weathering of this oil, Skimmer Group A systems were effective at removing oil, while Skimmer Group C systems were not. Due to the specific oil properties of Point Arguello Light, a viscous oil that weathers and becomes more viscous relatively quickly as the oil moves away from the wellhead, for a scenario similar to the one modeled herein, it is necessary to invest in high-volume mechanical recovery equipment as close to the point of discharge that works efficiently in highly viscous oil.

When surface applied dispersants were added, oil removed by mechanical recovery slightly decreased to 21%, while only an additional 1% of the oil was dispersed into the water column. In Situ Burning was not applied to this model since the Region IV pre-authorization for ISB does not include the area where the model discharge occurs. Further discussions with State officials also indicated that due to proximity to shoreline it was doubtful that RRT would approve as well. In situ burning is not preauthorized in the area where this discharge occurred; therefore, in situ burning was not applied as a response capability in this model simulation.

Figure 90 displays the fate of oil at the end of the 55-day simulation for Scenario 7, Pacific-SM6683 involving source control, mechanical recovery, and surface dispersant (e.g., SC+MR+D).

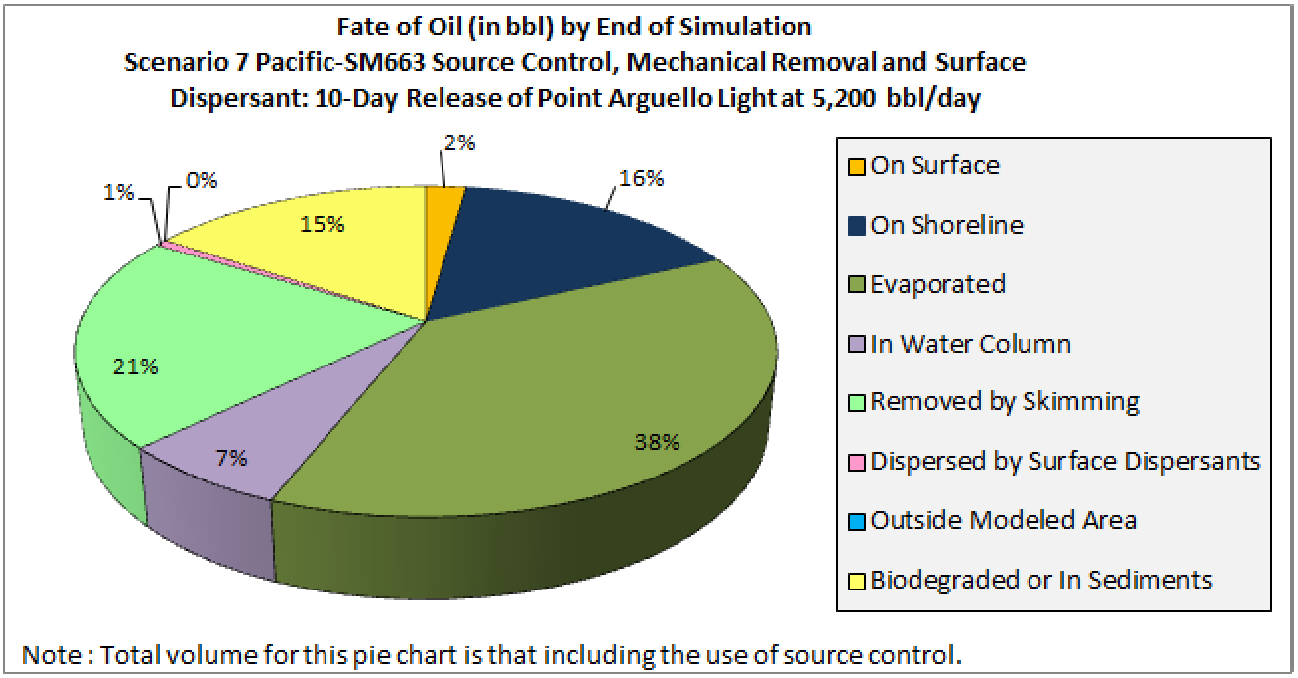


Figure 90: Scenario 7, Pacific-SM6683 – Fate of Oil at End of 55-Day Simulation (Scenario includes Source Control, Mechanical Recovery, and Surface Dispersant Response Operations)

Reductions in Surface and Shoreline Oiling

Table 60 provides a comparison of the shoreline and water surface oiling results for each of the Pacific-SM6683 response countermeasure simulations.

Table 60: Scenario 7, Pacific-SM6683 – Comparison of Shoreline and Water Surface Oiling Above Equipment Threshold Values or Limitations

Scenario 7, Pacific-SM6683	Relief Well Only (WCD)	Source Control	Source Control and Mechanical Recovery	Source Control, Mechanical Recovery, and Surface Dispersant
Volume (bbl) of Shoreline Oiling (to Any Degree)	51,566	14,082	8,565	8,360
Percent Reduction in Volume of Shoreline Oiled As Compared to Relief Well Only	-	73%	83%	84%
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	1,620	620	547	546
Percent Reduction in Shoreline Length Oiled with ≥1 g/m^2 As Compared to Relief Well Only	-	62%	66%	66%
Cumulative Area (mi^2) of Surface Affected by Oil ≥8g/m^2	56,173	4,958	2,662	2,632
Percent Reduction in Surface Affected by Oil ≥8g/m^2 As Compared to Relief Well Only	-	91%	95%	95%

Figure 91 is a visual depiction of the reduction in the surface area affected by ≥8.0 g/m^2 of oil over the 55-day period. The graphic directly compares the levels of maximum water surface oiling over time between the Source Control Only simulation and the simulation that adds mechanical recovery and surface dispersants (SC+MR+D).

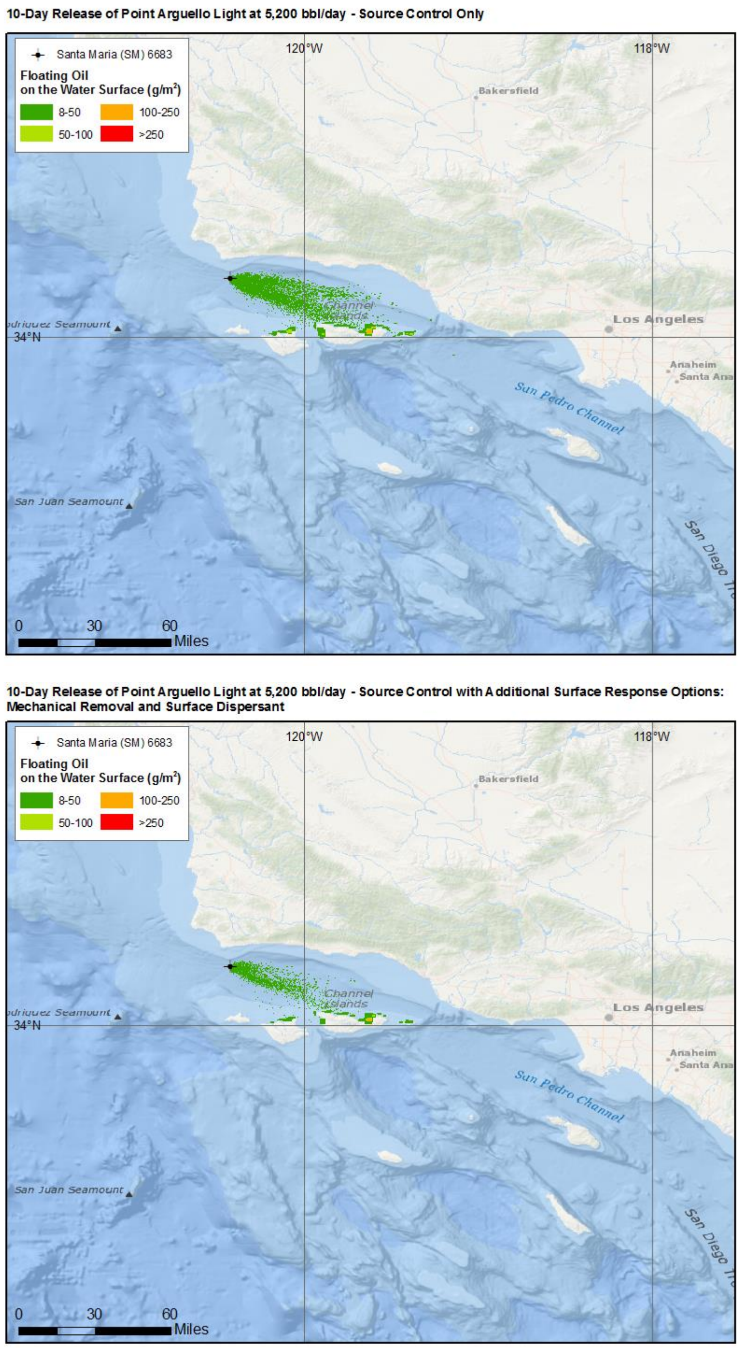


Figure 91: Scenario 7, Pacific-SM6683 – Comparison Floating Oil Concentration (≥8.0 g/m^2) over 55-Day SIMAP Model Simulation, Top Panel: Source Control (SC), Bottom Panel: Source Control, Mechanical Recovery, and Surface Dispersants (SC+MR+D)

2.3 WCD Profiles and Response Countermeasures Modeling For The Arctic OCS

Offshore oil activities have been relatively small in scope in recent years on the Arctic OCS Region, and include platforms on offshore gravel islands and some recent exploration activities. The Chukchi Sea and Beaufort Sea Planning Areas are within the Arctic Circle, and are referred to collectively as the Artic OCS within this report. Scenarios were modeled in the Arctic OCS for this report because it is anticipated that offshore oil exploration and drilling activities could occur in the U.S. Arctic OCS in the near-to-medium term.

There was also some exploration activity during the 1980s and 1990s, and more recently in 2003 amounting to a total of 35 exploration wells drilled. The water depths of these exploration wells were 20 to170 feet, with most of the wells in less than 100 feet of water.

Figure 92 shows WCDs located on the Arctic OCS based on data from OSRPs collected on December 12, 2014. While this is not an exhaustive representation of all WCDs in the Arctic, it gives an informative overview of WCD sizes and locations in the region (for more information on the how these data were collected, see Section 5.1 of Volume I of this study). WCD volumes range from 800 to 85,000 bbl/day, with an average of 20,502 bbl/day. These WCDs are relatively close to shore ranging from approximately 1.5 to 69 miles off the Alaska coast, with the majority of the sites 1.5 to 6 miles from shore.

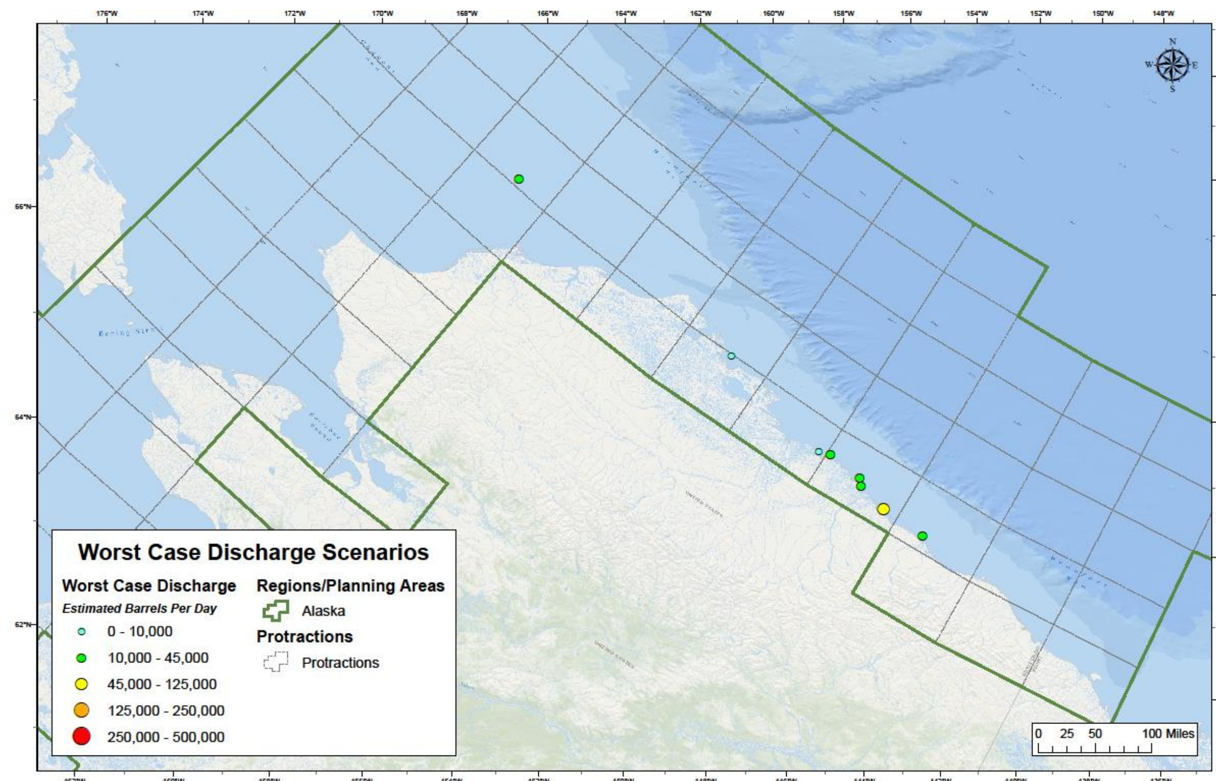


Figure 92: Worst Case Discharge Volumes (bbl/day) Specified in the OSRPs in the Arctic OCS

For the Arctic scenarios, spill events were simulated during the operating season, an industry definition for the partial- to open-ice season whereby drilling operations can occur (typically defined as June-October in the Beaufort and Chukchi Seas), and oil was assumed to spill until a temporary source control measure was implemented. All the oil spill scenarios modeled for the Beaufort Sea and Chukchi Sea were initiated on dates during which ice would not be present (e.g., during the ice-free season, July to September). The scenarios that were started late in the ice-free season (mid to late September), however, interacted with ice over the course of the simulation. These oil releases were still within the ice-free season; but the fate of the oil was simulated and tracked for 45 days beyond the date that the discharge was secured. Thus, those spills beginning in mid to late September did overlap with the beginning of the ice season.

Ice affects the fate and transport of the oil when spilled into the environment. The presence of ice can shelter oil from the wind and waves (Drozdowski et al., 2011), and slow down weathering processes such as evaporation and emulsification, as well as transport behaviors such as spreading and entrainment (Spaulding, 1988). Field data shows that evaporation, dispersion, and emulsification are all significantly slowed in ice leads. Wave-damping, limitations on spreading, and reduced temperatures appear to be the primary factors (Sørstrøm et al., 2010). Ice coverage or concentration provided in the ice model is used as an index to control oil weathering and behavior processes (Table 61).

Table 61: Percent Ice Coverage Thresholds for Oil Fates and Behavior Processes Applied in the SIMAP Model

Ice Cover(Percent)	Advection	Evaporation & Emulsification	Entrainment	Spreading
0 – 30 **(Drift Ice)**	Surface oil moves as in open water	As in open water	As in open water	As in open water
30 – 80 **(Ice Patches and Leads)**	Surface oil moves with the ice	Linear reduction with ice cover (i.e., none at 80% ice cover)	Linear reduction with ice cover (i.e., none at 80% ice cover)	Terminal thickness increased in proportion to ice coverage
80 – 100 **(Pack Ice)**	Surface oil moves with the ice	None	None	None

Oil behaves as it would in open water in <30% ice coverage. Ice coverage exceeding 80% is assumed fast ice and effectively continuous ice cover. Evaporation and volatilization of oil under/in ice, as well as spreading, emulsification, and entrainment into the surface water are zeroed in fast ice. Degradation of subsurface and ice-bound oil occurs during all ice conditions, at rates occurring at the location (i.e., floating versus subsurface) without ice present. Dissolution of soluble aromatics proceeds for subsurface oil and oil under ice using the normal open-water algorithm (French McCay, 2004).

In ice coverage between 30% and 80%, a linear reduction in wind speed from the open-water value (used in <30% ice) to zero in fast ice (>80% ice coverage) is applied to simulate shielding from wind effects. This reduces the evaporation, volatilization, emulsification, and entrainment rates due to reduced wind and wave energy. Terminal thickness of oil is increased in proportion to ice coverage in this range (i.e., oil is thickest at >80% ice coverage).

The applied thresholds, or the discrete bands of 0 to 30, 30 to 80, and 80 to 100%, may not reflect the fate of oil in real ice cover at fine scales. Assumptions applied to fates and behavior processes are not well quantified by field experiments or other studies. In addition, the coupled ocean-ice models available to date do not resolve the details of leads, fractures, and ice roughness. A full description of how the ice influences the oil in the SIMAP model is provided in Appendix C of Volume I of this report. Provided herein is a brief summary of the effects of ice on the oil fate and behavior process.

2.3.1 Alaska Unified Contingency Plan and Arctic Subarea Contingency Plan Strategies

Under the NCP, the state of Alaska is assigned a dedicated RRT that oversees the Alaska Unified Plan. The Unified Plan is supported by a series of Subarea Plans, and the North Slope Subarea Plan and Northwest Arctic Subarea Plan cover all of the trajectories of the Arctic OCS WCD scenarios.

According to the plans, mechanical recovery is the preferred response option. Dispersants are not pre-authorized for approval by the FOSC, meaning that the Unified Command must receive incident-specific approval from required members of the RRT before surface-applied or subsurface-applied dispersants can be used. The Unified Command (UC) can authorize in situ burning operations if mechanical recovery is deemed inadequate to control spilled oil in marine waters. Additional response equipment listed in Geographic Response Plans (GRPs) for the Northwest Arctic and the North Slope Subarea Plans are listed in Table 62.

Table 62: Summary of Resources Required for Geographic Response Priorities for the Arctic

ACP	Boom (ft)	Number of Skimming Devices	Number of Boats [a]
Northwest Arctic	hard: 119,100 snare or sorbent: 40,000	unspecified type: 84	171 to 256
North Slope [b]	unspecified type: 156,700	not available	not available
Totals	**315,800**	**84**	**256**

[a] The total number of boats was estimated by adding the boats cited in all of the subarea plan Geographic Response Strategies (GRSs). It was not known whether adjacent GRSs cited the same boats, therefore the estimate is provided as a range to compensate for potential double counting.

[b] ACS Map Index is used for listing GRPs. Does not list equipment or tactical approach. Does provide an inventory of various equipment pre-staged caches.

2.3.2 Response Equipment Inventories

Stockpiles of oil spill response equipment currently available to the Arctic OCS were calculated by surveying OSRO equipment stockpiles and querying a variety of publically available databases on equipment stockpiles (for more information on these methods, see Section 1.7). Total response equipment in the Arctic OCS is shown in Table 63. Mechanical recovery equipment is categorized by nearshore and offshore equipment. There are no aircraft currently outfitted and standing by with dispersant application equipment in the Arctic or Alaska. In addition to the MSRC C-130's in Mississippi and Arizona, there is a C-130 available in the continental United States that could be equipped with an Airborne Dispersant Delivery System (ADDS) pack and cascaded to the Arctic. This C-130 is not on call at a particular location, rather, it is located at various staging areas throughout the United States throughout the course of the year. The fire boom in the table is staged in the Beaufort Sea Planning Area and is readily available for oil spill response in the Arctic OCS.

Table 63: Response Equipment in the Arctic OCS Region

Countermeasure Type	Type/Location	In Arctic	In Alaska	Outside Alaska [b]
Mechanical Recovery	Nearshore Equipment ERSP	19,063 bbl/day	31,787 bbl/day	559 bbl/day
	Offshore Equipment ERSP	2,102 bbl/day	95,482 bbl/day	52,418 bbl/day
	Total Mechanical Recovery ERSP	**21,165 bbl/day**	**127,269 bbl/day**	**52,977 bbl/day**
Fire Boom for In Situ Burning	**Total Fire boom staged in the Beaufort Sea Planning Area**	20,000 ft		
Dispersant Aircraft	C-130 in Mesa ,AZ			1
	C-130 in various locations in United States [a]			1
	C-130 in Stennis, MS			1
	Total Number of Aircraft			**3**
Dispersants	**Total Dispersant Stockpile**	**164,725 gal**		

[a] This C-130 is not on standby and changes location regularly in the U.S. It can be fitted with an ADDS pack at any time to apply dispersants, but transit time to the U.S. Arctic is dependent upon its location at the time of an oil spill.

[b]Drilling companies have brought equipment in from outside of Alaska to meet their response requirements due to the lack of resources and infrastructure available in Arctic.

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2.3.2.1 *Scenario 8: Posey 6912 Early Season– Chukchi Sea*

Scenario Site Information

Arctic Posey 6912 (P6912) is an offshore (69 miles [60 nm] from shore) and shallow water (190 ft) well in the Chukchi Sea Planning Area. In the event of a WCD at this site, there is a medium probability of shoreline oiling along the northwest coast of Alaska (see Figure 93) if spill response countermeasures are not immediately taken. Based on 100 stochastic model runs, the worst case release date for the Posey 6912 WCD early season scenario was July 19, 2012.

Table 64: Scenario 8, Arctic-P6912 Early Season – Well Information and Shoreline Contact Times

WCD Scenario Parameters	
Discharge Flow Rate	25,000 bbl/day
WCD Duration	28 days, Relief Well Only 14 days, Source Control
Total WCD Release Volume	700,000 bbl, Relief Well Only 350,000 bbl, Source Control
Simulation Duration (45 days following end of discharge)	73 days, Relief Well Only 59 days, Source Control
Oil Type	Alaskan North Slope Crude
API Gravity	30.9
Viscosity @ 15°C (cp)	11.5
Latitude, Longitude	71.1024°N / 163.281852°W
Depth to Sea Floor	190 ft
Distance to Shoreline	69 miles (60 nm)
SIMAP Model Results [a]	
Time for oil above 1 g/m^2 to reach shore [b]	4 days
Time for oil greater than 8 g/m^2 to reach shore [c]	7 days, Figure 93

[a] SIMAP model results presented in this table are based on the 100 stochastic model runs.

[b] The 1 g/m^2 value is the threshold for socio-economic resource effects (e.g., closure of fisheries) (French-McCay et al. 2011; French McCay et al. 2012)

[c] The 8 g/m^2 value is the minimum thickness of floating oil for which response equipment can be effectively used (NOAA 2010)

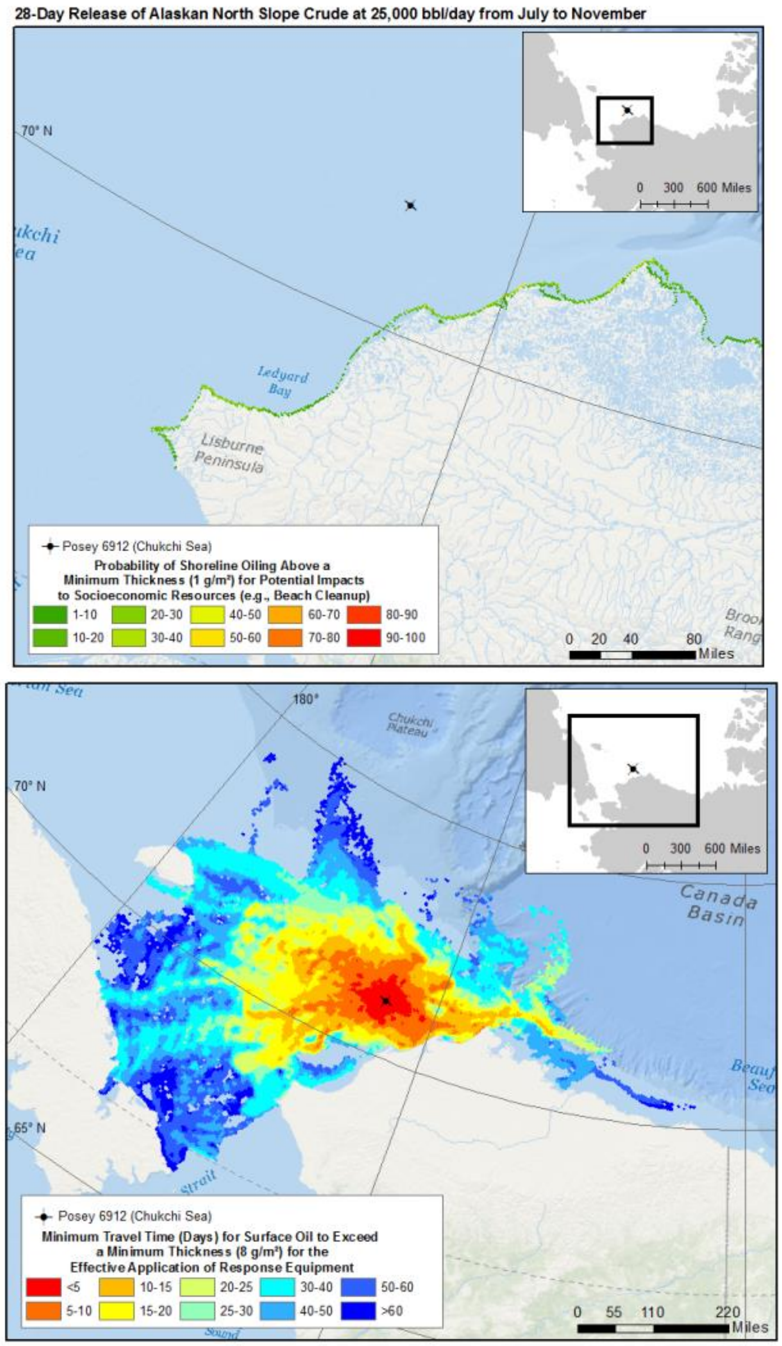


Figure 93: Scenario 8, Arctic-P6912 Early Season Relief Well Only Scenario, 28-Day Discharge – Probability of Shoreline Oiling and Minimum Travel Times for Surface Oiling

Application of Source Control

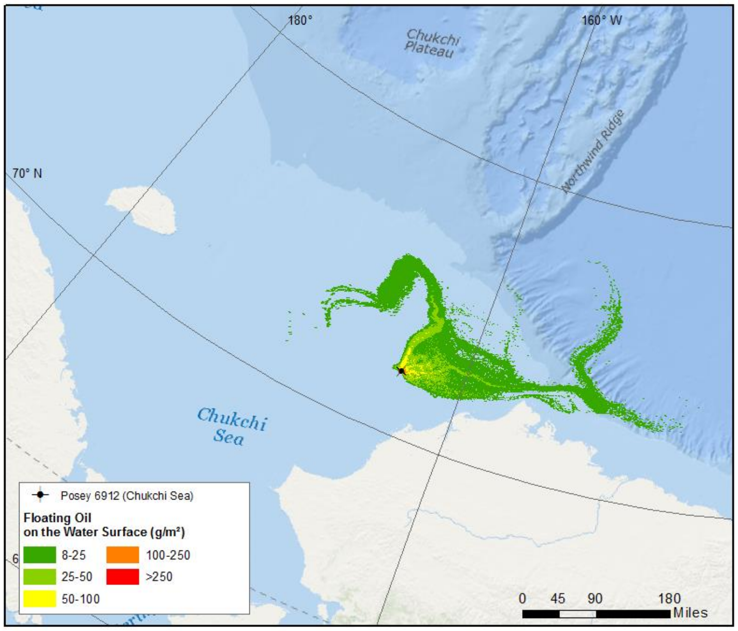
When a source control operation is modeled for the WCD Arctic Posey 6912 Early Season scenario, the discharge period is reduced by 14 days, and the volume of oil released to the environment is reduced by 350,000 bbl. Correspondingly, source control results in substantially less impact to the water column and shoreline in comparison to the Relief Well Only simulation. Table 65 and Figure 94 compare discharge volume, shoreline-oiling volume, length of oiled shoreline, area of surface oiling, and the amount of oil biodegraded or in the sediments for the Relief Well Only and Source Control modeling simulations.

Table 65: Scenario 8, Arctic-P6912 Early Season – Comparison of Relief Well Only and Source Control Response Scenarios

Scenario 8, Arctic-P6912 Early Season	Relief Well Only (28-day flow duration)	Source Control (14-day flow duration)	Reduction Due to Source Control	Percent Reduction Due to Source Control
Volume Discharged (bbl)	700,000 bbl	350,000 bbl	350,000 bbl	50 %
Volume Shoreline Oiling (bbl) any thickness	37,738 bbl	14,192 bbl	23,546 bbl	62 %
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	600 mi	223 mi	377 mi	63 %
Cumulative Area (mi^2) of Surface Oiling ≥8g/m^2	1,004,913 mi^2	634,349 mi^2	370,564 mi^2	37 %
Amount Biodegraded or In Sediments (bbl) at the End of the Simulation	182,560 bbl	82,311 bbl	100,249 bbl	55 %

As shown in Figure 94, the volume and spread of oil spilled from this WCD is reduced by a source control intervention on Day 14; however, without the application of additional response operations to remove or mitigate spilled oil on the surface, the expected contact and exposure to oil in the environment still occurs in sensitive regions.

28-Day Release of Alaskan North Slope Crude at 25,000 bbl/day During the Early Season- Relief Well Only (WCD)



14-Day Release of Alaskan North Slope Crude at 25,000 bbl/day During the Early Season- Source Control Only

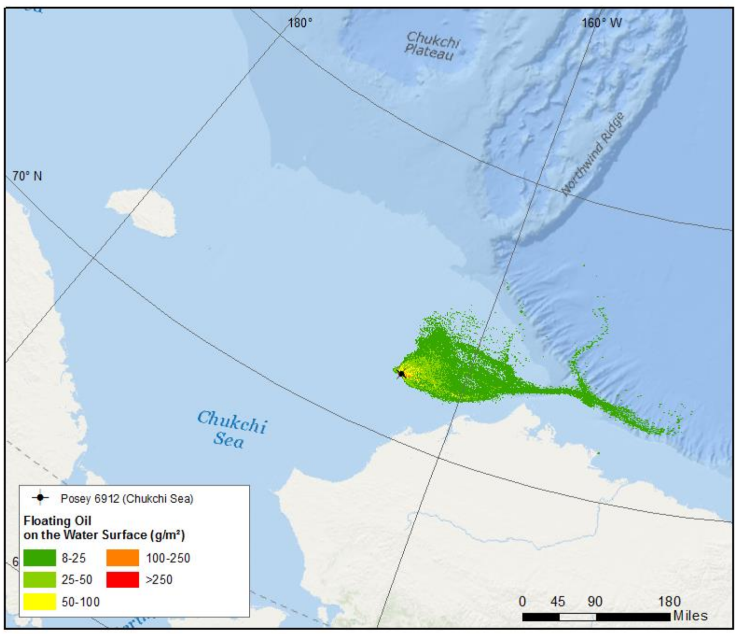


Figure 94: Scenario 8, Arctic-P6912 Early Season – Comparison of Maximum Concentrations of Surface Oiling Experienced Throughout Simulation Periods for Relief Well Only (28-Day Discharge) and Source Control (14-Day Discharge)

Oil Discharge Behavior

Figure 95 shows the fate of oil for 59 days from the beginning of the discharge (14-day discharge duration and 45 days following the source control). At the end of the simulation, 41% percent of the total oil had evaporated, 28% of the oil remained floating on the surface, 23% biodegraded or remained in the water column and sediments, and 4% of the oil remained on the shoreline. Note that the model does not simulate potential photooxidation of floating oil.

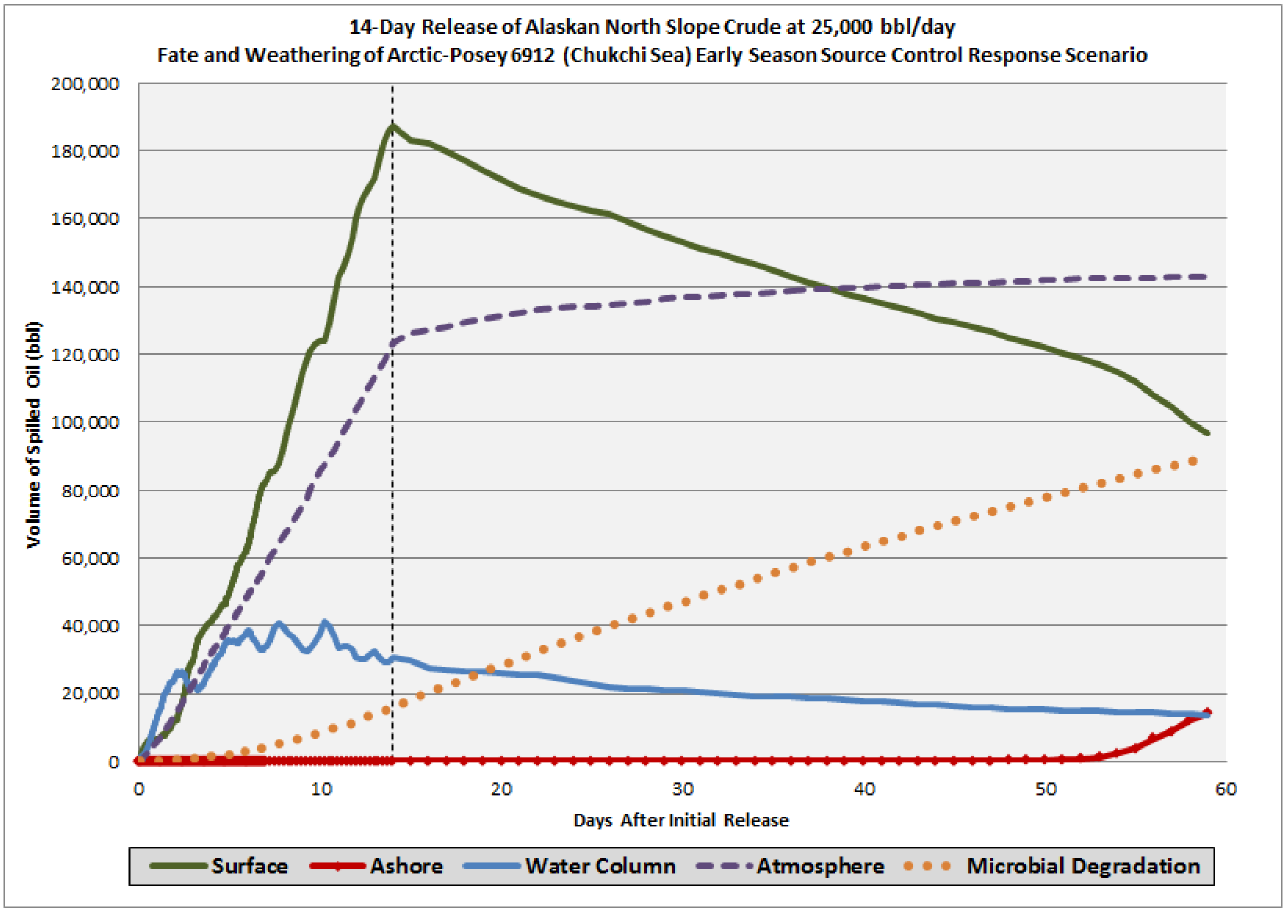


Figure 95: Scenario 8, Arctic-P6912 Early Season Source Control, 14-Day Discharge – Oil Fate and Weathering (Dotted Vertical Line Indicates Source Control on Day 14)

In the Arctic-P6912 Early Season Source Control Only simulation, 100% of the total oil mass discharged from the blowout reached the surface. Upon release from the blowout, oil droplets took less than 1 hour to reach the surface, with most surfacing in the immediate vicinity of the well location.

As the oil slick spreads, the surface oil remains fresh and thick enough to treat or recover in the high volume removal area, but only for short periods of time when wind conditions are calm. By the end of day 2, oil that was discharged at the beginning of the spill moved to the edge of the High Volume Recovery Division and reached the upper limit (15,000 cST) for the mechanical recovery equipment being modeled in the simulation. By the end of day 3, the oil began to move outside the High Volume Recovery Division, while staying within the Dispersant Application Division. By the end of day 4, the weathered oil reached viscosities up to 30,000 cST as far as away as 100 miles from the well site. Following day 3, the oil continued to move in a northeasterly direction with the majority of the oil as large patches in the Dispersant Application Division that were too viscous to be recovered or treated

(>20,000 cST). However, small amounts of oil with viscosities that could be recovered or treated (<20,000 cST) approached the Nearshore Recovery Division by day 5 (Figure 96 and Figure 97).

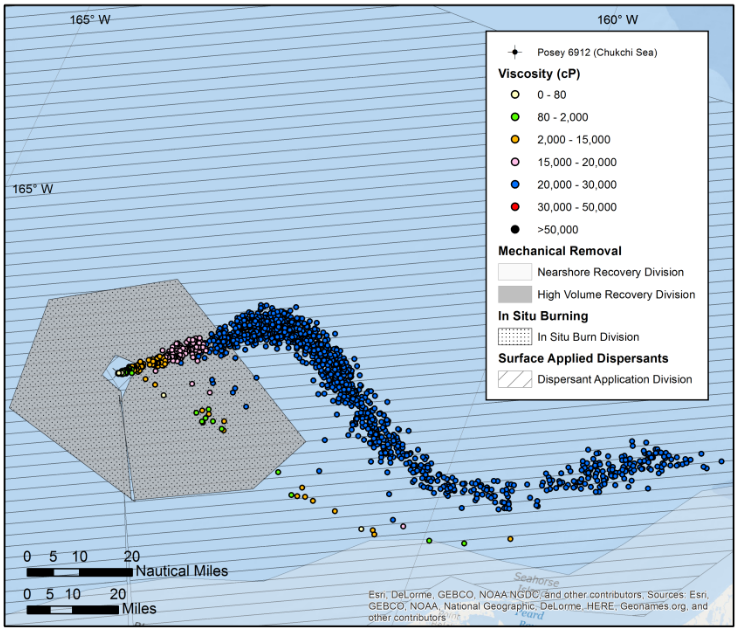


Figure 96: Scenario 8, Arctic-P6912 Early Season Source Control - Surface Spillet Viscosity (cp) at Day 5

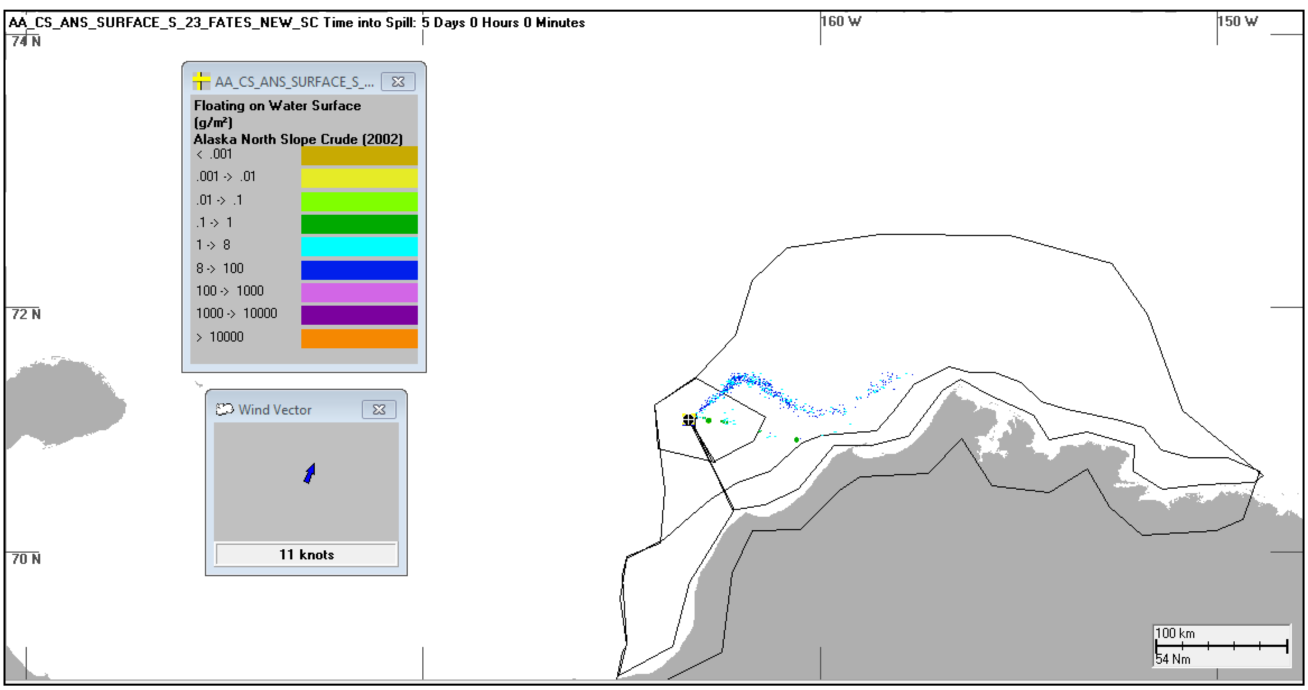


Figure 97: Scenario 8, Arctic-P6912 Early Season Source Control – Floating Oil on Water Surface (g/m^2) at Day 5

The path of the plume in this simulation does not vary significantly over time. Over the course of 59 days model period, oil moved generally north-northeast of the well location. The minimum travel time for contact to shorelines was 46 days, with substantial shoreline impacts beginning after 55 days of the start of the discharge. At the end of the simulation, the majority of the shoreline oiling over 1 g/m^2 was along the North Slope of the Alaskan coast (Figure 98).

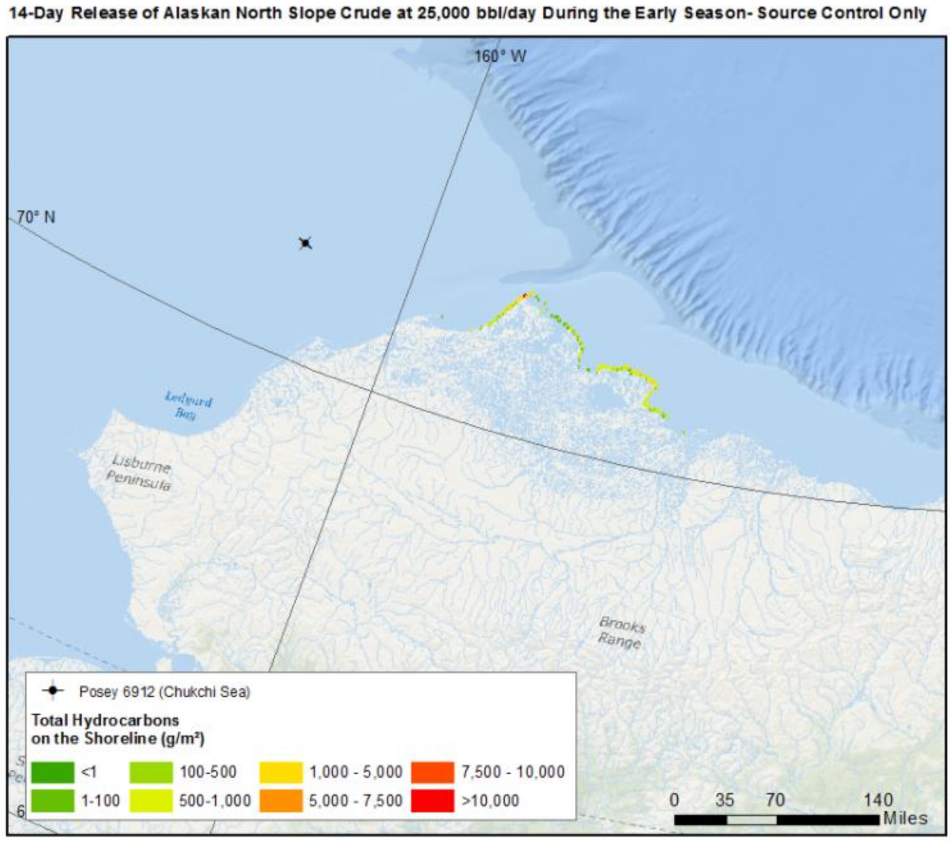


Figure 98: Scenario 8, Arctic-P6912 Early Season Source Control, 14-Day Discharge – Shoreline Oil ≥1 g/m^2, including Weathered Tarballs

Application of Response Countermeasures

Countermeasure Response Divisions

The following equipment types were employed in each of the following countermeasure response divisions, and are shown in Figure 99.

- High Volume Recovery Division – High volume mechanical recovery operations were employed beyond a 3.5 mile (3 nm) radius area established around the well for source control.
- In situ Burning Division – In situ burning operations were used in the same geographical area as the high volume mechanical recovery operations (3.5 mile [3 nm]) away from the source control area.
- Nearshore Recovery Division – Nearshore mechanical recovery operations were used to remove oil from the surface of the water before it was washed onto shorelines.
- Dispersant Application Division – Surface applied dispersants were employed in the High Volume Recovery Division up to 3.5 mile (3 nm) from shore and beyond a 3.5 mile (3 nm) radius area established around the well for source control, as appropriate.

No subsurface dispersants were applied in the Arctic-P6912 Early Season scenario.

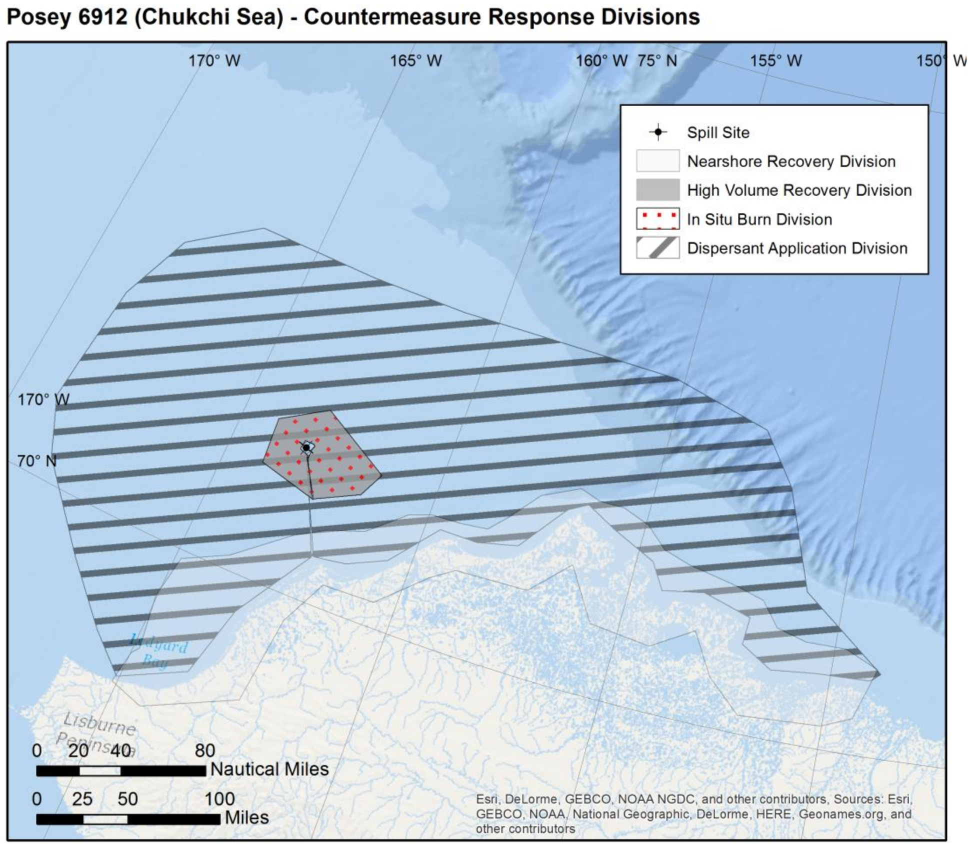


Figure 99: Scenario 8, Arctic-P6912 Early Season – Geographic Coverage of Oil Countermeasure Response Divisions

The size and placement of the Arctic-P6912 response operation divisions in the model were developed based on a review of the oil spill trajectories from the 14-day discharge in the Source Control simulation.

Countermeasure/Division Removal Rates (Model Inputs)

The removal rates by countermeasure type and response division that are shown in Table 66 represent the *maximum* potential rate that would be available at any point during the response operation.

As in an actual oil spill response operation, the model cascades response equipment into the response divisions as the assets arrive on the scene. The modeling reflects response equipment threshold values and limitations based on the availability of the response equipment to be deployed to the location of the appropriate divisions. As such, the model used oil removal rates for each division (i.e., SIMAP model polygon), based on the maximum potential daily removal rates (bbl/day) of the assigned asset (refer to Table 66), corrected by weather restrictions and daylight operations (as described in Section 1.8). Maximum removal rates are not realized in practice because of the limitations of weather delays, suspension of operations at night, the location of oil in relation to equipment, and performance thresholds, such as oil thickness on the water surface, sea state and currents, winds, and water content during oil emulsification.

These maximum rates are not necessarily applicable for the entire response period. This is because equipment cascades in at different times, and in some cases, resources are allocated to different applications. For example, in this WCD scenario, in situ burning could be conducted in a relatively small area only and was limited by both availability of fire boom and other equipment, as well as thresholds for wave height, winds, viscosity, and thickness of oil on the water surface were reached.

Table 66: Maximum Potential Daily Oil Removal Rates for Arctic-P6912-Early Season SC+MR+D+ISB Response Scenario

Countermeasure Type	Response Division	Response System Category [b]	Removal Rate Applied [c]	Maximum Potential Daily Removal Rates (bbl/day)
Mechanical	**High-Volume**	Skimmer Group A	ERSP Day-1	16,363
		Skimmer Group C	ERSP Day-1	44,785
	Nearshore	Skimmer Group A	ERSP Day-3	1,168
	Total	**All Mechanical Countermeasures**		**62,316**
In Situ Burning	**High-Volume In Situ Burning**	In Situ Burning	Based on ISB Calculator	**5,484**
Surface Dispersant	**High-Volume and Dispersant Application**	Surface Dispersants	Based on DMP 2	**31,191**
	Total	**All Countermeasures**		**98,991**

[a] Arctic-P6912 Early Season SC+MR+D+ISB Response Scenario by countermeasure type and response division *without* application of weather restrictions.

[b] The characteristics of the different types of mechanical equipment and the specific pieces of equipment applied in this scenario are described in Section 2.1. The viscosity thresholds for different types of equipment are further described in Section 1.8.2.

[c] ERSP is described in Section 5.0. "ERSP Day-1" rates are the higher removal rates applied in the areas and times when the oil was flowing from the well and the oil is the thickest. "Day-1" does not necessarily indicate that this is only applied for the first day. "ERSP Day-3" rates are applied in the areas more distant from the well where the oil is thinner and more spread out making removal less efficient. "Day-3" does not necessarily indicate that this is the third day of the response.

Scenario 8, Arctic-P6912 Early Season, scenario response operation divisions were cascaded in over the course of the initial 14 days (as depicted in Figure 100). Oil reached the surface after approximately one hour. Dispersant application began on day 3 due to logistical constraints and expected time to secure regulatory approvals for dispersant use.[24] Between day 3 and discharge shutdown on day 14, a total of 768,000 gallons of dispersant was applied aerially (65,500 gallons per day for 12 days), with an additional 29,250 gallons applied over the following four days. There was no subsurface dispersant response for this scenario.

[24] With pre-approval of dispersant use at this site, surface dispersant application could have started on Day 2.

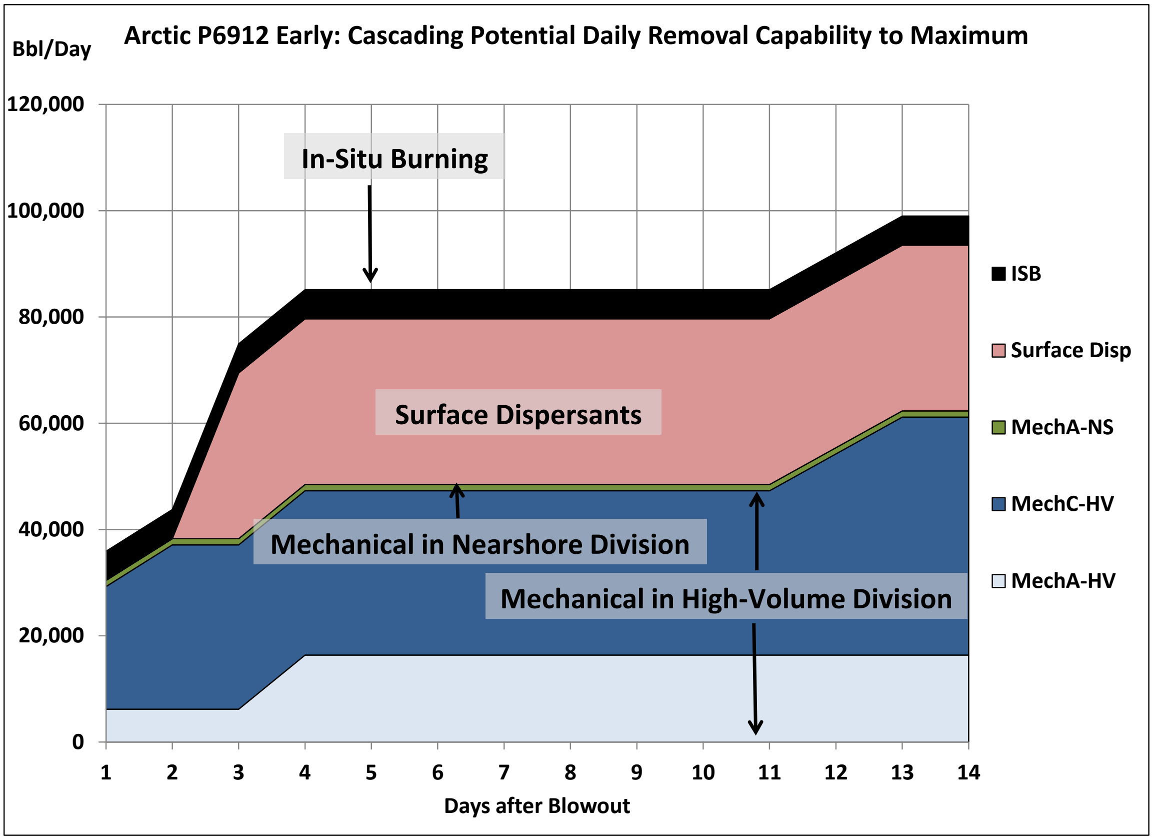


Figure 100: Scenario 8, Arctic-P6912 Early Season SC+MR+D+ISB – Cascading SC+MR+D+ISB Response Assets and Cumulative Potential Daily Removal Capacity

Countermeasure Simulation Results & Analysis

Achieved Removal versus Potential Equipment Capabilities

Maximum potential removal rates of oil removal systems are not achieved due to the limitations on countermeasures resulting from oil weathering and other environmental factors (such as increased sea state and darkness which often limited when the countermeasures could be applied). For the Arctic-P6912 Early Season SC+MR+D+ISB simulation, weather restrictions were in effect for 62.5% of the time, and for most equipment, the operating period was limited to 12 hours of daylight (other equipment limitations applied are listed in Table 10, Table 12, and Table 13). Because of these thresholds and limitations, as well as the availability of recoverable, burnable, or dispersible oil in the response divisions, achieved oil removal was significantly less than the potential recovery capabilities (as shown in Table 67, Figure 101, and Figure 102) for the Arctic-P6912 Early Season SC+MR+D+ISB simulation.

Table 67 shows the system potential with regard to barrels of oil that could be treated or removed based on the sum total of removal/treatments rates over the course of the entire response operation (i.e., during the release of oil from the well and for an additional 45 days after source control is achieved to stop the flow of oil). The "achieved" removal or treatment reflects the sum total of oil removed or treated over the course of the response operations. Figure 101 contrasts the sum total of potential removal/treatment over the course of the operations and the sum total of the achieved removal/treatment. The daily well flow is shown as a benchmark. The potential removal/treatment capability greatly exceeds the achieved removal/treatment due to the various environmental and logistical factors that limit performance.

Table 67: Scenario 10, Arctic-P6912-Early Season SC+MR+D+ISB Cumulative System Potential Oil Recovery versus Achieved Oil Recovery over 59-Day Simulation

Response Type	Response Division	Response System Type	Total Recovery		
			System Potential (bbl)	Achieved (bbl)	% Potential [a]
Mechanical [b]	**High-Volume**	Skimmer Group A	448,715	17,685	4%
		Skimmer Group C	1,033,088	0	0%
	Nearshore	Skimmer Group A	68,912	453	1%
	Mechanical Total	**All**	**1,550,715**	**18,138**	**1%**
In Situ Burning [c]	**High-Volume In Situ Burning**	-	**323,556**	**11,632**	**4%**
Dispersants	**High-Volume/ Dispersant Application**	-	**388,221**	**28,779**	**7%**
All Categories	**All**	**All**	**2,262,492**	**58,549**	**3%**

[a] Modeled recovery divided by potential recovery as percentage.

[b] ERSP Day-1 rates assumed for High-Volume Division until well capping (source control); ERSP Day-3 rates assumed for Nearshore Division, and for High-Volume Division after day 14 source control.

[c] EBSP Day-1 rates assumed until day 14 source control, after which EBSP Day-3 rates were applied.

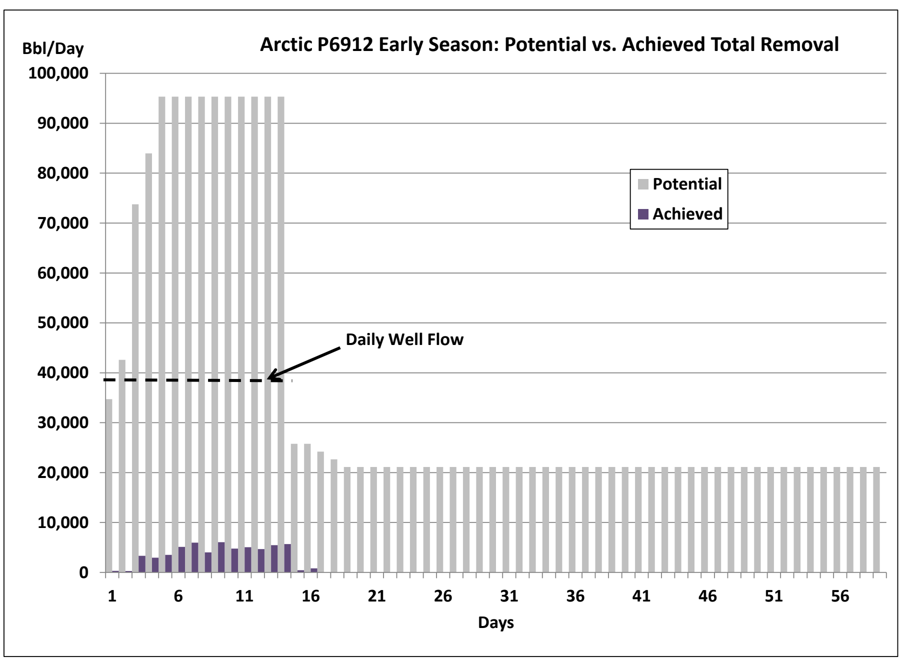


Figure 101: Scenario 8, Arctic-P6912 Early Season - SC+MR+D+ISB - Total Oil Removal System Potential and Achieved Total Daily Removal

Figure 102 contrasts the amount of oil flowing from the well on a daily basis along with the maximum potential daily capability per day, as well as the achieved average daily removal rate. The achieved average daily removal rate is lower than the potential daily removal rate for each day of the scenario.

During the response period, some systems have very low or near-zero removal for some periods because of performance limitations due to environmental conditions, or because there is insufficient oil available. For example, in the nearshore response area, oil does not appear on the surface until very late in the response and long after the oil has stopped flowing from the well.

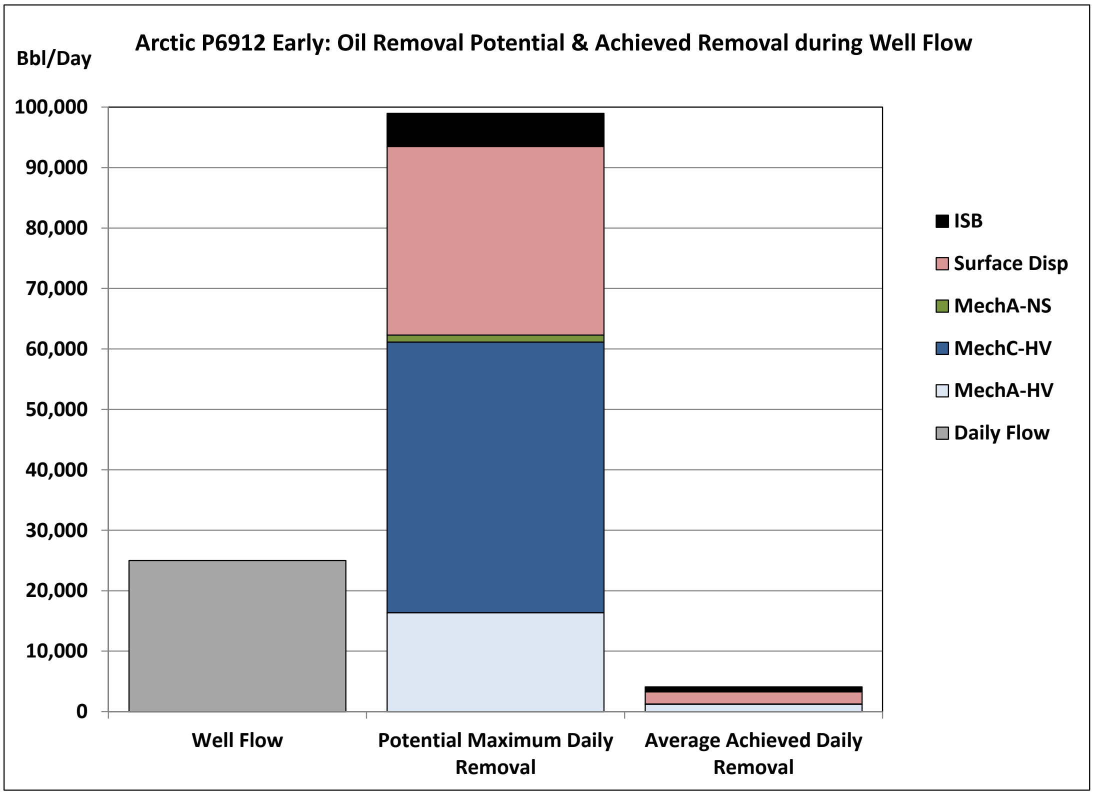


Figure 102: Scenario 8, Arctic-P6912 Early Season SC+MR+D+ISB Total Maximum Oil Removal System Potential and Achieved Removal Compared with Well Flow during 14-Day Discharge Period

Oil Removal by Countermeasure Type

Table 68 is a summary of model results for the various response countermeasures applied to the Arctic-P6912 Early Season scenario. This table allows for comparison of the oiling and oil removal by each countermeasure across the various model simulations. Values within Table 68 represent the volume of oil present/removed at the completion of the response scenarios (59 days).

Table 68: Scenario 8, Arctic-P6912 Early Season – Comparison of Shoreline Oiling and Oil Removal for the Relief Well Only Scenario and Four Response Scenarios at the End of the Model Simulations

Scenario	Volume (bbl) of Discharge	Volume (bbl)/ Percent of Oil on Shoreline	Volume (bbl)/ Percent Removed by Skimming	Volume (bbl)/ Percent Dispersed	Volume (bbl)/ Percent Removed by Burning	Volume (bbl)/ Percent Bio-degraded or in Sediments
Relief Well Only, 37 Day Discharge	700,000	37,738				182,560
Source Control (SC), 21 Day Discharge	350,000	14,192 4%				82,311 24%
Source Control and Mechanical Recovery (SC+MR)	350,000	12,739 4%	21,861 6%			73,947 21%
Source Control, Mechanical Recovery and Surface Dispersant (SC+MR+D)	350,000	11,299 3%	21,767 6%	28,481 8%		77,477 22%
Source Control, Mechanical Recovery, Surface Dispersant and In Situ Burning (SC+MR+D+ISB)	350,000	10,405 3%	18,138 5%	28,744 8%	11,651 3%	74,633 21%

Scenario 8, Arctic-P6912 Early Season is a WCD from an offshore shallow-water well where mechanical recovery, surface dispersant and in situ burning all had similar percentages (≤8%) of oil removed or dispersed at the end of the model simulations. When used without the aid of other response operations, mechanical recovery was able to remove up to 6% of the oil discharged in this scenario. These results are partially due to the fact that there is no Secondary Recovery Division applied in the Chukchi. While the High Volume Recovery Division is quite large (~25-40 miles in each direction surrounding the wellhead), the equipment capabilities are not sufficient enough in the area to place them in a Secondary Recovery Division. Therefore, as the oil moves out of the High Volume Recovery Division, it is picked up by surface dispersant and not further removed by mechanical recovery.

When surface applied dispersants were added, oil removed by mechanical recovery remained at 6%; however, an additional 8% of the oil was also dispersed into the water column thus significantly reducing the amount of surface area oiling that occurs offshore.

In situ burning accounted for 3% of the oil removed when used, which is likely a reflection of the limited area where burning could be applied (e.g., restricted to the High Volume Recovery Division) in this scenario. In situ burning in this scenario was limited by the lack of suitable vessels for towing both enhanced encounter boom and fire boom at the same time. Additional fire boom could have been added had there been vessels available for towing it. The In situ burn equipment was further limited by the equipment thresholds for wave height, wind, and viscosity and thickness of oil on the water surface that were encountered in this distant offshore scenario.

Figure 103 displays the fate of oil at the end of the 59-day simulation for Scenario 8, Arctic-P6912 Early Season involving source control, mechanical recovery, in situ burning, and surface dispersants (e.g., SC+MR+D+ISB).

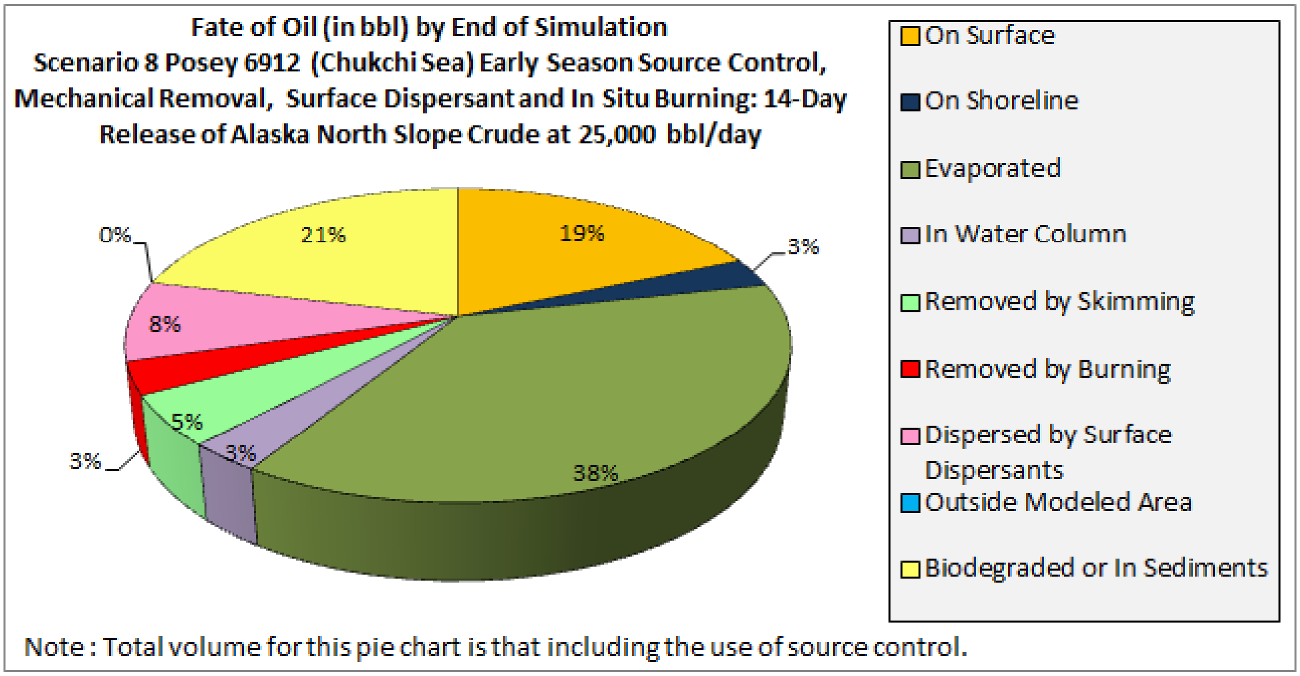


Figure 103: Scenario 8, Arctic-P6912 Early Season – Fate of Oil at End of 59-Day Simulation (Scenario includes Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning Response Operations)

Reductions in Surface and Shoreline Oiling

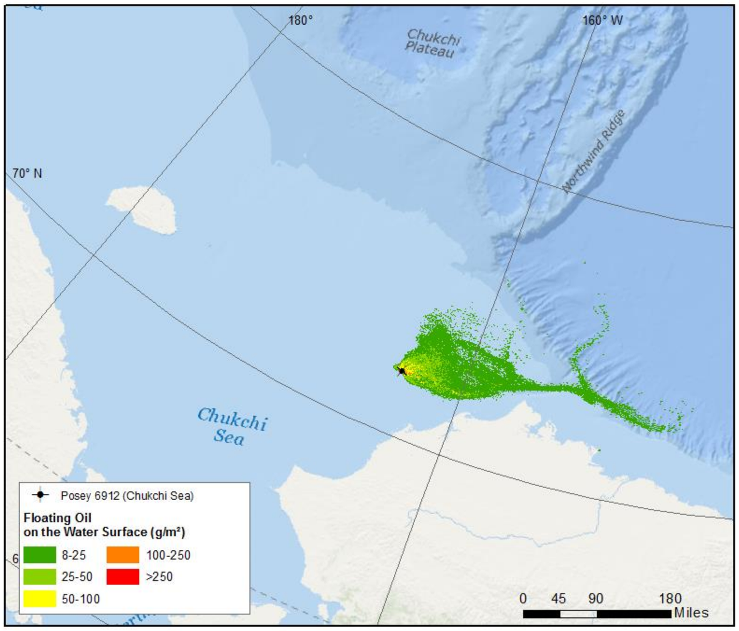
Table 69 provides a comparison of the shoreline and water surface oiling results for each of the Arctic-P6912 Early Season response countermeasure simulations.

Table 69: Scenario 8, Arctic-P6912 Early Season – Comparison of Shoreline and Water Surface Oiling Above Equipment Threshold Values or Limitations

Scenario 8, Arctic-P6912 Early Season	Relief Well Only (WCD)	Source Control	Source Control and Mechanical Recovery	Source Control, Mechanical Recovery, and Surface Dispersant	Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning
Volume (bbl) of Shoreline Oiling (to Any Degree)	37,738	14,192	12,739	11,299	10,405
Percent Reduction in Volume of Shoreline Oiled As Compared to Relief Well Only	-	62%	66%	70%	72%
Total Length (mi) of Shoreline Oiled with ≥1g/m²	600	223	211	200	203
Percent Reduction in Shoreline Length Oiled with ≥1 g/m² As Compared to Relief Well Only	-	63%	65%	67%	66%
Cumulative Area (mi²) of Surface Affected by Oil ≥8g/m²	1,004,913	634,349	586,816	461,478	440,290
Percent Reduction in Surface Affected by Oil ≥8g/m² As Compared to Relief Well Only	-	37%	42%	54%	56%

Figure 104 is a visual depiction of the reduction in the surface area affected by ≥8.0 g/m² of oil over the 59-day period. The graphic directly compares the levels of maximum water surface oiling over time between the Source Control Only simulation and the simulation that adds mechanical recovery, dispersants, and burning (SC+MR+D+ISB).

14-Day Release of Alaskan North Slope Crude at 25,000 bbl/day During the Early Season- Source Control Only



14-Day Release of Alaskan North Slope Crude at 25,000 bbl/day During the Early Season -
Source Control with Additional Surface Response Options: In Situ Burning, Mechanical Removal and Surface Dispersant

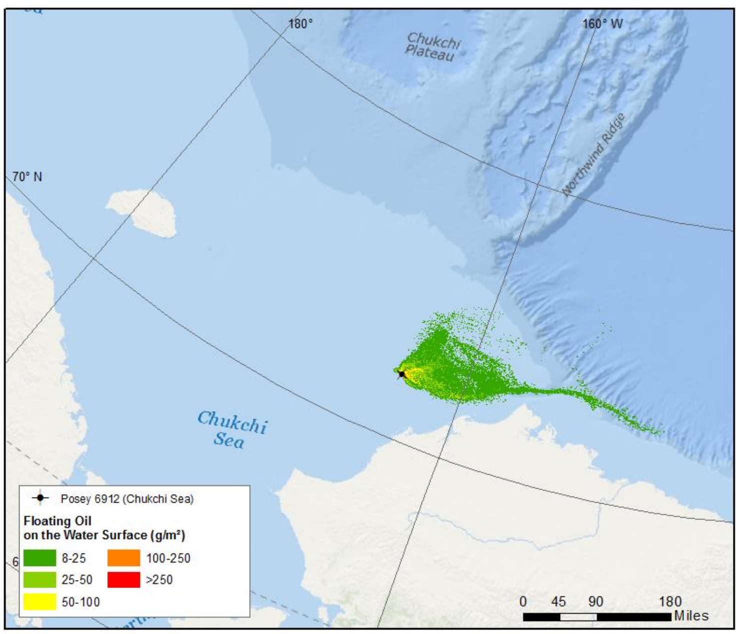


Figure 104: Scenario 8, Arctic-P6912 Early Season – Comparison Floating Oil Concentration (≥8.0 g/m^2) over 59-Day SIMAP Model Simulation, Top Panel: Source Control (SC), Bottom Panel: Source Control, Mechanical Recovery, Surface Dispersants, and In Situ Burning (SC+MR+D+ISB)

2.3.2.2 *Scenario 9: Posey 6912 Late Season– Chukchi Sea*

Scenario Site Information

Arctic Posey 6912 (P6912) is an offshore (69 miles [60 nm] from shore) and shallow-water (190 ft) well in the Chukchi Sea Planning Area. In the event of a worst case discharge at this site, there is a medium probability of shoreline oiling along the northwest coast of Alaska (see Figure 105) if spill response countermeasures are not immediately taken. Based on 100 stochastic model runs, the worst case release date for the Posey 6912 WCD late season scenario was September 9, 2010.

Table 70: Scenario 8, Arctic-P6912 Late Season – Well Information and Shoreline Contact Times

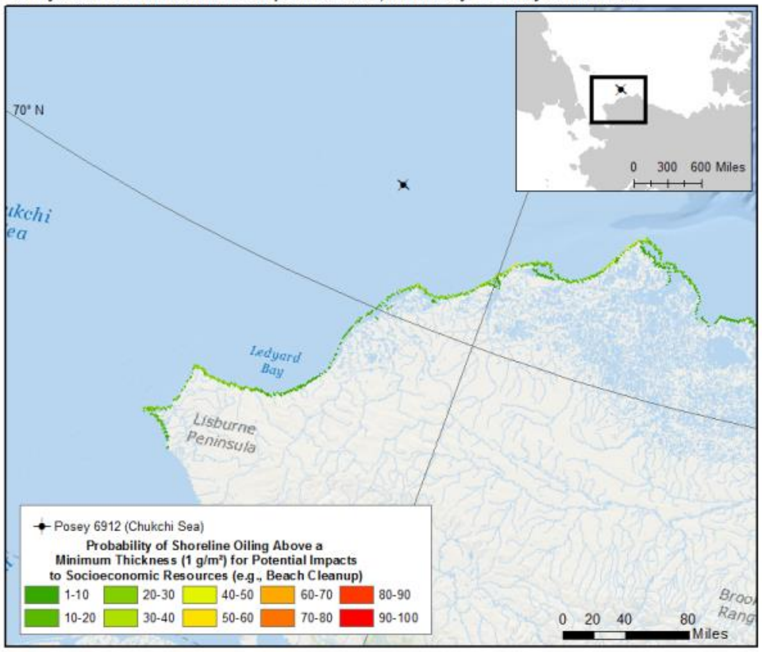
WCD Scenario Parameters	
Discharge Flow Rate	25,000 bbl/day
WCD Duration	28 days, Relief Well Only 14 days, Source Control
Total WCD Release Volume	700,000 bbl, Relief Well Only 350,000 bbl, Source Control
Simulation Duration (45 days following end of discharge)	73 days, Relief Well Only 59 days, Source Control
Oil Type	Alaskan North Slope Crude
API Gravity	30.9
Viscosity @ 15°C (cp)	11.5
Latitude, Longitude	71.1024°N / 163.281852°W
Depth to Sea Floor	190 ft
Distance to Shoreline	69 miles (60 nm)
SIMAP Model Results [a]	
Time for oil above 1 g/m^2 to reach shore [b]	4 days
Time for oil greater than 8 g/m^2 to reach shore [c]	7 days, Figure 105

[a] SIMAP model results presented in this table are based on the 100 stochastic model runs.

[b] The 1 g/m^2 value is the threshold for socio-economic resource effects (e.g., closure of fisheries) (French-McCay et al. 2011; French McCay et al. 2012)

[c] The 8 g/m^2 value is the minimum thickness of floating oil for which response equipment can be effectively used (NOAA 2010)

28-Day Release of Alaskan North Slope Crude at 25,000 bbl/day from July to November



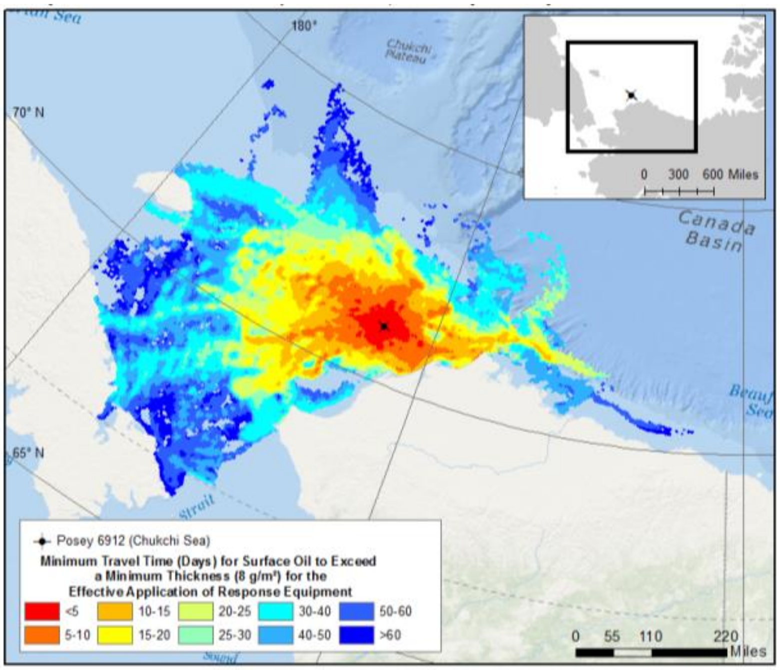


Figure 105: Scenario 9, Arctic-P6912 Late Season, Relief Well Only Scenario, 28-Day Discharge – Probability of Shoreline Oiling and Minimum Travel Times for Surface Oiling

Application of Source Control

When a source control operation is modeled for the WCD Arctic Posey 6912 Late Season scenario, the discharge period is reduced by 14 days, and the volume of oil released to the environment is reduced by 350,000 bbl. Correspondingly, source control results in substantially less impact to the water column and shoreline in comparison to the Relief Well Only simulation. Table 71 and Figure 106 compare discharge volume, shoreline-oiling volume, length of oiled shoreline, area of surface oiling, and the amount of oil biodegraded or in the sediments for the Relief Well Only and Source Control modeling simulations.

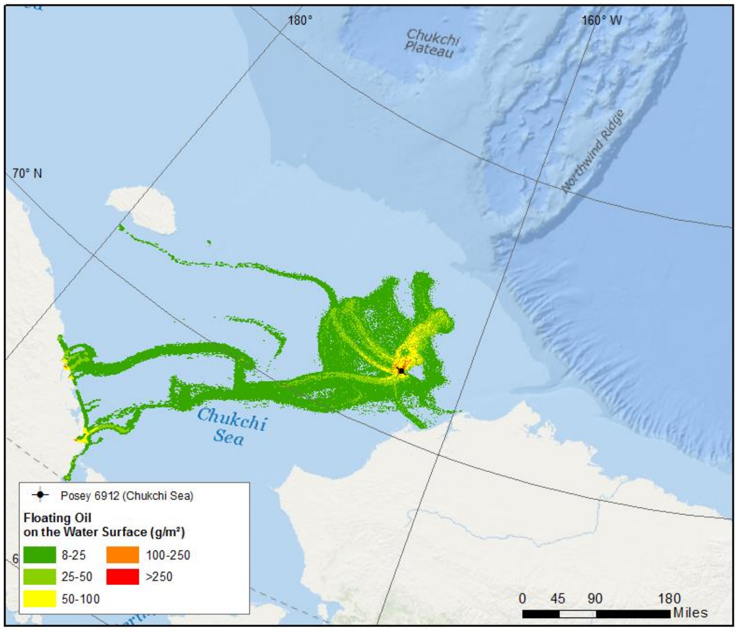
Table 71: Scenario 9, Arctic-P6912 Late Season – Comparison of Relief Well Only and Source Control Response Scenarios

Scenario 9, Arctic-P6912 Late Season	Relief Well Only (30-day flow duration)	Source Control (14-day flow duration)	Reduction Due to Source Control	Percent Reduction Due to Source Control
Volume Discharged (bbl)	700,000 bbl	350,000 bbl	350,000 bbl	50 %
Volume Shoreline Oiling (bbl) any thickness	57,162 bbl	32,295 bbl	24,867 bbl	44 %
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	729 mi	440 mi	289 mi	40 %
Cumulative Area (mi^2) of Surface Oiling ≥8g/m^2	786,343 mi^2	468,027 mi^2	318,316 mi^2	40 %
Amount Biodegraded or In Sediments (bbl) at the End of the Simulation	176,785 bbl	83,128 bbl	93,657 bbl	53 %

As shown in Figure 106, the volume and spread of oil spilled from this WCD is reduced by source control intervention on Day 14; however, without the application of additional response operations to remove or mitigate spilled oil on the surface, the expected contact and exposure to oil in the environment still occurs in sensitive regions.

When comparing the results after applying source control between the early and late season spills in the Chukchi, the amount of surface oiling for the late season is less; however, the amount of shoreline oiling is about twice that experienced for the early season spill. This may be largely due to the fact that a much greater portion of the oil is remaining entrained in the water column over time in the late season than in the early season.

28-Day Release of Alaskan North Slope Crude at 25,000 bbl/day During the Late Season- Relief Well Only (WCD)



14-Day Release of Alaskan North Slope Crude at 25,000 bbl/day During the Late Season- Source Control Only

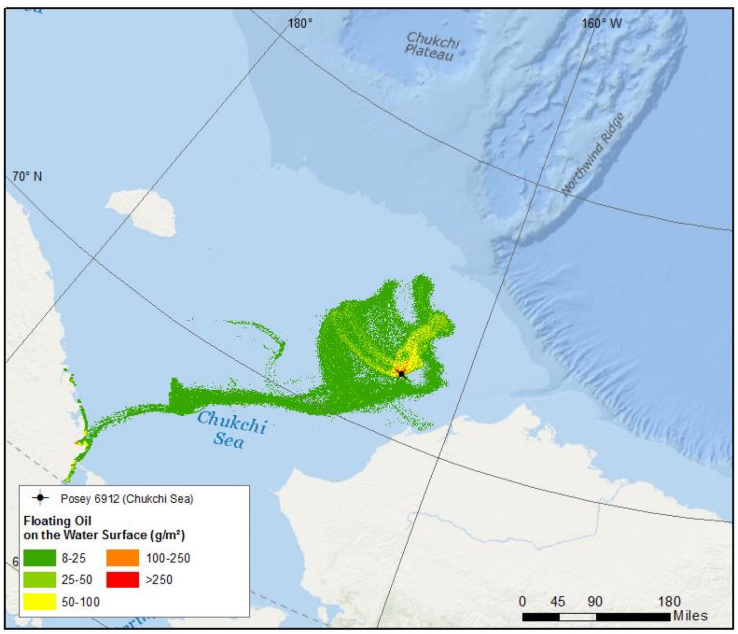


Figure 106: Scenario 9, Arctic-P6912 Late Season – Comparison of Maximum Concentrations of Surface Oiling Experienced Throughout Simulation Periods for Relief Well Only (28-Day Discharge) and Source Control (14-Day Discharge)

Oil Discharge Behavior

Figure 107 shows the fate of oil for 59 days from the discharge (14-day discharge duration and 45 days following the source control). At the end of the simulation, 39% percent of the total oil had evaporated, 24% biodegraded or remained in the water column and sediments, 13% of the oil remained floating on the surface, and 9% of the oil remained on the shoreline. Note that the model does not simulate potential photooxidation of floating oil.

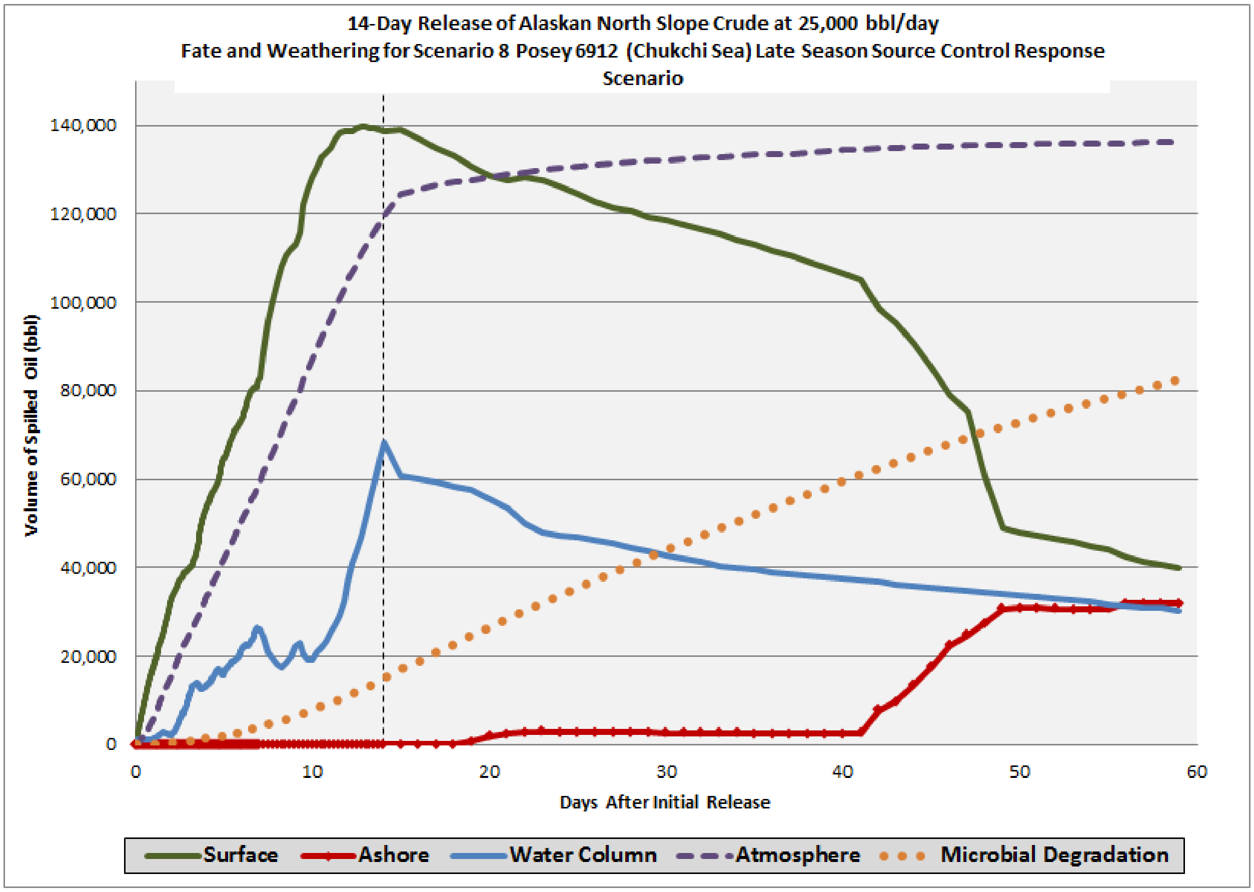


Figure 107: Scenario 9, Arctic-P6912 Late Season Source Control, 14-Day Discharge – Oil Fate and Weathering (Dotted vertical line indicates source control on Day 14)

In the Arctic-P6912 Late Season Source Control simulation, 100% of the total oil mass discharged from the blowout would reach the surface when conditions are calm and the oil is not entraining in the water surface. Under calm conditions, oil droplets will take less than an hour to reach the surface, with most surfacing in the immediate vicinity of the well location.

By the end of day 3, oil that was discharged at the beginning of the spill moved to the edge of the High Volume Recovery Division and reached the upper limit (15,000 cST) for the mechanical recovery equipment being modeled in the simulation. By the end of day 5, the oil began to move outside the High Volume Recovery Division, while staying within the Dispersant Application Division. At this point in the simulation, the weathered oil reached viscosities up to 30,000 cST as far as 40 miles from the well site (Figure 108 and Figure 109). From day 5 to day 11, the oil continues to move in a north/northwest direction following the steady though relatively strong (>10 knot) winds with the majority of the oil as large patches in the Dispersant Application Division that were too viscous to be recovered or treated (>20,000 cST). After day 11, the wind shifts direction and becomes even stronger reaching speeds of 20 knots forcing the large patches of viscous oil traveled south/southwest toward the Alaskan and Russian shorelines.

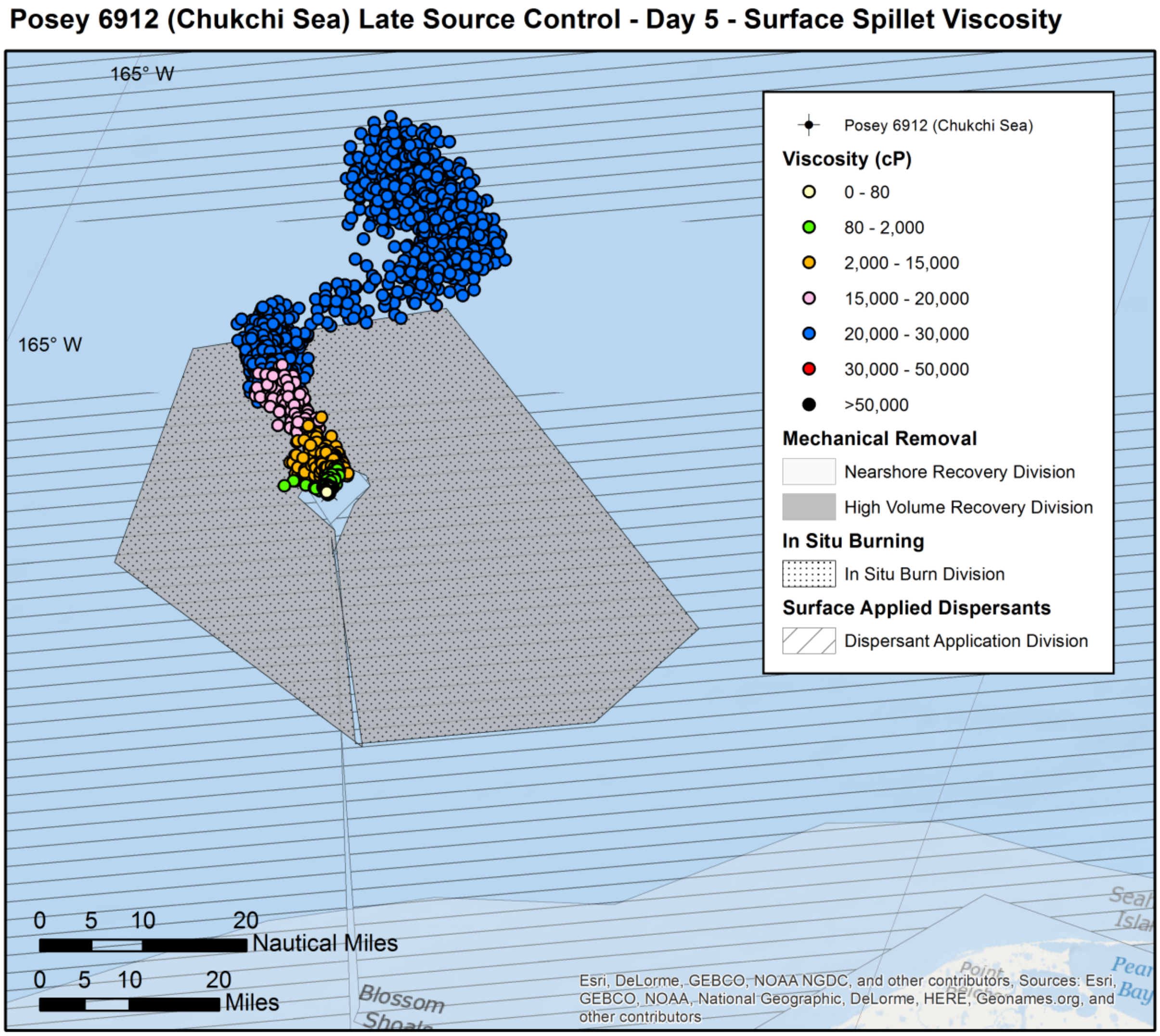


Figure 108: Scenario 9, Arctic-P6912 Late Season Source Control – Surface Spillet Viscosity (cp) at Day 5

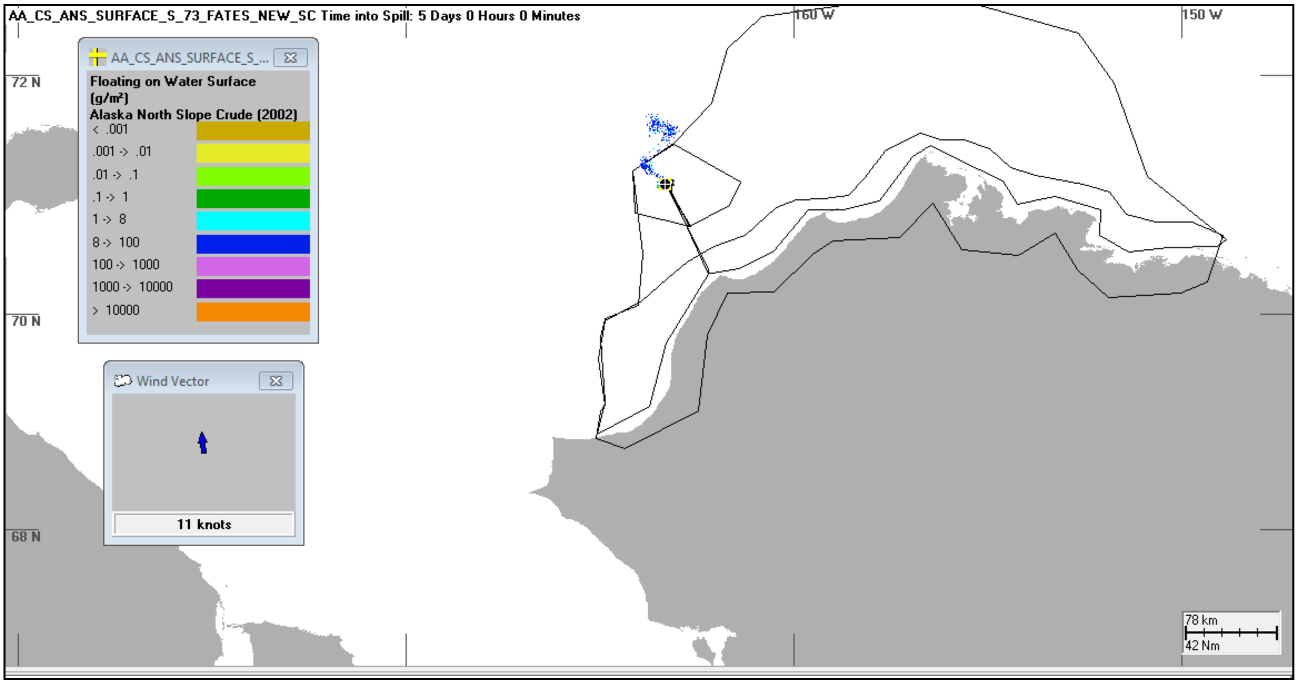
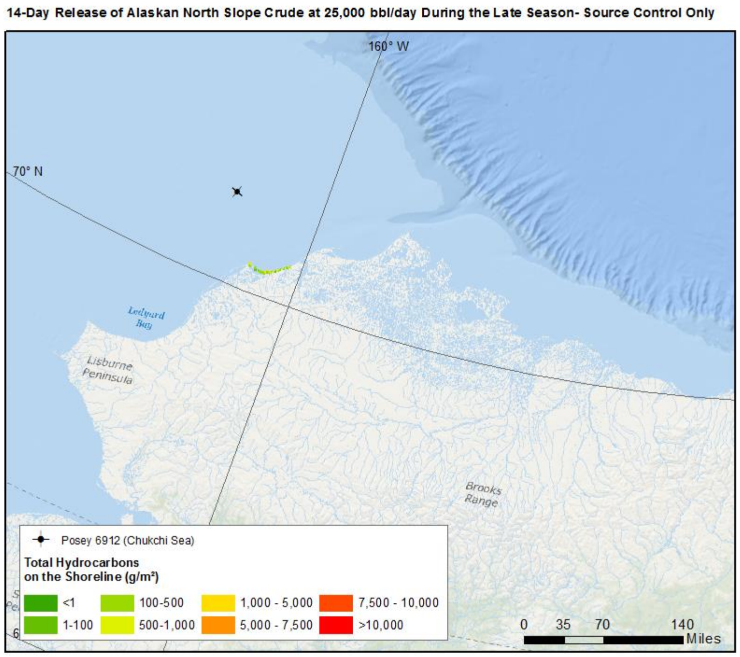


Figure 109: Scenario 9, Arctic-P6912 Late Season Source Control – Floating Oil on Water Surface (g/m^2) at Day 5

The minimum travel time for contact to shorelines was 19 days, with substantial shoreline impacts beginning after 42 days of the start of the discharge. At the end of the simulation, there was a limited amount of shoreline oiling over 1 g/m^2 along the Alaska coast with more oiling along the Russian coast (Figure 110).



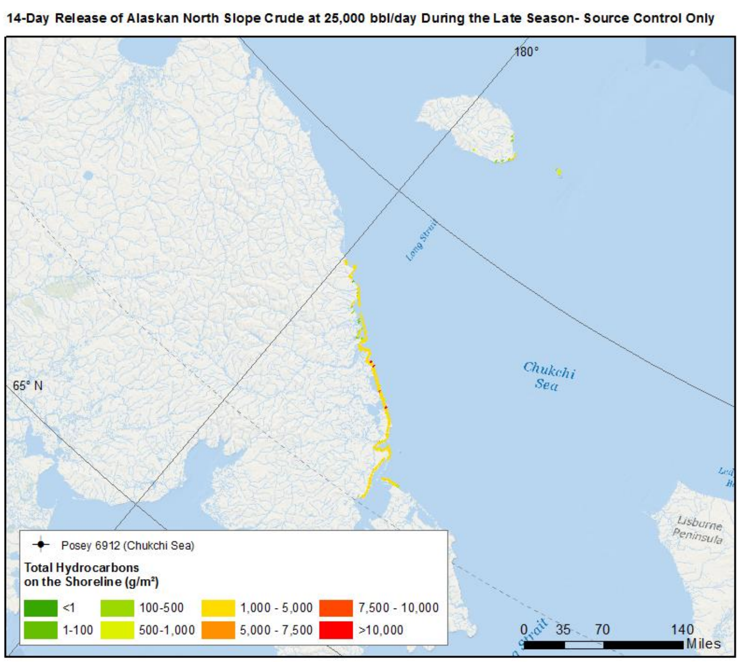


Figure 110: Scenario 9, Arctic-P6912 Late Season Source Control, 14-Day Discharge – Shoreline Oil ≥1 g/m^2, including Weathered Tarballs

Application of Response Countermeasures

Countermeasure Response Divisions

The following equipment types were employed in each of the following countermeasure response divisions, and are shown in Figure 99.

- High Volume Recovery Division – High volume mechanical recovery operations were employed beyond a 3.5 mile (3 nm) radius area established around the well for source control.
- In situ Burning Division – In situ burning operations were used in the same geographical area as the high volume mechanical recovery operations (3.5 mile [3 nm]) away from the source control area.
- Nearshore Recovery Division – Nearshore mechanical recovery operations were used to remove oil from the surface of the water before it was washed onto shorelines.
- Dispersant Application Division – Surface applied dispersants were employed in the High Volume Recovery Division to 3.5 mile (3 nm) from shore and beyond a 3.5 mile (3 nm) radius area established around the well for source control, as appropriate.

Subsurface dispersants, which were applied at the point of discharge in the vicinity of the wellhead, are not shown in Figure 99 or assigned to a geographic response division.

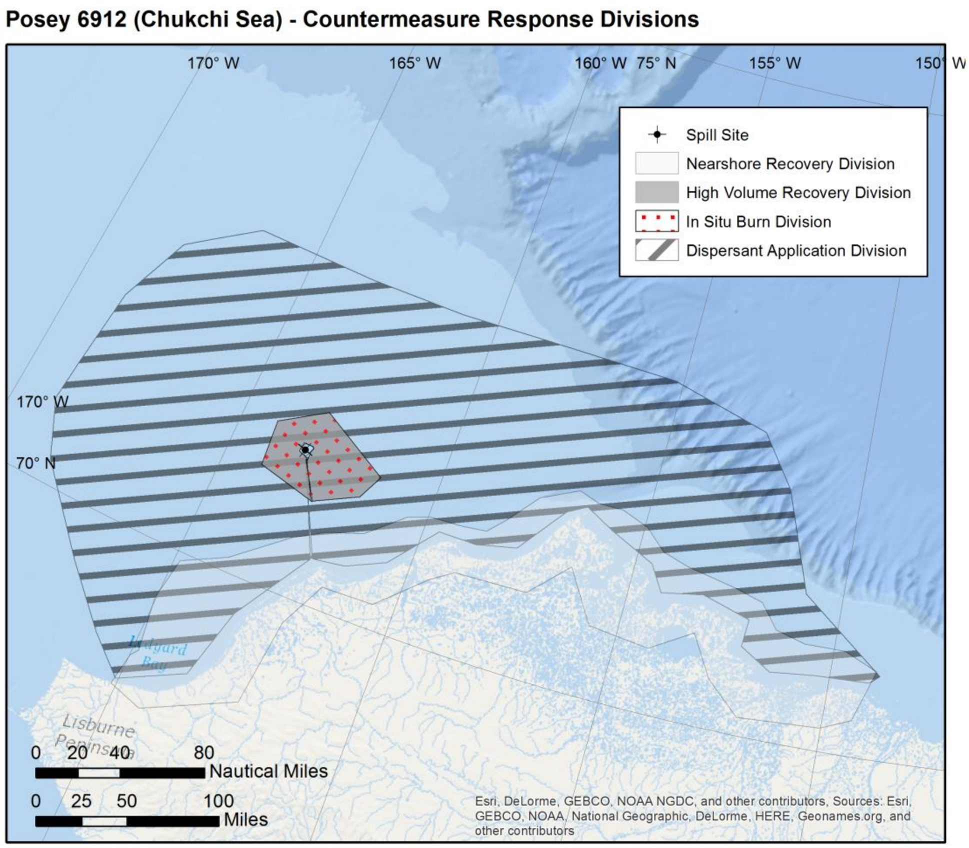


Figure 111: Scenario 9, Arctic-P6912 Late Season – Geographic Coverage of Oil Countermeasure Response Divisions

The size and placement of the Arctic-P6912 response operation divisions in the model were developed based on a review of the oil spill trajectories from the 14-day discharge in the Source Control simulation.

Countermeasure/Division Removal Rates (Model Inputs)

The removal rates by countermeasure type and response division that are shown in Table 72 represent the *maximum* potential rate that would be available at any point during the response operation.

As in an actual oil spill response operation, the model cascades response equipment into the response divisions as the assets arrive on the scene. The modeling reflects response equipment threshold values and limitations based on the availability of the response equipment to be deployed to the location of the appropriate divisions. As such, the model used oil removal rates for each division (i.e., SIMAP model polygon), based on the maximum potential daily removal rates (bbl/day) of the assigned asset (refer to Table 72), corrected by weather restrictions and daylight operations (as described in Section 1.8). Maximum removal rates are not realized in practice because of the limitations of weather delays, suspension of operations at night, the location of oil in relation to equipment, and performance thresholds, such as oil thickness on the water surface, sea state and currents, winds, oil viscosity and water content during oil emulsification.

These maximum rates are not necessarily applicable for the entire response period. This is because equipment cascades in at different times, and in some cases, resources are allocated to different applications. For example, in this WCD scenario, in situ burning could be conducted in a relatively small area only and was limited by both availability of fireboom and other equipment, as well as thresholds for wave height, winds, viscosity, and thickness of oil on the water surface were reached.

Table 72: Maximum Potential Daily Oil Removal Rates for Arctic-P6912-Late Season SC+MR+D+ISB Response Scenario [a]

Countermeasure Type	Response Division	Response System Category [b]	Removal Rate Applied [c]	Maximum Potential Daily Removal Rates (bbl/day)
Mechanical	**High-Volume**	Skimmer Group A	ERSP Day-1	16,363
		Skimmer Group C	ERSP Day-1	44,785
	Nearshore	Skimmer Group A	ERSP Day-3	1,168
	Total	**All Mechanical Countermeasures**		**62,316**
In Situ Burning	**High-Volume In Situ Burning**	In Situ Burning	Based on ISB Calculator	5,484
Surface Dispersant	**High-Volume and Dispersant Application**	Surface Dispersants	Based on DMP2	6,191
Subsurface Dispersant	**Wellhead**	Subsurface Dispersant	Based on a DOR of 1:100	24,000
Total		**All Countermeasures**		**97,991**

[a] Arctic-P6912-Late Season SC+MR+D+ISB+SubD Response Scenario by countermeasure type and response division *without* application of weather restrictions.

[b] The characteristics of the different types of mechanical equipment and the specific pieces of equipment applied in this scenario are described in Section 2.1. The viscosity thresholds for different types of equipment are further described in Section 1.8.2.

[c] ERSP is described in Section 5.0. "ERSP Day-1" rates are the higher removal rates applied in the areas and times when the oil was flowing from the well and the oil is the thickest. "Day-1" does not necessarily indicate that this is only applied for the first day. "ERSP Day-3" rates are applied in the areas more distant from the well where the oil is thinner and more spread out making removal less efficient. "Day-3" does not necessarily indicate that this is the third day of the response.

For Scenario 9, Arctic-P6912 Late Season, response operation divisions are cascaded in over the course of the initial 14 days (as depicted in Figure 112). Oil reached the surface after approximately one hour.

Two separate dispersant response simulations were modeled for the Arctic-P6912 Late Season scenario: Surface-Only dispersant response and Surface and Subsurface dispersant response.

In the Surface-Only dispersant response simulation, application began on day 3 due to logistical constraints and expected time to secure regulatory approvals for dispersant use.[25] An average of 65,500 gallons of dispersant was applied each day, between day 3 and discharge shutdown on day 14. A total of 768,000 gallons of dispersant was used in the Surface-Only dispersant response simulation.

[25] With pre-approval of dispersant use at this site, dispersant application could have started on Day 2

In the Surface and Subsurface dispersant response simulation, both aerial spraying and subsurface pumping began on day 3, with 13,000 gallons/day of surface dispersant and 10,500 gallons/day of subsurface dispersant applied for 12 consecutive days (until the discharge was brought under control on day 14). A total of 282,000 gallons of dispersant was applied in the Surface and Subsurface dispersant response simulation.

Scenario 9, Arctic-P6912 Late Season, is a relatively small WCD, and a 7-gpm pump rate was modeled for subsurface dispersant application. The 7-gpm pump is sufficient to treat 100% of the 25,000 bbl/day flow. Use of a higher rate subsurface pump (such as the 10-gpm pumps used in the Gulf of Mexico WCD scenarios) would have resulted in more than 100% theoretical oil treatment.

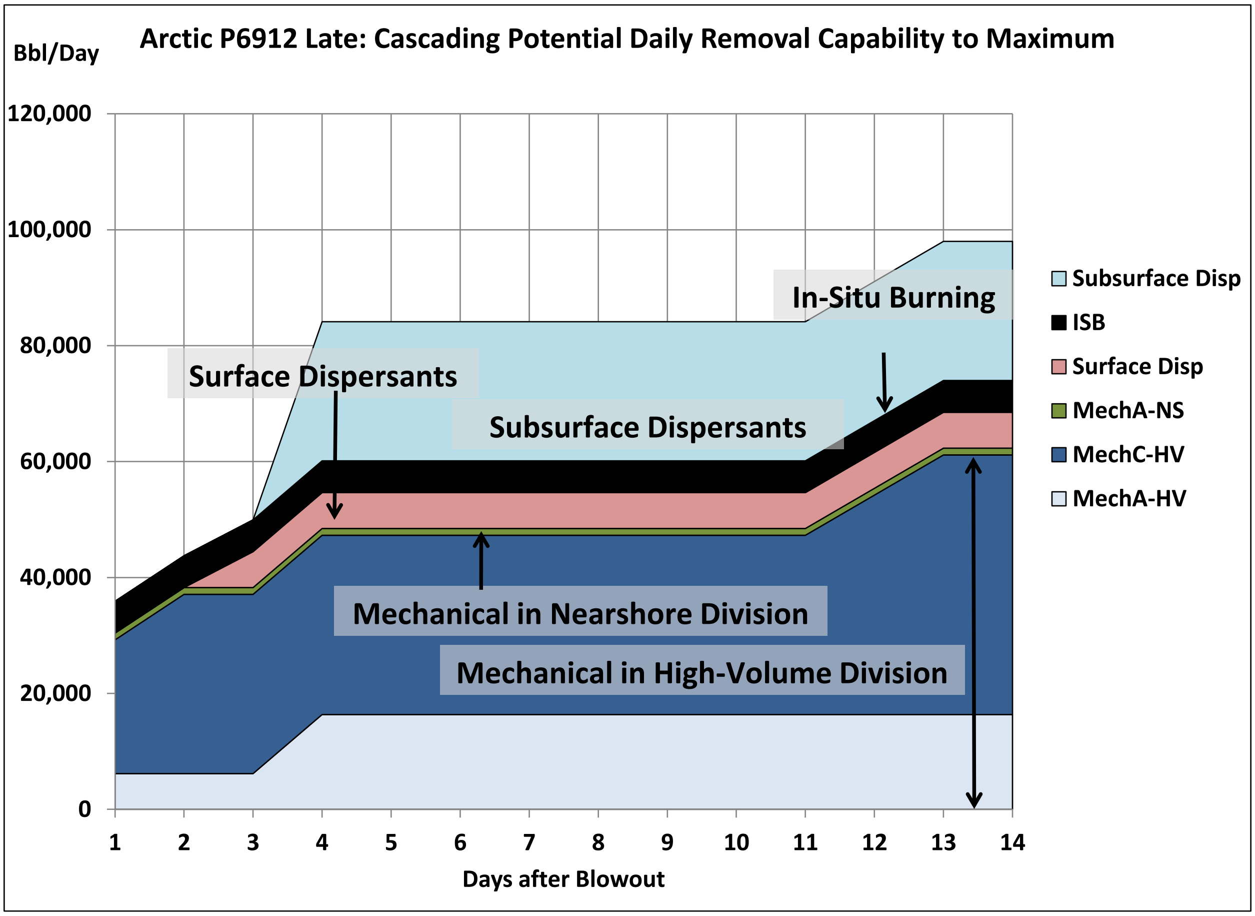


Figure 112: Scenario 9, Arctic-P6912 Late Season SC+MR+D+ISB+SubD – Cascading SC+MR+D+ISB+SubD Response Assets and Cumulative Potential Daily Removal Capacity

Countermeasure Simulation Results & Analysis

Achieved Removal versus Potential Equipment Capabilities

Maximum potential removal rates of oil removal systems are not achieved due to the limitations on countermeasures resulting from oil weathering and other environmental factors (such as increased sea state and darkness which often limited when the countermeasures could be applied). For the Arctic-P6912 Late Season SC+MR+D+ISB+SubD simulation, weather restrictions were in effect for 62.5% of the time for surface applied countermeasures, and for most equipment, the operating period was limited to

12 hours of daylight (other equipment limitations applied are listed in Table 10, Table 12, and Table 13). Because of these thresholds and limitations, as well as the availability of recoverable, burnable, or dispersible oil in the response divisions, achieved oil removal was significantly less than the potential recovery capabilities (Table 73, Figure 113, and Figure 114) as shown in for the Arctic-P6912 Late Season SC+MR+D+ISB+SubD simulation.

Table 73 shows the system potential with regard to barrels of oil that could be treated or removed based on the sum total of removal/treatments rates over the course of the entire response operation (i.e., during the release of oil from the well and for an additional 45 days after source control is achieved to stop the flow of oil). The "achieved" removal or treatment reflects the sum total of oil removed or treated over the course of the response operations. Figure 113 contrasts the sum total of potential removal/treatment over the course of the operations and the sum total of the achieved removal/treatment. The daily well flow is shown as a benchmark. The potential removal/treatment capability greatly exceeds the achieved removal/treatment due to the various environmental and logistical factors that limit performance.

Table 73: Scenario 8, Arctic-P6912-Late Season - SC+MR+D+ISB+SubD Cumulative System Potential Oil Recovery versus Achieved Oil Recovery over 59-Day Simulation

Response Type	Response Division	Response System Type	Total Removal/Treatment		
			System Potential (bbl)	Achieved (bbl)	% Potential [a]
Mechanical [b]	**High-Volume**	Skimmer Group A	425,831	16,324	**3.8%**
		Skimmer Group C	980,401	0	0.0%
	Nearshore	Skimmer Group A	65,397	0	0.0%
	Mechanical Total	**All**	**1,471,629**	**16,324**	**1.1%**
In Situ Burning [c]	**High-Volume In Situ Burning**	-	307,104	5,368	1.7%
Surface Dispersants	**Dispersant Application**	-	74,292	5,172	7.0%
Subsurface Dispersants	**Wellhead**	-	264,000	51,955	19.7%
All Categories	**All**	**All**	**2,117,025**	**78,819**	**3.7%**

[a] Achieved Total Recovery divided by System Potential Total Recovery as percentage.

[b] ERSP Day-1 rates assumed for High-Volume Division until well capping (source control); ERSP Day-3 rates assumed for Nearshore Division, and for High-Volume Division after day 14 source control.

[c] EBSP Day-1 rates assumed until day 14 source control, after which EBSP Day-3 rates were applied.

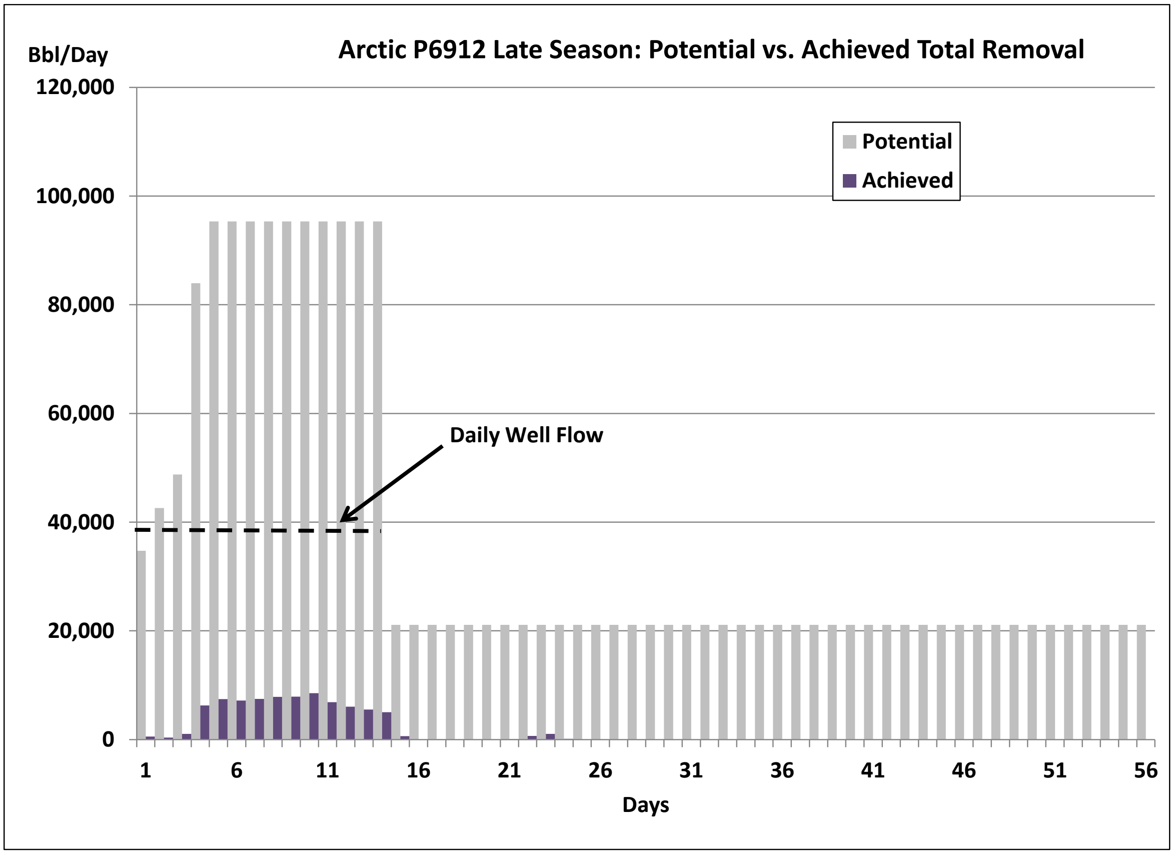


Figure 113: Scenario 9, Arctic-P6912 Late Season - SC+MR+D+ISB+SubD Total Oil Removal System Potential and Achieved Total Daily Removal

Figure 113 contrasts the amount of oil flowing from the well on a daily basis along with the maximum potential daily capability per day, as well as the achieved average daily removal rate. The achieved average daily removal rate is lower than the potential daily removal rate for each day of the scenario.

During the response period, some systems have very low or near-zero removal for some periods because of performance limitations due to environmental conditions, or because there is insufficient oil available

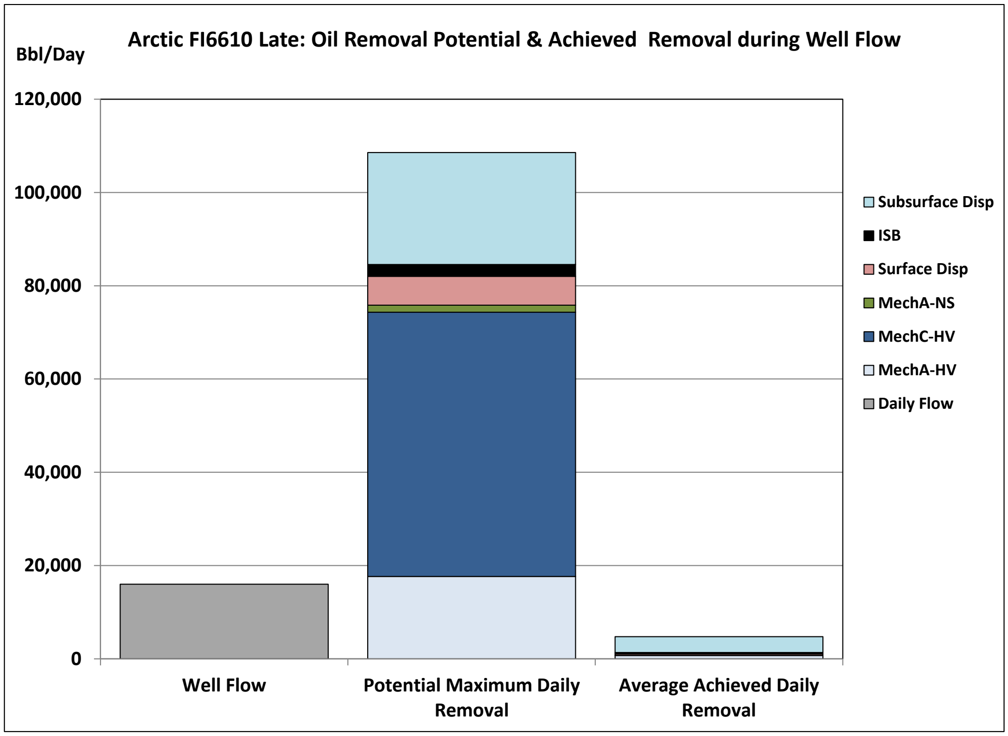


Figure 114: Scenario 9, Arctic-P6912 Late Season SC+MR+D+ISB Total Maximum Oil Removal System Potential and Achieved Removal Compared with Well Flow during 14-Day Discharge Period

Oil Removal by Countermeasure Type

Table 74 is a summary of model results for the various response countermeasures applied to the Arctic-P6912 Late Season scenario. This table allows for comparison of the oiling and oil removal by each countermeasure across the various model simulations. Values within Table 74 represent the volume of oil present/removed at the completion of the response scenarios (59 days).

Table 74: Scenario 9, Arctic-P6912 Late Season – Comparison of Shoreline Oiling and Oil Removal for the Relief Well Only Scenario and Four Response Scenarios at the End of the Model Simulations

Scenario	Volume (bbl) of Discharge	Volume (bbl)/ Percent of Oil on Shoreline	Volume (bbl)/ Percent Removed by Skimming	Volume (bbl)/ Percent Dispersed	Volume (bbl)/ Percent Removed by Burning	Volume (bbl)/ Percent Bio-degraded or in Sediments
Relief Well Only, 28 Day Discharge	700,000	57,162				176,785
Source Control (SC), 14 Day Discharge	350,000	32,295 9%				83,128 24%
Source Control and Mechanical Recovery (SC+MR)	350,000	32,598 9%	17,8667 5%			75,389 22%
Source Control, Mechanical Recovery and Surface Dispersant (SC+MR+D)	350,000	29,515 8%	17,199 5%	20,575 6%		77,790 22%
Source Control, Mechanical Recovery, Surface Dispersant and In Situ Burning (SC+MR+D+ISB)	350,000	28,678 8%	15,614 5%	20,266 6%	5,056 1%	76,884 22%
Source Control, Mechanical Recovery, Surface Dispersant, In Situ Burning, Subsurface Dispersant (SC+MR+D+ISB+SubD)	350,000	21,832 6%	16,324 5%	72,221 21%	5,368 2%	89,855 26%

Scenario 9, Arctic-P6912 Late Season is a WCD from an offshore shallow-water well where mechanical recovery, surface dispersant and in situ burning all had similar percentages (≤8%) of oil removed or dispersed at the end of the model simulations. When used without the aid of other response operations, mechanical recovery was able to remove up to 5% of the oil discharged in this scenario.

Because of the very large High Volume Recovery Division area (25-40 miles surrounding the wellhead), available equipment is spread thin, and mechanical recovery volume is relatively low. Due to rapid oil weathering, Skimmer Group C mechanical recovery systems in this scenario are ineffective, even in the High Volume Area. There is no Secondary Mechanical Recovery Division. As the oil moves out of the High Volume Recovery Division, it is treated in the Dispersant Application Division by surface dispersants only. There was some additional mechanical recovery capability in the Nearshore Recovery Division, however, it was not effective due to oil weathering and spreading thin before reaching this zone.

When surface-applied dispersants were added, oil removed by mechanical recovery remained at 5%; however, an additional 6% of the oil was also dispersed into the water column thus causing less oil to reach the shoreline. When subsurface dispersants were added, oil removed by mechanical removal remained at 5%; however, 21% was also dispersed into the water column causing less oil to surface, reach the shoreline, or be evaporated.

In situ burning accounted for 1% of the oil removed when used, which is likely a reflection of the limited area where burning could be applied (e.g., restricted to the High Volume Recovery Division) in this scenario. In situ burning in this scenario was limited by the lack of suitable vessels for towing both enhanced encounter boom and fire boom at the same time. Additional fire boom could have been added had there been vessels available for towing it. In situ burn response was limited by the equipment thresholds for wave height, wind, and viscosity and thickness of oil on the water surface.

Figure 115 displays the fate of oil at the end of the 59-day simulation for Scenario 9, Arctic-P6912 Late Season involving source control, mechanical recovery, in situ burning, surface dispersants and subsurface dispersants (e.g., SC+MR+D+ISB+SubD).

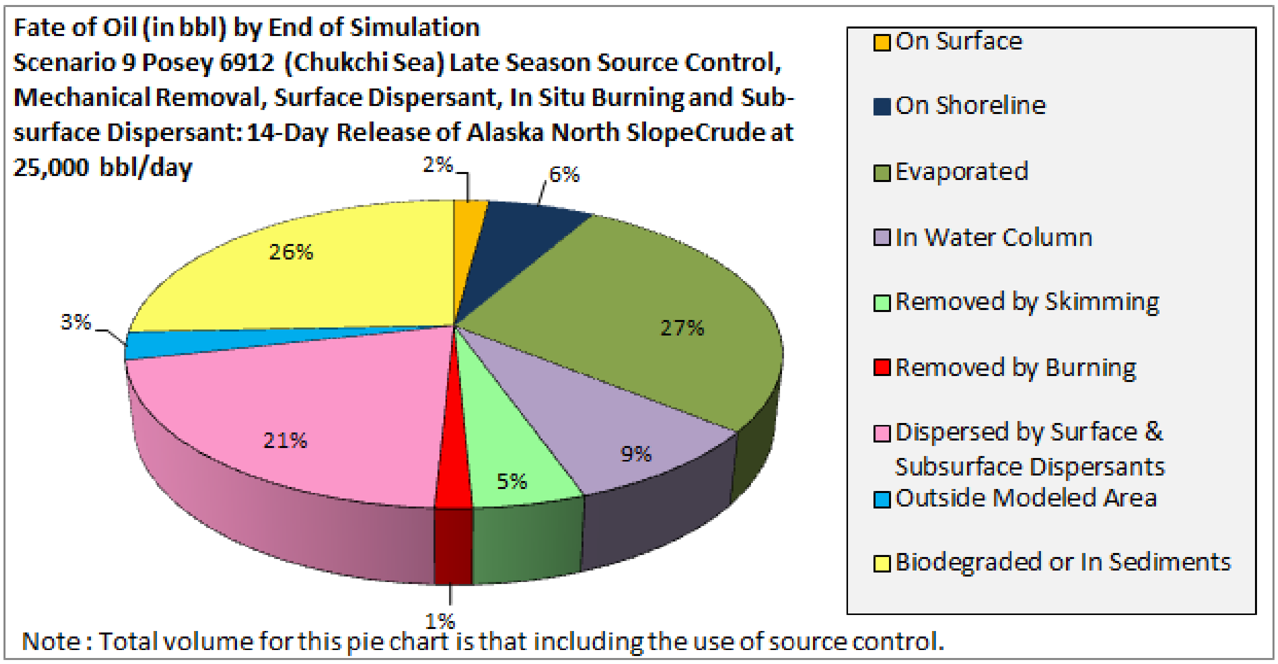


Figure 115: Scenario 9, Arctic-P6912 Late Season – Fate of Oil at End of 59-Day Simulation (Scenario includes Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning Response Operations)

Reductions in Surface and Shoreline Oiling

Table 75 provides a comparison of the shoreline and water surface oiling results for each of the Arctic-P6912 Late Season response countermeasure simulations.

Since two seasons (early and late) were modeled for the same Chukchi location, it is important to compare the two modeling scenarios. One specific difference is that, regardless of response countermeasure simulation, the early season scenario had significantly more cumulative surface area oiled by >8g/m^2 than the late season scenario (Table 75). On the other hand, the late season scenario had more entrainment and twice as much shoreline oiling as the early season scenario. This is a result of higher and more variable winds and seas, on average, observed during the late season scenario as compared to the early season scenario. The strong winds during the late season forced more oil to be entrained into the water column and moved by the currents and wind to create tarballs that reached the Alaskan and Russian shorelines. As shown in Figure 110, it should be noted that for this particular late season scenario in which source control only was applied, the majority of the shoreline oiling (≥1 g/m^2), including weathered tarballs, was along the Russian as opposed to Alaskan shoreline at the end of the simulation. In the early season scenario, all of the shoreline oiling ≥1 g/m^2 was along the Alaskan shoreline. This was again a result of the wind pattern observed during the late season as opposed to early season scenarios.

Table 75: Scenario 9, Arctic-P6912 Late Season – Comparison of Shoreline and Water Surface Oiling Above Equipment Threshold Values or Limitations

Scenario 9, Arctic-P6912 Early Season	Relief Well Only (WCD)	Source Control	Source Control and Mechanical Recovery	Source Control, Mechanical Recovery, and Surface Dispersant	Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning	Source Control with Mechanical Recovery, Surface and Subsurface Dispersant, and In Situ Burning
Volume (bbl) of Shoreline Oiling (to Any Degree)	57,162	32,295	32,598	29,515	28,678	21,832
Percent Reduction in Volume of Shoreline Oiled As Compared to Relief Well Only	-	44%	43%	48%	50%	62%
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	729	440	467	422	419	384
Percent Reduction in Shoreline Length Oiled with ≥1 g/m^2 As Compared to Relief Well Only	-	40%	36%	42%	43%	47%
Cumulative Area (mi^2) of Surface Affected by Oil ≥8g/m^2	786,343	468,027	460,035	381,144	377,353	179,818
Percent Reduction in Surface Affected by Oil ≥8g/m^2 As Compared to Relief Well Only	-	40%	41%	52%	52%	77%

Figure 116 is a visual depiction of the reduction in the surface area affected by ≥8.0 g/m^2 of oil over the 59-day period. The graphic directly compares the levels of maximum water surface oiling over time between the Source Control Only simulation and the simulation that adds mechanical recovery, surface and subsurface dispersants, and burning (SC+MR+D+ISB+SubD).

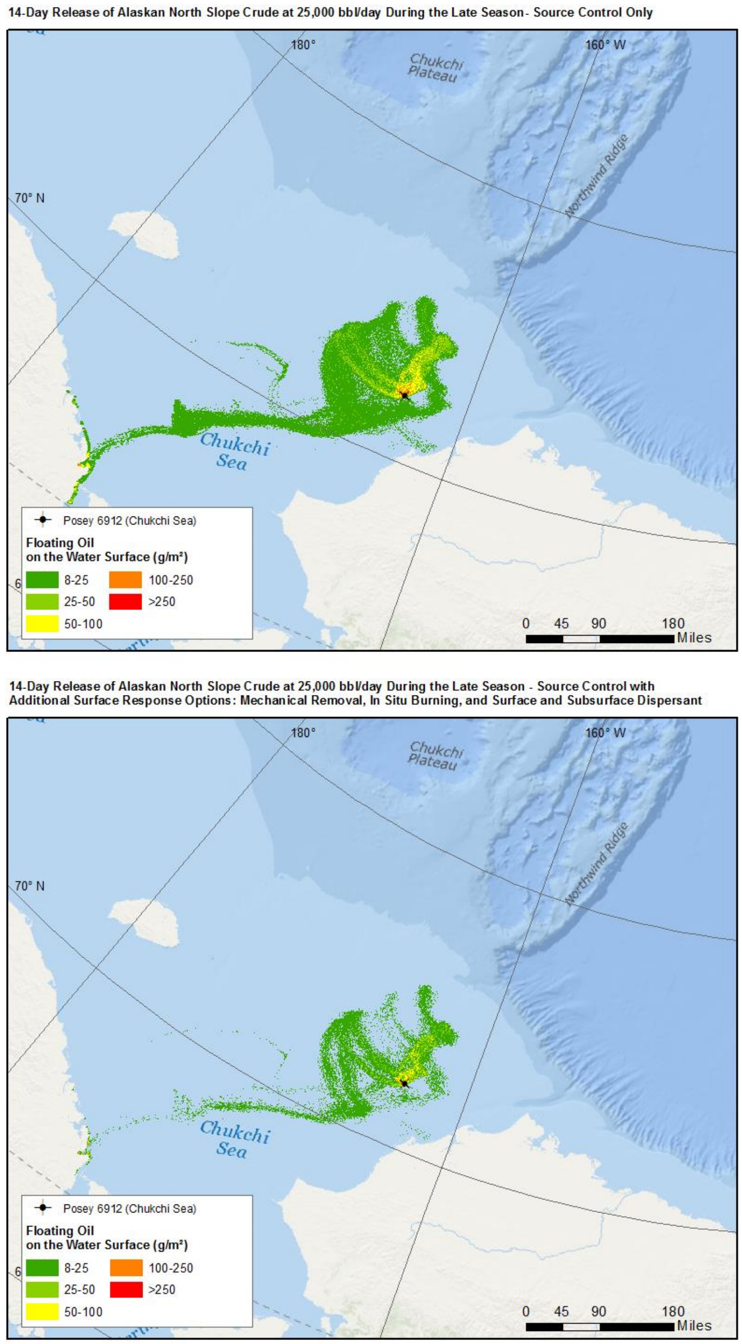


Figure 116: Scenario 9, Arctic-P6912 Late Season – Comparison Floating Oil Concentration (≥8.0 g/m^2) over 59-Day SIMAP Model Simulation, Top Panel: Source Control (SC), Bottom Panel: Source Control, Mechanical Recovery, Surface and Subsurface Dispersants, and In Situ Burning (SC+MR+D+ISB+SubD)

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2.3.2.3 *Scenario 10: Flaxman Island 6610 Early Season– Beaufort Sea*

Scenario Site Information

Flaxman Island 6610 (FI6610) is a nearshore (1.5-4.5 miles [1.3-3.9 nm] from shore) and shallow-water (160 ft) well in the Beaufort Sea Planning Area. In the event of a worst case discharge at this site, there is a high probability for rapid, significant shoreline contact (see Table 76 and Figure 117) if spill response countermeasures are not immediately taken. Based on 100 stochastic model runs, the worst case release date for the Flaxman Island 6610 WCD early season scenario was July 11, 2012.

Table 76: Scenario 10, Arctic-FI6610 Early Season – Well Information and Shoreline Contact Times

WCD Scenario Parameters	
Discharge Flow Rate	16,000 bbl/day
WCD Duration	30 days, Relief Well Only 14 days, Source Control
Total WCD Release Volume	480,000 bbl Relief Well Only 224,000 bbl Source Control
Simulation Duration (45 days following end of discharge)	75 days, Relief Well Only 59 days, Source Control
Oil Type	Alaskan Prudhoe Bay Crude
API Gravity	24.8
Viscosity @ 15^{o}C (cp)	38.9
Latitude, Longitude	70.227^{o}N / 146.0186^{o}W
Depth to Sea Floor	160 ft
Distance to Shoreline	4.5 miles (3.9 nm) to mainland, 1.5 miles (1.3 nm) to coastal barrier islands
SIMAP Model Results [a]	
Time for oil above 1 g/m^2 to reach shore [b]	1 day
Time for oil greater than 8 g/m^2 to reach shore [c]	1 day, Figure 117
[a] SIMAP model results presented in this table are based on the 100 stochastic model runs. [b] The 1 g/m^2 value is the threshold for socio-economic resource effects (e.g., closure of fisheries) (French-McCay et al. 2011; French McCay et al. 2012) [c] The 8 g/m^2 value is the minimum thickness of floating oil for which response equipment can be effectively used (NOAA 2010)	

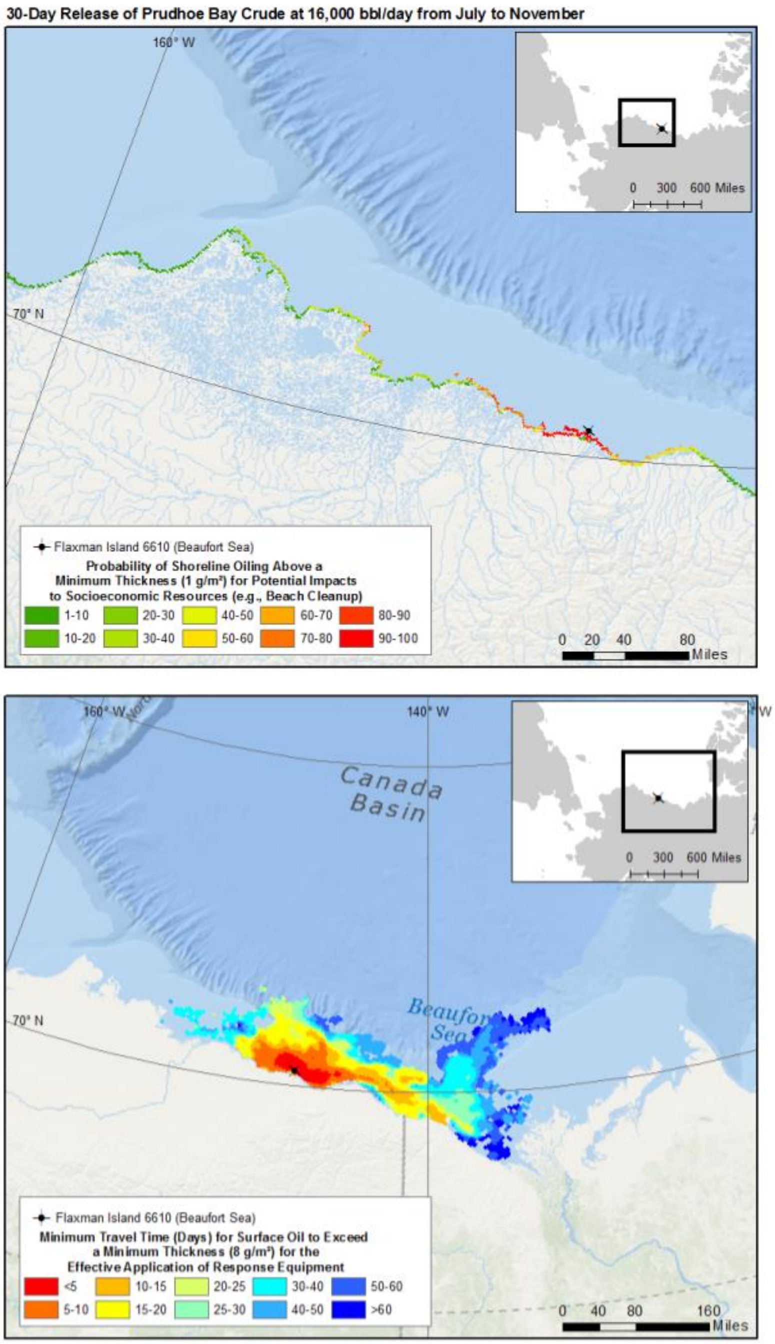


Figure 117: Scenario 10, Arctic-FI6610 Early Season Relief Well Only Scenario, 30-Day Discharge – Probability of Shoreline Oiling and Minimum Travel Times for Surface Oiling

Application of Source Control

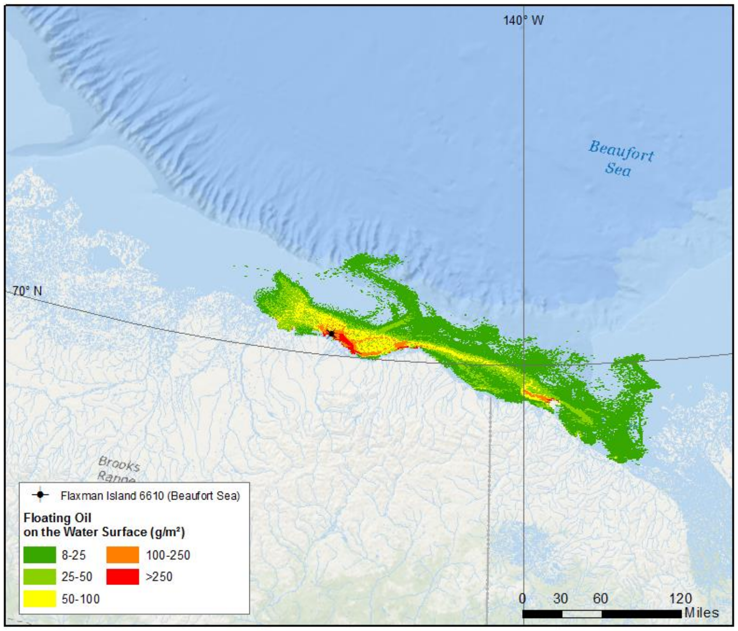
When a source control operation is modeled for the WCD Arctic Flaxman Island 6610 Early Season scenario, the discharge period is reduced by 16 days and the volume of oil released to the environment is reduced by 256,000 bbl. Correspondingly, source control results in substantially less impact to the water column and shoreline in comparison to the Relief Well Only simulation. Table 77 and Figure 118 compare discharge volume, shoreline-oiling volume, length of oiled shoreline, area of surface oiling, and the amount of oil biodegraded or in the sediments for the Relief Well Only and Source Control modeling simulations.

Table 77: Scenario 10, Arctic-FI6610 Early Season – Comparison of Relief Well Only and Source Control Response Scenarios

Scenario 10, Arctic-F6610 Early Season	Relief Well Only (30-day flow duration)	Source Control (14-day flow duration)	Reduction Due to Source Control	Percent Reduction Due to Source Control
Volume Discharged (bbl)	480,000 bbl	224,000 bbl	256,000 bbl	53 %
Volume Shoreline Oiling (bbl) any thickness	146,190 bbl	71,283 bbl	74,907 bbl	51 %
Total Length (mi) of Shoreline Oiled with ≥1g/m²	782 mi	353 mi	429 mi	55 %
Cumulative Area (mi²) of Surface Oiling ≥8g/m²	418,712 mi²	147,689 mi²	271,023 mi²	65 %
Amount Biodegraded or In Sediments (bbl) at the End of the Simulation	152,803 bbl	64,572 bbl	88,231 bbl	58 %

As shown in Figure 118, the volume and spread of oil spilled from this WCD is reduced by a source control intervention on Day 14; however, without the application of additional response operations to remove or mitigate spilled oil on the surface, the expected contact and exposure to oil in the environment still occurs in sensitive regions.

30-Day Release of Prudhoe Bay Crude at 16,000 bbl/day During the Early Season- Relief Well Only (WCD)



14-Day Release of Prudhoe Bay Crude at 16,000 bbl/day During the Early Season- Source Control Only

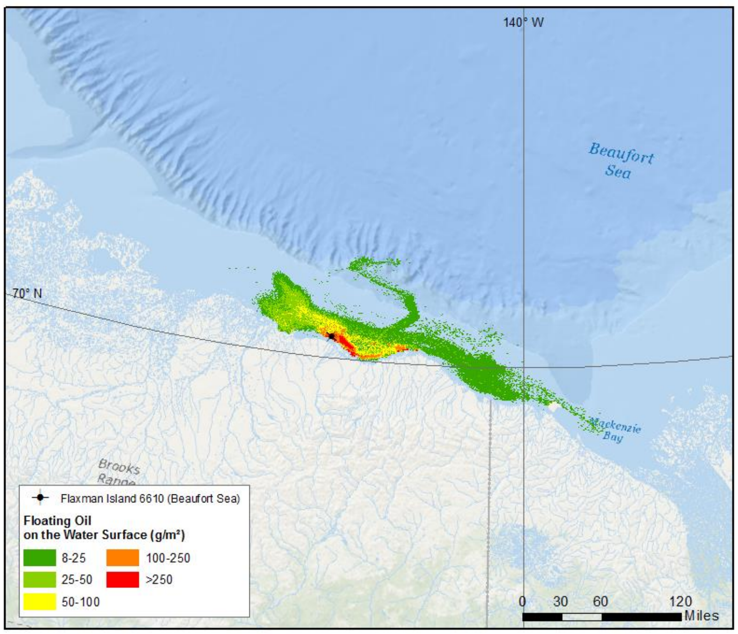


Figure 118: Scenario 10, Arctic-FI6610 Early Season– Comparison of Maximum Concentrations of Surface Oiling Experienced Throughout Simulation Periods for Relief Well Only (30-Day Discharge) and Source Control (14-Day Discharge)

Oil Discharge Behavior

Figure 119 shows the fate of oil for 59 days from the beginning of the discharge (14-day discharge duration and 45 days following the source control). At the end of the simulation, 32% of the oil remained on the shoreline, 29% biodegraded or remained in the water column and sediments, 28% percent of the total oil had evaporated, and 11% of the oil remained floating on the surface. Note that the model does not simulate potential photooxidation of floating oil.

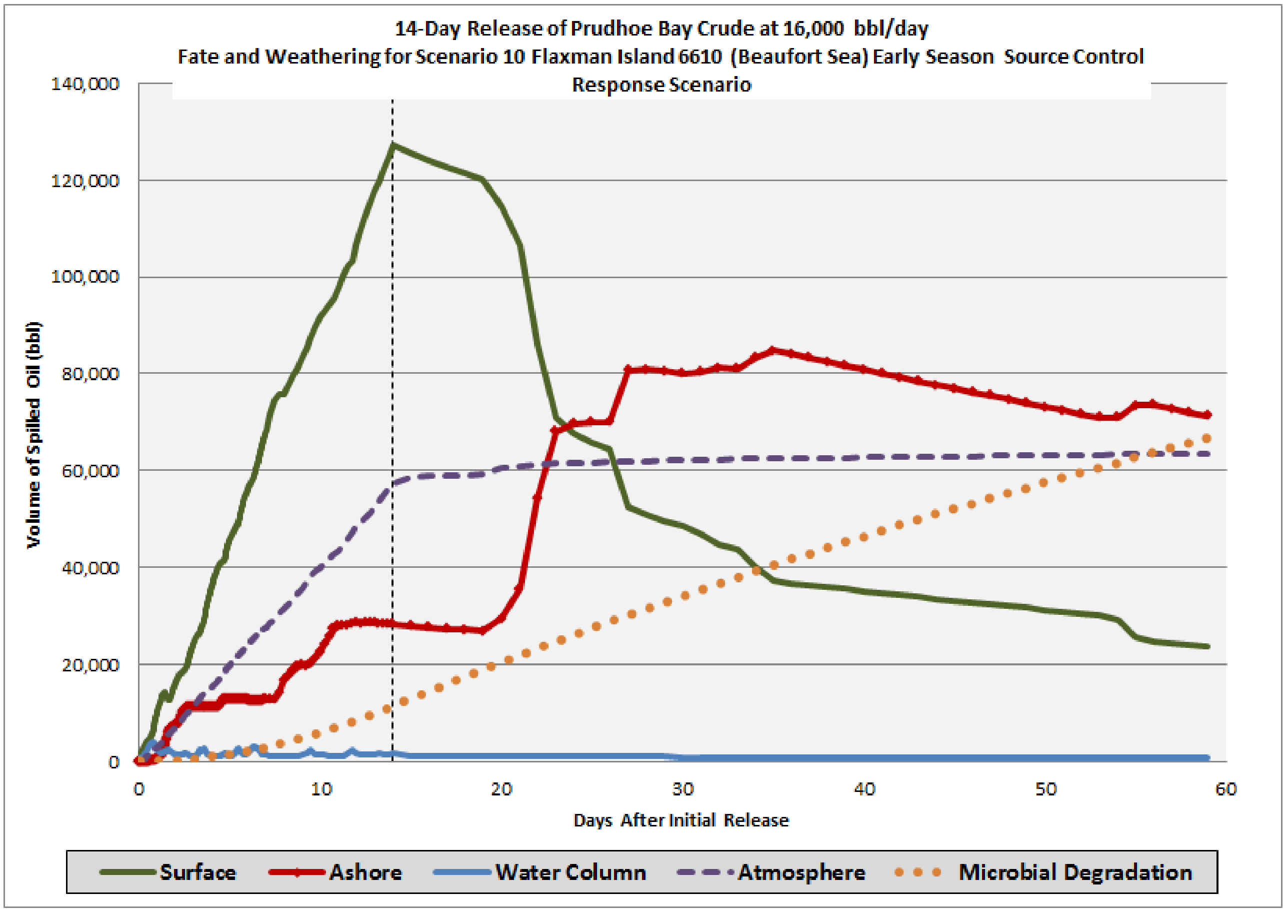


Figure 119: Scenario 10, Arctic-FI6610 Early Season Source Control, 14-Day Discharge – Oil Fate and Weathering (Dotted Vertical Line Indicates Source Control on Day 14)

In the Arctic-FI6610 Early Season Source Control, 100% of the total oil mass discharged from the blowout reached the surface. Upon release from the blowout, oil droplets took less than one hour to reach the surface, with most surfacing in the immediate vicinity of the well location.

For the first 14 days after oil the initial discharge of oil, the winds remained relatively calm (<10 knots) and moved the oil toward the east of the well location. During those first 14 days, the oil that could be recovered or treated (at viscosities <20,000 cST) remained within the High Volume Recovery Division. By the end of day 7, large patches of weathered oil with viscosities ranging from 30,000-50,000 cST stretched out as far as 50 miles from the well site in the Dispersant Application Division and Nearshore Recovery Division (Figure 120 and Figure 121). After day 14, the wind shifted directions and moved to the weathered oil that was too viscous to be treated or recovered to the west, northwest and northeast of the well location in and around the Nearshore Recovery Division and the Dispersant Application Division. Due to this oil's tendency to weather quickly beyond the thresholds for mechanical recovery or dispersants (usually one to two days), and the winds and currents in this simulation, the majority of the mechanical removal and surface dispersant that were applied occurred within the High Volume Recovery Division.

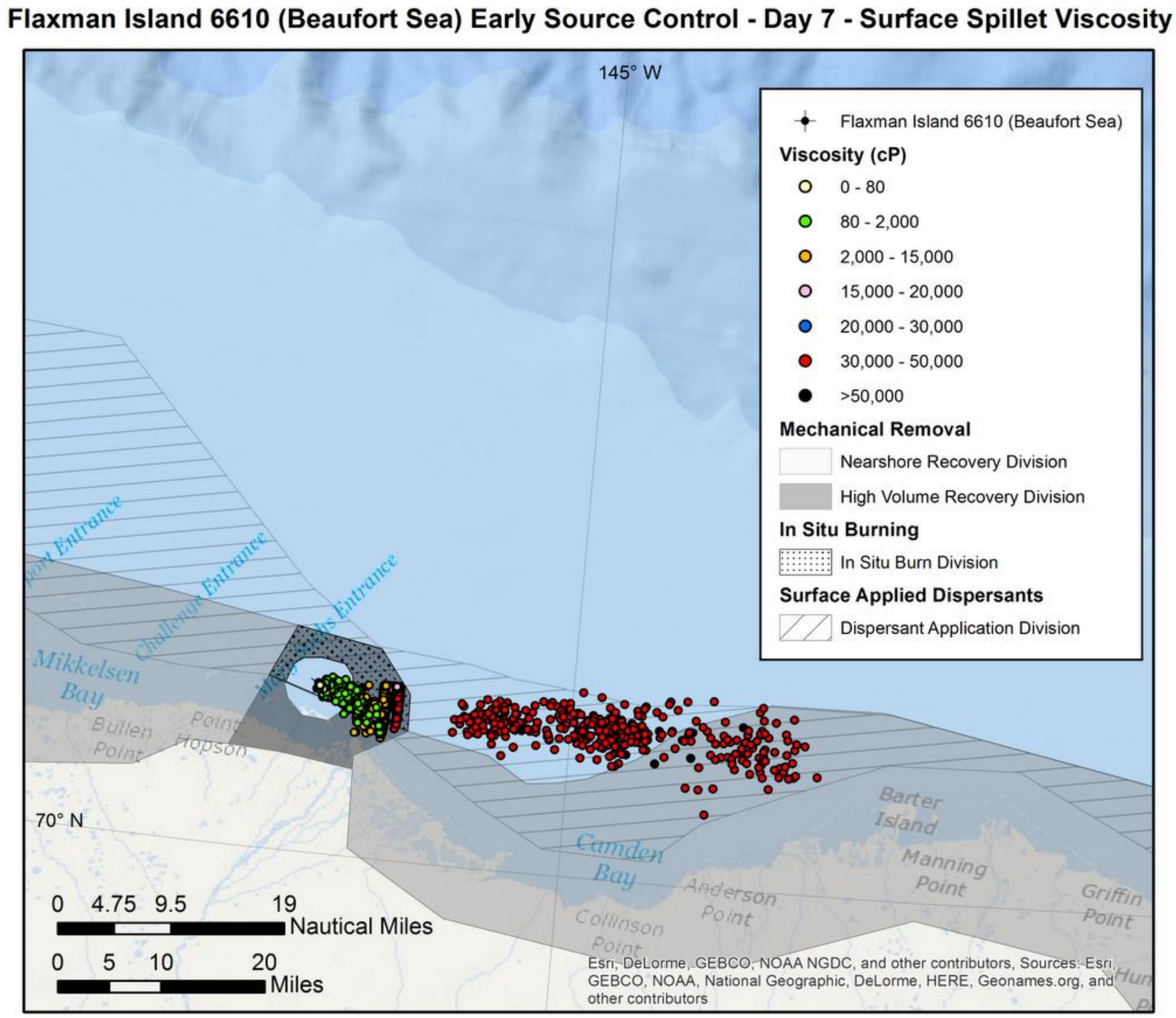


Figure 120: Scenario 10, Arctic-FI6610 Early Season Source Control – Surface Spillet Viscosity (cp) at Day 7

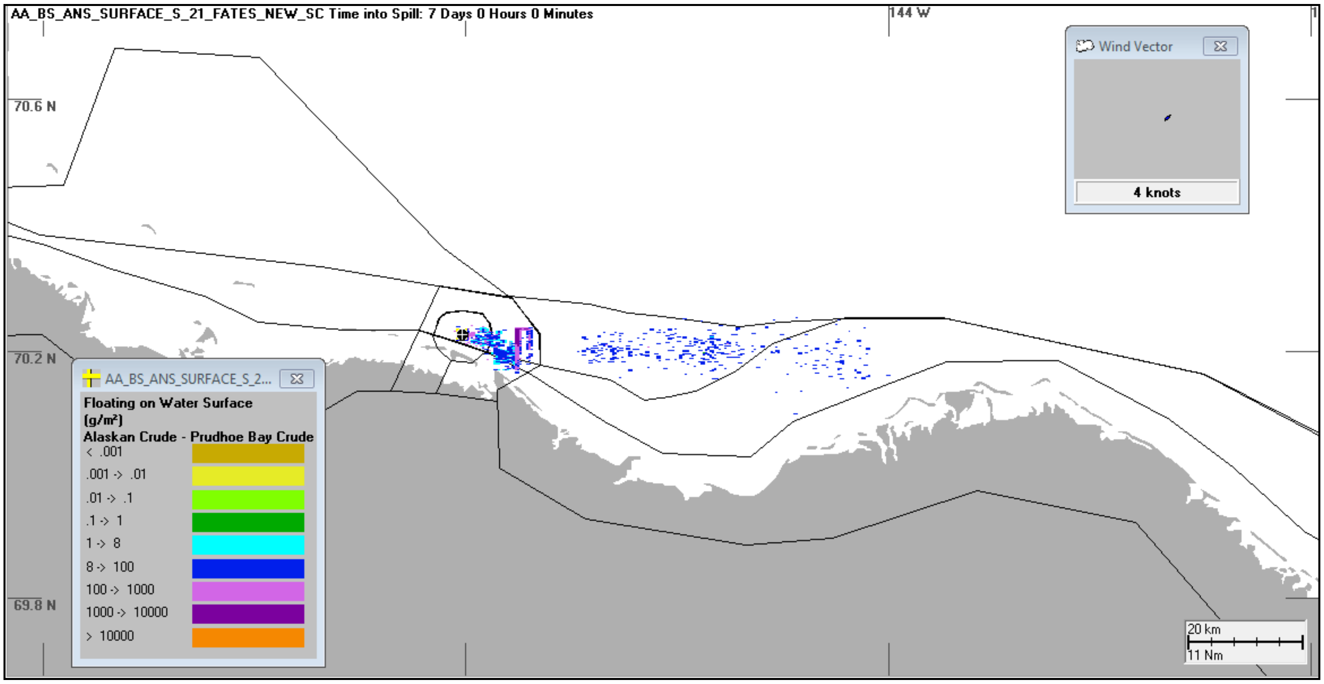


Figure 121: Scenario 10, Arctic-FI6610 Early Season Source Control – Floating Oil on Water Surface (g/m^2) at Day 7

Minimum travel time for contact to shorelines is 8 hours, with substantial shoreline impacts beginning after 24 hours of the start of the discharge. At the end of the simulation, the majority of the shoreline oiling over 1 g/m^2 is along the Alaskan and Canadian coast (Figure 122).

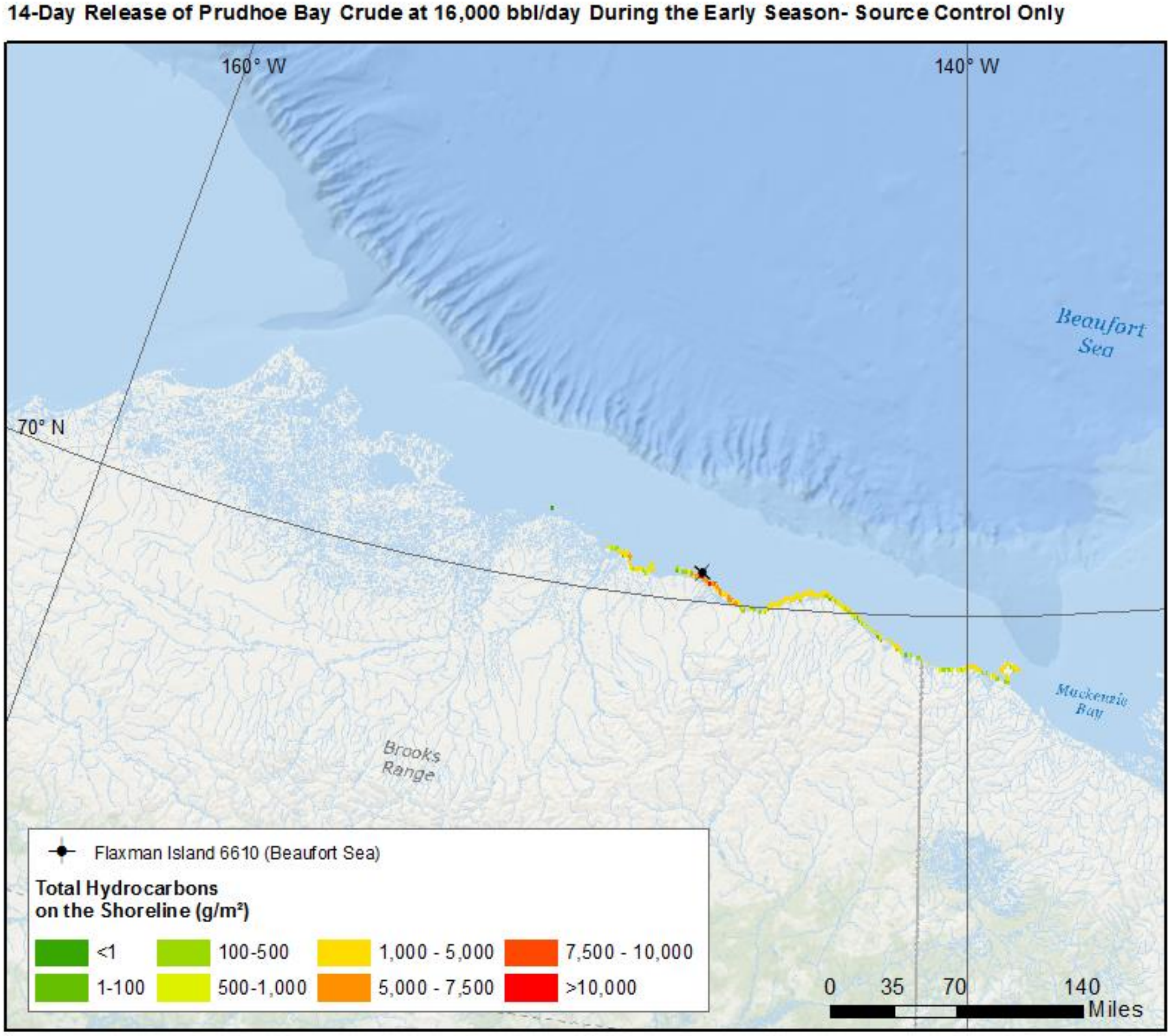


Figure 122: Scenario 10, Arctic-FI6610 Early Season Source Control, 14-Day Discharge – Shoreline Oil ≥1 g/m^2, including Weathered Tarballs

Application of Response Countermeasures

Countermeasure Response Divisions

The following equipment types were employed in each of the following countermeasure response divisions, and are shown in Figure 123.

- High Volume Recovery Division – High volume mechanical recovery operations were employed beyond a 3.5 mile (3 nm) radius area established around the well for source control.
- In situ Burning Division – In situ burning operations were used in the same geographical area as the high volume mechanical recovery operations (3.5 mile [3 nm]) away from the source control area.
- Nearshore Recovery Division – Nearshore mechanical recovery operations were used to remove oil from the surface of the water before it was washed onto shorelines.

- Dispersant Application Division – Surface applied dispersants were employed in the High Volume Recovery Division to 3.5 mile (3 nm) from shore and beyond a 3.5 mile (3 nm) radius area established around the well for source control, as appropriate.

No subsurface dispersants were applied in the Arctic-FI6610 Early Season scenario.

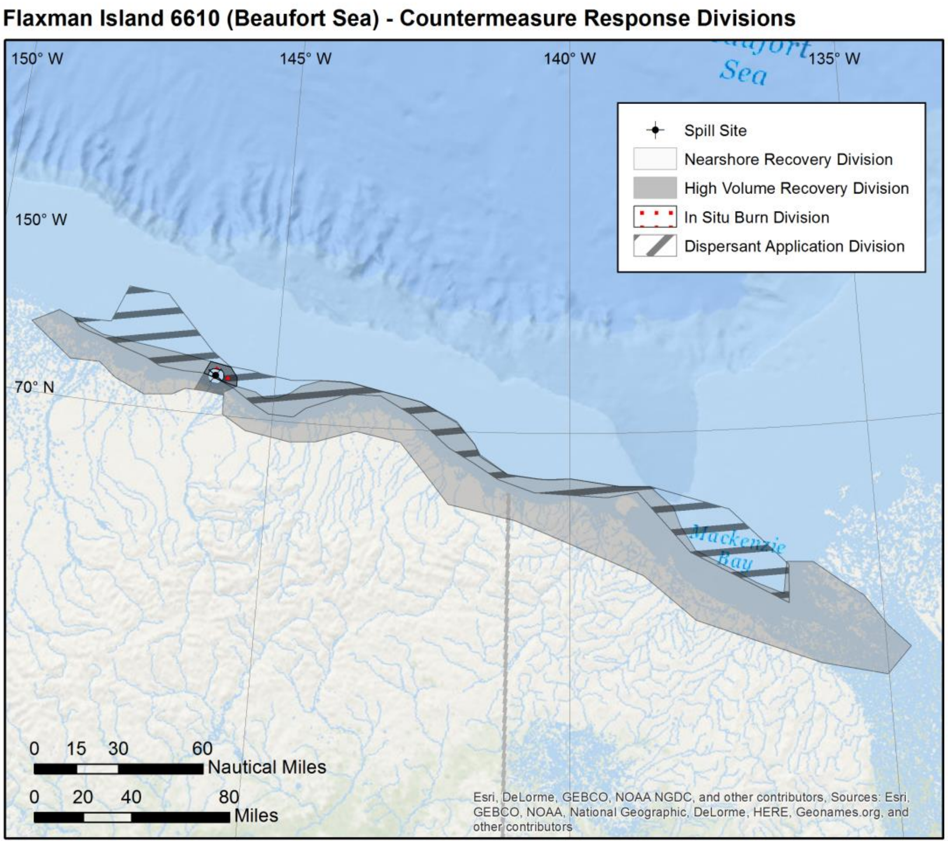


Figure 123: Scenario 10, Arctic-FI6610 Early Season – Geographic Coverage of Oil Countermeasure Response Divisions

The size and placement of the Arctic-FI6610 response operation divisions in the model were developed based on a review of the oil spill trajectories from the 14-day discharge in the Source Control simulation.

Countermeasure/Division Removal Rates (Model Inputs)

The removal rates by countermeasure type and response division that are shown in Table 78 represent the *maximum* potential rate that would be available at any point during the response operation.

As in an actual oil spill response operation, the model cascades response equipment into the response divisions as the assets arrive on the scene. The modeling reflects response equipment threshold values and limitations based on the availability of the response equipment to be deployed to the location of the appropriate divisions. As such, the model used oil removal rates for each division (i.e., SIMAP model polygon), based on the maximum potential daily removal rates (bbl/day) of the assigned asset (refer to Table 78), corrected by weather restrictions and daylight operations (as described in Section 1.8). Maximum removal rates are not realized in practice because of the limitations of weather delays, suspension of operations at night, the location of oil in relation to equipment, and performance thresholds, such as oil thickness on the water surface, sea state and currents, winds, and water content during oil emulsification.

Table 78: Maximum Potential Daily Oil Removal Rates for Arctic-FI6610-Early Season SC+MR+D+ISB Response Scenario [a]

Countermeasure Type	Response Division	Response System Category [b]	Removal Rate Applied [c]	Maximum Potential Daily Removal Rates (bbl/day)
Mechanical	**High-Volume**	Skimmer Group A	ERSP Day-1	17,655
		Skimmer Group C	ERSP Day-1	56,662
	Nearshore	Skimmer Group A	ERSP Day-3	1,500
	Total	**All Mechanical Countermeasures**		**76,817**
In Situ Burning	**High-Volume In Situ Burning**	In Situ Burning	Based on ISB Calculator	2,742
Surface Dispersant	**High-Volume and Dispersant Application**	Surface Dispersants	Based on DMP 2	18,571
	Total	**All Countermeasures**		**98,130**

[a] Arctic-FI6610-Early Season SC+MR+D+ISB Response Scenario by Response Type and Response Division *without* application of weather restriction.

[b] The characteristics of the different types of mechanical equipment and the specific pieces of equipment applied in this scenario are described in Section 2.1. The viscosity thresholds for different types of equipment are further described in Section 1.8.2.

[c] ERSP is described in Section 5.0. "ERSP Day-1" rates are the higher removal rates applied in the areas and times when the oil was flowing from the well and the oil is the thickest. "Day-1" does not necessarily indicate that this is only applied for the first day. "ERSP Day-3" rates are applied in the areas more distant from the well where the oil is thinner and more spread out making removal less efficient. "Day-3" does not necessarily indicate that this is the third day of the response.

For Scenario 10 Arctic-FI6610-Early Season, response operation divisions were cascaded in over the course of the initial 14 days of the discharge (as depicted in Figure 124).

Dispersant application began on day 3 due to logistical constraints and expected time to secure regulatory approvals for dispersant use.[26] Between day 3 and discharge shutdown on day 14, a total of 468,000 gallons of dispersant was applied aerially (39,000 gallons per day for 12 days), after which an additional 13,929 gallons were applied over the following four days. There was no subsurface dispersant response for this scenario.

[26] With pre-approval of dispersant use at this site, surface dispersant application could have started on Day 2.

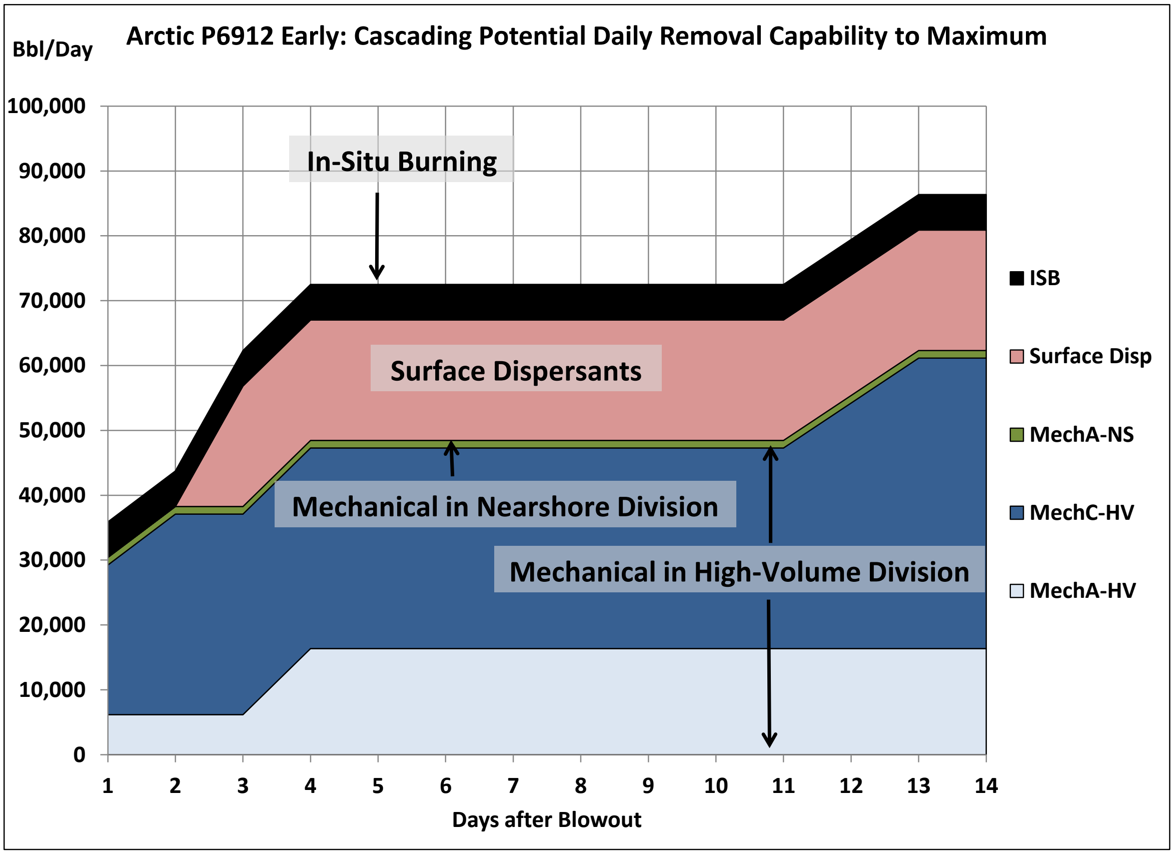


Figure 124: Scenario 10, Arctic-FI6610-Early Season SC+MR+D+ISB – Cascading SC+MR+D+ISB Response Assets and Cumulative Potential Daily Removal Capacity

Countermeasure Simulation Results & Analysis

Achieved Removal versus Potential Equipment Capabilities

Maximum potential removal rates of oil removal systems are not achieved due to the limitations on countermeasures resulting from oil weathering and other environmental factors (such as increased sea state and darkness which often limited when the countermeasures could be applied). For the Arctic-FI6610-Early Season SC+MR+D+ISB simulation, weather restrictions were in effect for 62.5% of the time, and for most equipment, the operating period was limited to 12 hours of daylight (other equipment limitations applied are listed in Table 10, Table 12, and Table 13). Because of these thresholds and limitations, as well as the availability of recoverable, burnable, or dispersible oil in the response divisions, achieved oil removal was significantly less than the potential recovery capabilities (as shown in Table 67, Figure 125 and Figure 126) for the Arctic-FI6610-Early Season SC+MR+D+ISB simulation.

Table 79 shows the system potential with regard to barrels of oil that could be treated or removed based on the sum total of removal/treatments rates over the course of the entire response operation (i.e., during the release of oil from the well and for an additional 45 days after source control is achieved to stop the flow of oil). The "achieved" removal or treatment reflects the sum total of oil removed or treated over the course of the response operations.

Figure 125 contrasts the sum total of potential removal/treatment over the course of the operations and the sum total of the achieved removal/treatment. The daily well flow is shown as a benchmark. The potential removal/treatment capability greatly exceeds the achieved removal/treatment due to the various environmental and logistical factors that limit performance.

Table 79: Scenario 10, Arctic-FI6610-Early Season SC+MR+D+ISB Cumulative System Potential Oil Recovery versus Achieved Oil Recovery over 59-Day Simulation

Response Type	Response Division	Response System Type	Total Recovery		
			System Potential (bbl)	Achieved (bbl)	% Potential [a]
Mechanical [b]	**High-Volume**	Skimmer Group A	343,506	10,557	3%
		Skimmer Group C	1,074,888	0	0%
	Nearshore	Skimmer Group A	88,500	932	1%
	Mechanical Total	**All**	**1,506,894**	**11,489**	**1%**
In Situ Burning [c]	**High-Volume In Situ Burning**	-	159,036	680	0.4%
Dispersants	**High-Volume/ Dispersant Application**	-	236,781	7,200	3%
All Categories	**All**	**All**	**1,902,711**	**19,369**	**1%**

[a] Modeled recovery divided by potential recovery as percentage.

[b] ERSP Day-1 rates assumed for High-Volume Division until well capping (source control); ERSP Day-3 rates assumed for Nearshore Division, and for High-Volume Division after day 14 source control.

[c] EBSP Day-1 rates assumed until day 14 source control, after which EBSP Day-3 rates were applied.

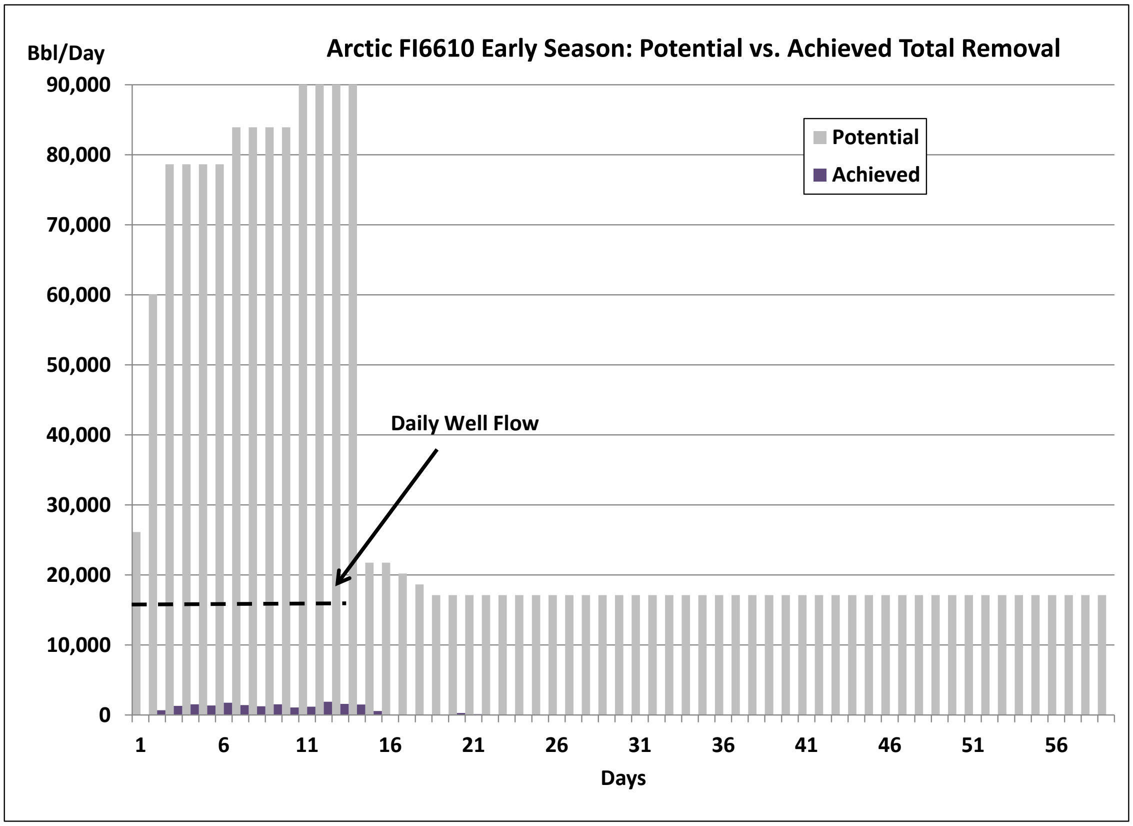


Figure 125: Scenario 10, Arctic-FI6610-Early Season - SC+MR+D+ISB Total Oil Removal System Potential and Achieved Total Daily Removal

Figure 126 contrasts the amount of oil flowing from the well on a daily basis along with the maximum potential daily capability per day, as well as the achieved average daily removal rate. The achieved average daily removal rate is lower than the potential daily removal rate for each day of the scenario.

During the response period, some systems have very low or near-zero removal for some periods because of performance limitations due to environmental conditions, or because there is insufficient oil available, particularly in the nearshore response area where oil may not appear on the surface until after the oil has stopped flowing.

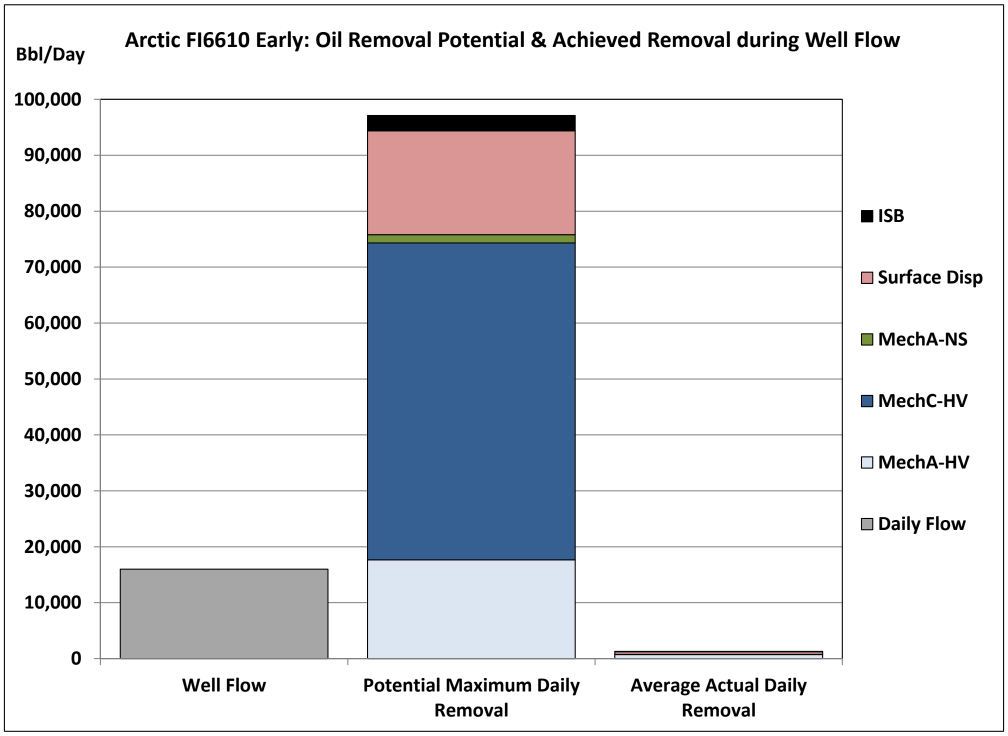


Figure 126: Scenario 10, Arctic-FI6610-Early Season SC+MR+D+ISB Total Maximum Oil Removal System Potential and Achieved Removal Compared with Well Flow during 14-Day Discharge Period

Oil Removal by Countermeasure Type

Table 80 is a summary of model results for the various response countermeasures applied to the Arctic-FI6610 Early Season scenario. This table allows for comparison of the oiling and oil removal by each countermeasure across the various model simulations. Values within Table 80 represent the volume of oil present/removed at the completion of the response scenarios (59 days).

Table 80: Scenario 10, Arctic-FI6610 Early Season – Comparison of Shoreline Oiling and Oil Removal for the Relief Well Only Scenario and Four Response Scenarios at the End of the Model Simulations

Scenario	Volume (bbl) of Discharge	Volume (bbl)/ Percent of Oil on Shoreline	Volume (bbl)/ Percent Removed by Skimming	Volume (bbl)/ Percent Dispersed	Volume (bbl)/ Percent Removed by Burning	Volume (bbl)/ Percent Bio-degraded or in Sediments
Relief Well Only, 30 Day Discharge	480,000	146,191				152,803
Source Control (SC), 14 Day Discharge	224,000	71,283 32%				64,572 29%
Source Control and Mechanical Recovery (SC+MR)	224,000	68,764 31%	10,377 5%			60,769 27%
Source Control, Mechanical Recovery and Surface Dispersant (SC+MR+D)	224,000	64,776 29%	11,390 5%	9,151 4%		61,008 27%
Source Control, Mechanical Recovery, Surface Dispersant and In Situ Burning (SC+MR+D+ISB)	224,000	64,613 29%	10,974 5%	10,135 5%	818 0.4%	60,877 27%

Scenario 10 is a WCD from a nearshore shallow-water well where mechanical recovery and surface dispersant had similar effects to the fate of the oil at the end of the model simulations. When used without the aid of other response operations, mechanical recovery was able to remove up to 5% of the oil discharged in this scenario. These results show that for this oil and this scenario simulation, effective mechanical recovery and dispersant treatment is largely limited to the High Volume Recovery Area. Even within the High Volume Area, Skimmer Group C mechanical recovery systems were ineffective, and Skimmer Group A systems were needed to skim the rapidly weathering oil.

When surface applied dispersants were added, oil removed by mechanical recovery remained at 5%; however, an additional 4% of the oil was also dispersed into the water column resulting in small decreases in the amount of oil on the water surface and on the shoreline.

In situ burning accounted for 0.4% of the oil removed when used, which is likely a reflection of the limited area where burning could be applied (e.g., restricted to the High Volume Recovery Division) in this nearshore scenario. In situ burning in this scenario was limited by the availability of fireboom and other in situ burning equipment, and modeling equipment thresholds for wave height, wind, and viscosity and thickness of oil on the water surface.

Figure 127 displays the fate of oil at the end of the 59-day simulation for Scenario 10, Arctic-FI6610 Early Season involving source control, mechanical recovery, in situ burning, and surface dispersants (e.g., SC+MR+D+ISB).

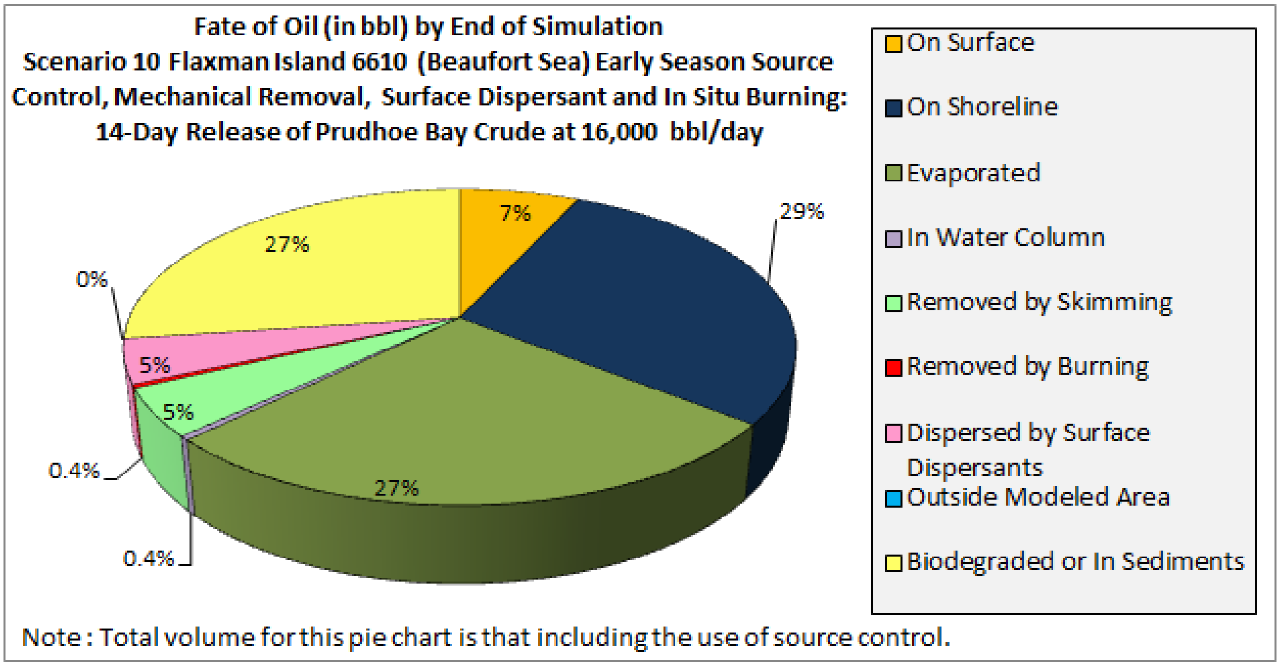


Figure 127: Scenario 10, Arctic-FI6610 Early Season – Fate of Oil at End of 59-Day Simulation (Scenario includes Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning Response Operations)

Reductions in Surface and Shoreline Oiling

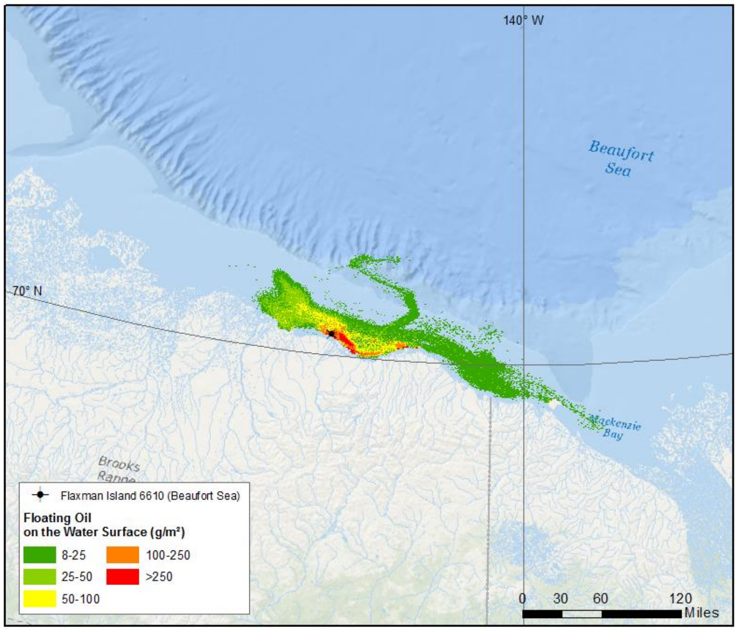
Table 81 provides a comparison of the shoreline and water surface oiling results for each of the Arctic-FI6610 Early Season response countermeasure simulations.

Table 81: Scenario 10, Arctic-FI6610 Early Season – Comparison of Shoreline and Water Surface Oiling Above Equipment Threshold Values or Limitations

Scenario 10, Arctic- FI6610 Early Season	Relief Well Only (WCD)	Source Control	Source Control and Mechanical Recovery	Source Control, Mechanical Recovery, and Surface Dispersant	Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning
Volume (bbl) of Shoreline Oiling (to Any Degree)	146,190	71,283	68,764	64,776	64,613
Percent Reduction in Volume of Shoreline Oiled As Compared to Relief Well Only	-	51%	53%	56%	56%
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	782	353	347	336	337
Percent Reduction in Shoreline Length Oiled with ≥1 g/m^2 As Compared to Relief Well Only	-	55%	56%	57%	57%
Cumulative Area (mi^2) of Surface Affected by Oil ≥8g/m^2	418,712	147,689	133,573	115,134	111,190
Percent Reduction in Surface Affected by Oil ≥8g/m^2 As Compared to Relief Well Only	-	65%	68%	73%	73%

Figure 128 is a visual depiction of the reduction in the surface area affected by ≥8.0 g/m^2 of oil over the 59-day period. The graphic directly compares the levels of maximum water surface oiling over time between the Source Control Only simulation and the simulation that adds mechanical recovery, dispersants, and burning (SC+MR+D+ISB).

14-Day Release of Prudhoe Bay Crude at 16,000 bbl/day During the Early Season- Source Control Only



14-Day Release of Prudhoe Bay Crude at 16,000 bbl/day During the Early Season -
Source Control with Additional Surface Response Options: In Situ Burning, Mechanical Removal and Surface Dispersant

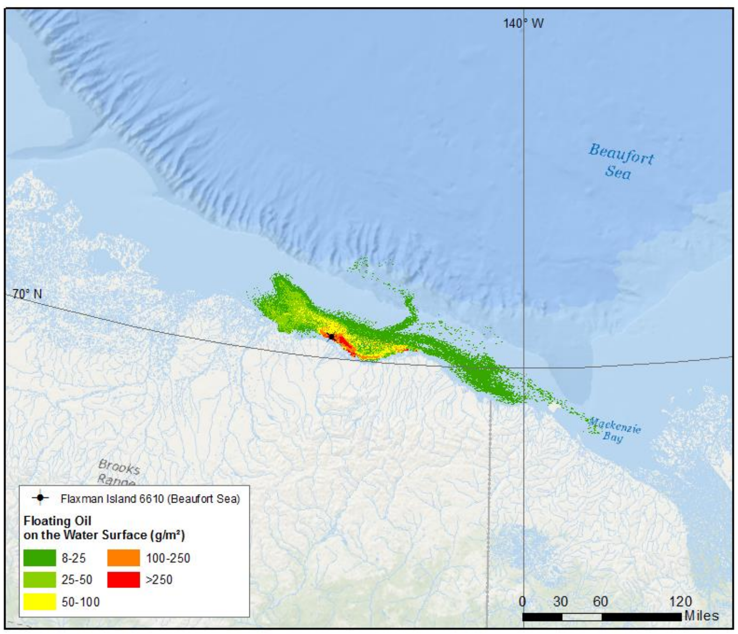


Figure 128: Scenario 10, Arctic-FI6610 Early Season – Comparison Floating Oil Concentration ($\geq$8.0 g/m^2) over 59-Day SIMAP Model Simulation, Top Panel: Source Control (SC), Bottom Panel: Source Control, Mechanical Recovery, Surface Dispersants, and In Situ Burning (SC+MR+D+ISB)

2.3.2.4 *Scenario 11: Flaxman Island 6610 Late Season– Beaufort Sea*

Scenario Site Information

Flaxman Island 6610 (FI6610) is a nearshore (1.5-4.5 miles [1.3-3.9 NM] from shore) and shallow water (160 ft) well in the Beaufort Sea Planning Area. In the event of a worst case discharge at this site, there is a high probability of rapid, significant shoreline contact (see Table 82 and Figure 129) if spill response countermeasures are not immediately taken. Based on 100 stochastic model runs, the worst case release date for the Flaxman Island 6610 WCD late season scenario was August 31, 2008.

Table 82: Scenario 11, Arctic-FI6610 Late Season – Well Information and Shoreline Contact Times

WCD Scenario Parameters	
Discharge Flow Rate	16,000 bbl/day
WCD Duration	30 days, Relief Well Only 14 days, Source Control
Total WCD Release Volume	480,000 bbl, Relief Well Only 224,000 bbl, Source Control
Simulation Duration (45 days following end of discharge)	75 days, Relief Well Only 59 days, Source Control
Oil Type	Alaskan Prudhoe Bay Crude
API Gravity	24.8
Viscosity @ 15°C (cp)	38.9
Latitude, Longitude	70.227°N / 146.0186°W
Depth to Sea Floor	160 ft
Distance to Shoreline	4.5 miles (3.9 nm) to mainland, 1.5 miles (1.3 nm) to coastal barrier islands
SIMAP Model Results [a]	
Time for oil above 1 g/m^2 to reach shore [b]	1 day
Time for oil greater than 8 g/m^2 to reach shore [c]	1 day, Figure 129

[a] SIMAP model results presented in this table are based on the 100 stochastic model runs.

[b] The 1 g/m^2 value is the threshold for socio-economic resource effects (e.g., closure of fisheries) (French-McCay et al. 2011; French McCay et al. 2012)

[c] The 8 g/m^2 value is the minimum thickness of floating oil for which response equipment can be effectively used (NOAA 2010)

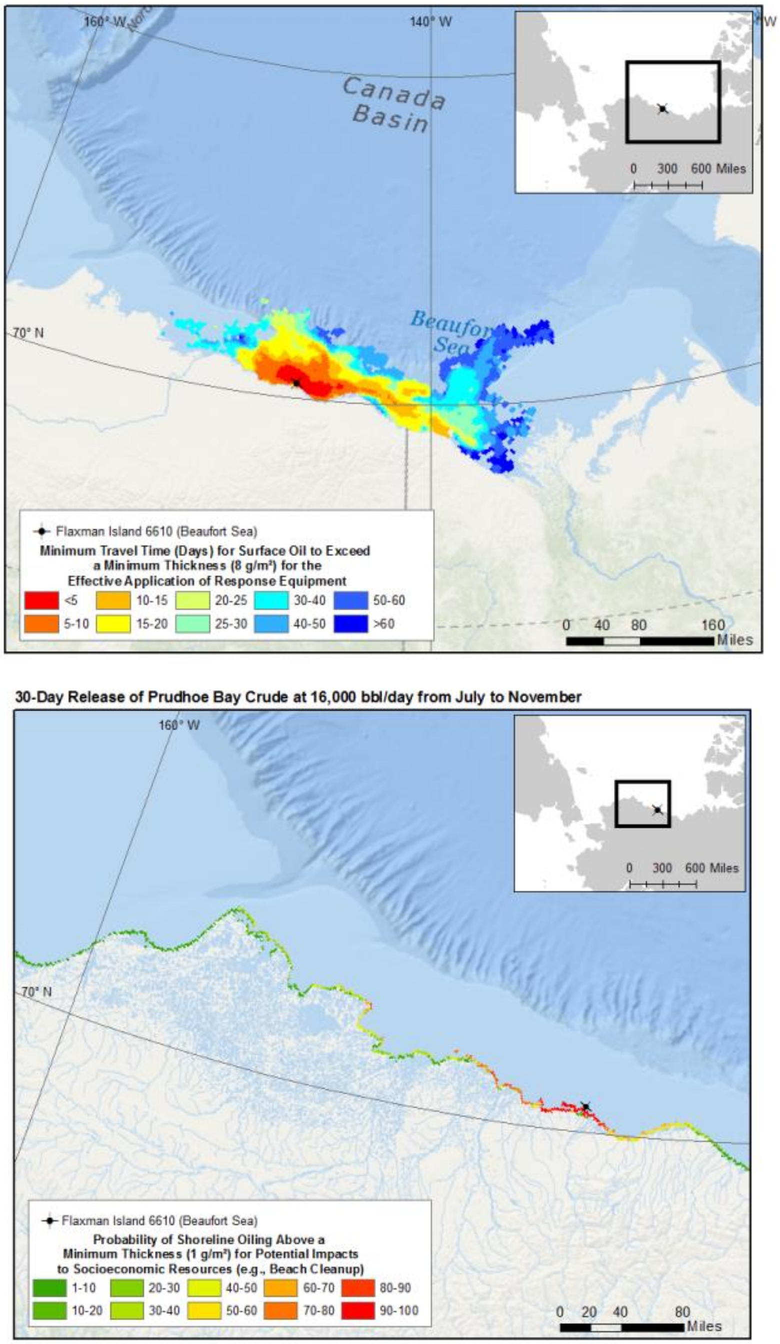


Figure 129: Scenario 11, Arctic-FI6610 Late Season Relief Well Only Scenario, 30-Day Discharge – Probability of Shoreline Oiling and Minimum Travel Times for Surface Oiling

Application of Source Control

When a source control operation is modeled for the WCD Arctic Flaxman Island 6610 Late Season scenario, the discharge period is reduced by 16 days and the volume of oil released to the environment is reduced by 256,000 bbl. Correspondingly, source control results in substantially less impact to the water column and shoreline in comparison to the Relief Well Only simulation. Table 83 and Figure 130 compare discharge volume, shoreline-oiling volume, length of oiled shoreline, area of surface oiling, and the amount of oil biodegraded or in the sediments for the Relief Well Only and Source Control modeling simulations.

Table 83: Scenario 11, Arctic-FI6610 Late Season – Comparison of Relief Well Only and Source Control Response Scenarios

Scenario 11, Arctic-FI6610 Late Season	Relief Well Only (30-day flow duration)	Source Control (14-day flow duration)	Reduction Due to Source Control	Percent Reduction Due to Source Control
Volume Discharged (bbl)	480,000 bbl	224,000 bbl	256,000 bbl	53 %
Volume Shoreline Oiling (bbl) any thickness	145,687 bbl	89,807 bbl	55,880 bbl	38 %
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	583 mi	501 mi	82 mi	14 %
Cumulative Area (mi^2) of Surface Oiling ≥8g/m^2	137,538 mi^2	40,663 mi^2	96,875 mi^2	70 %
Amount Biodegraded or In Sediments (bbl) at the End of the Simulation	154,720 bbl	65,499 bbl	89,221 bbl	58 %

As shown in Figure 130, the volume and spread of oil spilled from this WCD is reduced by a source control intervention on Day 14; however, without the application of additional response operations to remove or mitigate spilled oil on the surface, the simulated contact and exposure to oil in the environment still occurs in sensitive geographic areas.

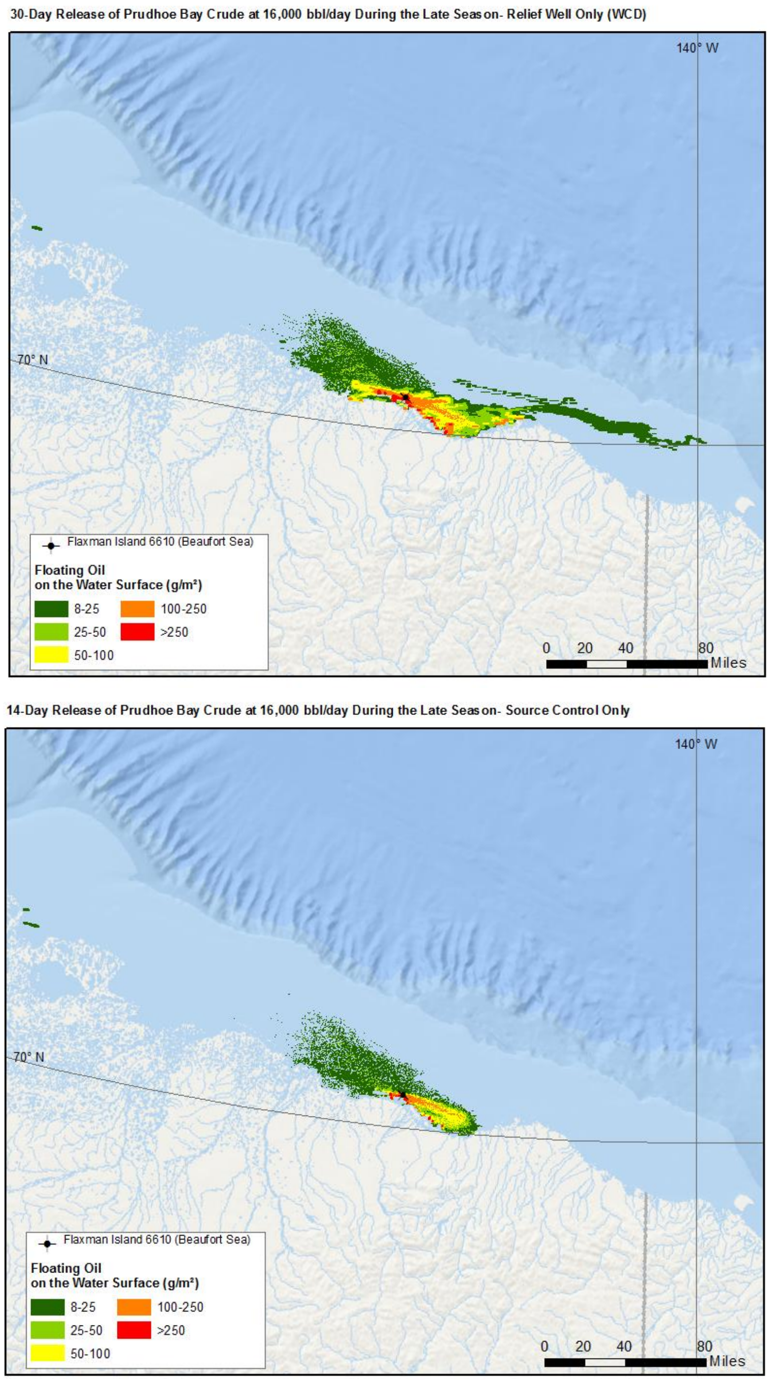


Figure 130: Scenario 11, Arctic-FI6610 Late Season– Comparison of Maximum Concentrations of Surface Oiling Experienced Throughout Simulation Periods for Relief Well Only (30-Day Discharge) and Source Control (14-Day Discharge)

Oil Discharge Behavior

Figure 131 shows the fate of oil for 59 days beginning on the first day of the discharge (14-day discharge duration and 45 days following the source control). At the end of the simulation, 40% of the oil remained on the shoreline, 30% degraded and remained in the water column and sediments, 27% percent of the total oil had evaporated, 3% of the oil remained floating on the surface. Note that the model does not simulate potential photooxidation of floating oil.

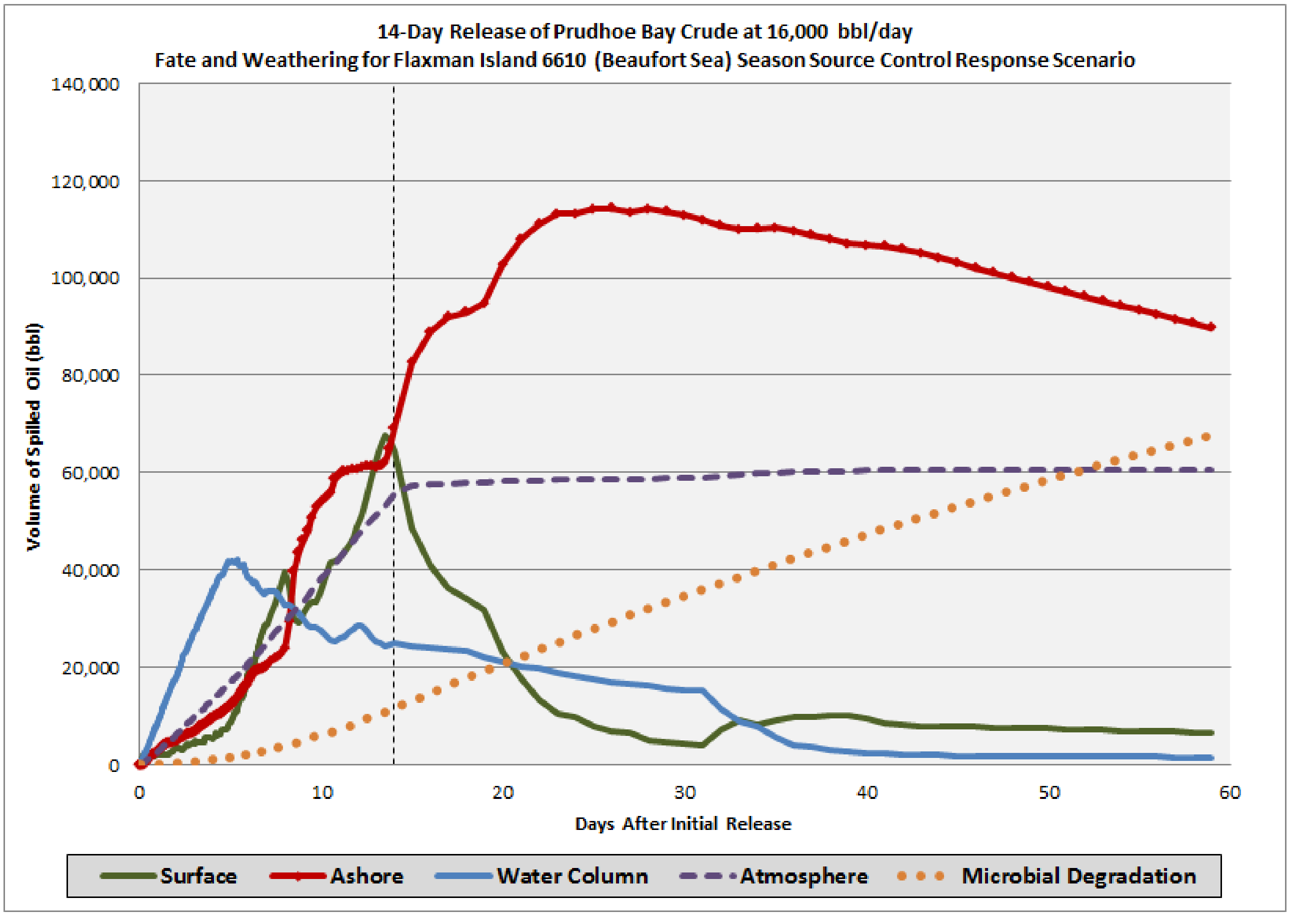


Figure 131: Scenario 11, Arctic-FI6610 Late Season Source Control, 14-Day Discharge – Oil Fate and Weathering (Dotted vertical line indicates source control on Day 14)

In Scenario 11, Arctic-FI6610 Late Season Source Control, 100% of the total oil mass discharged from the blowout reached the surface. Upon release from the blowout, oil droplets took less than 1 hour to reach the surface, with most surfacing in the immediate vicinity of the well location.

The winds in this simulation were quite strong from the beginning of the spill, with a peak wind speed of 18 knots 1.5 days into the spill. This caused the oil to become weathered quickly and also limited the oil that was thick enough to recover in the High Volume Recovery Area. By the end of day 2, oil that was discharged at the beginning of the spill moved to the edge of the High Volume Recovery Division and reached the upper viscosity limit (15,000 cST) for the modeled mechanical recovery equipment. By the end of day 4, the weathered oil continued to move into the Dispersant Application Division and the Nearshore Recovery Division. At this point in the simulation, the weathered oil reached viscosities greater than 50,000 cST as far as 40 miles from the well site. . By day 7, the oil that could be recovered or treated (with viscosity <15,000 cST and thickness of >8g/m^2) reached the farthest extent of the Dispersant Application Division, approximately 50 miles from the wellhead (Figure 132 and Figure 133). After this point, the winds continued to vary over time with another strong wind event at 17.25 days into the spill, thus causing the oil to continue to be quite viscous making it unable to be treated or recovered.

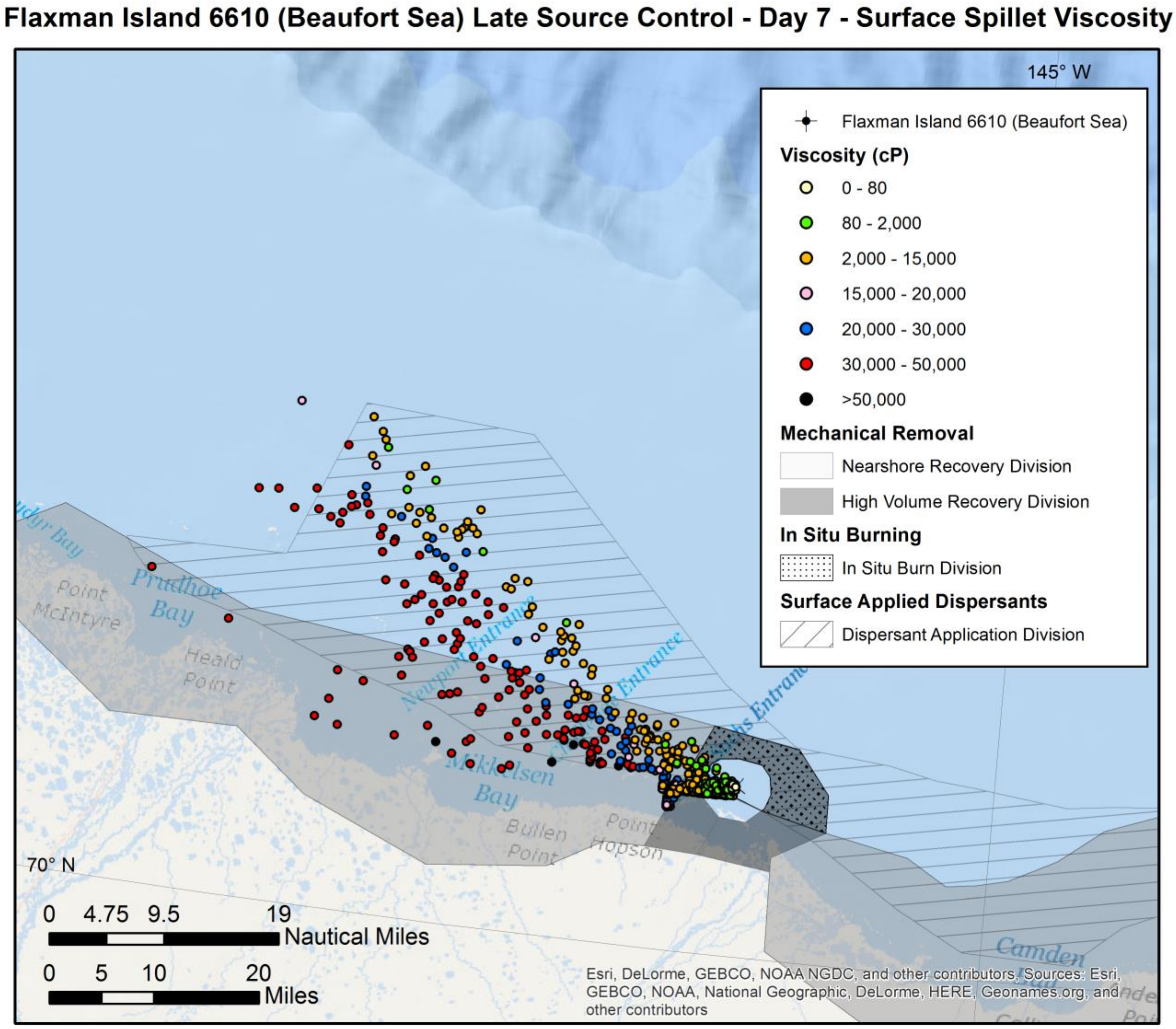


Figure 132: Scenario 11, Arctic-FI6610 Late Season Source Control – Surface Spillet Viscosity (cp) at Day 7

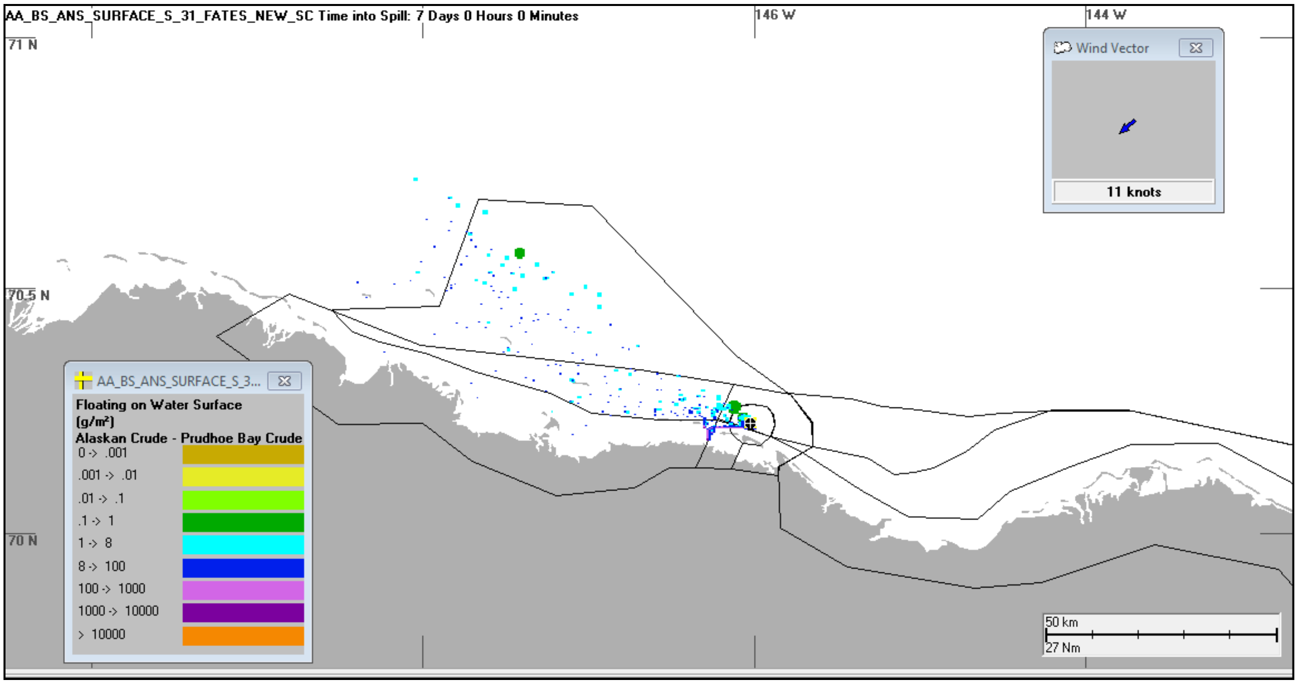


Figure 133: Scenario 11, Arctic-FI6610 Late Season Source Control – Floating Oil on Water Surface (g/m2) at Day 7

The path of the oil plume varied over time, but the oil moved in a generally west/northwesterly longshore direction. At day 12, the wind shifted direction slightly, which caused the plume to also travel to the east of the well location. However, this change in direction was brief; thus, for the majority of time, the plume travels along the coast westward of the well location. Minimum travel time for contact to shorelines was 5 hours, with substantial shoreline impacts beginning after 12 hours of the start of the discharge. At the end of the simulation, the majority of the shoreline oiling (over 1 g/m^2) was along the Alaskan and Canadian coast (Figure 134).

Spills in both the early and late open-water seasons were modeled for the same Beaufort well location. Comparing the two simulations, the late season involved stronger wind patterns that resulted in less surface oiling, increased entrainment, and reduced opportunities for removing oil with surface-based spill countermeasures. While the shoreline length and volume of shoreline oiling were relatively similar between the two simulations due to the close proximity of the wellhead to the shoreline, the main difference was that the early season (see Table 81) had significantly more surface area oiled by >8g/m^2 than is available for removal in the late season (Table 87). For such situations, applying dispersants directly to the source may be the most effective countermeasure if the environmental resource considerations support using such a response strategy.

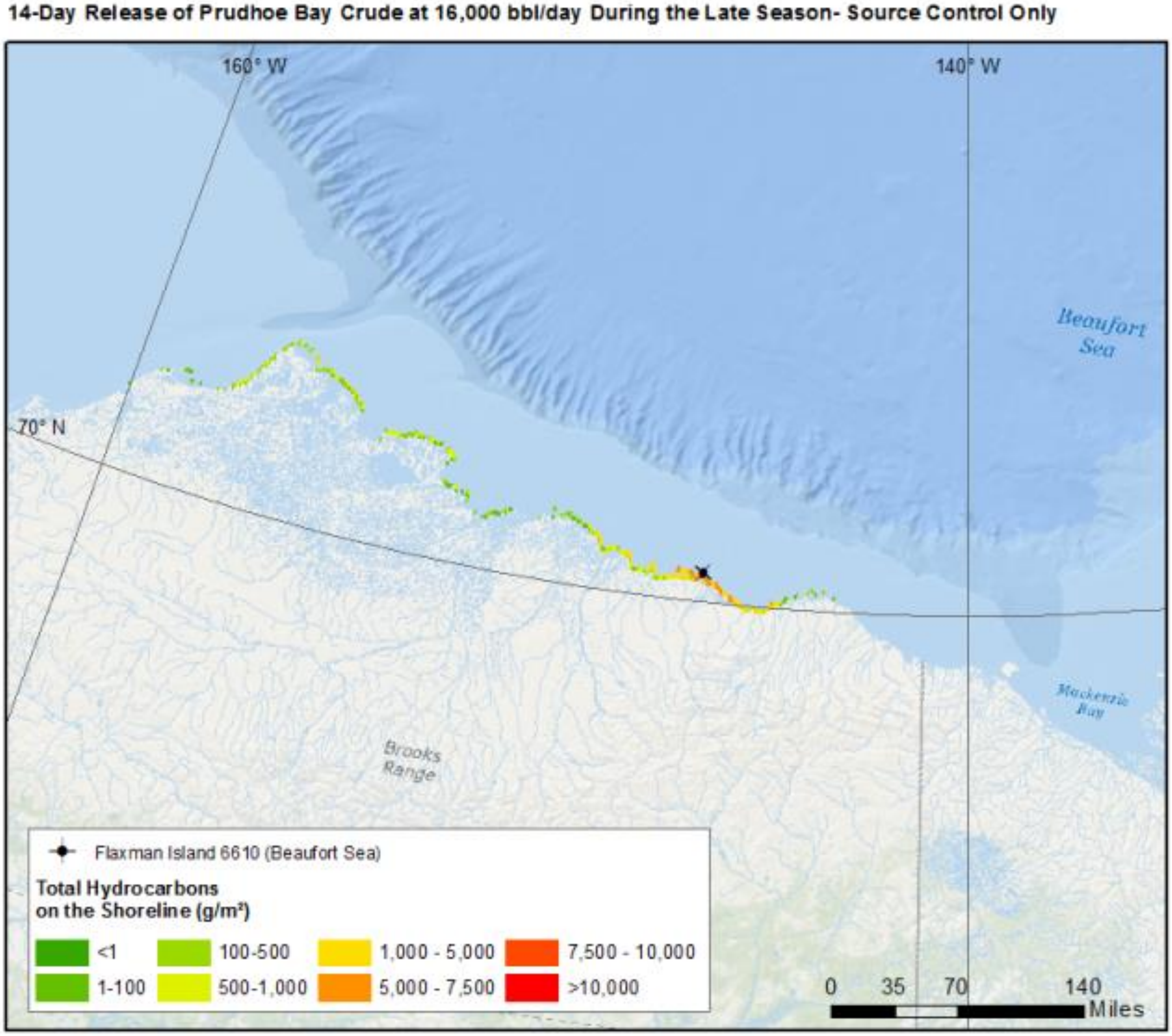


Figure 134: Scenario 11, Arctic-FI6610 Late Season Source Control, 14-Day Discharge – Shoreline Oil ≥1 g/m^2, including Weathered Tarballs

Application of Response Countermeasures

Countermeasure Response Divisions

The following equipment types were employed in each of the following countermeasure response divisions, and are shown in Figure 135.

- High Volume Recovery Division – High volume mechanical recovery operations were employed beyond a 3.5 mile (3 nm) radius area established around the well for source control.
- In situ Burning Division – In situ burning operations were used in the same geographical area as the high volume mechanical recovery operations (3.5 mile [3 nm]) away from the source control area.
- Nearshore Recovery Division – Nearshore mechanical recovery operations were used to remove oil from the surface of the water before it was washed onto shorelines.

- Dispersant Application Division – Surface applied dispersants were employed in the High Volume Recovery Division up to 3.5 miles (3 nm) from shore and beyond a 3.5 mile (3 nm) radius area established around the well for source control, as appropriate.

Subsurface dispersants, which were applied at the point of discharge in the vicinity of the wellhead, are not shown in Figure 135 or assigned to a geographic response division.

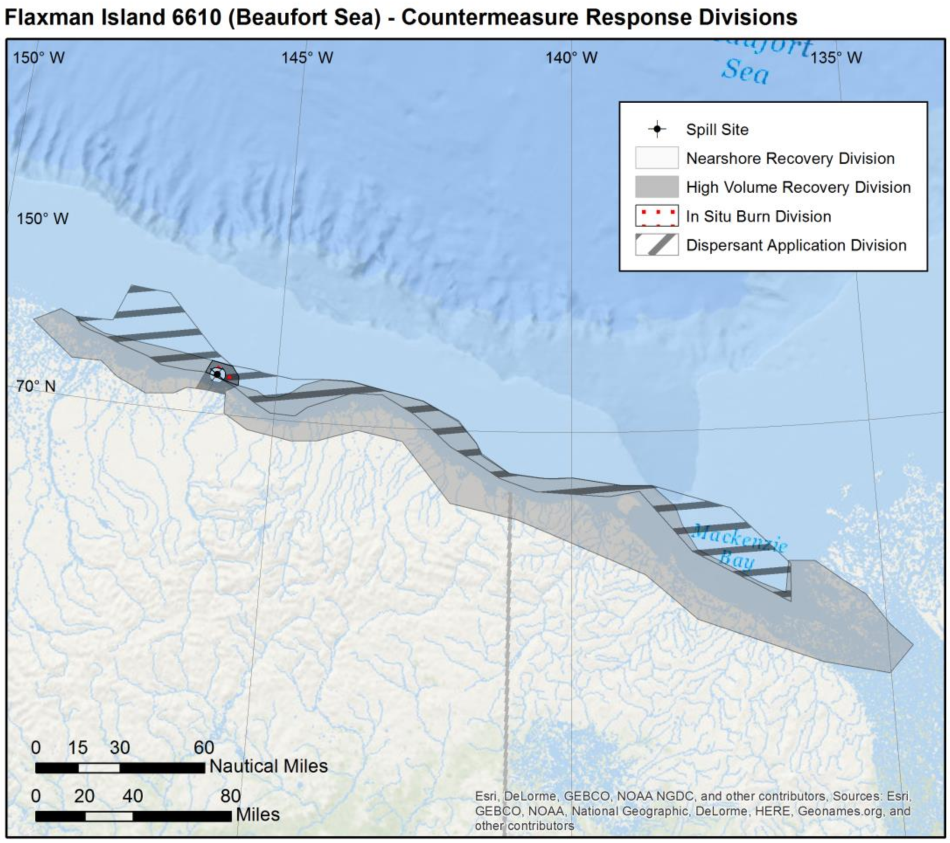


Figure 135: Scenario 11, Arctic-FI6610 Late Season – Geographic Coverage of Oil Countermeasure Response Divisions

The size and placement of the Arctic-FI6610 response operation divisions in the model were developed based on a review of the oil spill trajectories from the 14-day discharge in the Source Control simulation.

Countermeasure/Division Removal Rates (Model Inputs)

The removal rates by countermeasure type and response division that are shown in Table 84 represent the *maximum* potential rate that would be available at any point during the response operation.

As in an actual oil spill response operation, the model cascades response equipment into the response divisions as the assets arrive on the scene. The modeling reflects response equipment threshold values and limitations based on the availability of the response equipment to be deployed to the location of the appropriate divisions. As such, the model used oil removal rates for each division (i.e., SIMAP model polygon), based on the maximum potential daily removal rates (bbl/day) of the assigned asset (refer to Table 84), corrected by weather restrictions and daylight operations (as described in Section 1.8). Maximum removal rates are not realized in practice because of the limitations of weather delays, the location of oil in relation to equipment, and performance thresholds, such as oil thickness on the water surface, oil viscosity, sea state and currents, winds, and water content during oil emulsification.

Table 84: Maximum Potential Daily Oil Removal Rates for Arctic-FI6610-Late Season SC+MR+D+ISB+SubD Response Scenario [a]

Countermeasure Type	Response Division	Response System Category [b]	Removal Rate Applied [c]	Maximum Potential Daily Removal Rates (bbl/day)
Mechanical	**High-Volume**	Skimmer Group A	ERSP Day-1	17,655
		Skimmer Group C	ERSP Day-1	56,662
	Nearshore	Skimmer Group A	ERSP Day-3	1,500
	Total	**All Mechanical Countermeasures**		**76,817**
In Situ Burning	**High-Volume In Situ Burning**	In Situ Burning	Based on ISB Calculator	2,742
Surface Dispersant	**High-Volume and Dispersant Application**	Surface Dispersants	Based on DMP2	6,191
Subsurface Dispersant	**Wellhead**	Subsurface Dispersant	Based on a DOR of 1:100	16,893
Total		**All Countermeasures**		**102,643**

[a] Arctic-FI6610-Late Season SC+MR+D+ISB+SubD+SubD Response Scenario by countermeasure type and response division *without* application of weather restrictions.

[b] The characteristics of the different types of mechanical equipment and the specific pieces of equipment applied in this scenario are described in Section 2.1. The viscosity thresholds for different types of equipment are further described in Section 1.8.2.

[c] ERSP is described in Section 5.0. "ERSP Day-1" rates are the higher removal rates applied in the areas and times when the oil was flowing from the well and the oil is the thickest. "Day-1" does not necessarily indicate that this is only applied for the first day. "ERSP Day-3" rates are applied in the areas more distant from the well where the oil is thinner and more spread out making removal less efficient. "Day-3" does not necessarily indicate that this is the third day of the response.

For Scenario 11, Arctic-FI6610 Late Season, response operation divisions are cascaded in over the course of the initial 14 days (is depicted in Figure 136).

Two separate dispersant response simulations were modeled for the Arctic-FI6610 Late Season scenario: Surface-Only dispersant response and Surface and Subsurface dispersant response.

In the Surface-Only dispersant response simulation, application began on day 3 due to logistical constraints and expected time to secure regulatory approvals for dispersant use.[27] An average of 39,000

[27] With pre-approval of dispersant use at this site, dispersant application could have started on Day 2

gallons of dispersant was applied each day, between day 3 and discharge shutdown on day 14. A total of 468,000 gallons of dispersant was used in the Surface-Only dispersant response simulation.

In the Surface and Subsurface dispersant response simulation, both aerial spraying and subsurface pumping began on day 3, with 13,000 gallons/day of surface dispersant and 7,095gallons/day of subsurface dispersant applied for 12 consecutive days (until the discharge was brought under control on day 14). A total of 241,140 gallons of dispersant was applied in the Surface and Subsurface dispersant response simulation.

Scenario 11, Arctic-FI6610 Late Season, is a relatively small WCD, and a 4.5 gpm pump rate modeled for subsurface dispersant application. The 5gpm pump is sufficient to treat 100% of the 16,000 bbl/day flow. Use of a higher rate subsurface pump (such as the 10 gpm pumps used in the Gulf of Mexico WCD scenarios) would have resulted in more than 100% theoretical oil treatment.

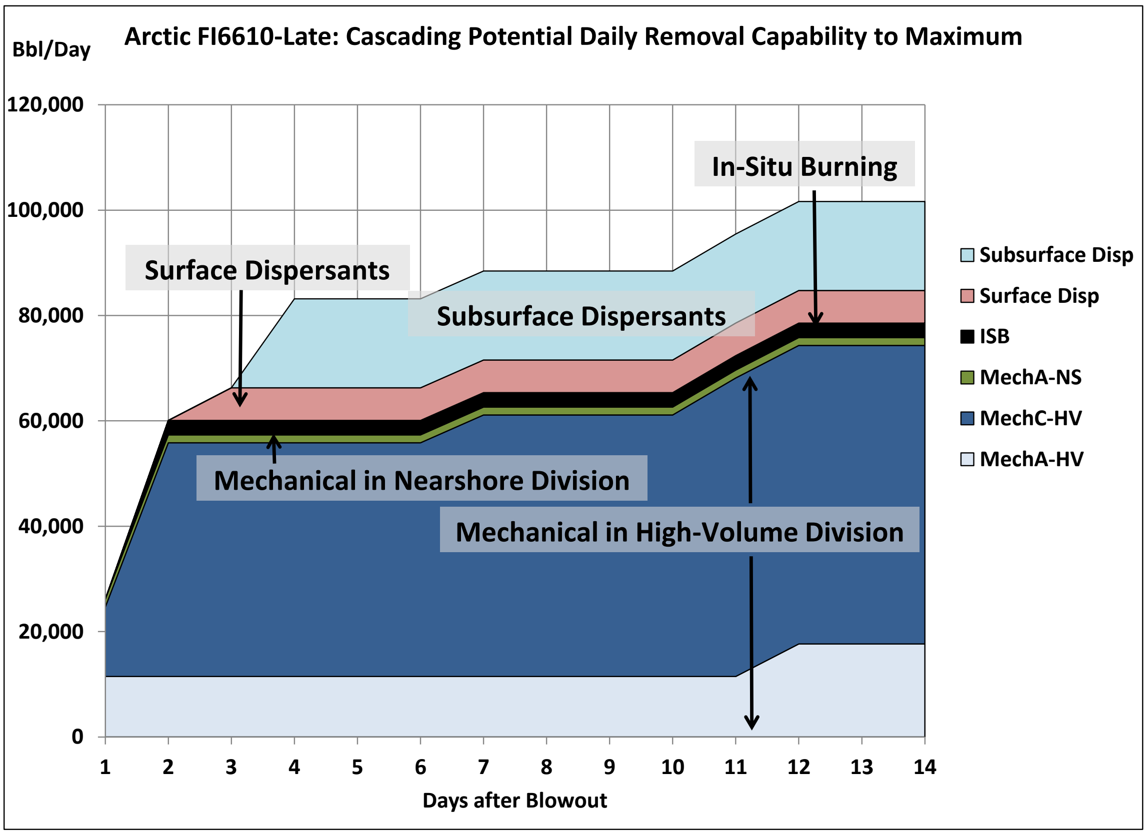


Figure 136: Scenario 11, Arctic-FI6610-Late Season SC+MR+D+ISB+SubD – Cascading SC+MR+D+ISB Response Assets and Cumulative Potential Daily Removal Capacity

Countermeasure Simulation Results & Analysis

Achieved Removal versus Potential Equipment Capabilities

Maximum potential removal rates of oil removal systems were not achieved due to the limitations on countermeasures resulting from oil weathering and other environmental factors (such as increased sea state and darkness which often limited when the countermeasures could be applied). For the Arctic-FI6610-Late Season SC+MR+D+ISB simulation, weather restrictions were in effect for 62.5% of the time, and for most equipment, the operating period was limited to 12 hours of daylight (other equipment limitations applied are listed in Table 10, Table 12, and Table 13). Because of these thresholds and limitations, as well as the availability of recoverable, burnable, or dispersible oil in the response divisions, achieved oil removal was significantly less than the potential recovery capabilities (as shown in Table 85, Figure 137, and Figure 138) for the Arctic-FI6610-Late Season SC+MR+D+ISB simulation. Table 85 shows the system potential with regard to barrels of oil that could be treated or removed based on the sum total of removal/treatments rates over the course of the entire response operation (i.e., during the release of oil from the well and for an additional 45 days after source control is achieved to stop the flow of oil). The "achieved" removal or treatment reflects the sum total of oil removed or treated over the course of the response operations. Figure 137 contrasts the sum total of potential removal/treatment over the course of the operations and the sum total of the achieved removal/treatment. The daily well flow is shown as a benchmark. The potential removal/treatment capability greatly exceeds the achieved removal/treatment due to the various environmental and logistical factors that limit performance.

Table 85: Scenario 11, Arctic-FI6610-Late Season SC+MR+D+ISB+SubD Cumulative System Potential Oil Recovery versus Achieved Oil Recovery over 59-Day Simulation

Response Type	Response Division	Response System Type	Total Removal/Treatment		
			System Potential (bbl)	Achieved (bbl)	% Potential [a]
Mechanical [b]	**High-Volume**	Skimmer Group A	259,556	10,296	4.0%
		Skimmer Group C	862,920	0	0.0%
	Nearshore	Skimmer Group A	54,000	1,291	2.4%
	Mechanical Total	**All**	**1,176,476**	**11,587**	**1.0%**
In Situ Burning [c]	**High-Volume In Situ Burning**	-	95,970	4,005	4.2%
Surface Dispersants	**High-Volume/ Dispersant Application**	-	87,861	4,025	4.6%
Subsurface Dispersants	**Wellhead**	-	185,823	47,815	25.7%
All Categories	**All**	**All**	**1,546,130**	**67,432**	**4.4%**

[a] Achieved Total Recovery divided by System Potential Total Recovery as percentage.

[b] ERSP Day-1 rates assumed for High-Volume Division until well capping (source control); ERSP Day-3 rates assumed for Nearshore Division, and for High-Volume Division after day 14 source control.

[c] EBSP Day-1 rates assumed until day 14 source control, after which EBSP Day-3 rates were applied.

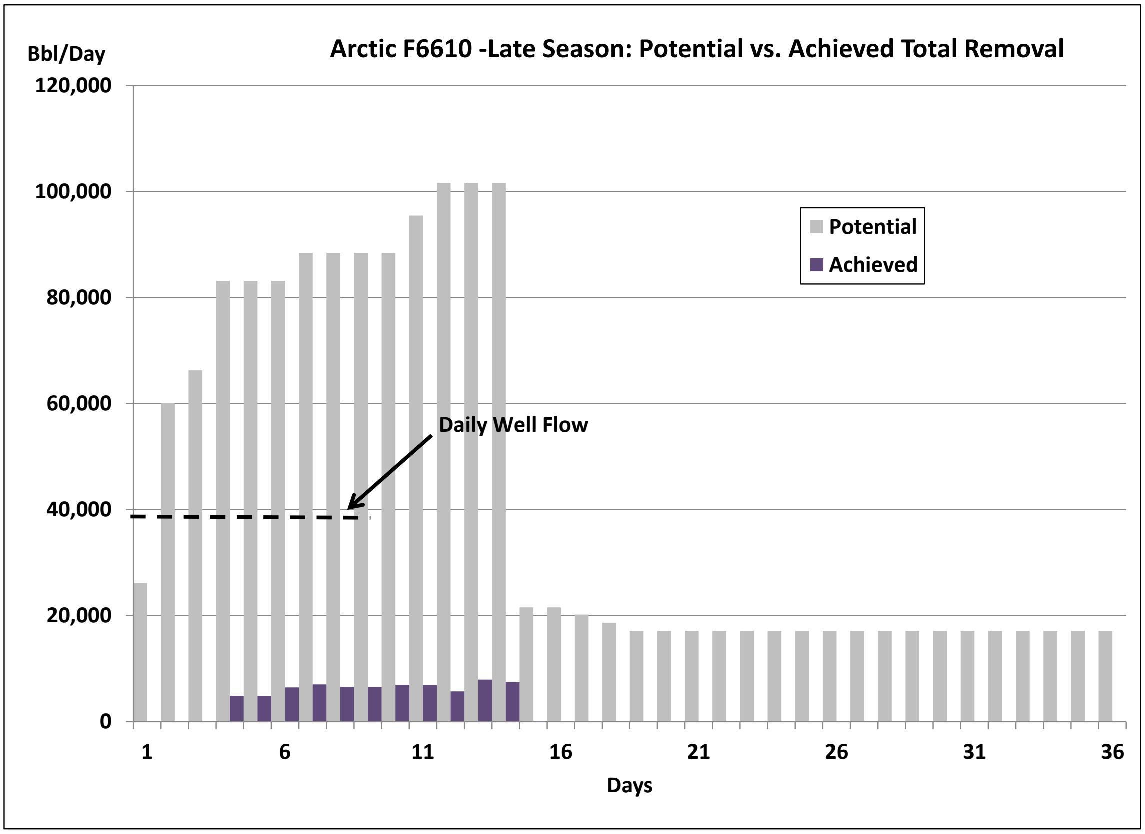


Figure 137: Scenario 11, Arctic-FI6610-Late Season SC+MR+D+ISB+SubD Total Oil Removal System Potential and Achieved Total Daily Removal

Figure 138 contrasts the amount of oil flowing from the well on a daily basis along with the maximum potential daily capability per day, as well as the achieved average daily removal rate. The achieved average daily removal rate is lower than the potential daily removal rate for each day of the scenario.

During the response period, some systems have very low or near-zero removal for some periods because of performance limitations due to environmental conditions.

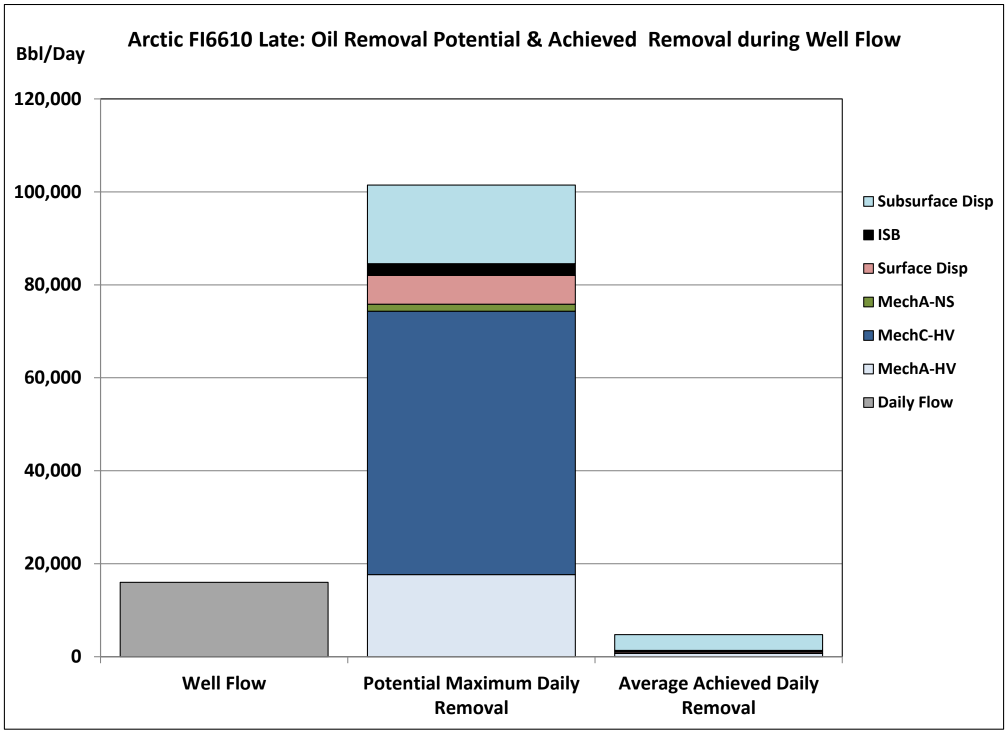


Figure 138: Scenario 11, Arctic-FI6610-Late Season SC+MR+D+ISB+SubD Total Maximum Oil Removal System Potential and Achieved Removal Compared with Well Flow during 14-Day Discharge Period

Oil Removal by Countermeasure Type

Table 86 is a summary of model results for the various response countermeasures applied to the Arctic-FI6610 Late Season scenario. This table allows for comparison of the oiling and oil removal by each countermeasure across the various model simulations. Values within Table 86 represent the volume of oil present/removed at the completion of the response scenarios (59 days).

Table 86: Scenario 11, Arctic-FI6610 Late Season – Comparison of Shoreline Oiling and Oil Removal for the Relief Well Only Scenario and Four Response Scenarios at the End of the Model Simulations

Scenario	Volume (bbl) of Discharge	Volume (bbl)/ Percent of Oil on Shoreline	Volume (bbl)/ Percent Removed by Skimming	Volume (bbl)/ Percent Dispersed	Volume (bbl)/ Percent Removed by Burning	Volume (bbl)/ Percent Bio-degraded or in Sediments
Relief Well Only, 37 Day Discharge	480,000	145,687				154,720
Source Control (SC), 21 Day Discharge	224,000	89,807 40%				65,499 29%
Source Control and Mechanical Recovery (SC+MR)	224,000	81,708 36%	10,606 5%			61,739 28%
Source Control, Mechanical Recovery and Surface Dispersant (SC+MR+D)	224,000	78,898 35%	11,080 5%	2,099 1%		61,473 27%
Source Control, Mechanical Recovery, Surface Dispersant and In Situ Burning (SC+MR+D+ISB)	224,000	76,907 34%	10,044 5%	2,777 1%	488 1%	60,641 27%
Source Control, Mechanical Recovery, Surface Dispersant, In Situ Burning, Subsurface Dispersant (SC+MR+D+ISB+SubD)	224,000	35,992 16%	11,152 5%	50,592 23%	554 2%	69,931 31%

Scenario 11, Arctic-FI6610 Late Season is a WCD from a nearshore shallow-water well where all surface-applied countermeasures had limited effectiveness (≤5%) in removing or treating oil. When used without the aid of other response operations, mechanical recovery was able to remove up to 5% of the oil discharged in this scenario. These results highlight the necessity of deploying high-volume mechanical recovery as close to the point of discharge onto the water's surface as possible, before the oil has widely spread out and becomes too thin to remove from the environment. For this particular early season simulation and the late season simulation, Skimmer Group C mechanical recovery systems were completely ineffective.

When surface applied dispersants were added, oil removed by mechanical recovery remained at 5%; however, only 1% of the oil was also dispersed into the water column. The use of surface-applied dispersants in this simulation had very little effect in terms of reducing shoreline or water surface oiling. When subsurface dispersants were added, oil removed by mechanical removal remained at 5%; however, 23% was also dispersed into the water. Subsurface dispersants applied at the discharge point were the most effective countermeasure for this simulation, and resulted in significant reductions in surface and shoreline oiling.

In situ burning accounted for 1-2% of the oil removed when used, which is likely a reflection of the limited area where burning could be applied (e.g., restricted to the High Volume Recovery Division) in this nearshore scenario. In situ burning in this scenario was limited by the lack of suitable vessels for towing both enhanced encounter boom and fire boom at the same time. Additional fire boom could have been added had there been vessels available for towing it. In situ burning response was also limited by the equipment thresholds for wave height, wind, and viscosity and thickness of oil on the water surface.

Figure 139 displays the fate of oil at the end of the 59-day simulation for Scenario 11, Arctic-FI6610 Late Season involving source control, mechanical recovery, in situ burning, and surface and subsurface dispersants (e.g., SC+MR+D+ISB+SubD).

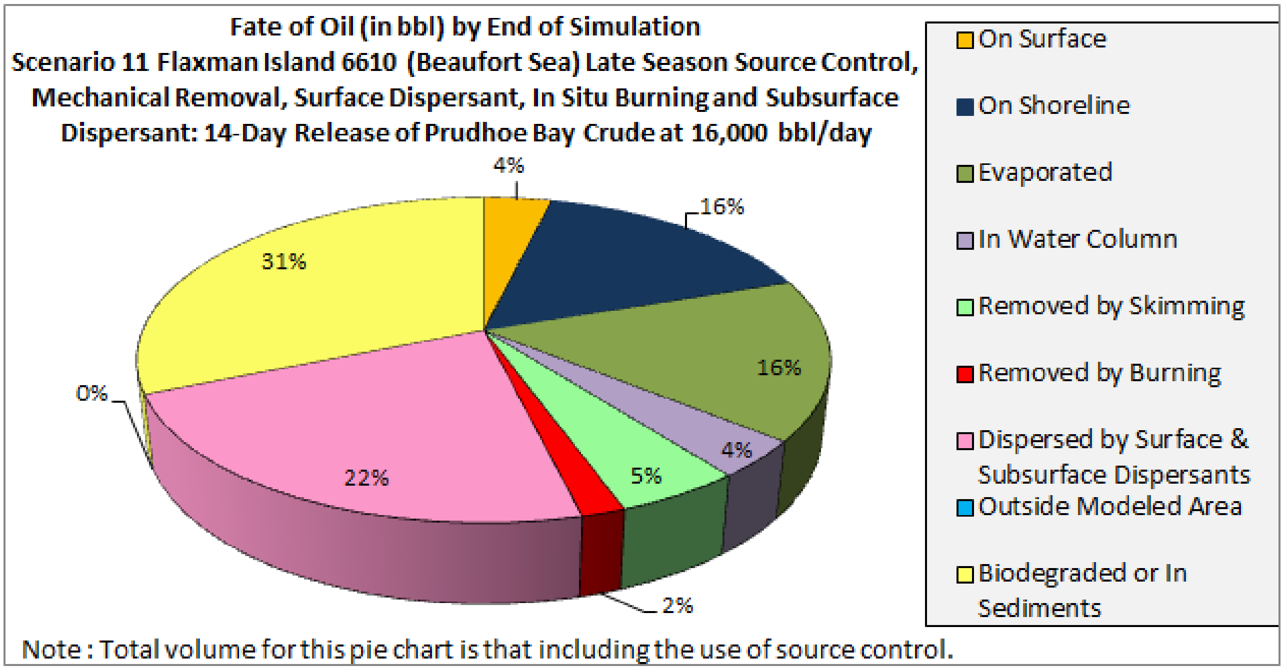


Figure 139: Scenario 11, Arctic-FI6610 Late Season – Fate of Oil at End of 59-Day Simulation (Scenario includes Source Control, Mechanical Recovery, Surface and Subsurface Dispersant, and In Situ Burning Response Operations)

Reductions in Surface and Shoreline Oiling

Table 87 provides a comparison of the shoreline and water surface oiling results for each of the Arctic-FI6610 Late Season response countermeasure simulations.

Since two seasons (early and late) were modeled for the same Beaufort location, it is important to compare the two modeling scenarios. While the shoreline length and volume of shoreline oiling were relatively similar between the two scenarios (Table 87 and Table 81 of early season scenario) due to the close proximity of the wellhead to the shoreline, the main difference between scenarios was that, regardless of response countermeasure simulation, the early season scenario (see Table 81) had significantly more cumulative surface area oiled by >8g/m^2 than the late season scenario (Table 87). This is due to the strong winds that occurred in the beginning of the late season scenario (e.g., 18 knots at 1.5 days into the simulation), which then caused the oil to entrain into the water column and result in less oil remaining on the water surface.

Table 87: Scenario 11, Arctic-FI6610 Late Season – Comparison of Shoreline and Water Surface Oiling Above Equipment Threshold Values or Limitations

Scenario 11, Arctic-FI6610 Late Season	Relief Well Only (WCD)	Source Control	Source Control and Mechanical Recovery	Source Control, Mechanical Recovery, and Surface Dispersant	Source Control, Mechanical Recovery, Surface Dispersant, and In Situ Burning	Source Control with Mechanical Recovery, Surface and Subsurface Dispersant, and In Situ Burning
Volume (bbl) of Shoreline Oiling (to Any Degree)	145,687	89,807	81,708	78,898	76,907	35,992
Percent Reduction in Volume of Shoreline Oiled As Compared to Relief Well Only	-	38%	44%	46%	47%	75%
Total Length (mi) of Shoreline Oiled with ≥1g/m^2	583	501	335	357	349	349
Percent Reduction in Shoreline Length Oiled with ≥1 g/m^2 As Compared to Relief Well Only	-	14%	43%	39%	40%	40%
Cumulative Area (mi^2) of Surface Affected by Oil ≥8g/m^2	137,538	40,663	32,819	31,851	30,436	19,023
Percent Reduction in Surface Affected by Oil ≥8g/m^2 As Compared to Relief Well Only	-	70%	76%	77%	78%	86%

Figure 140 is a visual depiction of the reduction in the surface area affected by ≥8.0 g/m^2 of oil over the 59-day period. The graphic directly compares the levels of maximum water surface oiling over time between the Source Control Only simulation and the simulation that adds mechanical recovery, surface and subsurface dispersants, and burning (SC+MR+D+ISB+SubD).

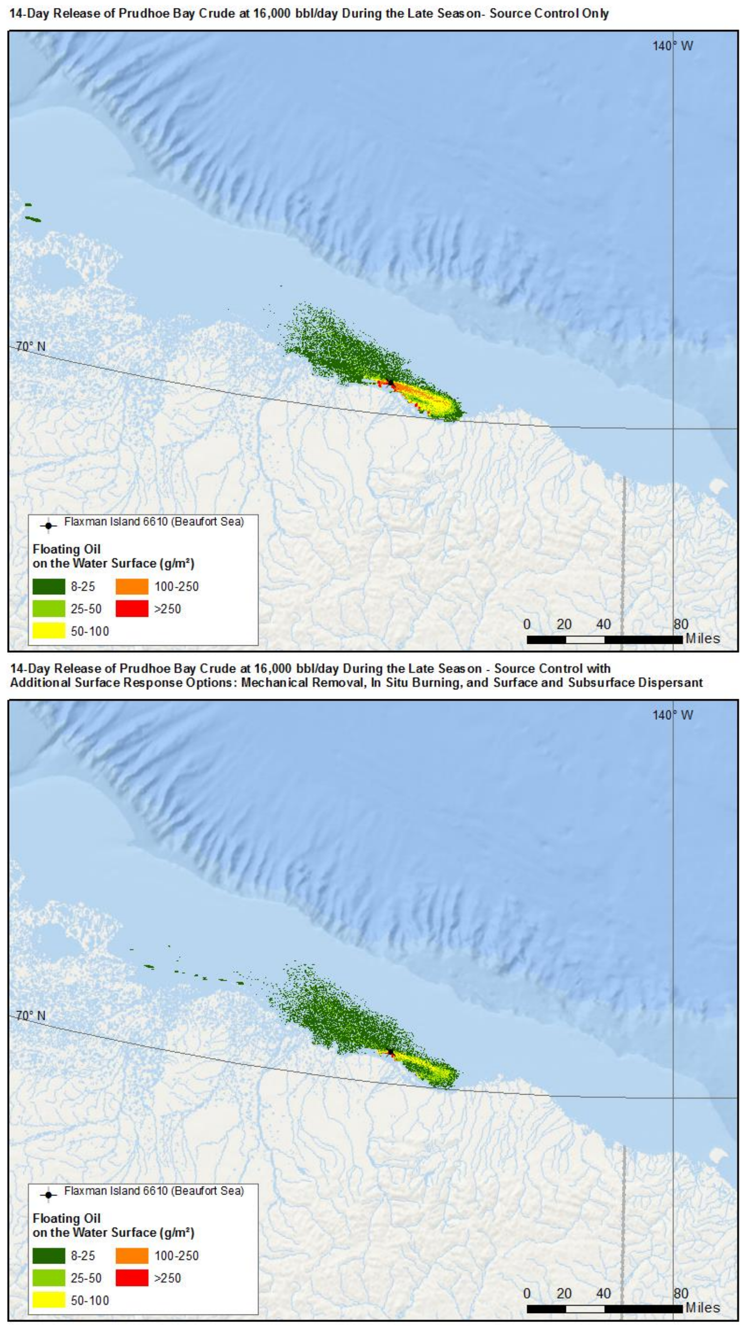


Figure 140: Scenario 11, Arctic-FI6610 Late Season – Comparison Floating Oil Concentration (≥8.0 g/m^2) over 59-Day SIMAP Model Simulation, Top Panel: Source Control (SC), Bottom Panel: Source Control, Mechanical Recovery, Surface and Subsurface Dispersants, and In Situ Burning (SC+MR+D+ISB+SubD)

2.4 Modeling of Additional Mechanical Recovery for Four Selected Scenarios

The WCD scenario response modeling in Section 2.0 reflects response operations using a baseline of existing equipment inventories currently available to OSROs. To determine the degree to which additional mechanical equipment might increase oil removal rates and decrease surface and shoreline oiling impacts, four scenarios were selected for additional model runs using increased recovery equipment levels. Mississippi Canyon 807, West Delta 28, and Posey 6912 (early and late seasons) were modeled with a 25%, 50%, and 75% increases in mechanical recovery capacity. The results are shown in Table 88, Table 89, **Table 90**, and Table 91. These results were then compared with the simulation results for the various baseline simulations that used the original mechanical recovery equipment amounts in conjunction with other countermeasures such as dispersants.

Table 88: Comparison of SC+MR Simulations with 25%, 50%, and 75% Increases in MR Levels to SC+MR+D and SC+MR+D+ISB+SubD for MC807 WCD Scenario (20,205,000 bbl spill)

Recovery Potential (ERSP) Modeled	% of Total WCD Volume Removed*	Total Volume Removed* (bbl)	Amount (bbl) of Oil on Shorelines (any threshold)	Cumulative Area (mi^2) of Surface Affected by Oil ≥8g/m^2
SC+MR Original Level (Max = 290,057 bbl/day)	10.7%	2,161,794	1,103,144	6,269,404
25% increase to MR level	12.5%	2,515,664	1,073,839	6,186,824
50% increase to MR level	13.7%	2,769,691	1,066,245	6,065,847
75% increase to MR level	15.3%	3,097,378	1,025,178	5,969,503
SC+MR(Original)+D	12%	2,400,315	985,038	5,614,293
SC+MR(Original)+D+ISB+SubD	18%	3,499,242	871,526	4,948,193

Table 89: Comparison of SC+MR Simulations with 25%, 50%, and 75% Increases in MR Levels to SC+MR+D for WD28 WCD Scenario (2,037,000 bbl spill)

Recovery Potential (ERSP) Modeled	% of Total WCD Volume Removed*	Total Volume Removed* (bbl)	Amount (bbl) of Oil on Shorelines (any threshold)	Cumulative Area (mi^2) of Surface Affected by Oil ≥8g/m^2
SC+MR Original Level (Max = 301,623 bbl/day)	46.5%	947,315	83,674	406,291
25% increase to MR level	49.9%	1,015,716	64,337	304,994
50% increase to MR level	53.3%	1,085,995	42,647	224,966
75% increase to MR level	55.2%	1,123,490	32,740	141,477
SC+MR(Original)+D	51%	1,042,383	19,026	33,870

** Oil removed as calculated in these tables includes any oil that was recovered, dispersed, or burned.*

Table 90: Comparison of SC+MR Simulations with 25%, 50%, and 75% Increases in MR Levels to SC+MR+D for P6912 Early Season WCD Scenario (350,000 bbl spill)

Recovery Potential (ERSP) Modeled	% of Total WCD Volume Removed*	Total Volume Removed* (bbl)	Amount (bbl) of Oil on Shorelines (any threshold)	Cumulative Area (mi^2) of Surface Affected by Oil $\geq 8 g/m^2$
SC+MR Original Level (Max = 62,316 bbl/day)	6.2%	21,861	12,739	586,816
25% increase to MR level	7.5%	26,162	12,995	575,829
50% increase to MR level	8.8%	29,636	12,640	560,230
75% increase to MR level	10.2%	34,989	12,331	548,625
SC+MR(Original)+D	14%	50,248	11,299	461,478

Table 91: Comparison of SC+MR Simulations with 25%, 50%, and 75% Increases in MR Levels to SC+MR+D and SC+MR+D+ISB+SubD for P6912 Late Season WCD Scenario (350,000 bbl spill)

Recovery Potential (ERSP) Modeled	% of Total WCD Volume Removed*	Total Volume Removed* (bbl)	Amount (bbl) of Oil on Shorelines (any threshold)	Cumulative Area (mi^2) of Surface Affected by Oil $\geq 8 g/m^2$
SC+MR Original Level (Max = 62,316 bbl/day)	5.1%	17,844	32,598	460,035
25% increase to MR level	6.0%	20,921	32,545	453,527
50% increase to MR level	7.2%	25,333	32,531	444,034
75% increase to MR level	8.3%	29,075	32,525	436,460
SC+MR(Original)+D	11%	37,774	29,515	381,144
SC+MR(Original)+D+ISB+SuD	28%	187,826	21,832	179,818

The simulations show that there is direct relationship between increased mechanical recovery resources and increased in oil removal and reductions in surface and shoreline oiling; however, in most cases there is also a pattern of diminishing returns that did not result in significantly increased overall positive outcomes. For the WD28 scenario, significant reductions in surface and shoreline oiling did occur, likely due to conditions that were generally favorable for mechanical recovery success, possibly due to its proximity to shore. Other scenarios that were less favorable for recovery operations showed much less in terms of positive outcomes for reduced oiling. A notable observation was that the addition of surface dispersants, and to an even larger degree subsea dispersants, resulted in significantly greater positive outcomes for reduced oiling than was achieved through additional mechanical recovery equipment.

3.0 CASE STUDY: DEEPWATER HORIZON RESPONSE

On April 20, 2010, a loss of well control occurred in the Gulf of Mexico in the Mississippi Canyon 252 lease block, Macondo well, triggering the largest accidental marine oil spill in U.S. history. Over the following 86 days, the well discharged an estimated 4.2 million barrels of crude oil into the Gulf of Mexico until its flow was successfully capped on July 15, 2015 with a newly designed, purpose-built device known as a "capping stack." A relief well drilled into and permanently sealed the Macondo well on September 19, 2010.[28]

The Deepwater Horizon oil spill had geographically widespread and long-lasting environmental and socio-economic impacts including oiled shorelines, closed fisheries, and polluted marine ecosystems. The response to the spill was unprecedented in scope and included the mechanical recovery of oil; the application of dispersants from the air as well as under water at the wellhead; the burning of oil on the water surface; extensive shoreline cleanup in marshes, sandy shorelines, and in subtidal zones; and the use of large quantities of shoreline protection boom. The magnitude and unique nature of the Deepwater Horizon oil spill also drove the use of novel source control strategies and technologies by oil spill response experts to respond to and ultimately stop the flow of oil into the Gulf of Mexico.[1]

Because the Deepwater Horizon oil spill represents an actual worst case discharge event and occurred relatively recently, with the use of modern drilling and response technologies, it serves as an informative example for BSEE to consider as the Bureau updates oil spill response regulations for OCS facilities. The characteristics of the Deepwater Horizon spill and response were taken into consideration as model scenarios and parameters were selected for Section 2.0 of this study, and BSEE has a unique opportunity to incorporate lessons learned from the spill response efforts into new oil spill response requirements. Figure 141 serves as a "dashboard" that compares the parameters of the model scenarios to the actual characteristics of the Deepwater Horizon oil spill. The black arrows represent the range of parameters used in the 11 model scenarios, and the green triangles represent actual values of the Deepwater Horizon oil spill. While WCD events should be expected to vary greatly in their magnitude and characteristics, the Deepwater Horizon oil spill can serve as a rough guide as to what outcomes are within the realm of possibilities. Because of the familiarity of the Deepwater Horizon event to BSEE regulators and industry experts, the spill also serves as an informative benchmark, as this study explores rare, extreme WCD events that can be difficult to compare with offshore oil and gas operations. Figure 141 shows that for most parameters, the Deepwater Horizon oil spill falls well within the range of the values that were modeled with two exceptions – WCD duration and mechanically recovered oil. The model scenarios were all simulated with shorter WCD durations due to significant advances in well capping technology that have occurred since, and largely due to, the Deepwater Horizon oil spill. Mechanical recovery in the Deepwater Horizon oil spill was estimated to be lower than what was simulated in the model scenarios; however, it should be cautioned that measurement of oil recovery rates during an actual spill event is very difficult and can be inaccurate, making a direct comparison to model results difficult.

[28] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. Deep Water, the Gulf Oil Disaster and the Future of Offshore Drilling. Washington: Government Printing Office, 2011.

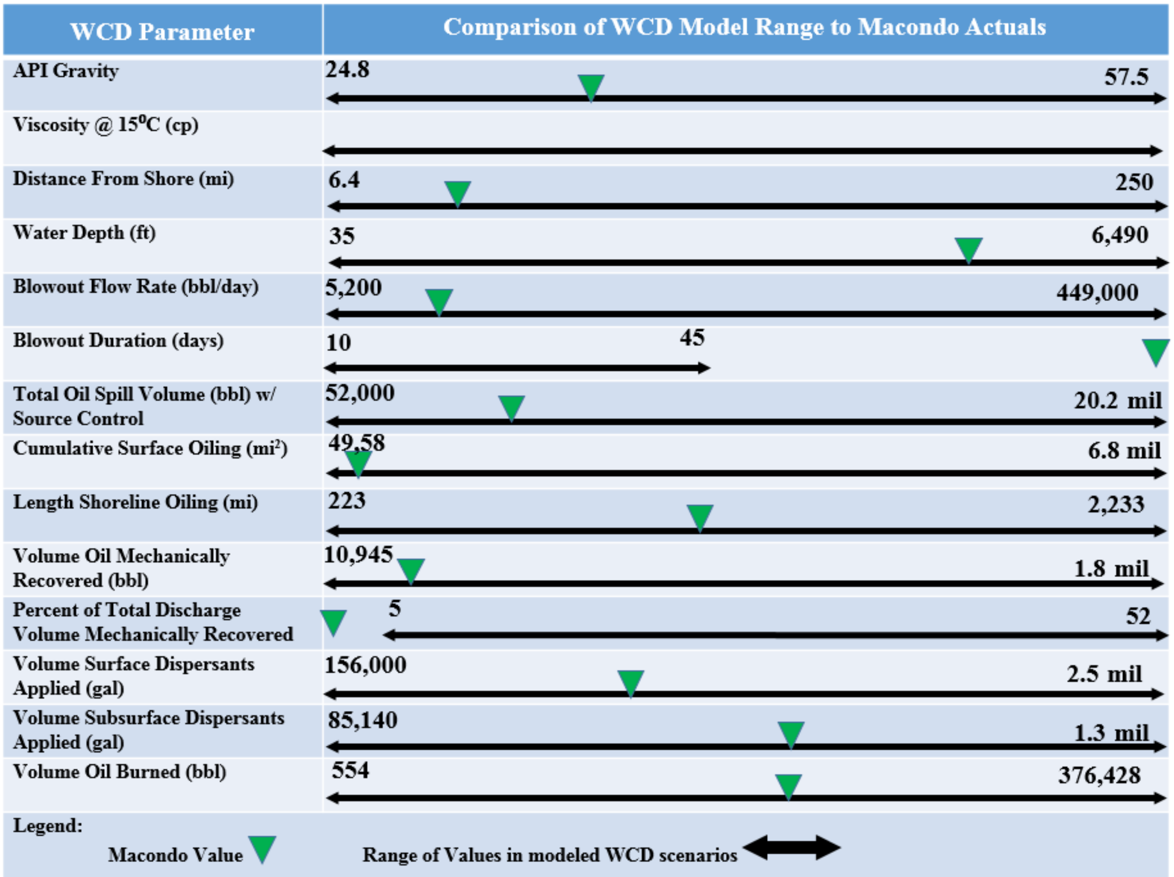


Figure 141: Comparison of Model Parameters with Deepwater Horizon

3.1 Macondo Oil Well Characteristics

The Macondo well was drilled by the *Deepwater Horizon,* a semi-submersible drilling rig, about 40 miles off the Louisiana coast in water depths of about 5,000 feet.[29] The *Deepwater Horizon* was drilling an exploration well into a hydrocarbon formation that yielded Louisiana Sweet Crude, a type of low-sulfur, low density crude oil,[30] and had drilled to a depth of 18,360 feet below sea level[1] before the blowout occurred. Prior to the loss of well control, conditions inside the Macondo well included a temperature of 245° F and a pressure of about 13,000 PSI — at or approaching the lower bounds of conditions considered high-pressure high-temperature (HPHT).[31] The initial flow rate of the discharge was calculated to be 62,000 barrels per day; the rate decreased to approximately 53,000 barrels per day over the 87-day course of the incident.[2]

3.2 Geographic Scope of the Oil Spill: Surface Exposure to Oil

Sea surface oiling from the Deepwater Horizon oil spill directly affected a cumulative total of 46,324 square miles[32] of Gulf of Mexico waters, and eventually led to the closure of 88,522 square miles of

[29] U.S. Coast Guard, On Scene Coordinator Report, Deepwater Horizon Spill, Washington: Government Printing Office, 2011
[30] NOAA. Deepwater Horizon Oil: Characteristics and Concerns. 2010.
[31] Vassel, Raymond, "Lessons Learned from the Macondo Blowout in the Gulf of Mexico," The Bridge on Social Sciences and Engineering Practice 42, no. 3 (2012).
[32] ERMA Deepwater Gulf Response

federal fishing area,[33] which is about a third of the total federal fishing area in the Gulf of Mexico (see Figure 142). More than 1,000 miles of shoreline came into contact with oil from the spill, primarily along the coasts of Louisiana, Mississippi, Alabama, and the Florida panhandle (see Figure 143).[34] Tarballs and other forms of weathered oil washed up on Gulf of Mexico shorelines many month after the well was capped and sealed. Figure 143, Figure 144, and Figure 145 show the length and severity of beach and marsh shoreline oiling associated with the Deepwater Horizon oil spill extending to November 2012, more than two years after the spill. Roughly equal lengths of beach and marsh shoreline were impacted, and while moderate to severe shoreline oiling attenuated over time, significant lengths of shoreline remained impacted by trace oiling two years after the spill, and small lengths of shoreline still had heavy oiling two years after the oil spill.

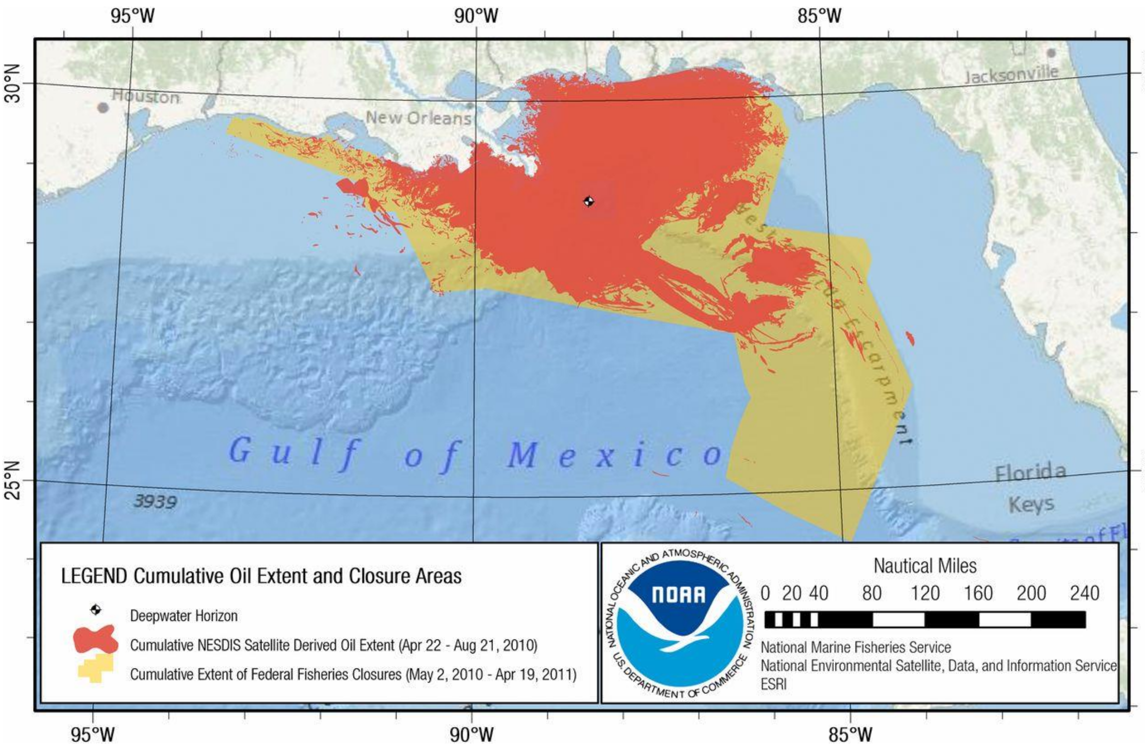


Figure 142: Cumulative Extent of Surface Oiling (Red) and Total Area Affected by Fisheries Closures (Brown) Due to Macondo Incident (Source: Ylitalo et al., 2012, Federal Food Safety Response to Deepwater Horizon Oil Spill)

[33] Ylitalo, Gina M. et al., 2012, Federal Food Safety Response to Deepwater Horizon Oil Spill
[34] Michel, Jacqueline et al., 2013, Extend and Degree of Shoreline Oiling: Deepwater Horizon Oil Spill, Gulf of Mexico, USA

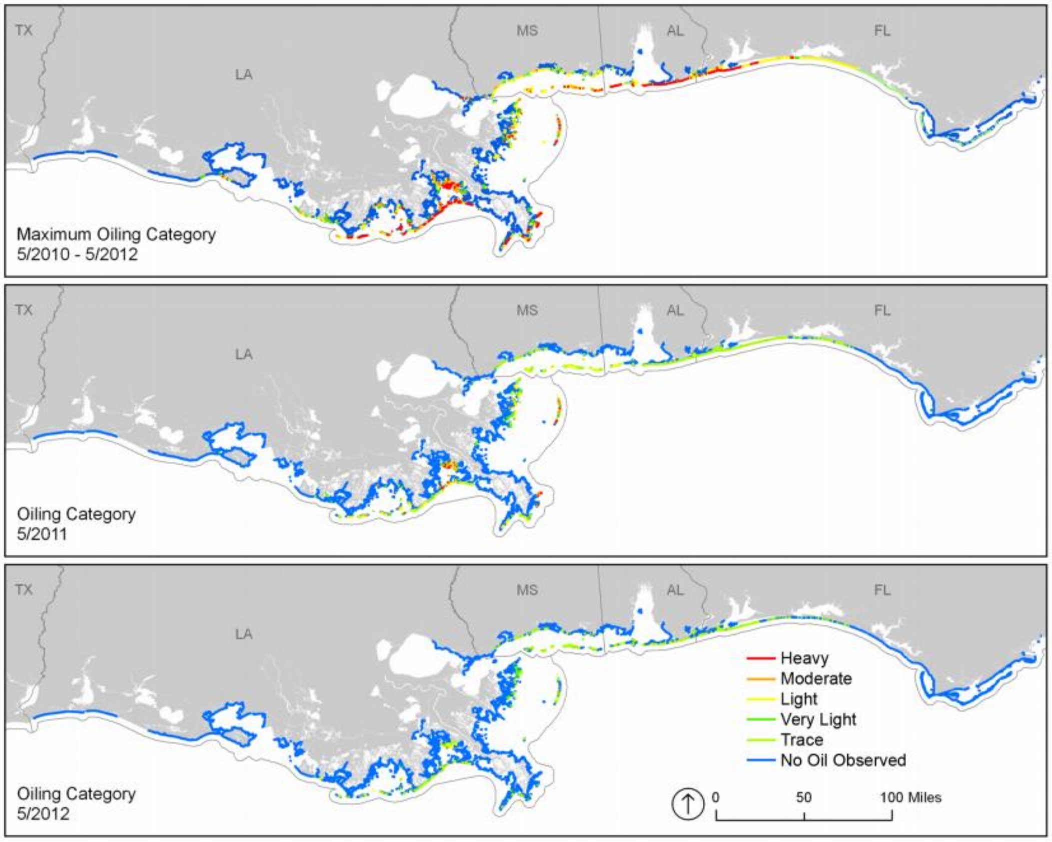


Figure 143: Geographic Extent and Severity of Shoreline Oiling from Macondo Incident at Maximum Oiling (Top Panel), One Year After Spill (Middle Panel), and Two Years After Spill (Bottom Panel) (Source: Michel Jacqueline et al., 2013, Extend and Degree of Shoreline Oiling: Deepwater Horizon Oil Spill, Gulf of Mexico, USA)

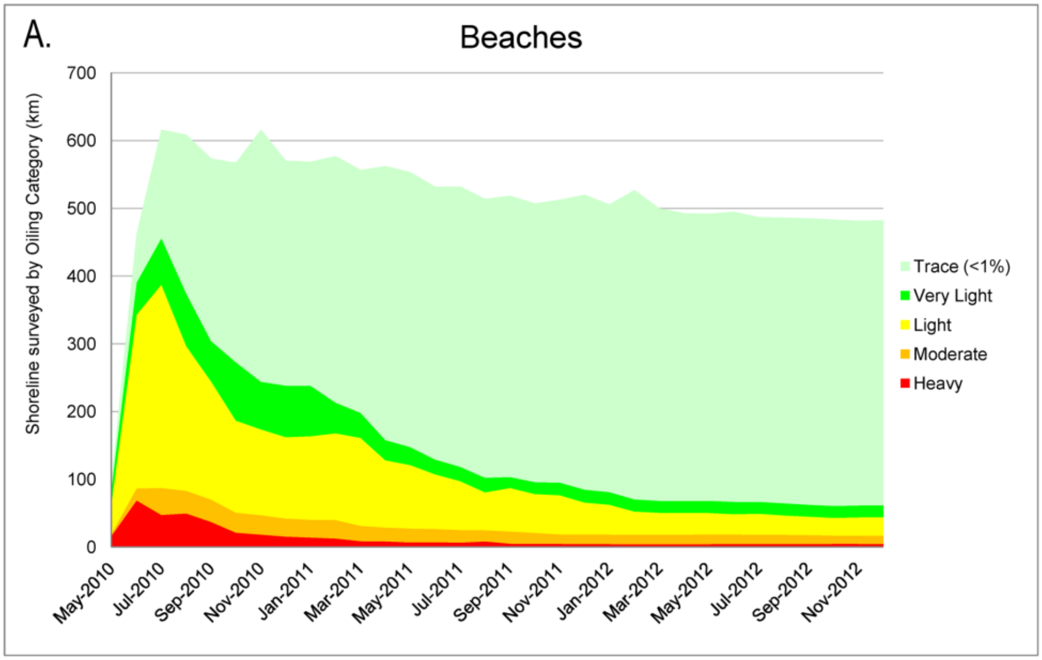


Figure 144: Total Length and Severity of Beach Shoreline Oiling from May 2010 to November 2012 (Source: Michel Jacqueline et al., 2013, Extend and Degree of Shoreline Oiling: Deepwater Horizon Oil Spill, Gulf of Mexico, USA)

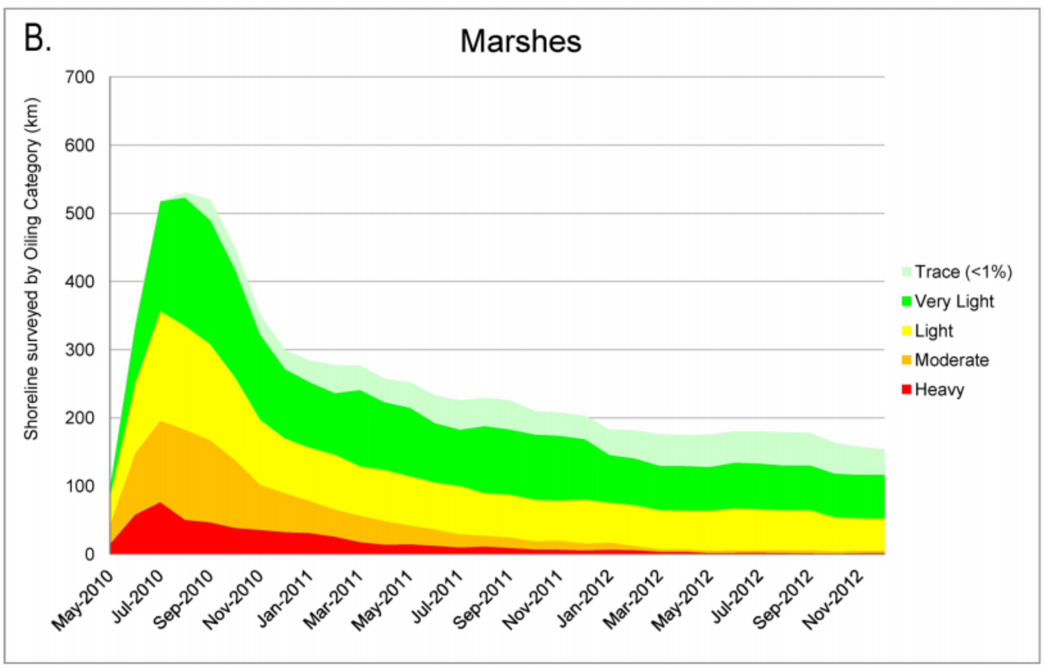


Figure 145. Total Length and Severity of Marsh Shoreline Oiling from May 2010 to November 2012 (Source: Michel Jacqueline et al., 2013, Extend and Degree of Shoreline Oiling: Deepwater Horizon Oil Spill, Gulf of Mexico, USA)

3.3 Geographic Scope of The Oil Spill: Subsurface Exposure to Oil

While surface oil and shoreline oiling were more visible to the public, a large fraction of the oil discharged formed small droplets that were suspended in the water column or deposited to the ocean floor. Oil entrained in the water column and deposited in ocean sediments exposed marine life to its chemical constituents and created the possibility of depleting the water column's dissolved oxygen as microbes consumed the spilled oil through aerobic processes.[35] According to the National Commission Report to the President: "*As of November 2010, three independent, peer-reviewed studies confirmed the presence of a deepwater plume of highly dispersed oil droplets and dissolved gases at between 3,200 and 4,200 feet deep and extending for many miles, primarily to the southwest of the wellhead*."

The Operational Scientific Advisory Team (OSAT), composed of scientists from federal agencies and academic research institutions, was commissioned by the U.S. Coast Guard in August 2010, and charged with monitoring and reporting on sub-sea environmental conditions. OSAT collected tens of thousands of water and sediment samples from 25 research ships on more than 125 separate cruises during response efforts. OSAT's *Summary Report for Sub-Sea and Sub-Surface Oil and Dispersant Detection* indicated that sediment polycyclic aromatic hydrocarbon (PAH) concentrations exceeded the EPA's aquatic life benchmark for PAHs[36] within three kilometers of the wellhead and exceeded reference levels (concentrations prior to the oil spill) within 10 kilometers of the wellhead; however, no exceedances of the benchmark were detected beyond 3 kilometers from the wellhead that could be ascribed to Macondo oil. There was no exceedance of EPA's human health benchmark for oil-polluted water, and after August 3, 2010, no exceedance of the aquatic life benchmark for PAHs in water that could be ascribed to Macondo oil. Separately, OSAT reported the presence of tarmats in shallow water areas as a concern because of their potential to be re-mobilized and subsequently re-oil nearby shorelines.[37]

The NOAA Joint Analysis Group (JAG) studied dissolved oxygen levels in the water column to assess whether Macondo well oil was contributing to hypoxic conditions impacting aquatic life in the Gulf of Mexico. Based on sampling conducted between May and August 2010, JAG concluded that, while dissolved oxygen levels in the water column were depressed relative to background concentrations and corresponded with the presence of oil in the water column, dissolved oxygen levels did not drop low enough to result in hypoxic conditions.[38]

3.4 Oil Spill Response Capabilities Employed

The response to the Deepwater Horizon oil spill drew on oil spill response resources from around the world. Response equipment included skimmers, temporary storage vessels, aircraft for dispersant application and oil spill surveillance, sub-sea dispersant equipment, in situ burn equipment and spotter aircraft, shoreline cleanup crews, containment and sorbent boom, and hundreds of support vessels.[9]

3.4.1 Mechanical Recovery of Oil

Mechanical oil recovery systems were deployed in three distinct zones to collect oil from the water's surface: (1) the offshore environment above the wellhead, (2) nearshore areas along the coast, and (3) shoreline areas to protect environmentally and economically important beaches, bays, and marshes. A wide variety of skimming vessels were used, including dedicated oil spill response vessels specifically

[35] National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. Deep Water, the Gulf Oil Disaster, and the Future of Offshore Drilling. Washington: Government Printing Office, 2011.
[36] EPA's aquatic life benchmarks are screening-level chemical-specific thresholds for potential adverse effects to aquatic life.
[37] Operational Science Advisory Team, Summary Report for Sub-Sea and Sub-Surface Oil and Dispersant Detection: Sampling and Monitoring, Washington, Government Printing Office, 2010
[38] Joint Analysis Group, Deepwater Horizon Oil Spill, Review of Preliminary Data to Examine Oxygen Levels in the Vicinity of MC252#1, May 8 to August 9, 2010, Silver Spring, Maryland, 2011

designed to collect and decant oily water, Coast Guard Buoy Tender vessels equipped with the Spilled Oil Recovery Systems (SORS) or retrofitted with the Vessel of Opportunity Skimming System (VOSS), and other vessels of opportunity, including fishing vessels, fitted with skimming and recovery systems.

Vessels suited for offshore operations were characterized by their large size, usually more than 50 feet in length, which gave them the ability to operate in greater wind and wave conditions, and made it possible to support crews for extended periods at sea. Nearshore skimming vessels were typically smaller than 50 feet in length and operated within three miles of shore. The small vessels were better suited for response activities near shore where they could move quickly between patches of weathered oil more than 40 miles from the well site. Nearshore skimming was typically coordinated with aerial surveillance resources that could direct skimmers to dispersed patches of weathered oil that threatened environmentally sensitive areas such as reefs and wetlands. Oil recovery operations at and near beaches, tidal and subtidal zones, bays, and marshes were conducted with a variety of skimming and other oil removal technologies deployed from land, small vessels, and barges. Oil encountered in this zone was found in a wide range of conditions including mousse, tarballs, and mats of weathered oil.[39]

Hundreds of skimming vessels were deployed to the Gulf of Mexico over the course of the spill response. Figure 146 reflects the U.S. Coast Guard's records of the total number of skimmers and total vessels (including skimmers) involved in response efforts. At its peak, the number of skimmers responding to the spill in the Gulf of Mexico totaled 835. Many of these skimmers remained in operation for months after the well was capped on July 15, 2010. The total number of vessels involved in the response numbered in the thousands and included temporary storage vessels, remote operated vehicle (ROV) support vessels, and other vessels associated with source control such as capping, subsurface containment, and relief well drilling.[12]

The Oil Pollution Act of 1990 requires offshore operators to contract with sufficient skimming resources to mechanically recover "to the maximum extent practicable" a volume of oil equal to a worst case discharge as defined by U.S. regulations in 30 CFR Part 254. The Macondo well's Oil Spill Response Plan (OSRP) anticipated a worst case discharge of 162,000 bbl/day (about 100,000 bbl/day *greater* than the actual flow rate encountered during the spill). The OSRP also stipulated that the operator had access, through contracts, to a total oil recovery capacity of 492,000 bbl/day. This oil recovery rate was calculated using the effective daily recovery capacity (EDRC) planning standard, which is set forth in U.S. regulations in 30 CFR §254.44. If the oil recovery rate cited in the OSRP had been accurate, the contracted skimming resources should have been more than sufficient to recover the 50,000 to 60,000 bbl/day discharged from Macondo; however, the contracted skimming resources, along with a huge supplement of response equipment from elsewhere in the United States and abroad, is estimated to have only recovered 3% to 4% of the spilled oil. These facts illustrate the limitations of mechanical recovery as a response strategy and of regulatory planning standards, including the EDRC standard.[40]

[39] U.S. Coast Guard, On Scene Coordinator Report, Deepwater Horizon Spill, Washington: Government Printing Office, 2011
[40] United States Coast Guard, BP Deepwater Horizon Oil Spill Incident Specific Preparedness Review, 2011

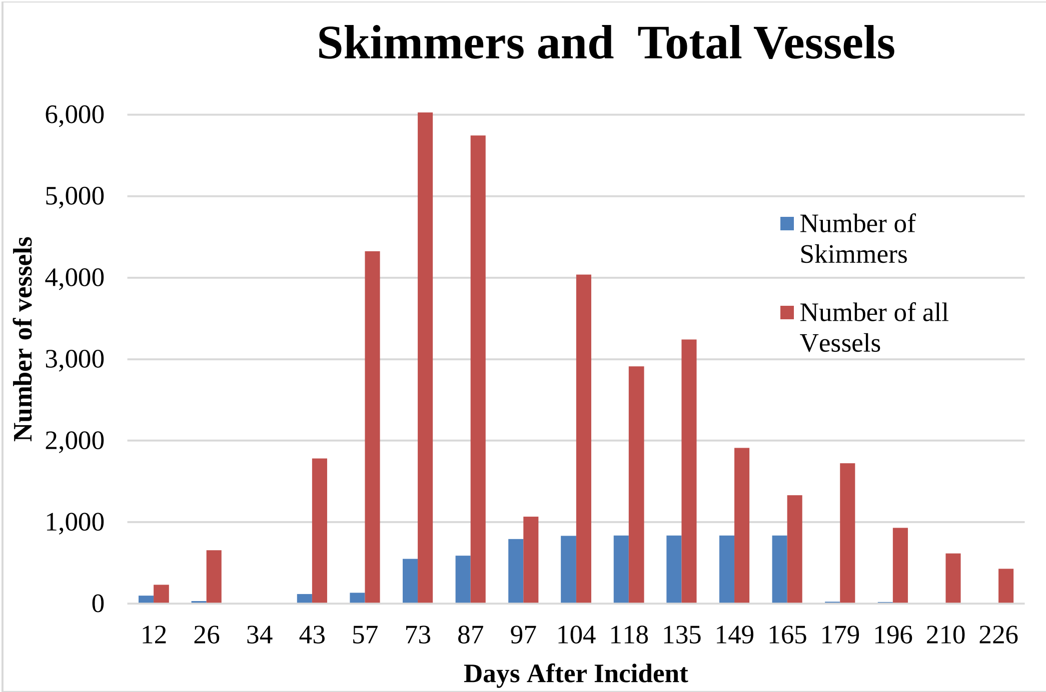


Figure 146: Number of Skimming Vessels and Total Number of Vessels (Including Skimmers) Deployed for Deepwater Horizon Oil Spill Response, Note That Periods Between Reporting Days Are Irregular (Source: U.S. Coast Guard, 2011, On Scene Coordinator Report Deepwater Horizon Oil Spill)

3.4.2 Surface Dispersant Application

Industrial grade oil dispersants, such as those used to respond to the Deepwater Horizon oil spill, are a mixture of surfactants that chemically break oil into small droplets. After the oil is broken into droplets, it is more readily degraded by biological (microbial) and physical processes. Dispersants such as those used during the Deepwater Horizon oil spill are composed of several active compounds, including 2-butoxyethanol, which is a moderately flammable organic hydrocarbon, presenting relatively low toxicity to human beings, if exposed to skin or inhaled.

The application of dispersants does not remove oil from the water's surface or from the water column. Rather, dispersants alter the transport and fate of spilled oil in an attempt to minimize environmental and socioeconomic impacts. The Federal On-Scene Coordinator (FOSC) authorized the use of dispersants on April 22, 2010, two days after the Deepwater Horizon oil spill, and the first aerial dispersant application sortie occurred later that day. Sorties consisted of spotter planes to locate oil slicks as well as dispersant application aircraft. Small boats were also involved in some cases to monitor the effectiveness of dispersant application.[41]

Dispersed oil may have negative impacts on sensitive environmental endpoints especially under local conditions that limit the mixing and dilution of oil, such as areas with shallow water depth or little wave action. For this reason, the application of dispersants in nearshore areas was avoided as outlined in the Region 6 Regional Response Team Dispersant Preauthorization Plan. During the Deepwater Horizon oil

[41] U.S. Coast Guard, On Scene Coordinator Report, Deepwater Horizon Spill, Washington: Government Printing Office, 2011

spill response, 98% of aerially sprayed dispersant was deployed more than 10 nautical miles offshore (Figure 147)[14].

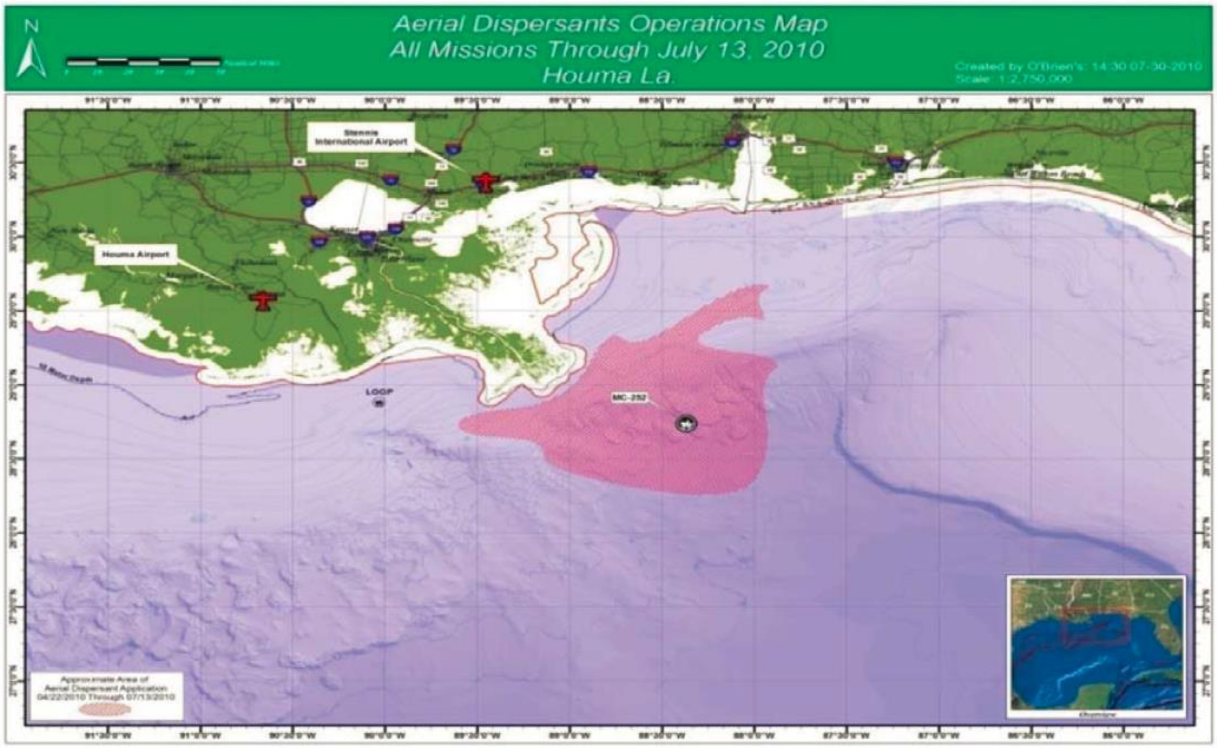


Figure 147: Area Where Aerial Dispersant Operations Occurred (Pink) During the Macondo Incident (Source: U.S. Coast Guard, 2011, On Scene Coordinator Report Deepwater Horizon Oil Spill)

According to the Houma Incident Command Post After Action Report, aerial dispersant operations were carried out using 14 spray aircraft and 8 spotter aircraft that flew a total of 412 spray sorties and 816 reconnaissance and spotter sorties to apply a total of 972,880 gallons of dispersant. Aircraft used to apply dispersants are shown in Table 92. Spotter aircraft used in support of dispersant operations included King Air BE-90s and Aero Commander aircraft. Approximately 305 square miles were sprayed with dispersant over an 18,000 square mile operating area, and an estimated 12 million to 18 million gallons of oil was dispersed.[42]

[42] U.S. Coast Guard. After Action Report Deepwater Horizon MC252 Aerial Dispersant Response. Houma, LA, 2010

Table 92: Individual Aircraft Used in Dispersant Operations, Payload, and Dispersant Applied Per Aircraft (Source: U.S. Coast Guard, After Action Report Deepwater Horizon MC252 Aerial Dispersant Response. Houma, LA. 2010)

Aircraft	Engine Configuration	Payload (lbs)	Dispersant Applied (gal)
C-130	quad engine	3,250	244,873
C-130	quad engine	5,000	336,256
C-130	quad engine	5,000	23,537
C-130	quad engine	5,000	35,379
C-130	quad engine	2,000	67,184
C-130	quad engine	2,000	31,952
C-130	quad engine	2,000	40,143
C-130	quad engine	2,000	16,269
Basler BT-67	twin engine	1,800	122,441
Douglas DC-3	twin engine	1,000	31,658
Douglas DC-3	twin engine	1,000	7,100
Air Tractor AT-802	single engine	800	13,868
King Air BE-90	twin engine	425	1,910
King Air BE-90	twin engine	425	200
Total			**972,880**

According to the U.S. Coast Guard On Scene Coordinator Report, aerial dispersants were applied at an average rate of 24,386 gallons per day from the beginning of aerial dispersant operations on April 22, 2010 until May 26, 2010 at which time EPA requested a reduction in aerial dispersant application. Aerial dispersants were used during 33 of the 54 days between May 27, 2010 and July 19, 2010, with an average application rate of 8,892 gallons per day. The Report also notes that there was a correlation between reduction in aerial dispersant application and increased shoreline oiling.

3.4.3 Subsurface Dispersant Application

Prior to the Deepwater Horizon oil spill, sub-sea dispersants had never been used on a substantial scale, and had only been tested six times worldwide in shallow water conditions. The decision to use sub-sea dispersants was made because of two major advantages of this method over aerial application: (1) the ability to apply dispersants directly at the subsurface point of origin for the spill is likely to be more efficient and effective (thereby potentially reducing the amount of dispersant that need to be used), and (2) sub-sea application can continue 24 hours a day in nearly all types of weather conditions, whereas aerial dispersant application can only occur during the day when aircraft can spot oil slicks. The application of subsurface dispersants also served as a means to reduce VOC emissions from spilled oil above the wellhead. VOC emissions near the wellhead, posed a safety risk to workers involved in source control operations.[43]

Application of dispersants to the sub-sea plume of oil involved deploying large tanks of dispersants on a support vessel and guiding an application hose to the Macondo wellhead more than 5,000 feet below the surface using ROVs. ROVs were also used to calibrate the subsurface dispersant system and monitor the dispersant effectiveness. Approximately 770,000 gallons of dispersant were injected at the wellhead between late April and the capping of the well in July 2010 (see Figure 148).[44]

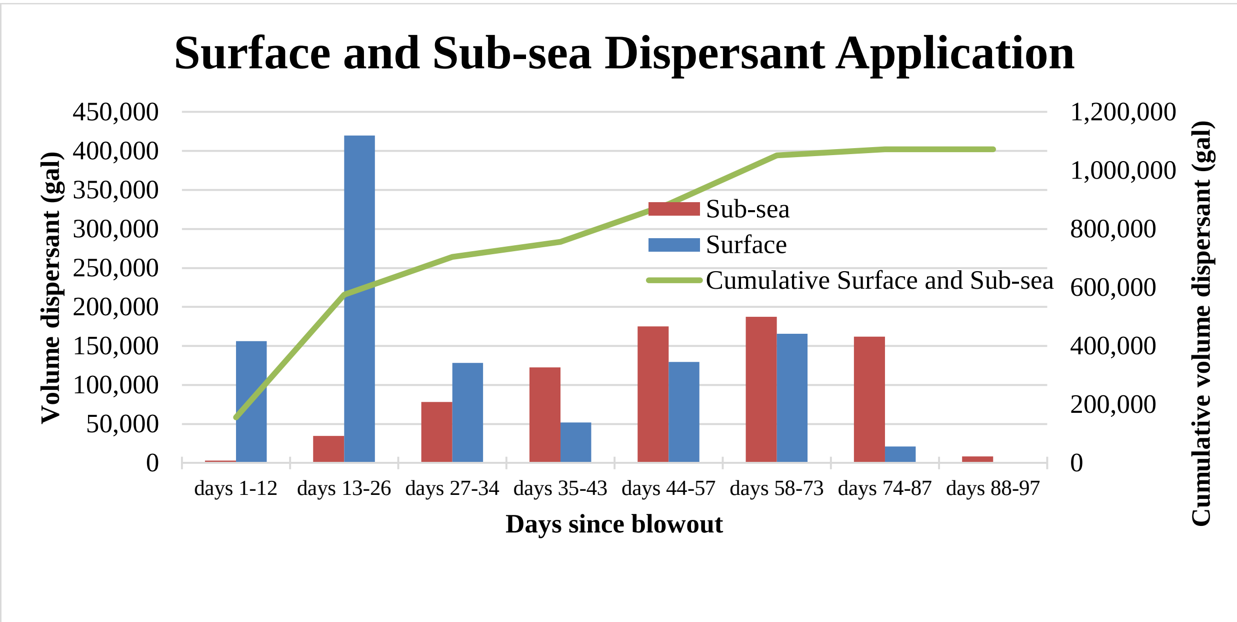


Figure 148: Application of Subsurface and Aerially Applied Dispersants Over the Course of the Deepwater Horizon Oil Spill Response. Note that time increments between reporting days are irregular (Source: U.S. Coast Guard, 2011, On Scene Coordinator Report Deepwater Horizon Oil Spill)

Because of the novel nature of the sub-sea dispersant operations and the potential for environmental impacts from dispersed oil on marine life at depth in the water column, significant resources were dedicated to monitoring the dispersed oil plume and water quality in the surrounding environs. To coordinate and deploy these monitoring resources, the FOSC established the Environmental Unit, comprised of federal, state, and industry scientists and coordinated the monitoring of subsurface dispersant application. A separate subsurface monitoring unit was also established at the Incident Command Post (ICP) Houma, referred to as the Subsurface Monitoring Unit (SMU). Additionally EPA and the U.S. Coast Guard issued a directive to the Responsible Party (RP) to develop and implement a subsurface monitoring plan to ensure that use of subsurface dispersants did not result in unacceptable water column impacts. The subsurface monitoring plan was developed by the RP in cooperation with the Environmental Unit, and set forth requirements for monitoring of temperature, dissolved oxygen, detection of dispersed oil concentrations using a fluorometer system, collection of water samples at depth

[43] U.S. Coast Guard, On Scene Coordinator Report, Deepwater Horizon Spill, Washington: Government Printing Office, 2011
[44] U.S. Coast Guard, On Scene Coordinator Report, Deepwater Horizon Spill, Washington: Government Printing Office, 2011

to assess oil concentrations, and biological assessment to screen for dispersed oil toxicity. Equipment used for monitoring efforts included a dedicated merchant ship to support marine scientists and monitoring equipment in the deep-water environment near the wellhead, and numerous small craft that monitored in the nearshore environment. The Deepwater Horizon oil spill was the first time an RP was expected to provide the capabilities necessary to conduct dispersant application monitoring (as well as in situ burning monitoring) to evaluate the fate and effects of oil discharged to the environment.[45]

3.4.4 In Situ Burning

In situ burning is a spill response technique that burns the oil in place (in situ) to eliminate/remove spilled oil from the environment where the oil is spilled. While in situ burning presents ignition risks to spill response crews and equipment and the smoke plumes negatively impact regional air quality, in situ burning has the potential to remove large amounts of oil from the ocean with less need for major pieces of response equipment, such as offshore oil storage vessels.[19]

In situ burn operations for the Deepwater Horizon oil spill began in late April 2010 and grew to include a crew of 264 people, 43 vessels, and 2 dedicated King Air twin-engine spotter planes. VOO were used to tow fire-resistant boom to collect oil to a thickness sufficient for ignition. Spotter planes flew two sorties daily during daylight hours. In situ burn teams used 23,000 feet of fire boom, including fire boom acquired from South America, Alaska, and Algeria.[46] Fire boom designs included water-cooled, stainless float, and ceramic booms[19]. While fire boom is resistant to fire, crews found that about 400 to 500 feet of boom were destroyed daily during regular operations.[18]

Over the course of Deepwater Horizon oil spill response operations, in situ burn teams conducted 411 burns and removed an estimated 5% of the oil released from the Macondo well (approximately 265,450 barrels of oil). The most successful day of burning occurred on June 18, 2010 when 16 different burns removed an estimated 50,000 to 70,000 barrels of surface oil. Figure 149 shows the number of in situ burns performed over the course of the Deepwater Horizon oil spill response.[19]

[45] U.S. Coast Guard, On Scene Coordinator Report, Deepwater Horizon Spill, Washington: Government Printing Office, 2011
[46] Allen, Alan. *The Use of Controlled Burning during the Gulf of Mexico Deepwater Horizon MC-252 Oil Spill Response*, 2011

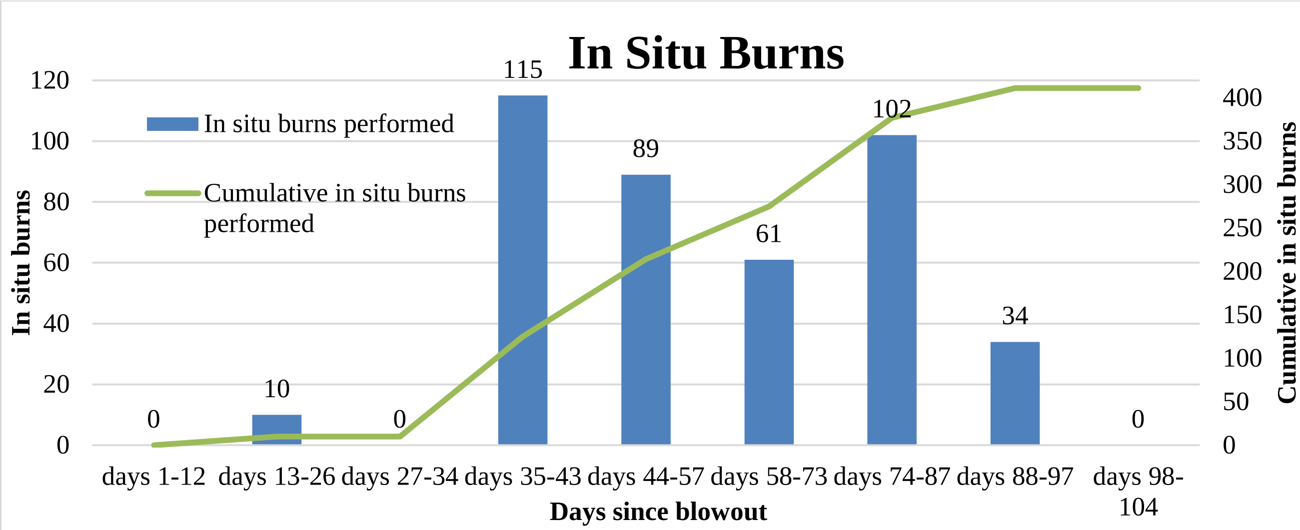


Figure 149: Number of In Situ Burns Performed Over the Course of the Macondo Incident Response. Note that periods between reporting days are irregular (Source: U.S. Coast Guard, 2011, On Scene Coordinator Report Deepwater Horizon Oil Spill)

3.4.5 Shoreline Protection and Oil Collection Boom

Protective boom was deployed along shorelines in Florida, Alabama, Mississippi, and Louisiana as a final barrier between surface oil and coastal areas of socioeconomic or environmental importance. Various types and configurations of protective boom was deployed to protect sensitive shoreline endpoints identified by Area Contingency Plans (ACPs), including economically important beaches and entrances to inland waters, and environmentally sensitive areas such as marshes and estuaries. Deflection boom was used to direct surface oil to collection areas where it could be cleaned up using shallow water or land-based skimming devices, isolation boom was used to protect environmentally sensitive areas in calm water with little or no current, and sorbent boom was used to adsorb and collect oil. More than 2,000 rigid pilings were also used along the Gulf coast to affix rigid pipe boom and flexible boom. After boom was in place, daily air sorties were flown to monitor its integrity and direct repair or replacement operations.[47]

Figure 150 shows the amount of shoreline boom deployed at various stages of the spill response efforts. At its peak, protection and containment boom totaled about 3.7 million linear feet and sorbent boom totaled more than 9 million linear feet. Figure 150 also reflects the reduction in deployed boom that began after the well was successfully capped on day 87, July 15, 2010.[20]

[47] U.S. Coast Guard, On Scene Coordinator Report, Deepwater Horizon Spill, Washington: Government Printing Office, 2011

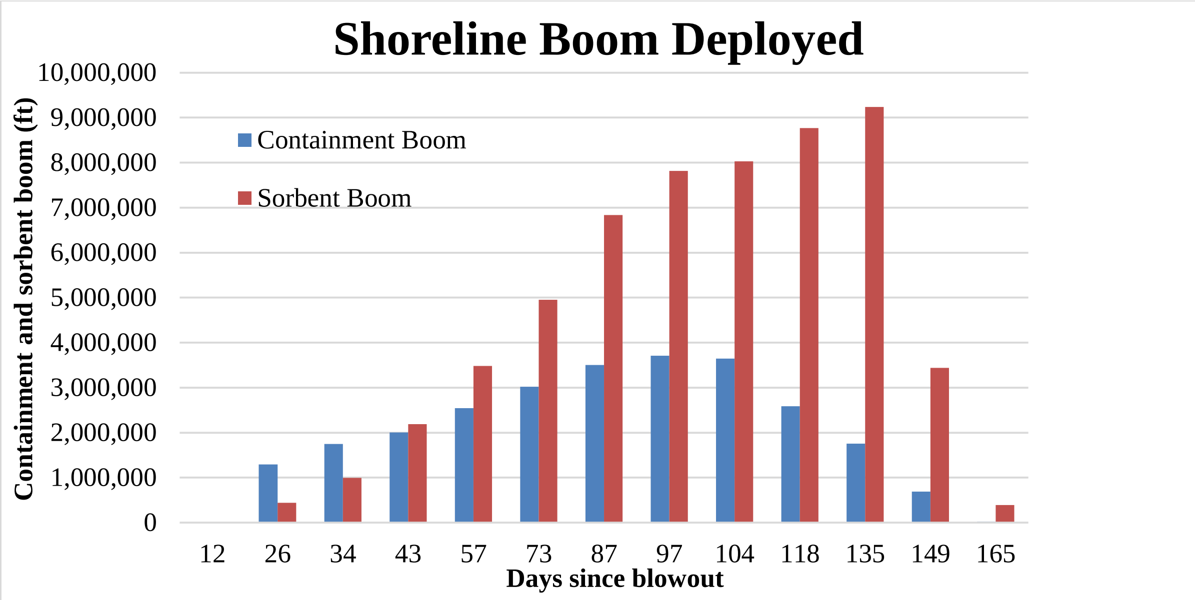


Figure 150: Total Containment and Sorbent Boom Deployed Over the Course of the Deepwater Horizon Oil Spill Response. Note that time increments between reporting days are irregular (Source: U.S. Coast Guard, 2011, On Scene Coordinator Report Deepwater Horizon Oil Spill)

3.4.6 Source Control

While the many and varied oil spill response efforts attempted to remove spilled oil and protect sensitive environmental and economic endpoints, source control operations occurred simultaneously in an attempt to stop the uncontrolled discharge from the Deepwater Horizon oil spill. The only proven method of permanently plugging a well that is discharging oil to the environment is the drilling of a relief well, but this process can take months as it involves transporting a drill rig to the blowout site and drilling a new well thousands of feet deep to intercept and plug the failed well. On May 2, 2010, a mobile offshore drilling unit arrived at the incident site and began drilling a relief well, which was expected to require at least 90 days to complete. In the meantime, various temporary source control methods were attempted to stop the flow of oil or capture discharged oil before it could escape into the environment.[48]

Since loss of well control resulting in a discharge of oil of this magnitude had never occurred before, source control experts were forced to resort to a series of untested, ad-hoc methods to cease the flow of oil. This included the deployment of devices known as containment dome, a top hat, and a riser insertion tube tool, which were designed to fit over the wellhead or into the riser, and capture and successfully delivered some of the flowing oil to a tanker on the surface. None of these early efforts succeeded in completely stopping the flow of oil; however, later efforts were successful in containing and flowing much of the released oil to temporary storage and processing vessels at the surface. Responsible Party engineers also designed and fabricated a new device that they dubbed a "capping stack," which was essentially a blowout preventer that could be lowered onto and attached to the existing riser, at which time the blowout preventer rams in the capping stack would be slowly closed to stop the flow of oil. Fabrication of the capping stack device was completed on June 28, 2010, and operations to install the capping device began at the incident site on July 10, 2010. Two days later, on July 12, 2010, the capping stack was successfully installed on the Macondo well. On July 13, 2010, source control operations began recovering oil from the capping stack at a rate of about 20,000 barrels per day, and on July 15, 2010, after

[48] U.S. Coast Guard, On Scene Coordinator Report, Deepwater Horizon Spill, Washington: Government Printing Office, 2011

testing to ensure integrity under high pressures, the capping stack was closed, which ended the flow of oil into the Gulf of Mexico.[21]

On September 16, 2010, 123 days after drilling of the relief well began, the relief well intercepted the well bore of the Macondo well. Three days later, on September 19, 2010, the Macondo well was permanently sealed. Table 93 shows the timeline of the key source control efforts of the relief well and capping stack. The capping stack ended the flow of oil 66 days sooner than if source control efforts had been limited to the relief well. Assuming a flow rate of 53,000 barrels per day, the capping stack abated the flow of oil into the Gulf of Mexico by roughly 3.5 million barrels.

Table 93: Dates and Timeline of the Key Source Control Efforts of the Capping Stack and Relief Well (Source: U.S. Coast Guard, 2011, On Scene Coordinator Report Deepwater Horizon Oil Spill)

Source Control Timeline	Date	Time period
Macondo loss of well control occurs	April 20, 2010	
Drilling of first relief well begins	May 2, 2010	13 days after loss of well control
Capping stack stops flow of oil from wellhead	July 15, 2010	87 days after loss of well control
Relief well permanently plugs Macondo well	September 19, 2010	153 days after incident, 66 days after flow of oil is stopped

3.4.7 Simultaneous Operations

One of the greatest challenges of the Deepwater Horizon oil spill response was coordinating and de-conflicting the vast array of simultaneously occurring aerial and on-water spill response operations. Failure to establish exclusive operating zones for different response strategies could have resulted in aerial dispersants being sprayed on mechanical skimming vessels, in situ burn operations delaying source control support vessels, or worse, mid-air collision of aircraft.[49]

To minimize these risks, different response methods were assigned exclusive zones in which to conduct operations. Response operations were not permitted to come closer than three miles of the incident site to avoid conflict with source control operations.[22] In situ burn, aerial dispersant, and mechanical recovery crews coordinated daily to establish exclusive zones in which to conduct their operations; this process was made easier by the fact that different response options perform optimally against oil of different weathered states and, therefore, different distances from the spill source.

Surveillance aircraft were used to direct response resources to areas where they could be most effective and avoid interference from other response operations.[50] The extensive use of aircraft during response operations presented both operational and safety risks. Over the course of response operations, 120 fixed wing aircraft and helicopters participated in dispersant application, aerial surveillance, and transportation. An Aviation Coordination Center was established at Tyndall Air Force Base near Panama City, FL, to direct air response operations. This centralized approach proved essential in preventing collisions

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[49] U.S. Coast Guard, On Scene Coordinator Report, Deepwater Horizon Spill, Washington: Government Printing Office, 2011

[50] Allen, Alan A., *et al.* *The Use of Controlled Burning During the Gulf of Mexico Deepwater Horizon MC-252 Oil Spill Response*. International Oil Spill Conference. 2011

between aircraft and enhancing operators' abilities to track, recover, burn, and disperse oil.[51] Air-to-ground communications links, Automatic Identification Systems (AIS), and live video from shore-based and vessel-mounted systems were used in an integrated manner across the spill response enterprise.[23]

3.4.8 Aerial Surveillance and Remote Sensing

The ability to track spilled oil and direct response resources to oil slicks of sufficient thickness was critical to the efficient assignment and operation of response assets. Several different advanced remote sensing technologies were deployed on fixed-wing aircraft and satellites to:

- Track the overall extent of the oil spill;
- Locate patches of oil that could be recovered, burned, or dispersed;
- Monitor the placement of protective boom; and
- Locate shoreline segments impacted by oiling.

Table 94 shows the major air assets deployed by the government of the United States, as well as Canada and Iceland. Not shown in Table 94 are the numerous Cessna 172 and 182 single engine aircraft that were flown by the Civil Air Patrol during response efforts. Civil Air patrol aircraft flew over 1,000 sorties to monitor shoreline impacts and placement of protective boom.[52]

[51] United States Coast Guard, National Incident Command, National Incident Commander's Report: MC252 Deepwater Horizon, 2010
[52] Huber, Mark. The Other Gulf War. Smithsonian Air & Space Magazine. January, 2011

Table 94: Aerial Surveillance Aircraft Used in Macondo Incident Response

Organization	Aircraft	Capabilities	Missions Flown
U.S. Customs and Border Protection	2 Predator UAVs	Tested for oil detection capabilities	4
U.S. Customs and Border Protection	Cheyenne-PA42	Forward Looking Thermal IR (FLIR) and geo-referenced oblique images	no data
U.S. Navy	MZ-3A airship	Oil detection for skimming support, ability to stay aloft for 20 hrs.	19
EPA	ASPECT Aero Commander 680	Generates geo-referenced visible and infrared images	15
NOAA	2 DHC-6 Twin Otters	Multi-spectral scanner for oil thickness evaluation, on-board observers to detect marine mammals and sea turtles	19
NASA	King Air B-200	High Spectral Resolution Lidar (HSRL) that measured thickness of oil below surface	no data
U.S. Air Force	RC-26	Live Full Motion Video (FMV) to direct skimming operations	63
Transport Canada	Bombadier Dash-8	High Altitude Side Looking Airborne Radar (SLAR), geo-referenced imagery	no data
Icelandic Coast Guard	Bombadier Dash-8	Side Looking Airborne Radar (SLAR), 360 degree Maritime Search Radar	no data
NASA	ER-2 high altitude aircraft	Airborne Visible/Infrared Imaging Spectrometer (AVIRIS), Cirrus Digital Camera System	no data
U.S. Coast Guard	HC-103H	SELEX 7500E radar, Full Motion Video (FMV) to direct skimming operations	17
U.S. Coast Guard	HC-144	radar and electro optical/infrared sensors system to direct skimming operations	16
Note: this information is not exhaustive and specific mission data were not available for some aircraft. (Sources: Houma IC, 2010, Interim Report: Remote Sensing, Establishing Priorities, Selecting Resources, Data Collection, Analysis, Distribution and U.S. Coast Guard, Combined Aircraft Effectiveness Assessments)			

NASA satellites were heavily relied upon to track the overall extent of the spill, provide spill trajectory forecasts, and assist in the planning effort to deploy shoreline boom. The Terra and Aqua satellites, both of which employ NASA's Moderate Resolution Imaging Spectroradiometer (MODIS) technology, were each able to record the entire extent of the oil spill twice a day due to their 2,300-km view swath. The Aqua and Terra satellites were not effective in distinguishing between oil sheen and thick, fresh oil and could not view the spill through cloud cover. The Earth Obersving-1 (EO-1) satellite was also employed to track the extent of the oil spill. It has a narrower field of view (8-37 km), but compared to the Terra and Aqua satellites, was able to provide higher resolution images of surface oil.[53]

3.5 Comparison of key observations from Deepwater Horizon Incident and SIMAP Model Results

Comparing computer modeling simulations of large WCD oil spills to real-world events like the Deepwater Horizon incident is inherently difficult and must be done with a number of caveats. Data collected from actual oil spills is done with a wide range of instruments including remote sensing, visual observation, and chemical monitoring. These instruments and methods each have unique challenges and possibilities for human error. Data from model simulations are the result of deterministic computer simulations which are arguably less subject to human error, but models are oversimplified representation of reality, and cannot capture the full complexity of real-world events. Despite these caveats, it is possible to make some very general observations and conclusions from the comparison of WCD scenarios modeled in this study and the Deepwater Horizon oil spill response.

3.5.1 Criticality of Temporary Source Control Capabilities

After 123 days of drilling operations, the relief well intercepted the well bore of the Macondo well. Three days later, on September 19, 2010, the Macondo well was permanently sealed. Fortunately, responders were able to use a capping stack and end the flow of oil on Jul 15, 2010, 66 days sooner than if source control efforts had been limited to drilling the relief well. Assuming a flow rate of 53,000 barrels per day, the capping stack abated the flow of by approximately 3.5 million barrels of oil into the Gulf of Mexico.[54]

The implementation of temporary source control actions was simulated for all the WCD modeling scenarios done for this study. The model results show, not surprisingly, that temporary source control actions are likely to be the most effective means of reducing the total discharge volume of an oil spill. This is largely because source control can prevent oil from flowing into the environment, rather than removing it once the oil has been discharged. A comparison of the percent of oil discharge prevented by well capping among the model scenarios and the Macondo well is shown in Figure 151. The amount of oil discharge prevented by the simulated source control actions in the model scenarios range from about 250,000 bbl to 19 million bbl of oil. The simulated time to complete the temporary source control actions in the model scenarios ranged from 14 to 45 days, based on the specifics of each WCD scenario, and information contained within representative OSRPs and Regional Containment Demonstration plans. While temporary source control actions took 87 days to stop the flow of oil in the Macondo incident, source control technologies are now better developed and readily available, and it is anticipated that in most scenarios, the time to implement a temporary source control action in the future is likely to be shorter than what was experienced with the Macondo well. Regardless, both the Deepwater Horizon incident and the modeling studies suggest temporary source control measures are a critical capability that can significantly reduce the impact from a WCD oil spill scenario.

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[53] Scholz, Debbie, *et al*. Remote Sensing, Establishing Priorities, Selecting Resources, Data Collection, Analysis, and Distribution. 22 October, 2010.

[54] This estimated volume does not include the amount of oil that flowed to the surface with the “cap and flow” device in the Macondo incident. This was done to make a more valid comparison with the model results, which did not model a cap and flow device.

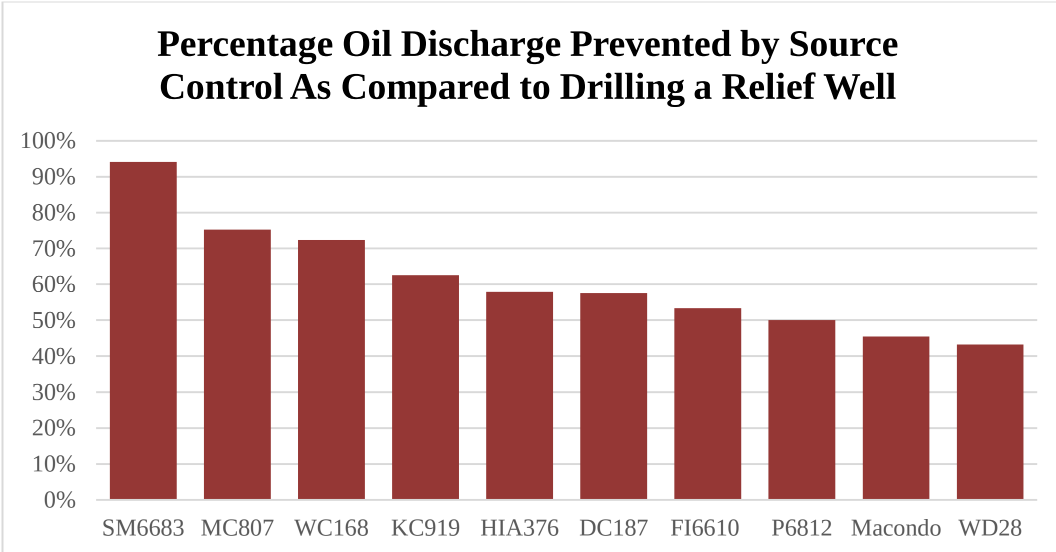

Figure 151: Comparison of Deepwater Horizon Oil Spill to Modeled Scenarios for Percentage of Oil Discharge Prevented by Source Control as Compared to the Total Volume of Oil Discharged When Drilling A Relief Well

3.5.2 Coordination of Simultaneous Offshore Response Operations and the Use of Oil Spill Surveillance and Tracking to Direct Response Countermeasures

During the Deepwater Horizon response, source control, subsurface containment, and subsurface dispersant operation were all conducted in an exclusion zone surrounding the wellhead. Beyond this area, the Unified Area Command, through the ICPs, employed a layered approach to oil containment and removal, with in situ burn, surface-applied dispersants, and mechanical recovery operations all being performed simultaneously. The Offshore Operations Branch at the Incident Command Post (ICP) in Houma managed an integrated response for all these surface-based spill countermeasures that required extensive coordination and aerial surveillance support. Mechanical recovery resources were placed in either an offshore division near the source or in nearshore geographical divisions. In situ burning task forces were given their own approved burn areas, typically three to eight miles from the wellhead source. Spotter aircraft searched for and identified patches and streamers of oil that were fresh enough to treat with dispersants throughout a wide area that typically spanned from near the discharge site to three miles from shore. Every effort was made to treat oil when it was fresh, resulting in spraying operations that were closer to the wellhead than the shoreline. 98% of all dispersants sprayed by air were applied beyond 10 miles from shore.

The model simulations in this report applied lessons learned from the simultaneous operations of the Macondo response to generate more realistic model scenarios. The various response methods used in the model scenarios (in situ burning, mechanical recovery, and aerial dispersants) were assigned specific geographic areas of operation, referred to as "Response Divisions" based on where they would optimally operate. Mechanical recovery equipment was staged at various distances from the wellhead based on the optimal oil viscosity in which they would operate. Similarly, aerial dispersants were applied in areas where dispersible oil was likely to occur. Each WCD scenario also simulated an exclusion zone around the wellhead, similar to the source control operations exclusion zone that was created during the Macondo response. Finally, the various countermeasures in the modeling simulations had an inherent assumption built into their methodology for estimating oil removal rates that the use of aerial surveillance was present in support of their operations.

3.5.3 Limitations on Mechanical Recovery Countermeasures

Mechanical oil recovery systems were deployed in three distinct zones during Deepwater Horizon to collect oil from the water's surface: (1) the offshore environment above the wellhead, (2) nearshore areas along the coast, and (3) shoreline areas to protect environmentally and economically important beaches, bays, and marshes. Despite the wide area deployment of many recovery systems, whose sum total potential for recovery capacities far exceeded the daily flowrate of oil discharged from the Macondo well, skimming resources employed during the spill were estimated to have only recovered 3% to 4% of the spilled oil.

While the factors that may have affected the performance of skimming systems is complex and multi-faceted, the USCG FOSC Report for the Deepwater Horizon noted that 1) as the oil aged and became more viscous, the number of assets capable of removing the oil became limited, 2) as oil and oil emulsion was transferred from mechanical recovery platforms to secondary storage tanks, operations were hindered by the high viscosity of the recovered oil, and 3) as the oil reached the nearshore environment, it was co-mingled with debris, or was in bands of emulsion or tar-like, making it difficult or impossible to skim. Many skimmers mobilized to nearshore sites were ineffective in removing this material; however, it was noted that certain types of skimmers, such as oleophilic belt devices, proved effective and were well suited to the high viscosity of the oil. These facts illustrate the limitations of mechanical recovery as a response strategy, the limitations associated with attempting to tie equipment recovery levels in planning standards to actual oil recovery during an oil spill, and necessity of having the right types of mechanical recovery equipment deployed for crude oil spills that undergo continuous weathering processes as they are transported away from the discharge site by wind and currents.

Similar to the Deepwater Horizon incident, simulated mechanical recovery equipment was assigned to different areas of operation within each WCD scenario for this modeling study and its effectiveness was tracked based on the equipment type, location, and oil properties and weather conditions. The modeling scenarios employed High Volume, Secondary, and Nearshore Recovery Divisions, and tracked the removal of oil in each by broad equipment types, each with a defined viscosity range where that equipment could operate at targeted efficiency levels. The model results highlight the importance of oil weathering and changes in oil thickness and viscosity for mechanical recovery operations. Model results confirmed that the fresh, low viscosity oil that is found near the wellhead in a WCD is the oil that is most easily mechanically recovered. As oil spreads and is transported away from the source of the discharge, it thins, becomes discontinuous and patchy in its surface footprint, and becomes more viscous, all making mechanical recovery more difficult. For example, in the MC807 model scenario, 2 million bbl of oil were recovered in the High Volume Division, about 470,000 bbl were recovered in the Secondary Division, and only about 69,000 bbl were recovered in the Nearshore Division. Like the Deepwater Horizon incident, the SIMAP modeling strongly suggests that skimming devices should be contracted and deployed that will be well suited for the range of viscosities that can be expected for the type of oil and recovery area where they will be working. The modeling also suggests that it is critical to deploy high volume skimming systems capable of sustained offshore operations in the vicinity of the discharge site in order to remove high volumes of concentrated, fresh oil before it spreads and weathers.

3.5.4 Use of Chemical Dispersion Countermeasures

The USCG FOSC Report for Deepwater Horizon states that the volume and duration of dispersant use during the response was unprecedented for both surface and subsurface dispersant use. In Deepwater Horizon, surface-applied dispersant operations were carried out using 14 spray aircraft and 8 spotter aircraft that flew a total of 412 spray sorties and 816 reconnaissance and spotter sorties to apply a total of 972,880 gallons of dispersant. Additionally, a total of 771,000 gallons of dispersant were injected subsurface into the discharge point over the well site by ROVs. The FOSC Report concludes that the use of dispersants during the response were an effective response tool that prevented millions of gallons of oil from impacting the sensitive shorelines of the Gulf of Mexico.

The simulated surface-applied dispersant operations in the modeling WCD scenarios for this study were assigned to discrete areas of operation, specifically, the High Volume and Secondary Divisions. The total amount of dispersants available for simulated surface application was calculated based on current industry supplies and predicted ability to manufacture and deploy additional product, and was not sufficient to apply to all treatable surface oil in some of the modeled WCD scenarios. The WCD scenarios modeled for the Gulf of Mexico simulated the application of about 1 million to 2.5 million total gallons of surface dispersant. This compares closely with the amount of surface dispersants used in the Macondo response.

The model results, similar to the Deepwater Horizon FOSC Report, support the conclusion that surface-applied dispersants are an effective way to remove oil from the water's surface and reduce the amount of oil that comes into contact with sensitive resources. However, the level of oil removed using surface dispersants in the modeling simulations appears to be driven in most cases by the scenario conditions, such as the availability of fresh oil to be treated that was not mechanically recovered, the available stockpile of dispersants, and in some cases, the oil type. The percentages of total oil discharge removed by dispersants in the model scenarios and in Deepwater Horizon are shown in Figure 152. The WD28 and HIA376 simulations achieved 7% and 10% oil removed respectively, and the P6912 simulation in the Chukchi Sea in the Arctic achieved 6%; in contrast, dispersants were not really used or effective for the WC168 scenario due to the non-persistent nature of the of the condensate oil discharged from the well.

The model results also indicate that the use of surface-applied dispersants reduces the amount of oil on shorelines, but may also reduce the amount of oil that is mechanically recovered, and will also increase the amount of oil that is biodegraded over time in the water column. For example, in the WD28 scenario, the application of surface dispersants reduced the amount of oil on shoreline from 17% of the total discharge to 4%, but reduced the amount of oil mechanically recovered from 46% of the total discharge to 44%, and increased the amount of oil being biodegraded in the water column from 10% to 12%.

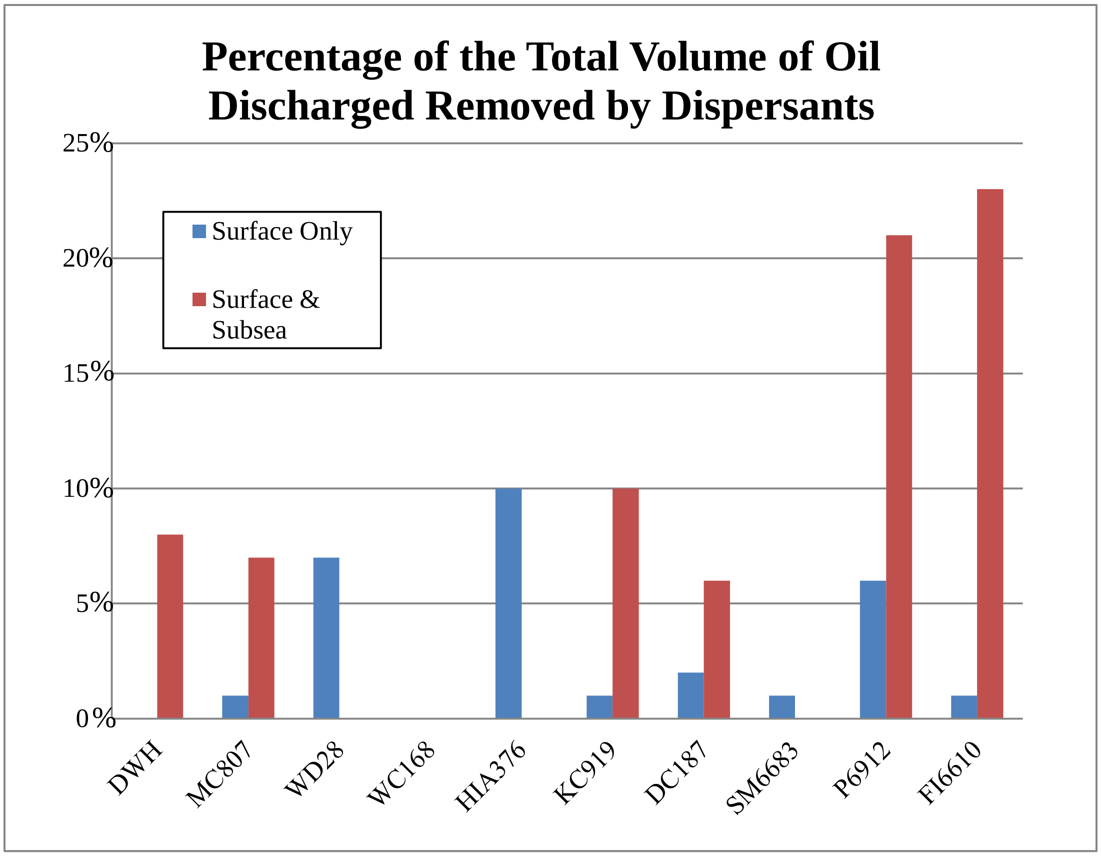

Figure 152: Comparison of Deepwater Horizon Response to Modeled Scenarios for Percentage of the Total Volume of the Oil Discharged Removed by Dispersants

Three well locations in the Gulf of Mexico (MC807, KC919, and DC187) and two well locations in the Arctic OCS (P6912 and F6610) modeled responses where the use of both surface and subsurface dispersants were simulated. In the Gulf of Mexico, results range from 6-10% of the total oil discharged being dispersed through a combination of surface and subsurface dispersants, which is similar to the 8% estimated dispersed for the Deepwater Horizon oil spill response. In the Arctic, the results indicate that dispersants, and in particular, subsurface dispersants, can have a major impact on mitigating the discharged oil.

As described in Section 3.4.2, the total amount of dispersants available for subsurface application was calculated based on current industry supplies and predicted ability to manufacture and deploy additional product, and was insufficient to apply to all treatable oil. The total volume of subsurface dispersants used in the Gulf of Mexico model scenarios ranged from about 1.3 million gallons to about 1.5 million gallons; which is significantly greater than the approximately 700,000 gallons used in the Macondo response. This is not unexpected, as the daily flowrates and total discharge volumes for these WCD scenarios were also much greater than the Deepwater Horizon spill.

The two late season Arctic scenarios (Chukchi and Beaufort Seas) applied approximately 85,000 and 116,000 total gallons of subsurface dispersants, and in each case achieved 15-20% oil removed of the total oil discharged. In both cases, the use of subsurface dispersants was the most effective response countermeasure modeled, likely due to the environmental constraints on the surface-based countermeasures for this area and time of year.

The model results support the conclusion that subsurface dispersants are an effective tool for dispersing oil and reducing the amount of oil that comes into contact with sensitive resources. The Gulf of Mexico scenarios that simulated subsurface dispersants (KC919, and DC187) showed a similar pattern of increased oil dispersed, and a decrease in shoreline oiling and volume of oil mechanically recovered. The Arctic scenarios with subsurface dispersants showed a similar reduction in shoreline oiling and an increase in the amount of surface oil dispersed.

3.5.5 Use of In Situ Burning Countermeasures

Over the course of Deepwater Horizon oil spill response operations, in situ burn teams conducted 411 burns and removed an estimated 5% of the oil released from the Macondo well (approximately 265,450 barrels of oil). The Deepwater Horizon spill response was the largest in situ burn operation on open water in U.S. history, and successfully demonstrated that in situ burning can be effectively used as one of the primary spill countermeasures on a large continuous release of oil.

In situ burning was simulated in the modeling scenarios done for this study. In situ burning was simulated in an area of operation not too distant from the discharge point referred to as the High Volume Burning Division where oil would be sufficiently thick on the surface to burn, would not interfere with ongoing source control actions at the wellhead, and where in situ burning would be allowed under Federal and State law. The model results support the conclusion that in situ burning is an effective way to remove spilled oil; however the model results do not show oil removal rates as large as those estimated for the Macondo response. The amount of oil removed with simulated in situ burning ranged from about 0.5% to 2% of the total discharge volume, which is lower than the estimated 5% that was removed by in situ burning in the Macondo response. In terms of absolute volumes of oil burned, the model results ranged from about 2,000 bbl to greater than 300,000 bbl removed with in situ burning. The total volume of oil burned during the Macondo discharge falls within the range of volumes of oil burned in the various modeled scenarios.

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4.0 SUMMARY OF NATIONAL OIL SPILL RESPONSE REGULATIONS

Offshore oil development on the OCS is not unique to the United States; more than 100 nations have offshore oil exploration and production facilities. Like the United States, many of these countries have statutes and regulations that govern the preparation for and execution of response operations for large oil spills from offshore facilities.

For this study, oil spill response regulations of eight countries were reviewed and summarized to provide BSEE an inventory of recommended practices for BSEE consideration when updating current U.S. oil spill response regulations for OCS facilities. Regulatory regime data for the eight countries listed below are presented in Appendix B. The remainder of this section contains summaries of the analysis of these regulations.

1. Australia
2. Brazil
3. Canada
4. Denmark
5. Greenland
6. New Zealand
7. Norway
8. United Kingdom

The USCG regulations for response to oil spills from vessels were also summarized. While USCG regulations are not directly applicable to offshore facilities, BSEE may consider whether certain best practices and policy mechanisms from vessel spill response can be adapted to offshore facilities.

These national regulatory regimes were assessed based on a variety of specific policy categories that are of interest to BSEE such as mobilization factors and oil weathering factors. Regulations were also assessed based on their relative composition of either prescriptive or performance-based policies. Prescriptive regulations are those that prescribe a specific action that the regulated community must take based on specific numeric targets. For example, the requirement for an OCS facility operator to have 50 skimmers under contract that can be deployed within 12 hours is a prescriptive requirement. Performance-based regulations direct the regulated community to conduct any action sufficient to achieve a given outcome without prescribing exactly *how* that outcome must be achieved. For example, a requirement for an OCS facility operator to have enough oil spill response equipment on contract to remove 50% of all oil spilled within 24 hours is a performance-based requirement. Most regulatory regimes use a mixture of both types of policies and can, therefore, be assessed based on a sliding scale from entirely prescriptive regulations to entirely performance-based regulations.

4.1 REGULATORY REGIME SUMMARIES

4.1.1 Australia

> ***Reader Note:*** *This summary of oil spill response regulations for OCS facilities accurately summarizes key regulatory language (including terms such as "should" vs. "must"). However, this is not a comprehensive legal analysis of the regulations and policies, and does not present the often complex legal and administrative rules applicable to the policy tiers, including relationships among national statutes, implementing regulations, and agency guidance.*

Australia's regulatory regime is largely performance-based with few prescriptive requirements. Operators must submit an Environmental Plan (EP) that contains an Oil Pollution Emergency Plan (OPEP) to the Australian National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA). Operators are responsible for the initial response to oil spills, which are categorized into Levels 1, 2, and 3, based on size.

Level 1 spills are addressed by operator-owned and other local equipment. Level 2 spills are of moderate size and complexity, and Level 3 spills require response from national resources including equipment owned by the Australia Maritime Safety Authority (AMSA). Australian regulations state that the OPEP should include characterization of the fate, weathering, and toxicity of produced oil, but do not require characterization based upon specific categories and factors.

Unlike the U.S. regulations, there is no requirement to describe a WCD scenario; however, guidance documents recommend that operators describe a "high-consequence spill" scenario in the EP. Oil spill modeling is also recommended but not required.

Australian OPEPs must contain a risk assessment that describes what activities the operator will be conducting, what sensitive environmental endpoints could be impacted by an oil spill, and what oil spill response measures will be used to reduce risks to "as low as reasonably practicable" or ALARP. The ALARP standard is a performance-based standard as it casts a regulatory requirement in terms of a desired outcome rather than what actions must be taken to achieve that outcome. The ALARP standard is arguably a vague standard, as it does not dictate a specific numeric outcome, but rather a potentially subjective outcome based on what is considered by regulators to be practicable and reasonable.

Australian oil spill response regulations do not contain specific requirements for mechanical recovery, dispersant application, in situ burning, or source control. There is a series of generic recommended capabilities for oil spill surveillance and tracking, with recommendations to respond in a timely manner, maintain responsibility for the incident, and monitor performance of response operations. In another performance-based policy mechanism, operators are required to identify Environmental Performance Outcomes (EPO) and Environmental Performance Standards (EPS) in their EPs. EPOs define what outcomes are acceptable during oil spill response operations, and EPSs are the standards by which individual response activities (e.g., mechanical recovery) are assessed and describe how a response measure should perform. Similar to the concept of ALARP, the EPSs and EPOs are not tied to any prescriptive or numeric requirements, but rather are a conceptual framework intended to guide the operator’s decision making regarding oil spill response preparedness. The performance-based standards of EPSs and EPOs are novel and may be of interest to BSEE if the Bureau is considering developing performance-based standards for oil spill response regulations.

Regulations Reviewed:

- Offshore Petroleum and Greenhouse Gas Storage (Environment) Regulations 2009
- National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) Guidance Note, N04750-GN1344, Revision No2, September 2015, Environment Plan Content Requirements

4.1.2 Brazil

Brazil’s oil spill response regulations are among the most prescriptive of the countries studied, and similar to those of the United States. The regulations require operators to submit Individual Emergency Plans (PEI) to the Brazilian Institute of Environment and Renewable Natural Resources (IBAMA) for offshore oil development facilities. IBAMA has the regulatory authority to assign responsibility for oil spill response to state environmental agencies, assign responsibility to the operator (which is a single, state-owned oil company), or retain responsibility for directing cleanup operations. The PEI should describe the types of oil being stored and produced on the facility, but characterization based on specific categories or factors is not required. The PEI must also include the calculation of a WCD volume based on the maximum well flow rate over a period of 30 days. It is recommended that trajectory modeling be used to identify the sensitive environmental and socioeconomic endpoints that could be impacted by spilled oil and to track oil spills in real-time. The PEI must also contain a risk assessment based on the likely characteristics and volume of spilled oil, site-specific meteorological and oceanographic information, and socioeconomic and environmental resources at risk from oil spills.

The PEI must include detailed information on all owned and contracted oil spill response equipment including quantity, type, and response times. Brazil also requires that operators use the Effective Daily Recovery Capacity (EDRC) calculation (named CEDRO in Portuguese) to calculate the volume of oil that mechanical recovery operations can recover, and the regulations contain specific, prescriptive requirements for certain volumes of CEDRO to arrive on-scene at cascading time intervals. There are also maximum wave height and wind speed requirements for aerially applied dispersants based upon aircraft type. The regulations require that the PEI must include procedures for aerial surveillance and tracking, but do not require information on relief wells or well capping. While Brazil's regulations are highly prescriptive, they may be of limited interest to BSEE because they are so similar to U.S. regulations and, therefore, feature few novel or unfamiliar policy mechanisms.

Regulations Reviewed:

- CONAMA Resolution No. 398

4.1.3 Canada

Canada's offshore drilling and oil spill response regulations are developed and implemented by three boards that regulate activities in the Canadian Arctic, Nova Scotia, and the Newfoundland and Labrador regions. There is no offshore oil development on Canada's Pacific coast. This study includes analyses of Canada's Arctic regulatory regime, as well as the Nova Scotia regulatory regime. It was determined that Newfoundland and Labrador's regulations were sufficiently similar to those of Nova Scotia that analysis of the Newfoundland and Labrador regulations was not conducted.

Offshore oil spill response regulations in Nova Scotia are developed and implemented by the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) and are mostly performance-based. Operators in the region must submit Environmental Protection Plans (EPP) and Contingency Plans (CP) to the CNSOPB. In the event of a spill, operators must notify the Canadian Coast Guard and the CNSOPB and are responsible for responding to the spill using third party contractors. The Coast Guard is also available to assist with response operations, and Transport Canada and Environment Canada provide aerial surveillance and tracking capabilities. While there is no specific requirement to calculate a WCD, it is recommended that operators conduct oil spill trajectory modeling for large spills. Operators should also have the ability to conduct real-time oil spill trajectory modeling and forecasting. The EPP must include a risk assessment that summarizes the risks posed to the environmental and socioeconomic resources, as well as the measures taken to reduce those risks. The regulations contain no specific requirements for mechanical recovery or in situ burning. The use of subsurface and surface-applied dispersants must be approved of by CNSOPB. The regulations state that the CP should contain information on arrangements to drill relief wells, but have no requirements for well capping or intervention.

Offshore drilling in the Canadian Arctic is regulated by the National Energy Board (NEB), and oil spill response regulations for the region are mostly prescriptive, in contrast to regulations for the Canadian Atlantic region. Operators must submit an EPP and a CP to NEB, and operators are responsible for oil spill response using third party contractors. The Coast Guard is also available to assist with response operations, and Transport Canada and Environment Canada provide aerial surveillance and tracking capabilities. The regulations require that the CP include a description of properties of the produced oil, but there is no requirement to describe the oil based on specific categories or factors. The CP must also include a calculation of the WCD based on the maximum flow rate and the "maximum duration" of a subsurface discharge. This is similar to BSEE calculations of WCDs, but the inclusion of maximum duration is unique (U.S. regulations require a duration of 30 days) and could result in the calculation of very large WCD volumes if it is assumed that source control methods are delayed by sea ice, remoteness, or other Arctic conditions.

Oil spill modeling should be performed by operators to simulate the trajectory of a WCD and for real-time oil spill tracking and forecasting. The CP must include a risk assessment including the unique Artic environmental and socioeconomic resources at risk from oil spills, how the extreme Arctic conditions will affect the oil development project, and contingency measures that will be used if the operating limits of the oil development equipment are exceeded. Operators must also submit Ice Management Plans that include how ice hazards will be predicted, identified, tracked, and managed, and have contingency plans when ice conditions exceed an operator's ice management capabilities.

The regulations have no specific requirements for mechanical recovery or in situ burning, and the use of subsurface and surface dispersants must be approved by Environment Canada.

Regulations Reviewed:

- National Energy Board Filing Requirements for Offshore Drilling in the Canadian Arctic
- Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) Drilling and Production Guidelines, March 31, 2011
- Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) Environmental Protection Plan Guidelines, March 31, 2011

4.1.4 Denmark

Denmark's regulatory regime is almost entirely performance-based, with few prescriptive requirements. Operators of offshore facilities are required to submit Oil and Chemical Spill Contingency Plans (OCSCP) to the Danish Environmental Protection Agency (EPA). The regulations that dictate the contents of the OCSCP are relatively brief and require a general description of oil spill response methods and equipment that will be used. Operators must have access to enough owned or contracted oil spill response equipment to respond to the maximum outflow of the well. This a performance-based requirement similar to the WCD calculation used in regulation in the United States and other countries. However, Denmark's regulations only specify a flow rate and not a duration of the discharge; there is not a requirement to respond to the spill for a specific period or to remove a specific volume of oil over the course of the spill. The only prescriptive elements of the regulations are operational capability requirements for mechanical recovery vessels based on maximum wave height, and ranges of air and water temperature. Compared to other country regulations, Danish regulations are notable for their brevity and lack of specificity.

Regulations Reviewed:

- Notice of Preparedness in Case of Marine Pollution From Certain Offshore Installations, 1984

4.1.5 Greenland

Greenland's regulations are mostly performance-based, with few prescriptive requirements. Greenland's location, largely within the Arctic Circle, means that oil development and oil spill response operations face unique environmental challenges, including the presence of sea ice, short daylight hours during parts of the year, and extremely cold temperatures. A series of contingency plans must be submitted by operators of offshore oil facilities to the Greenland Bureau of Minerals and Petroleum (BMP) including an Ice Management Plan.

Operators are responsible for initiating and coordinating response efforts using third party oil spill response contractors. Operators must perform an Environmental Impact Assessment using oil spill trajectory modeling that simulates a discharge with a duration of at least seven days. The regulations have no specific requirements for mechanical recovery; however, government approval is required to initiate dispersant application and in situ burning. In situ burning is prohibited within 5.4 NM of the Greenland coast.

Regulations Reviewed:

- Bureau of Minerals and Petroleum, Drilling Guidelines, May 2011

- BMP Guidelines for Preparing and Environmental Impact Assessment (EIA) report for activities related to hydrocarbon exploration and exploitation offshore Greenland, January 2011

4.1.6 New Zealand

New Zealand's oil spill response regulations are performance-based. Operators must submit a Discharge Management Plan (DMP) and a Well Control Contingency Plan (WCCP) to Maritime New Zealand (MNZ). Various organizations are responsible for oil spill response depending upon spill size. Operators must respond to small spills using owned or contracted equipment. Regional Councils respond to spills that are too large to be effectively addressed by a single operator using privately owned equipment, contracted equipment, and government-owned equipment from MNZ. MNZ directs the response to spills that are too large to be effectively combatted by Regional Councils using private and MNZ-owned equipment.

The DMP must include a characterization of the properties of the produced oil including pour point, viscosity, density, API gravity, wax content, and asphaltene content. The DMP must also include a WCD calculation based on the maximum flow rate of the well and the maximum amount of time that could be required to stop the discharge of oil. New Zealand has the capacity to respond to a spill with a total volume of oil of 3,500 metric tons, or about 24,500 bbl. For larger spills, assistance will be sought from other countries. The operator must conduct oil spill trajectory modeling, as well as stochastic modeling. Modeling parameters must include depth of release, weather, and temperature data, and a release duration of at least 30 days. The DMP must include a risk assessment that describes socioeconomic and environmental resources at risk from oil spills. The regulations contain no specific requirements for mechanical recovery, in situ burning, oil spill tracking, or aerial surveillance. Operators must test treat any produced oil or condensate with a range of dispersants to determine which dispersant product is most effective against the produced oil. The use of surface-applied dispersants must be approved by the New Zealand government, and the regulations recommend a range of dispersant dosage rates.

Regulations Reviewed:

- Maritime Protection Rules Part 130C: Regional Contingency Circular
- Maritime Protection Rules Part 200: Offshore Installations – Discharge Circular
- National Oil Spill Contingency Plan
- Review of New Zealand's Oil Pollution Preparedness and Response Capability

4.1.7 Norway

Norway's regulations are entirely performance-based with no prescriptive requirements. Operators must submit a Plan for Development and Operation (PDO) and a Plan for Installation and Operation (PIO). Operators are responsible for responding to small spills with owned or contracted response equipment. For spills that exceed the oil spill response capabilities of a single operator, Intermunicipal Boards for Acute Pollution (IUA) are responsible for response efforts. IUAs also responds to spills where the source of the spill is unknown (e.g., floating oil that may have originated from a vessel). For spills that exceed the capabilities of an IUA, the Norwegian Coastal Administration (NCA) employs its government-owned response equipment and receives assistance from IUAs and individual operators.

The regulations require a characterization of the fate and weathering properties of produced oil but do not require characterization of the oil based on specific categories or factors. The regulations do not require calculation of a WCD but do require the use of modeling, although no specific model inputs or parameters are required. Operators must perform a risk assessment that includes potential oil spill scenarios and trajectories and environmental resources that are at risk from an oil spill. The risk assessment must be used as a basis for making decisions on the quantity and types of owned or contracted oil spill response equipment available to the operator. The regulations feature no specific requirements for mechanical recovery, in situ burning, subsurface-applied dispersants, or source control. The regulations state that aircraft use to apply dispersants should also be capable of assisting with aerial surveillance to track the spill and direct other response efforts.

All of the private oil spill response companies in Norway work together under a single organization called Norwegian Clean Seas Association for Operating Companies (NOFO). While NOFO's specific oil spill response techniques and strategies are not mandated by government regulations, NOFO's four-barrier concept of operations is novel and, therefore, should be considered by BSEE. NOFO's concept of operations is based upon four conceptual barriers between the source of spilled oil and sensitive endpoints such as beaches and coastlines. Barrier 1 comprises response efforts near the wellhead and involves multiple systems of mechanical recovery and dispersants. Oil should be allowed to drift and spread without interference for one to two hours in order to allow volatile chemical constituents to evaporate, allow oil to reach sufficient viscosity for mechanical recovery, and prevent the exposure of response efforts to explosions that can occur near the time of the initial discharge. Barrier 2 is located in the open waters between the discharge source and the coastline, and is established shortly after Barrier 1. Barrier 2 comprises mechanical recovery and surface dispersant systems that must be directed by remote sensing and aerial surveillance due to the diffuse and patchy nature of oil in open waters. Barrier 3 is located near coastal resources and uses a broad range of mechanical recovery systems including large and small skimming vessels, vessels of opportunity skimmers, and protective boom. Barrier 3 response equipment is strategically located to protect sensitive coastal and is guided by observations from aircraft, ships, and from shore. Barrier 4 is comprised of shoreline cleanup operations that remove spilled oil from beaches and shorelines.

Regulations Reviewed:

- Regulations Relating to Design and Outfitting of Facilities in the Petroleum Activities
- Regulations Relating to Conducting Petroleum Activities
- Guidelines Regarding the Management Regulations
- Guidelines Regarding the Facilities Regulations

4.1.8 United Kingdom

The United Kingdom's (UK) regulatory regime is a mixture of prescriptive and performance based policies. Operators are required to submit an Oil Pollution Emergency Plan (OPEP) to the UK Department of Energy and Climate Change. Operators are responsible for holding contracts with oil spill response equipment and responding to small spills. For spills that exceed the ability of an operator's contracted response equipment to effectively respond, the Maritime Coastguard Authority (MCA) will assist with the response with government-owned equipment.

The OPEP must include characteristics of the oil being produced including the ITOPF Grouping, specific gravity, viscosity, wax content, asphaltene content, and pour point. Operators must calculate a WCD scenario based on the maximum flow rate of the well, but the regulations do not specify a WCD duration. A WCD must be calculated for each facility, but the operator is only required to model the largest WCD scenario in each field. Modeling input parameters should include oil physical properties and weathering, and should be conducted using stochastic modeling with a minimum of 100 model runs and weather data from at least a two-year time period. Trajectory modeling should be run for a duration of at least 10 days or until simulated oil reaches shorelines. Modeling should also be conducted for all seasons (i.e., winter, spring, summer, and autumn). Modeling results must be displayed to a thickness of 0.3 micrometers, and should depict minimum travel times to shorelines and median lines. Shoreline contact probability should be displayed to a threshold of at least 1%. The OPEP should also use maps to display how the probability of oiling varies seasonally. The OPEP must contain a risk assessment of sensitive environmental endpoints that could be impacted by oil spills.

The regulations have no specific requirements for mechanical recovery or in situ burning. If dispersants are identified as a response option in the OPEP, the operator must include the total volume of dispersant stockpiles available, and should describe how the types of dispersants available are matched to the characteristics of the oil being produced. Approval from the MCA is required for the use of dispersants in waters of 66 feet (20 meters) depth or less, or within 1 NM of these waters; and for subsurface application of dispersants. For facilities within 25 NM of shore, the OPEP must include a Shoreline Protection Plan. OPEPs for facilities within 22 NM of shore must include provisions for applying dispersants within 30 minutes of an oil discharge, and for a sufficient stock of dispersants to treat 25 metric tons of oil (about 185 bbl depending upon oil density).

The regulations have specific requirements for timing and capabilities of response aircraft, including the testing of dispersants within six hours of a discharge and large-scale dispersant application within 18 hours. Aerial surveillance aircraft should be equipped with very high frequency (VHF) radio, digital imaging equipment, satellite telephone, and GPS navigation. In order to quantify spilled oil, aircraft should also be equipped with UV imaging and infrared imaging.

Regulations Reviewed:

- Guidance Notes for Preparing Oil Pollution Emergency Plans for Offshore Oil and Gas Installations and Relevant Oil Handling Facilities, August 2015

4.1.9 United States Coast Guard Regulations for Shipping

In the United States, BSEE oversees the preparedness to oil spills from offshore platforms, and the USCG oversees response to oil spills from vessels. Oil spills from vessels differ from oil spills from offshore facilities in a number of important ways. Spills from vessels are discreet events by which the entire volume of a vessels cargo may be discharged over the course of a few hours or days, while spills from offshore facilities may result in the continuous discharge of oil over the course of days, or even months depending upon the success of response efforts. For this reason, the total volume of spills from offshore facilities can be much larger than those from vessels. Another key difference is that vessels are mobile and encounter varying marine environments (e.g., harbors, nearshore, and open ocean) over the course of a single trip, while offshore facilities are stationary during drilling operations. Despite these differences, BSEE is interested in considering the adaptation of some elements of the USCG regulations for BSEE oil spill response regulations.

The USCG regulations are highly prescriptive and are more prescriptive than any of the eight national regulatory regimes studied, as well as BSEE regulations for oil spill response. Vessels carrying oil must submit Vessel Response Plans (VRP) to the USCG, and operators are responsible for responding to spills from vessels using owned or contracted equipment, while the USCG directs response operations.

The VRP must include the specific gravity of the cargo oil and a calculation of the WCD volume, which is a defined as a discharge of the entire oil cargo of the vessel. VRPs must also include calculations of the "average most probably discharge" (the lesser of 50 bbl or 1% of the vessel cargo), and the "maximum most probably discharge" (2,500 bbl for vessels that carry 25,000 bbl or more, or 10% of cargo for vessels that carry less than 25,000) and describe how response operations will be conducted in all three scenarios. VRPs must include a description of the risks posed to sensitive environmental endpoints, which is typically based on information derived from Regional Contingency Plans and Area Contingency Plans.

The regulations feature highly prescriptive requirements for mechanical recovery of spilled oil. This involves calculation of the oil recovery capacity of mechanical recovery equipment and calculation of the amount of oil that must be recovered in a WCD scenario. The capacity of mechanical recovery equipment is calculated using the Effective Daily Recovery Capacity (EDRC) formula. EDRC is calculated by multiplying the mechanical recovery device's maximum throughput by 0.2, a "de-rating" factor designed to account for oil emulsification, weather, sea state, and the limited daylight hours in which mechanical recovery equipment can operative efficiently.

Operators must calculate the timing and quantity of contracted EDRC required based on the WCD volume, oil fate and transport, distance from shore, emulsification factors, mobilization factors, and oil recovery "caps." These caps set limits on the contracted EDRC is required. For example, if a vessel is carrying 100,000 bbl of heavy crude oil in the offshore environment, the regulations estimate that 50% of the spilled oil from a WCD will be available for mechanical recovery (the other 50% will wash ashore, or evaporate). An emulsification factor of 1.4 (based on oil type) is then applied to generate a total oil emulsion volume of 70,000 bbl. Mobilization factors for spills in the offshore environment are then applied to calculate how much EDRC must arrive on scene at specified time intervals. In this example, mobilization factors require that 0.1 of the total required capacity (7,000 bbl/day) must arrive on scene within the first 24 hours, 0.165 (11,550 bbl/day) within the first 48 hours, and 0.21 (14,700 bbl/day) within the first 72 hours. Arrival times are to be calculated based on the storage location of equipment and an assumption of speeds of 35 miles per hour on land (e.g., moving a vessel by trailer) and 5 knots in water. The final step is to apply caps to the total amount of EDRC that can be required. For the offshore environment, operators need not provide any more than 12,500 bbl/day in the first 24 hours, 25,000 bbl/day in 48 hours, and 50,000 bbl/day in 72 hours. If the required oil recovery capacity exceeds these caps, operators must *identify* (not contract) available oil recovery resources with a total recovery capacity equal to twice the volume of the cap, or the difference between the WCD volume and the cap, whichever volume is less.

The regulations set forth sea state and wave height performance requirements for oil recovery vessels based upon the distance from shore. For example, in the open ocean, oil recovery vessels must be able to operate in waves of up to six feet in height, and in sea states 3 and 4.

The regulations also include prescriptive requirements for the quantity and timing of surface-applied dispersants based on the specific gravity of the oil. Specific gravity is used to calculate weathering factors and a dispersant-to-oil dosage rate. For example, if a VRP has a WCD of 1,000,000 gallons of medium crude oil, the regulations provide that 30% of the oil volume is lost to weathering. A one to twenty dispersant-to-oil application ratio is applied to the remaining 700,000 gallons of oil, yielding a total required volume of 35,000 gallons of dispersants. The timing of the application of the dispersants is determined by mobilization factors based on distance from shore, similar to mobilization factors used for mechanical recovery. A certain total amount of dispersants must be applied within the first 12, 36, and 60 hours of the incident. The Effective Daily Application Capacity (EDAC) formula is used to calculate how much dispersant application equipment is needed to apply a given volume of dispersants. EDAC is a more complex calculation than EDRC and is based upon the application platform used (often an aircraft) and specific operating characteristics of that platform.

The regulations require similar procedures for calculating the amount of shoreline cleanup capacity that must be contracted by operators. The amount of oil from a WCD that is estimated to wash ashore is calculated based upon the oil specific gravity and the distance from shore, and an emulsion factor is applied based on oil specific gravity. There are no caps or mobilization factors for shoreline cleanup.

There are also requirements for the length and availability of contracted shoreline protection boom based on the vessel operating environment (e.g., open ocean, offshore, nearshore) and oil type (persistent or non-persistent). Similar to mechanical recovery vessels, boom has minimum performance standards for wave height, sea state, boom height, buoyancy, and material strength based on the marine environment.

Regulations Reviewed:

- 33 CFR Part 155, Oil or Hazardous Material Pollution Prevention Regulations for Vessels

4.2 RECOMMENDED PRACTICES FOR NATIONAL OIL SPILL RESPONSE REGULATIONS

The national oil spill response regulatory regimes were compared and assessed based on a range of regulatory categories to determine recommended practices. Recommended practices are defined as policies and regulations that are rigorous, robust, and/or novel and should therefore be considered as BSEE considers updating OSRP regulations for U.S. offshore facilities. The results of the benchmarking assessment show that there are many different regulatory schemes that are influenced by many different factors. No single system appears to be, at face value, inherently more effective or better than the others. Often these regimes are significantly influenced by the nation's national contingency plans and factors such as the subsequent division of responsibility for response activities between the private and public sector. This comparison did allow, however, for a broad examination of many varied practices currently being used by regulating entities on a global scale, as well as the identification of a number of elements that should be considered as recommended practices.

4.2.1 Recommended Practices for Oil Spill Scenario-Based Planning

Many, if not most, regulatory regimes contain some level of scenario-based risk assessment practices in developing their oil spill response plan requirements. Most performance-based regimes were heavily dependent upon the results of a plan holder developed risk assessment; however, these assessments often varied in scope and level of detail. These risk assessments often were supported by requirements (or recommended practices) to conduct oil characterizations to determine the baseline characteristics of the oil and its behavior once discharged, as well as oil spill modeling to predicts its fate and transport as it spreads out away from the site. Most performance-based regimes placed the onus on the plan holder to use this information to identify resources at risk, and to determine the appropriate levels and types of response equipment, as well as the timeliness of the response activities. The more prescriptive regimes tended to focus less on risk assessment-based results, and instead applied more globally applied requirements, such as removal targets, equipment levels, and response times. This report recommends that BSEE consider adopting a hybrid approach, where plan holders are required to conduct scenario-based assessment and planning activities, which will result in the development of plan information that will trigger certain performance-based or prescriptive requirements that have been set by BSEE

4.2.1.1 *Recommended Practices for Oil Characterization and Weathering Factors*

Most of the regulatory regimes studied require or recommend some type of oil characterization. Only Denmark, Greenland, and Nova Scotia, Canada have no requirements for oil characterization. Several regulatory regimes have general requirements for oil characterization that simply require a description of fate and weathering properties of the oil. Other countries have specific oil properties that must be described such as the specific gravity, viscosity, wax content, asphaltene content, pour point, ITOPF grouping, and toxicity. New Zealand requires a description of how oil properties change at 12, 24, and 48 hours. New Zealand also requires testing of dispersants with samples of produced oil at these time intervals in order to determine which dispersants will be most effective against the oil produced at a given facility. These oil characterization requirements are more specific and detailed that current BSEE or USCG regulations which do not require characterization of oil, but do require a grouping of oil into categories based on density.

BSEE should consider requiring plan holders to characterize produced oil for each well under a given OSRP based on the oil characteristics in Table 95.

Table 95: Recommended oil characteristics to report in OSRPs

Oil Characteristic Category	Properties
Bulk properties	Pour point
	American Petroleum Institute (API) specific gravity
	Viscosity
Chemical content	Boiling curve
	Benzene, toluene, ethylbenzene, and xylenes (BTEX) concentrations
	Gas Chromatography/Mass Spectrometry measurements of polyaromatic hydrochloride (PAH) and aliphatic concentration
	Wax, resin, and asphaltene content
Weathering properties at 12, 24, and 48 hours	Density of oil after specified proportions are evaporated (e.g., 25% evaporated, 50% evaporated, and 75% evaporated).
	Changes in viscosity with evaporative loss
	Emulsion-forming tendencies and maximum water content
Dispersibility of oil	Testing a selected dispersant on the oil to determine effectiveness.

4.2.1.2 *Oil Spill Modeling*

The UK, New Zealand, Canada, Greenland, Brazil, and Australia all require the modeling of oil spill scenarios to assess the geographic scope and trajectory of potential oil spills. Some countries do not require specific parameters for oil spill models and only require that modeling be used to identify areas potentially at risk from oil spills. Other countries have prescriptive requirements for specific model parameters. For example, the UK requires the use of both stochastic and deterministic modeling; stochastic modeling must be performed with at least 100 model runs. The UK also requires that simulated surface oil be displayed with a minimum thickness of 0.3μm, and minimum travel times for oil to reach shorelines must be displayed. New Zealand requires modeling to take into consideration the water depth of the oil release and requires modeling for a minimum of 30 days of a hypothetical spill.

BSEE should consider requiring modeling to be performed for each WCD scenario in an OSRP for a period of at least 30 days. Both deterministic and stochastic trajectory modeling should be performed and should model the following characteristics:

- Oil spill trajectories;
- Weathering, transport, and fate of spilled oil;
- Identification of resources that could come into contact with spilled oil, the probabilities of contact, and minimum travel times for contact with such resources;
- Geographic extent of shoreline oiling; and
- Use of three dimensional models that simulate the release of oil from a subsurface well and the properties of the buoyant plume of oil as it rises to the sea surface.

4.2.1.3 *Multiple Barrier Concept of Operations for Offshore Response Planning*

All of the private oil spill response companies in Norway work together under a single organization called Norwegian Clean Seas Association for Operating Companies (NOFO). NOFO's uses a concept of operations based upon four conceptual barriers between the source of spilled oil and sensitive endpoints such as beaches and coastlines. Barrier 1 comprises source control and high volume removal efforts near the wellhead and involves multiple systems of mechanical recovery and dispersants. Barrier 2 is located in the open waters between the discharge source and the coastline, and comprises mechanical recovery and surface dispersant systems that must be directed by remote sensing and aerial surveillance due to the diffuse and patchy nature of oil in open waters. Barrier 3 uses a broad range of mechanical recovery systems including large and small skimming vessels, vessels of opportunity skimmers, and protective boom strategically located to protect sensitive coastal habitats. Barrier 4 is comprised of shoreline cleanup operations that remove spilled oil from beaches and shorelines.

NOFO's four-barrier concept of operations should be considered by BSEE as a model for requiring offshore response planning. BSEE should require plan holders to conduct scenario-based planning for their WCD that combines their oil characterization and spill modeling with an offshore concept of operations similar to NOFO's 4-barrier concept. BSEE should also consider developing requirements for recovery targets, equipment types, and response times that are similarly built upon the results of the plan holder's oil characterization and spill modeling and the 4 barrier concept of operations.

4.2.1.4 *Removal Targets*

Oil removal and recovery targets are policies that specify the amount of oil that must be removed from an oil spill. Targets can be expressed in a prescriptive manner such as a certain percentage of the discharged volume, or in a narrative, performance-based manner, for example, "the operator must remove as much oil as possible." Targets can also be established as percentages of the potential oil that could be discharged adjusted for factors such as oil weathering (e.g., evaporation) that are derived from the scenario-based oil-spill modeling. These targets can be based on reaching a sum total amount of oil removed from the environment or can be applied specifically to different response methods.

Mechanical Recovery

The regulations for the USCG and Brazil are the only regulations that feature prescriptive, numeric recovery targets for mechanical recovery, and Brazil's regulations are closely modeled after BSEE regulations for offshore facilities. USCG regulations feature highly prescriptive calculations for the proportion of spilled oil that will remain on the sea surface based on oil weathering factors and distance from shore. USCG regulations also feature caps for the maximum amount of oil recovery capacity (EDRC) that must be available through contracts. Brazil requires operators to contract with sufficient EDRC to respond to a WCD scenario with a flow duration of 30 days, which is analogous to BSEE regulatory requirements. Other countries feature a range of performance-based requirements for example. Australia requires operators to define their own oil spill response objectives, which are referred to as Environmental Performance Outcomes (EPO).

Shoreline Cleanup

The USCG regulations are the only regulations studied that included any targets for shoreline oil removal and recovery. The regulations have a prescriptive calculation for how much oil will wash ashore based on distance from shore, oil specific gravity, and emulsion factors.

Dispersant Application

The USCG and New Zealand are the only regulatory regimes that have prescriptive requirements for dispersant application. New Zealand's regulations recommend a starting dispersant-to-oil dosage ratio between 1:20 and 1:30 for surface applied dispersants. The regulations note that dosage rates should be adjusted depending upon oil type and environmental conditions but provide no prescriptive calculations to make these adjustments. The USCG regulations have prescriptive calculations for the total volume of dispersants that must be available and able to be applied to the spilled oil. Operators are required to multiply the total volume of spilled oil by a weathering factor, and then apply a dispersant-to-oil dosage ratio of 1:20 in order to calculate the total volume of dispersants that must be applied. USCG regulations also feature caps for the maximum amount of effective daily application capacity (EDAC) for dispersants that must be available through contracts.

None of the regulations studied had any prescriptive or performance-based requirements for subsurface dispersants, although some regulations require approval for the use of subsurface dispersants or consideration of the impacts of subsurface dispersants in a risk assessment.

Targets for Equipment Types and Quantities

Many of the regulations studied have requirements for equipment type and quantity. Prescriptive requirements for equipment type could require specific characteristics such as a specific volume of on-board liquid storage for mechanical recovery. A performance-based requirement for equipment type could require a response vessel to be able to perform in a certain wave height. Prescriptive requirements for equipment quantity could involve a calculation of how much equipment is needed based on the total volume of oil spilled, while a performance-based quantity requirement could be, for example, "as many units as are needed to effectively remove all spilled oil." Scenario-based oil spill modeling could also be used to help determine the types of equipment that will be best suited for removing the oil. The research conducted for this study revealed that there are many different methods used by the various countries that were reviewed.

Mechanical Recovery Equipment

The USCG, Brazil, Australia, and Denmark are the only regulatory regimes with regulations for mechanical removal equipment type or quantity. Australia has entirely performance-based regulations for equipment type and quantity; Australia operators must define their own performance standards for response equipment, called EPSs, and must meet those standards with owned or contracted equipment. Denmark has relatively simple performance-based requirements for minimum operating conditions for response vessels based on wave height and temperature.

Both Brazil and the USCG have prescriptive regulations for estimating the amounts of equipment that must be available. Both regulatory regimes use EDRC (spelled CEDRO in Portuguese in Brazil), which is a means for calculating the daily oil recovery capacity of a mechanical removal device. EDRC is used in conjunction with oil recovery targets to calculate how much equipment must be available to respond to a spill of a given size. Currently BSEE regulations stipulate using EDRC to estimate the removal capacity of the equipment listed in the OSRP, but do not contain a defined removal target beyond the performance-based standard of "what is necessary, to the maximum extent practicable, to respond to the plan’s worst case discharge."

Both BSEE and the Coast Guard have over the last five years, have been engaged in an effort to improve on the EDRC removal capacity metric, and have developed a new methodology for measuring the removal capacity of mechanical recovery equipment, referred to as Estimated Removal System Potential (ERSP), which is still being evaluated by each agency for potential adoption into their regulations. The ERSP metric is an encounter-rate and systems-based methodology that is a much improved standard over EDRC, and it is recommended that BSEE adopt the new ERSP metric into its regulations.

BSEE should also consider adopting performance-oriented, scenario-based standards for the types of mechanical recovery equipment that take into account the results of a plan holder’s oil characterization, oil weathering studies, and scenario-based oil spill modeling. These performance based requirements could include stipulations for the ability to operate in expected prevailing weather conditions, or the ability to effectively recover oil at expected oil viscosity and emulsification stages.

Aerial Dispersant Application Equipment

The USCG and Brazil are the only regulatory regimes studied with requirements for surface applied dispersant equipment. Brazil's regulations feature prescriptive standards for small fixed wing aircraft, large fixed wing aircraft, and helicopters based on wind speed and wave height. The USCG regulations have no requirements for equipment type beyond stipulating that 50% of all spraying capacity must be from fixed wing aircraft. The Coast Guard does have prescriptive requirements for the capacity to spray particular volumes of dispersants called Effective Daily Application Capacity (EDAC). To calculate the equipment necessary to meet the EDAC targets, operators must first calculate the volume of dispersant required to be sprayed, and then calculate the equipment that would be needed to apply that volume based on a number of specific aircraft characteristics and the logistics involved between the staging of the spraying platforms and dispersant stockpiles and each plan holder's specific spill scenario. USCG-regulated plan holders currently use the Dispersant Mission Planner 2 (DMP2) calculator tool to estimate the application capacity of dispersant spray systems. BSEE and USCG have been engaged in an effort to update the DMP2, which is referred to as the Estimated Dispersant System Potential (EDSP) Calculator. If BSEE adopts dispersant capability targets into its regulations, it should incorporate the use of the EDSP Calculator as the means for measuring a spraying system's application capacity.

Dispersant Stocks

The USCG and the UK regulatory regimes are the only regulations with requirements for dispersant stockpiles. The USCG has a prescriptive requirement that operators must have available to them a sufficient quantity of dispersant to treat a WCD volume up to the EDAC cap (dispersant sufficient to treat 1,100,000 gallons of oil at a 1:20 dispersant to oil ration). The WCD volume is calculated by multiplying the WCD volume by a weathering factor based on oil viscosity and a dispersant application ratio. The UK requires that any offshore facility within 40 km of the coast have available sufficient dispersant stockpiles to treat 25 metric tons of oil.

Aerial Surveillance Equipment

Most of the regulatory regimes studied have some requirement for aerial surveillance of oil spills. Several of these, including the USCG, Brazil, Australia, and Greenland, have performance-based regulations that simply require some sort of aerial surveillance to track the location of spilled oil without specifying type or quantity for three ten hour operational periods over the first 72 hours of a spill. Only the UK has a specific, prescriptive requirement for equipment that must be on board aerial surveillance aircraft. Aircraft whose mission is to detect the presence of oil must be equipped with a marine VHF radio, digital still and video capabilities, satellite telephone, and GPS navigation. Aircraft whose mission is to detect and quantify spilled oil must be equipped with ultra violet and infrared imaging. BSEE should adopt a performance-based requirement for aerial surveillance and oil tracking capabilities that are well suited to supporting ongoing response operations, including spill assessment and cleanup activities.

4.2.1.5 *Response Times for Equipment*

Response times are requirements for how quickly equipment must arrive on-scene in the event of an oil spill. Response times often require resources to cascade into an area of response operations at staggered times because equipment is often being transported from depots at various locations, some of which may be a significant distance from the incident. Response times should take into account various scenario-based parameters such as distance from shore, depth, and oil discharge flow rates.

Response Times for Mechanical Recovery

The USCG is the only regulatory regime studied with response times and mobilization factors for mechanical recovery. The USCG's response times are closely tied to recovery targets and equipment quantity requirements. Operators must calculate the total EDRC that must be available to them, and then apply mobilization factors based on location (Table 96). For example, in the offshore environment, for a WCD, 10% of total EDRC must arrive on-scene within 24 hours, 16.5% must arrive within 48 hours, and 21% must arrive within 72 hours. The remaining 52.5% of EDRC has no arrival time requirement.

Table 96: Response Times for Mechanical Recovery in USCG Regulations

Location of Spill	Tier 1		Tier 2		Tier 3	
	Arrival Time (hrs)	% total EDRC	Arrival Time (hrs)	% total EDRC	Arrival Time (hrs)	% total EDRC
Inland/Nearshore	24	15%	48	0.25	72	40%
All other offshore areas	24	10%	48	0.165	72	21%
Open ocean	24	60%	48	0.10	72	12%

Response Times for Dispersants

Only the USCG and UK regulatory regimes have response times for dispersant application. The USCG has a prescriptive requirement for the amount of dispersants that must be applied within 12, 36, and 60 hours of the initial spill. . The UK requires all offshore facilities within 22 NM of the shoreline to have the ability to apply dispersants within 30 minutes of a discharge. For ALL facilities in the UK, the regulations require a dispersant test spray within 6 hours of the initial discharge and large-scale dispersant application within 18 hours.

Response Times for Aerial Surveillance

Only the UK and the USCG have response time requirements for aerial surveillance. The USCG regulations require aerial surveillance to arrive before any other response equipment, which in most cases will be within 12 hours. The UK regulations require aerial surveillance on scene to verify that a spill has occurred within 4 hours. The spill must be quantified within 6 hours.

4.2.2 Mobilization Factors for Response Equipment

Mobilization factors can be used to adjust the response times for resources based on the equipment's readiness status for deployment. The USCG's OSRO guidelines[55] differentiate whether response equipment is owned or subcontracted by a given OSRO and whether the equipment is solely dedicated to the purposes of oil spill response, or is used in other commercial activities and would need to be recalled from other potential activities before it could be deployed to a spill. The USCG guidelines also take into account whether equipment operators are available on site (i.e., where the response equipment is stored) or are "on-call" and must be recalled to the equipment deployment location. Table 97 shows how mobilization time is assessed for response equipment based on the various readiness factors considered. Such mobilization factors are usually applied equally to OSRO equipment depots of equipment and personnel, and are independent of each plan holder's unique site-specific scenarios.

[55] Guidelines for the U.S. Coast Guard Oil Spill Removal Organization Classification Program

While no other regimes outside of the USCG had specified readiness and mobilization factors, the use of these factors in the application of the response requirements provide incentives for OSROs to have their equipment in a higher state of readiness. BSEE should consider adopting similar mobilization factors that address the readiness of response resources to deploy in a timely manner.

Table 97: Resource Readiness/Mobilization Times in Hours

Resource Status	Additional Mobilization Times (hrs)	
	For On-Site Personnel	For On-Call Personnel
Owned and Dedicated	1.0	2.0
Contracted and Dedicated	1.5	2.5
Owned, not Dedicated	2.5	3.5
Contracted, not Dedicated	3.0	4.0

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5.0 ESTIMATED RECOVERY SYSTEM POTENTIAL (ERSP) ANALYSIS

The Estimated Recovery System Potential (ERSP) Calculator was developed by BSEE, in cooperation with the U.S. Coast Guard and other agencies. The purpose of the ERSP calculation is to develop a more accurate method of determining recovery capability than the Effective Daily Recovery Capacity (EDRC), which is the calculation for mechanical recovery capacity mandated by BSEE and USCG regulations.

The EDRC formula was developed during the Oil Pollution Act of 1990 (OPA 90) regulatory process and is calculated as follows:

> *R (EDRC) = T (throughput rate) or manufacturers nameplate efficiency rate X 24 Hours X 20% (or factor lower than 20% if reviewed and approved by USCG)*

The regulations allow for testing of equipment using American Society of Tests and Measurements (ASTM) standards, which may provide higher EDRC rates. The 20% reduction factor is intended to account for the effects of weather, sea state, and hours of darkness, which reduce the effectiveness of a recovery system.

It has been well documented, including in the USCG's BP Deepwater Horizon Oil Spill ISPR (refer to Section 3.5), that EDRC can provide inaccurate estimates of actual mechanical recovery capacity, including significant overestimates. EDRC only evaluates the performance of the skimming device, based solely on the system's pumping rate. However, the pump rate does not determine recovery rates; it only determines the ability to transfer liquid that is encountered by the skimmer. Further, manufacturer nameplate pump rate does not always indicate the pump's performance in the field, which can vary significantly depending upon the viscosity of the liquid being pumped.

Like the EDRC, ERSP requires the manufacturer's nameplate throughput efficiency as an input (Maximum Total Fluid Recovery Rate in GPM), unless the ASTM or other approved testing provides another validated rate. However, ERSP also considers additional factors such as the system's encounter rate with the oil, the recovery system platform's onboard storage capacity, the recovery system's skimming principal, decanting capability, system rigging and de-rigging time, transit time to secondary storage, and the offload transfer pumping rate. The ERSP Calculator uses various values for the above recovery system functions and calculates the resulting *potential* recovery rate of the system.

A comparison between the EDRC and ERSP calculations was achieved in a threefold manner. The first step was to have participating OSROs provide the EDRC value and ERSP 1st Generation calculation[56] for each recovery system they submitted in their survey for the WCD response scenarios. They also provided estimated mobilization and estimated time of arrival (ETA) for each system to each of the applicable WCD scenario locations for each of those skimming systems.

The ERSP 1st Generation calculations were completed using inventories provided or the recovery systems and tactical configurations found in publically available manuals and other websites. Although some invited OSROs and oil companies did not participate, they did provide publically available, online inventories of equipment. A second calculation was then completed for each of the recovery systems identified using the OSRO's ERSP 1st Generation inputs and values that were collected from the online inventories, as well as the default values for the 2nd Generation ERSP Calculator. This was necessary because the 2nd Generation ERSP Calculator was still under development at the time the OSROs submitted survey data.

Table 98 shows a comparison for EDRC and ERSP values nationally, and for each OCS region. ERSP was not calculated for shoreline skimming equipment because the calculation of ERSP requires a vessel platform. Therefore, a comparison of total EDRC and ERSP is biased toward EDRC because it was

[56] Genwest Estimated Recovery System Potential Calculator posted here: http://www.genwest.com/ERSP-Calculator.htm/view?searchterm=ersp

calculated based upon more skimming equipment. To correct for this, Table 98 include a column entitled "EDRC w/o [without] Shoreline" which was calculated based upon the exact same equipment as total ERSP. This comparison clearly shows that EDRC results in a much higher estimate of mechanical recovery rate than ERSP. Total EDRC for the Gulf of Mexico OCS Region was calculated to be about 8 times greater than ERSP on a same-equipment basis (i.e., comparing the two rightmost columns in Table 98). Continuing this comparison, EDRC is about 3 times greater than ERSP in the Pacific, 2.5 times greater in the Arctic, and 6 times greater than ERSP nationally.

Table 98: Comparison for Total EDRC and ERSP for the Three OCS Regions and Nationally

OCS Region	Shoreline [a]	Nearshore		Offshore		Total EDRC	EDRC w/o Shoreline	Total ERSP
	EDRC	EDRC	ERSP	EDRC	ERSP			
Gulf of Mexico	249,795	708,825	104,450	2,686,625	547,313	3,645,245	3,395,450	651,763
Pacific	101,642	423,181	78,707	800,047	295,102	1,324,870	1,223,228	373,809
Arctic	179,260	200,792	51,409	393,048	150,002	773,100	593,840	201,411
NATIONAL	**530,697**	**1,332,798**	**234,566**	**3,879,720**	**992,417**	**5,743,215**	**5,212,518**	**1,226,983**

[a] ERSP was not calculated for shoreline skimming devices because the calculation of ERSP requires a platform (e.g., a boat), and platforms are not applicable for more shoreline oil removal.

The results of this comparison are unambiguous: if the ERSP planning standard is implemented, OSRP holders may need to significantly increase the mechanical recovery capacity available to them if regulatory requirements for capability levels are to remain the same. While this study did not conduct an economic analysis of the costs of transitioning from EDRC to ERSP, it is reasonable to expect that this could be a costly transition, and warrants further economic analysis that is beyond the scope of this study.

PART III: RECOMMENDATIONS

6.0 OIL SPILL RESPONSE CAPABILITY RECOMMENDATIONS

The following sections of this report present oil spill response capability recommendations for BSEE based modeling of the selected WCDs (Section 2.0), lessons learned from the Deepwater Horizon response (Section 3.0), best practices of national oil spill response regulations (Section 4.0) and the ERSP analysis (Section 5.0). Each recommendation is followed by a rationale that is a brief supporting narrative for the recommendation.

6.1 NATIONAL RECOMMENDATIONS

6.1.1 Oil Characterization

NAT 1. BSEE should require OSRPs to include characterization of the chemical and physical properties of the produced oil. Oil properties may either be known (in the case of production wells) or estimated (in the case of exploration wells). Plan holders should assess the following characteristics:

- Bulk properties
  - Pour point,
  - density, API gravity
  - viscosity
- Chemical content (for wells producing)
  - Boiling curve
  - BTEX concentrations
  - GC/MS measurements of PAH and aliphatic concentrations
  - wax, resin and asphaltene content
- Weathering properties of the oil over a timeframe of 12, 24, 48+ hours
  - Evaporation: density at standard fractions evaporated
  - Changes in oil properties with evaporative loss: viscosity and density
  - Emulsion-forming tendencies and maximum water content
  - Color chart (visual guide) of degree of emulsification to use as an operational guide for aerial dispersant operations, i.e., oil color of varying degrees of emulsification that indicates an oil color that is no longer dispersible; useful for aircraft reconnaissance observers.

***Rationale*:** The review of national oil spill regulations and guidance as part of this study showed that a number of other countries (e.g., New Zealand) require oil characterization for offshore oil spill plans. Prior knowledge of the likely behavior of a spilled oil, and pre-spill analyses of the feasibility of response strategies are important to determine the windows of opportunity for effective recovery, burning, and dispersibility of the oil.

Previous research has shown that the effectiveness of all response countermeasures decrease as oil weathering and viscosity increases. Response countermeasures, including dispersant performance, vary widely based on the chemical properties of oil and its behavior once released into the environment.

6.1.2 Oil Spill Modeling, Offshore Response Concept of Operations (CONOPS), and Common Operating Picture (COP)

NAT 2. BSEE should require plan holders to use oil spill modeling to identify areas at risk from a WCD and to support the development of an offshore Concept of Operations for spill response. Stochastic modeling should be used to identify the likelihood of geographic areas coming into contact with spilled oil and minimum travel times to sensitive environments (e.g., wetlands or fishing areas). Deterministic trajectory modeling should be used as a basis for developing an offshore Concept of Operations. The deterministic modeling should track the fate and transport of the oil as it rises through the water column for subsurface releases, and/or moves away from the discharge site on the surface. The modeling should predict changes in oil viscosity and oil thickness over time and distance in order to estimate the geographic extent of the oil spill, develop response divisions, and match response capabilities to areas where they will be effective. Oil spill models used by plan holders should also have the ability to track spills in real-time to support ongoing response efforts.

Rationale: Oil spill modeling is a critical tool for spill response planning, and is not currently required under BSEE regulations for plan holders. Oil spill response models can identify resources at risk, inform response strategies, and assist in real-time spill tracking.

NAT 3. BSEE should require plan holders to plan for response assets to be assigned to different areas of operation based on their removal capabilities, maneuverability, command and control, and other inherent support capabilities.

***Rationale*:** Command and control issues during the Macondo response contributed to a less than optimal deployment of response assets. This could have been mitigated through better guidance in the RCPs, ACPs, and the OSRP on the effective assignment of assets to the Operations Section Chief and his staff. This assignment guidance should be based on the capabilities of the recovery systems, as well as other inherent features, such as their communications, command and control abilities, maneuverability, and their ability to provide localized oil spill surveillance and tracking that can be shared across the area of operations. The need for a Common Operating Picture is linked to the requirement for a common information reporting template. It is essential to be able to communicate adequately with officials, the public, and the media, as well as within the response, in a uniform manner."

NAT 4. BSEE should require that the Concept of Operations in the OSRPs is readily adaptable to changes in the oil's fate and transport throughout the WCD area of operations, to ensure that as the oil weathers, thins, and area extent expands, that resources will be distributed according to the individual capabilities of the systems. The concept of operations should also ensure that simultaneous operations across various response divisions are well coordinated, and that proper support is available to all sections of the WCD operations area. Corresponding planning guidance should be included in the OSRP and tested during NPREP exercises.

Rationale: Recovery systems should be assigned to areas of the spill plume according to their individual capabilities and the predicted properties of the oil plume in each division, including oil thicknesses, viscosities, and its distribution on the surface. The effectiveness of this approach was demonstrated in the modeling simulations (see Figure 153 for example of modeled response division geographic areas). The more efficient systems, which are often the less maneuverable, should be assigned to the division/group where the oil is concentrated, thick, and remains low in viscosity, such as near the wellhead or where the majority of the oil surfaces. More maneuverable systems adapted to more viscous oils may be better suited to areas where the oil has been broken up into weathered streamers and patches. Each division/group grid should be supported with appropriate secondary storage, surveillance and other support to ensure they are as efficient and successful as possible.

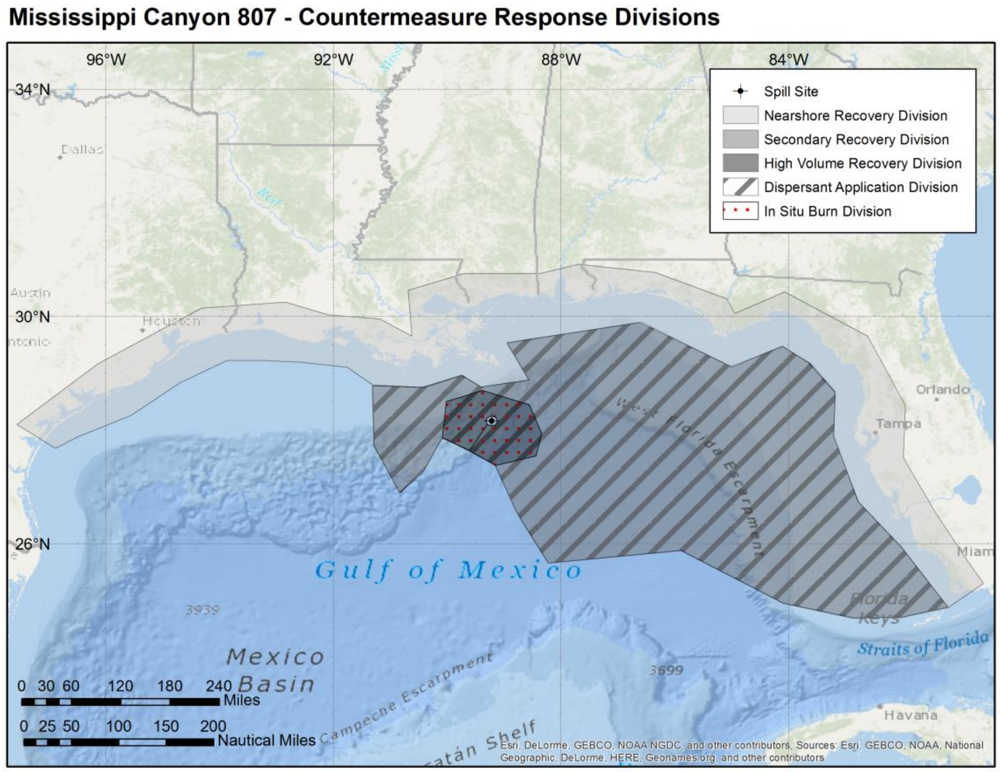

Figure 153: Illustration of Surface Oil Countermeasure Response Divisions, MC807

NAT 5. BSEE should require plan holders to integrate aerial surveillance into their Concept of Operations to provide real-time oil spill tracking (to be coordinated with modeling efforts), assign countermeasure response divisions, and direct available assets to where they can work most efficiently.

Rationale: Aerial surveillance can provide real time information to refine and execute the dynamic Concept of Operations and provide a Common Operating Picture for all stakeholders.

NAT 6. BSEE should require plan holders to integrate modeling, surveillance and tracking and the Concept of Operations with a pre-planned Common Operating Picture that is compatible with other government oil spill situational awareness tools, such as NOAA's Environmental Response Management Application (ERMA).

Rationale: The Deepwater Horizon FOSC report stated "The response demonstrated the need to capture accurately where critical resources were located, what was deployed, what was staged, and what activities had taken place. In any major spill, the ability immediately to report accurate information about response activities and resources is essential." The efficient use of resources is the key to response management, and having a clear picture of the location of resources and their status is essential for offshore oil spill response. The "Guidance for Offshore Oil and Gas Exploration, Production and Pipeline Facility Operators," API Technical Report #1145, September 2013 recommends that Spill Management Teams utilize a method of presenting a Common Operating Picture, using available technologies to the extent possible.

6.1.3 Temporary Source Control Capabilities

NAT 7. BSEE should require OSRPs to include detailed planning for the use of various temporary and permanent source control methods that are specific to each facility or well site.

Rationale: The WCD modeling results of this study provide strong evidence that the most significant impact in reducing the amount of oil released into the environment is the prompt implementation of a temporary source control measure to secure the discharge. In the case of a well blowout, regardless of whether source control is regained with a top kill or a subsurface capping stack, the ability to rapidly shut down the discharge with a temporary measure in lieu of the much longer timeframe associated with the drilling of a relief well should be emphasized as one of the highest priority preparedness and response actions that can be undertaken. Table 99 clearly shows that the prompt shutdown of well flow significantly reduces the discharge of oil into the environment and to economically and environmentally sensitive areas.

Table 99: Response Modeling Results for Relief Well and Source Control Intervention

Well	Relief Well Only Bbl Released	Relief Well Only Shoreline Miles Contaminated	Source Control Bbl Released	Source Control Shoreline Miles Contaminated	Source Control Release Volume Reduction: %	Source Control Shoreline Contamination Reduction: Miles/%
MC 807	81,718,000	4,528	20,205,000	2,233	-75.3%	2,295 -50.7%
WD 28	3,589,000	1,430	2,037,000	1,266	-41.6%	164 -11.5%
WC 168	2,006,400	539	554,400	122	-72.4%	417 -77.4%
HIA 376	3,850,000	1,452	1,617,000	851	-58%	601 -41.4%
KC 919	30,240,000	2,602	11,340,000	1,135	-61.8%	1,467 -56.4%
DC 187	25,546,000	2,990	10,845,000	1,075	-57.6%	1,915 -64.1%
CA SM6683	884,000	1,620	52,000	620	-94.1%	1,000 -61.7%
CS Early	700,000	600	350,000	223	-50%	377 -62.8%
CS Late	700,000	729	350,000	440	-50%	289 -39.6%
BS Early	480,000	782	224,000	353	-53.3%	429 -54.9%
BS Late	480,000	583	224,000	501	-53.3%	82 -14.1%

NAT 8. BSEE should require planning to sustain response resources for the duration of time necessary to implement a temporary source control measure, such as a capping stack, plus any additional time necessary to clean up the oil that was spilled. The plan holder should estimate their temporary source control optimal and suboptimal time frames for specific wells or facilities by including a Gantt chart of all the specific activities necessary that are occurring simultaneously and sequentially. The suboptimal timeline for securing the discharge should take into account potential delays that may arise from the following causes: adverse weather, delays in the requisition of support vessels, government agency approvals, debris removal, and difficulties in installing containment or capping devices, mechanical failures, and other unsafe working conditions at the site of the discharge. Each potential delay should be specifically shown on the Gantt chart and the time extension impact depicted on the overall source control timeline. Plan holders should use the suboptimal timeline for implementing the temporary source control measures as the base period for planning a sustained response to the spill.

***Rationale*:** BSEE's current regulations 30 CFR Part 254.26 (d) (1) states, "For operations at a drilling or production facility, your scenario must show how you will cope with the initial spill volume upon arrival at the scene and then support operations for a blowout lasting 30 days." Response operations for OCS WCD events can take much longer than 30 days. For example, the Macondo well flowed for 87 days and cleanup operations continued for many weeks after well capping. Plan holders should plan to sustain a response based on the suboptimal time frame to implement temporary source control measures plus the additional time necessary to complete cleanup operations. Currently, most source control documents, such as Regional Containment Demonstration (RCD) Plans, are generic, with similar format and content for all plan holders and all facilities, including activity timelines. Whereas the majority of the RCD can be boilerplate, there are certain activities that should be specific to the well. Distances from shore staging areas to the discharge site will impact transit and on scene times, environmental conditions for different regions or geographic areas may pose potential delays that should be accounted for, depth of the water at the discharge site may impact the capping operation, etc.

NAT 9. BSEE should require plan holders to have a definitive source control plan that is coordinated with the OSRP. The RCDs could meet this requirement, provided it includes the following items:

- IMT organizational structure for the source control functions.
- Job descriptions for the various source control positions shown in the IMT organizational structure.
- Matrix that clearly shows how responsibility for source control activities is divided between the plan holder and the source control organization.
- Plans for site survey, assessment, debris removal, and source control measures well capping or cap-and-flow.

***Rationale*:** A harmonized approach to implementation of source control activities among the regulated community will make OSRP implementation faster and more efficient, and result in reduced environmental consequences. A clear organizational structure will reduce problems with communication, command, and control activities during an actual spill.

NAT 10. Logistical and operational support of subsurface activities should be described in Well Control Plans and RCDs, and incorporated into the CONOPS in OSRPs. Well Control Plans or RDCs should address the need to have a Concept of Operations for the surface logistical and operational support for the subsurface activities.

Rationale: The surface component of subsurface containment logistical support operations needs to be coordinated with recovery and treatment of surface oil to minimize conflicts in the operational area above the wellhead. As was the case in DWH, there was a designated area where source control activities only were permitted with surface response operations being conducted outside of that source control allocated area. It was observed in the WCD modeling that oil removal amounts increased when mechanical recovery operations were conducted in close proximity to where the oil was surfacing near the well head. Expanding source control exclusion zones beyond the area actually required reduced substantially the volume of surface oil that could be mechanically recovered. The High Volume Recovery Division is most effective in areas where the oil fresh, thick, and concentrated on the surface. Source control exclusion zones should be as small as possible and should be closely coordinated with other surface-based spill countermeasures, especially mechanical recovery operations, occurring in any adjacent areas.

NAT 11. Providers of temporary subsurface source control devices, such as capping stacks and cap-and-flow systems, should notify BSEE if they plan to cascade these devices out of their respective OCS Regions.

Rationale: Temporary subsurface source control devices are critical resources to mitigate WCDs. BSEE should be in a position of approving or denying the removal of these critical equipment systems from their current storage locations in order to monitor and ensure oil spill preparedness in each OCS Region.

6.1.4 Resource Readiness and Mobilization Time Factors

NAT 12. BSEE should require OSRP's to include mobilization time factors for spill response resources based upon the equipment's readiness status for deployment. These mobilization factors would be used in conjunction with estimates of transit times to calculate the planned arrival of equipment at the site of a discharge. These time factors should differentiate whether response equipment is owned or subcontracted by a given OSRO and whether the equipment is solely dedicated to the purposes of oil spill response, or is used in other commercial activities and would need to be recalled from other potential activities before it could be deployed to a spill. The time factors should also take into account whether equipment operators are available on site (i.e., where the response equipment is stored) or are "on-call" and must be recalled to the equipment deployment location. Table 100 illustrates the relationship between the equipment and associated personnel readiness factors and mobilization times:

Table 100: Recommended Resource Readiness Factors/Mobilization Times

Resource Status	Mobilization Times (hrs)	
	On-Site Personnel	**On-Call Personnel**
Owned and Dedicated	1.0	2.0
Contracted and Dedicated	1.5	2.5
Owned, not Dedicated	2.5	3.5
Contracted, not Dedicated	3.0	4.0

Source: *USCG, 2013, Guidelines for the U.S. Coast Guard Oil Spill Removal Organization Classification Program*

Rationale: Accounting for recall and mobilization times in the calculation of response times gives incentive for OSROs to maintain equipment in a higher state of readiness. These mobilization factors, when added to transportation times necessary for equipment to travel from their staging sites to the spill, provide for a more realistic assessment of readiness.

NAT 13. BSEE should develop standards or regulatory guidance for estimating the transit speeds of equipment being deployed in response to a spill. These transit speeds could be used to verify the arrival times of equipment at a spill site and assess overall readiness.

Rationale: The Coast Guard currently uses 35 mph over land, 5 knots over water, and 100 knots for equipment being transported by air. The Coast Guard also uses platform-specific air speeds for each dispersant spraying aircraft in estimating their transit times to a spill. These default speeds do not always accurately represent true transit speeds for various types of equipment.

6.1.5 Oil Spill Tracking and Surveillance Capabilities

NAT 14. BSEE should require that OSRPs provide for oil spill surveillance and tracking resources that are capable of arriving on scene and providing an initial assessment of an offshore oil spill within six hours of notification to deploy.

Rationale: A rapid initial assessment of the nature and scope of an offshore oil spill incident is critical to commencing the deployment of response resources and the effective removal/mitigation of the oil.

NAT 15. BSEE should require a multi-tiered system of oil spill tracking and surveillance capabilities to support oil removal activities:

- Tier 1 capabilities are localized to the immediate vicinity of a response asset, and are focused on increasing that asset's effectiveness to remove, burn, or disperse oil. In the case of mechanical recovery platforms, these capabilities should be a vessel-mounted sensor system that can detect the thick oil in the immediate vicinity of the vessel (e.g., x-band radar) and can be used to both direct thick oil into the recovery device as well as assist in more efficiently removing the oil.
- Tier 2 capabilities should be able to provide a larger area of oil spill surveillance coverage for a task force or group assigned to recover, burn, or disperse oil. These systems may use sensors, such as infrared, mounted on an airborne platform, such as an aerostat or drone, to give a broader view of the surrounding area.
- Tier 3 capabilities should be aircraft-mounted, multi-spectral sensor capabilities that are capable of providing oil surveillance and tracking capabilities over a large area that can be relayed to various response groups or task forces and incident command posts.

Tier 1 and 2 tracking resources should be capable of arriving on scene and providing surveillance, tracking, and direction commensurate with the start of conducting oil removal activities. Tier 3 capabilities should be capable of arriving at the site of a discharge within 12 hours of being activated.

Rationale: Oil spill surveillance is needed to ensure that all response countermeasures operate efficiently. Given the large size of potential surface area of oil slicks resulting from WCDs, the present level of surveillance resources available are inadequate. Oil spill surveillance is an essential aspect of achieving recovery system maximum efficiency, especially when chasing patches of oil in the Secondary Recovery Division. Surveillance and transfer of the data achieved was one of the limiting factors for skimming systems during the Macondo response. The recommendation for all oil spill response vessels (OSRVs) and oil spill response barges (OSRBs) to have infrared capability is due to the fact that these recovery systems should and will be distributed throughout the area of operations and would support VOSS/VOO systems in their division/group.

NAT 16. BSEE should encourage OSROs to increase their inventories of portable, prepackaged surveillance systems that can be placed on VOOs, OSRVs, and available aircraft. This capability is especially important for OSROs that anticipate using large numbers of VOOs during response efforts.

***Rationale**:* Due to the size of operating areas resulting from potential WCD spills at OCS facilities, there may not be enough OSRVs with the proper surveillance equipment installed to be assigned to each required division/group. An inventory of packaged and portable surveillance systems would assist in meeting this recommended goal.

6.1.6 Mechanical Recovery Capabilities

NAT 17. BSEE should require plan holders to use the ERSP calculator to determine recovery potential of mechanical equipment.

Rationale: Model results in this study confirmed that the ERSP Calculator provides more realistic estimates of recovery potential than EDRC. The model results consistently estimated that oil recovery rates are much lower than the cumulative ERSP or EDRC rates for all the equipment simulated in the scenarios due to factors such as weather, sea conditions, low encounter rates, and changes in the physical and chemical characteristics of the oil. It was clear from the modeling, however, that ERSP rates offer a more realistic measure than EDRC.

NAT 18. BSEE should encourage OSROs to acquire more efficient skimming devices through the use of incentives linked to the recovery efficiency values for different types of systems in the ERSP Calculator.

Rationale: In general, oleophilic skimming systems are more efficient than other types of skimmers such as weir skimmers. Table 101 illustrates how incentives to procure more efficient systems can be created by ensuring ERSP values are sensitive to the different types of recovery systems and their corresponding recovery efficiency ratings. Currently the ERSP Calculator guidance assigns a default rating of 50% to weir skimmers and 75% to oleophilic skimmers.

Table 101: Comparison of Oleophilic and Weir Skimmers

Skimming Principal	Oil (bbl)	Water in Emulsion (bbl)	Free Water (bbl)	Total Fluids Recovered (bbl)
Weir System				
ERSP Day 1 Oil	1,636	881	1,512	4,029
ERSP Day 2 Oil	1,132	1,384	1,512	4,029
ERSP Day 3 Oil	625	1,874	1,502	4,000
Oleophilic System				
ERSP Day 1 Oil	2,454	1,322	756	4,532
ERSP Day 2 Oil	1,699	2,077	756	4,532
ERSP Day 3 Oil	761	2,282	609	3,653

NAT 19. BSEE should require that plan holders maintain OSRO inventory documents that provide Day 1 ERSP values for all mechanical recovery equipment in the High Volume Response Division, and Day 2 and Day 3 ERSP printouts for mechanical recovery equipment outside of the High Volume Recovery Division.

Rationale: Since these lists will be used during actual spills and exercises for tracking resources and their capabilities, the documentation will assist response planners with developing recovery, storage, and disposal requirements. During interviews with OSROs, it was found that OSROs are sometimes not consulted by the plan holder regarding oil recovery values, response times, and other technical information about OSRO-owned equipment that is included in OSRPs written by plan holder's or by their consultants. Plan holders may have an incentive to overestimate some OSRO capabilities and OSROs should be required to validate this information to ensure accuracy.

NAT 20. BSEE should consider changing the ERSP calculator default values for decanting.

Rationale: The current default values are based on the platform's number of tanks, heating coils, and whether there is an oil/water separator. The calculator currently gives 40% credit for separate tanks, an additional 5% increase for heating coils, and another 5% for an oil water separator. Most vessels have separate tanks. Therefore, the 40% value may not be valid. Simply installing two steel frac tanks on the deck of a VOO would qualify for the 40% value, while not meaningfully improving decanting ability. If incentive is going to be given to improve the systems, a greater value should be offered for those recovery system platforms with heated tanks. Based on discussions with pump specialists, it was found that pumping cold and viscous oils, having the ability to heat the tanks is more beneficial than having separate tanks and separators. This is especially true in WCD scenarios where systems may be recovering fluids faster than the oil water separator can function. To stop skimming or offloading to separate the recovered fluids decreases the efficiency of the response and recovery assets counterproductive. Small separate tanks, if recovering debris-laden emulsified oil, may be considered a detriment rather than an advantage. Especially if these separate tanks are small and not fitted with independent positive displacement pumps that can handle emulsified viscous oil and small debris. Bladders used for storing this type of oil should be given no credit at all. Once filled, they are extremely difficult to offload.

NAT 21. BSEE should ensure adequate total storage volumes are contracted to contain the daily combined total fluids recovered as calculated by the ERSP Calculator for all the recovery systems used to meet the ERSP requirements.

Rationale*:* Secondary storage vessels should offload to shore-based tertiary storage for disposal of recovered oil. During transit and offloading operations, secondary storage vessels are unavailable to receive recovered oil from OSRVs, which can result in OSRVs temporarily halting mechanical recovery operations. This is particularly problematic for response operations that are far from shore, as secondary storage vessels will face increased transit times to shore. Secondary storage vessels with greater capacities offload less frequently, resulting in fewer disruptions in mechanical recovery operations.

NAT 22. In addition to ensuring that adequate secondary storage volumes are available, BSEE should ensure that plan holders have an adequate number of secondary storage platforms that can cover all the active areas where mechanical recovery operations are occurring, enabling recovery systems to meet their transit times to secondary storage as estimated in the ERSP Calculator.

Rationale*:* Onboard and secondary storage components are both critical elements for effective mechanical recovery operations. The smaller the storage onboard a skimming platform, and the longer it takes for that system to transit to an available secondary storage site, the less time that will be available to the system for skimming and recovering oil. Table 102 illustrates the importance of having an adequate number of secondary storage platforms to support the recovery systems being used across the operational areas.

Table 102: Examples of Onboard Storage and Transit Times to Secondary Storage on the ERSP Values for a Mechanical Recovery System

On Board Storage (bbl)	ERSP with 30-Minute 1-Way Transit	ERSP with 1-Hour 1-Way Transit	ERSP with 2-Hour 1-Way Transit	ERSP with 3-Hour 1-Way Transit
4000	6590	4891	4394	4394
500	1992	1373	824	549

NAT 23. BSEE should require that OSRVs assigned to the High Volume Recovery Division to have sufficient onboard storage for recovered oil, oil/water emulsion, and free water to sustain their planned ERSP oil recovery rates in these potentially high oil encounter rate operating areas.

Rationale: Onboard storage volume is a significant factor for determining how effective an OSRV will be in recovering oil in the High Volume Recovery Division. If an OSRV has a very high throughput skimming device, but does not have sufficiently large onboard storage, it must unload to secondary storage more frequently, which decreases operational recovery time and reduces the overall system efficiency. Table 103 shows example ERSP capabilities of three systems using the same skimming device, operational periods and encounter rates, but the different onboard storage capacities.

Table 103: Comparison of Recovery Rates for OSRB, OSRV, and VOOs with Same Skimming Device

Recovery System	Day 1 ERSP (bbl)	Day 1 Total Fluids Recovered (bbl)
OSRB	14,506	26,413
OSRV	8,193	16,000
VOO	4,062	7,500

NAT 24. If BSEE updates the ERSP calculator, BSEE should require plan holders or OSROs to de-rate the GPM value of any transfer pumps by 20% for pumps when non-positive displacement pump will be used with oils that have been shown to rapidly weather into viscous oils. The derating of pumps should not apply to pumps that will be used only for decanting.

Rationale: Transfer pumps are used to transfer thick, viscous oil and oil emulsions that may include debris from the skimming device to storage tanks, and later from storage tanks to secondary storage vessels. Positive displacement pumps are more effective at moving these liquids and material than other types of pumps with similar manufacturer GMP ratings. This recommendation will give OSROs incentives to procure or contract for positive displacement transfer pumps, which will allow them to offload oil to secondary storage more effectively. As demonstrated in the modeling conducted in this study, highly vicious oils can hinder response efforts. Unfortunately, the use of EDRC over the past two decades has incentivized the purchase and use of pumps with high GMP rates, without consideration of their ability to pump thick, viscous oil.

NAT 25. BSEE should require plan holders to ensure that contracted mechanical recovery assets that can arrive in the following pre-established quantities and response times at the site of the discharge. The arrival times and quantities of ERSP are shown in Table 4 through Table 7, and are categorized based on a facility's maximum daily discharge flowrate, adjusted for oil weathering through oil spill modeling (otherwise referred to as a planning volume), and distance from the nearest shorelines.

Table 104: Recommended Mechanical Recovery Response Times for WCDs <15,000 bbl/day

	WCD Daily Flowrate Planning Volume <15,000 bbl/day			
Response Time (hrs)	ERSP Required (bbl/day)			
	0-20 miles from shore	20 -100 miles from shore	100-200 miles from shore	200+ miles from shore
12	10,000			
18	25,000	15,000	10,000	
24	50,000	30,000	25,000	15,000
48		50,000	50,000	50,000
96				

Table 105: Recommended Mechanical Recovery Response Times for WCDs 15,000 to 50,000 bbl/day

WCD Daily Flowrate Planning Volume between 15,000 to 50,000 bbl/day				
Response Times (hrs)	ERSP Required (bbl/day)			
	0-20 miles from shore	20-100 miles from shore	100-200 miles from shore	200+ miles from shore
12	25,000			
18	35,000	25,000	15,000	
24	50,000	35,000	30,000	25,000
48	150,000	100,000	75,000	50,000
96		150,000	150,000	150,000

Table 106: Recommended Mechanical Recovery Response Times for WCDs from >50,000 to 100,000 bbl/day

WCD Daily Flowrate Planning Volume between 50,000 to 100,000 bbl/day				
Response Times (hrs)	ERSP Required (bbl/day)			
	0-20 miles from shore	20-100 miles from shore	100-200 miles from shore	200+ miles from shore
12	25,000			
18	50,000	30,000	15,000	
24	75,000	50,000	35,000	25,000
48	200,000	150,000	125,000	100,000
96	250,000	250,000	250,000	250,000

Table 107: Recommended Mechanical Recovery Response Times for WCDs >100,000 bbl/day

WCD Daily Flowrate Planning Volume >100,000 bbl/day				
Response Times (hrs)	ERSP Required (bbl/day)			
	0-20 miles from shore	20-100 miles from shore	100-200 miles from shore	200+ miles from shore
12	25,000			
18	50,000	35,000	25,000	
24	75,000	50,000	35,000	25,000
48	250,000	200,000	150,000	125,000
96	300,000	300,000	300,000	300,000

Rationale: The recommendation for thresholds and response times are based on the analyses of this study, including results of the Deepwater Horizon Oil Spill review (Section 3.0), the Geographical Analyses of the Gulf of Mexico, Pacific, and Arctic OCS Region WCD Volumes from Volume I of this study (Sections 3.1, 4.1, and 5.1), the Market Research of Available Response Equipment (Section 1.7), and the Oil Spill Response Capabilities Analysis (Section 2.0), and National Oil Spill Response Regulations Review (Section 4.0).

The SIMAP modeling results showed that there is not a consistent relationship among the oil discharge volume, the cumulative oil removal potential of the equipment deployed to the site, and the actual amount of oil removed. The modeling results indicate that oil removal rates appear to be closely related to the environmental conditions (e.g., wind and waves) during the countermeasure period, the subsequent change in in the characteristics of the floating oil, and the capabilities of the removal equipment to deal with the oil characteristics encountered. Overall, the model results suggest that the removal potential of the combined response countermeasures must be significantly greater than the volume of the oil discharged in order to achieve significant oil removal levels in these large WCD events. However, because there is a diminishing return in terms of oil removal rates and requiring and deploying more equipment (as well as a significant economic cost to maintaining large caches of equipment), this study is recommending sustainable capped limits for the amounts of equipment (and associated trained personnel) that should be contracted in advance and maintained in a high readiness status.

Based upon the review of various national oil spill response plan regulations, it was determined that a prescriptive approach for mechanical recovery requirements, using a structure similar to that used by the USCG, would best meet BSEE's needs. The WCD profiles developed in Volume I of this study were used to generate broad categories for offshore facilities based on their distance from shore and their WCD planning volumes. Thresholds and response times were developed, using the OSRO survey data and SIMAP modeling analysis, and the following three principles:

1. ERSP thresholds should be required that are significantly greater than the associated WCD volume for an offshore facility (unless the WCD volumes exceed the designated equipment cap). The SIMAP modeling for the WCD scenarios demonstrated that oil recovery rates are substantially lower than the cumulative ERSP rates employed during a spill. Recovery rates as a percentage of ERSP ranged from 0.4% to 9.8% (see Table 108). Comparable recovery rates were achieved in the DWH spill response.

Table 108: Achieved Oil Recovery Rates as a Percentage of ERSP

Model Scenario	DWH	MC 807	WD28	WC 168	HIA 376	KC919	DC187	SM 6610	P6912	FI6610
Mechanical Recovery rates [a] (ERSP/achieved)	3-4%	9.8%	9%	0.4%	8%	8%	3.6%	0.7%	1%	1%
[a] recovery rates are for the SC+MR+D+ISB response scenarios [b] number derived from FOSC Report										

2. Response times should achievable. OSRO mechanical response capabilities are based in shore-based depots that can accommodate the vessels, equipment, and crews. It is unreasonable (and likely economically impossible) to pre-position high-capacity OSRO assets offshore in the vicinity of OCS facilities. Equipment thresholds and response times were developed based upon the SIMAP modeling of achievable responses to the various WCD scenarios using the OSRO survey data.

3. Thresholds and response times should comparable and consistent among OCS Regions whenever possible.

NAT 26. BSEE should require plan holders have some proportion of their mechanical recovery equipment dedicated to the nearshore environment. Plan holders should be given flexibility in the proportion of equipment dedicate to the nearshore environment, but this number should not be lower than 10%. Facilities closer to shore should have a larger proportion of their mechanical recovery resources dedicated to the nearshore environment, and this should be informed by the individual facility modeling results. Facilities close to shore should have no less than 15% of their ERSP requirements met by nearshore equipment.

Rationale: It is critical for response efforts to include some equipment platforms that are relatively small, maneuverable, and therefore able to chase and effectively remove the diffuse, weathered oil that is found in the nearshore environment. For spills from facilities that are close to shore, more surface oil can be expected to enter the nearshore environment, where large, offshore mechanical recovery platforms do not operate optimally.

NAT 27. BSEE should ensure that OSRPs contain or reference strategies for shoreline protection and shoreline cleanup that are consistent with the Regional and Area Contingency Plans. The OSRPs should also include specific quantities and types of resources that have been contracted in order to protect or clean up each geographical area that may be impacted, based on the results of the spill modeling done for that OSRP.

Rationale: Every WCD scenario modeled in this study, regardless of how much removal capability was applied offshore, still resulted in substantial shoreline impacts from the spilled oil. Shoreline protection and shoreline cleanup planning and capabilities should be an integral part of any OSRP.

6.1.7 Dispersant Stockpile Requirements

NAT 28. BSEE should require plan holders who must have surface applied dispersants as a response strategy in their OSRP to have access by contract or other approved means to existing dispersant stockpiles sufficient to sustain surface-applied dispersant capabilities as required for their facility in the Tables 111-114 or 116, for either the initial 14 days of a response, or until the source can be secured based on an optimal timeline, whichever is greater. Plan holders should have arrangements in place to sustain surface-applied dispersant capabilities through either existing stockpiles or through replenishment by a dispersant manufacturer until the source can be secured in accordance with a suboptimal timeline.

NAT 29. BSEE should require each plan holder to verify that they have access to each listed dispersant stockpile, and also that they have made arrangements to receive replenishment supplies within 14 days of notifying the dispersant manufacturer with a request for additional dispersants. BSEE should require OSRPS to show calculations for the amount of dispersant stockpiles needed based on planned daily application rates, discharge duration, and DOR for both surface and subsurface dispersants.

Rationale: Dispersant stockpiles are owned and or controlled by multiple entities in the United States and internationally. Access to dispersant stockpiles is usually based on organizational memberships or contracts, and if a plan holder is not a member of the organization or does not have a contract then that plan holder is not guaranteed access to those stockpiles.

NAT 30. BSEE should require OSRPs to include a Dispersant Management Plan (DMP) that includes information on the company, personnel, dispersant application methods and resources, and dispersant stockpiles that will be used in a response to a WCD.

***Rationale*:** Some of the modeled scenarios in this study involved extremely high daily oil spill flow rates and long durations (e.g., MC807, KC919, and DC187). Dispersant stockpiles applied in these modeled scenarios were divided between surface and subsurface applications to realize an overall maximum effectiveness based on the volume, duration, and daily trajectories of the spill.

At current stockpile sizes, the use of dispersants may need to be prioritized and apportioned between surface and subsurface applications during a large WCD event. The proper planning for application resources and stockpiles, and the prioritization of how and where, e.g., subsurface and surface applications will be used, coupled with the replenishment logistics, need to be evaluated and structured. For OSRPs involving a WCD scenario arises where both subsurface and surface dispersant application may be necessary, planning for the most effective use of existing stockpiles and the rapid replenishment of dispersant supplies to support extended operations is critical.

NAT 31. BSEE should require plan holders who list SSDI as a response strategy in their OSRP to have access by contract or other approved means to existing dispersant stockpiles sufficient to sustain surface-applied dispersant capabilities as required for their facility in Tables 111-114 or 116, until the application of subsea dispersants can be commenced. Plan holders must also have access to dispersant stockpiles to sustain simultaneous surface-applied and subsurface dispersant applications in accordance with the amounts specified in Table 109 once subsea dispersant operations are commenced. Plan holders must make arrangements for access to sufficient dispersant stockpiles to sustain simultaneous surface-applied and subsea dispersant operations until the well is secured in accordance with the suboptimal well capping timeline. Stockpile arrangements for simultaneous application operations may be met through both existing stockpiles and arrangements for sustainable replenishment by dispersant manufacturers. Existing stockpiles should be sufficient to sustain simultaneous application capabilities for a minimum of 14 days, or the time necessary to install a capping stack on a suboptimal timeline, whichever is less.

Table 109: Dispersant Stockpile Planning Requirements for Simultaneous Surface and Subsurface Application

Dispersant Application Method	WCD Daily Flowrate <50,000 bbl/day		WCD Daily Flowrate ≥50,000 bbl/day	
	Dispersant (gal)	EDSP (bbl/day)	Dispersant (gal)	EDSP (bbl/day)
Surface-Applied at 1:20 DOR	10,000	4,750	28,400	13,525
Subsurface Injection at 1:100 DOR	7,200	17,000	21,600	51,425
Daily Dispersant Stockpile Amounts	**17,200**	**21,750**	**50,000**	**77,625**

Rationale: Plan holders who plan to use subsurface dispersant injection should plan for the following:

a) Surface-applied dispersant operations may be required on a full scale basis until subsea dispersant injection equipment can be deployed and operated at the point of the discharge
b) Once subsea dispersant injection operations commence, depending upon the size of the discharge flowrate and the SSDI equipment being used, the need for surface-applied dispersant applications may quickly decrease
c) sustained simultaneous surface-applied and subsurface dispersant operations could quickly deplete existing dispersant stockpiles. Arrangements for the replenishment of existing stockpiles with additional dispersant stocks must be in place, and the use of stockpiles carefully planned to ensure dispersant operations can be sustained uninterrupted until a capping stack or other temporary source control measure can be installed on a suboptimal timeline basis.

6.1.7.1 *Surface Applied Dispersant Platform Capabilities*

NAT 32. BSEE should require plan holders to use the Estimated Dispersant System Potential (EDSP) Calculator to verify surface-applied dispersant application capabilities.

Rationale: The EDSP Calculator is a planning tool for surface dispersant application planning. The EDSP includes site-specific inputs such as the distance between discharge site and staging locations, which are used to calculate round-trip timing and daily application of dispersant volumes. The review of oil spill response regimes that was performed for this study lead to the conclusion that the EDSP, and its predecessor, the Dispersant Mission Planner 2 (DMP2) are among the most comprehensive dispersant application planning tools available worldwide.

NAT 33. The EDSP Calculator should be updated with additional platforms and their characteristics as they become available for use.

Rationale: Currently, the EDSP Calculator does not include any default values for specific vessel platforms or the Boeing 727-200 jet aircraft that are currently undergoing certification for use as dispersant aircraft by Oil Spill Response Limited (OSRL). The Calculator does, however, allow users to enter in new platforms and their characteristics, and perform the EDSP calculations on their local version of the software.

NAT 34. BSEE should require OSRPs to demonstrate that plan holders have contracted access to adequate numbers of aircraft and vessels for dispersant operations (see regional recommendations for specific dispersant capability requirements). Use of the EDSP Calculator should be mandated for plan holders by BSEE in order to demonstrate the ability of the platforms listed in the OSRP to achieve the required capacity to apply the dispersants with appropriately sized platforms operating out of the appropriate staging locations.

Rationale: While the model scenarios in this study assumed that all existing aircraft were available for all WCDs, the industry survey conducted for this study concluded that this may not be true in practice. Designated response aircraft are subject to contractual and/or organizational membership access restrictions. Depending upon the WCD volume, membership in or contracts with only one aircraft provider may not be sufficient.

NAT 35. BSEE should require OSRPs to include the results of dispersibility testing for the oils handled by an offshore facility. These tests should be performed using the dispersants that are listed in the OSRP.

Rationale**:** A review of other national oil spill regulations and guidance showed that a number of other countries require testing of dispersants with the oils being produced at a facility. This information is critical for informing response decisions regarding the effective use of dispersants during a response. Current BSEE regulations do not have similar requirements.

6.1.7.2 *Subsurface Dispersant Injection (SSDI) Capabilities*

NAT 36. BSEE should consider specific requirements for subsurface dispersant injection at depths shallower than about 985 ft (300m) or the pycnocline.

Rationale: Many OCS wells are in waters shallower than 985 feet (300 meters). The SIMAP modeling results in this study suggest that the use of SSDI in some shallower situations, such as well sites in the Arctic OCS, may be the most effective way to respond to a WCD. The review of U.S. and foreign regulations did not reveal any additional subsurface dispersant requirements or guidance that would be applicable for scenarios at these depths. The National Response Team's "Environmental Monitoring for Atypical Dispersant Operations: Including Guidance for Subsea Application & Prolonged Surface Application", dated May 30, 2013, addresses the use of subsurface dispersants in waters deeper than 300 meters, and is focused on the monitoring aspects of an SSDI operation. There is a need to further research and develop guidance regarding the use of subsurface dispersants, as well as monitoring activities, for shallower scenarios at depths less than 300 meters (and above the pycnocline).

NAT 37. BSEE should promote additional research in order to establish improved guidance regarding SSDI dispersant to oil ratios (DORs).

Rationale: The industry recommended 1:100 DOR was used to simulate SSDI operations in the SIMAP model scenarios in this study. Results of the model scenarios show that oil removal by SSDI range from about 5% to about 20% of the discharged oil plume. Greater oil removal may be possible with a different DOR (and associated dispersant stockpiles and equipment required to achieve this DOR). Research is being conducted by other parties on SSDI including the Coastal Response Research Center's (CRRC) review of dispersants in the Arctic. Brandvik et al. (2014)[57] indicated that DORs of 1:50, 1:100 or less may be sufficient to cause substantial additional dispersion.

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[57] "Dispersants: Subsea Application -- Good practice guidelines for incident management and emergency response personnel", authored by Brandvik, P. J., Johansen, O., Farooq, O., Angell, G. and Leirvik, F. (2014b). *Subsurface oil releases - Experimental study of droplet distributions and different dispersant injection techniques Version 2*. A scaled experimental approach using the SINTEF Tower basin. SINTEF report no. A26122. Trondheim, Norway

NAT 38. BSEE should require that OSRPs specify subsurface dispersant equipment that is 'right-sized' for the operating conditions around the corresponding well(s) and anticipated WCD flow rates. OSRPs should include information on SSDI application equipment and platforms, projected injection pump rates (see Table 110), size of the coiling tube unit, dispersant stockpiles, and stockpile resupply procedures/contracts and corresponding timeline for resupply.

Table 110: Dispersant pump rates for various blowout flow rates and DORs

Oil Flow Rate	Dispersant Pump Rate to achieve a DOR of 1:50-US Gallons/Minute	Dispersant Pump Rate to achieve a DOR of 1:100-US Gallons/Minute
20,000	12	6
40,000	23	12
50,000	29	15
60,000	35	18
100,000	58	28

Source: IPIECA

***Rationale*:** Currently there are no BSEE requirements to ensure that subsurface dispersant equipment is 'right-sized' to the potential range of oil discharge flowrates that may be associated with specific wells. Some WCD flowrates that currently exist in OSRPs exceed the maximum pump rate capacities of existing equipment to inject dispersants at the recommended 1:100 DOR.

NAT 39. BSEE should require that OSRPs demonstrate that SSDI equipment (e.g., ROVs, platforms, personnel) is ensured available and will not conflict with, or compete for the same equipment, as source control or other response operations.

***Rationale*:** During the industry survey that was performed for this study, it was found that the major contractors for source control/well capping equipment also provide the hardware to operate subsurface dispersant injection operations. It is unclear whether these contractors can provide sufficient equipment and coordination of equipment and personnel to ensure that ensure that these two processes can be simultaneously executed. If there is insufficient equipment or coordination, response efforts could be compromised.

NAT 40. Source control and subsurface dispersant injection operations should coordinate with surface response operations.

Rationale: Source control and subsurface dispersant injection operations may influence the flow rate and trajectory of the subsurface plume, as well as where, when and how much oil surfaces and is transported on the surface. For example, subsurface dispersant injection operations may need to be curtailed during installation of the capping stack, which will alter the amount of oil that will be necessary to remove or mitigate on the surface by other spill response countermeasures.

6.1.8 In Situ Burning Capabilities

NAT 41. BSEE should allow plan holders to substitute in situ burning capabilities for some required mechanical recovery capacity, up to a prescribed percentage of the total ERSP requirement. It is recommended that facilities more than 20 miles offshore should be allowed to offset up to 20% of the required ERSP mechanical capabilities with in situ burning. Facilities within 20 miles of shore should be allowed to offset up to 10% of the required ERSP mechanical recovery capabilities with in situ burning. The reduced percentage closer to shore is reflective of limitations that may be put on large scale ISB operations as operations move closer to shoreline communities and their population centers. BSEE should require plan holders to use the Estimated Burn System Potential (EBSP) Calculator to estimate the removal capability of all in situ burning equipment listed in their OSRPs.

Rationale: Plan holders can calculate the daily oil removal potential of in situ burning equipment with the EBSP Calculator. Plan holders can then directly offset ERSP with EBSP up to the allowable percentage limit. For example for a facility located less than 20 miles from shore with a planning volume of 35,000 bbl/day would have a maximum ERSP cap of 150,000 bbl/day. The plan holder could offset up to 15,000 bbl/day of mechanical recovery equipment (10% of their maximum ERSP requirement) with an equivalent amount of burning equipment rated at 15,000 bbl/day of removal capacity using the EBSP Calculator.

NAT 42. BSEE should ensure that plan holders who offset a portion of their ERSP requirements with in situ burning capabilities in their OSRP should also include the other components of a the system that are necessary to conduct in situ burning operations, including support from aerial spill tracking and surveillance, a means of ignition, vessels to tow fireboom, equipment and trained personnel for air monitoring, and the ability to collect burn residue.

6.1.9 Offshore Response Logistics Recommendations

NAT 43. BSEE should require OSRPs to demonstrate planning for sustained, long-term response operations in the offshore or open-ocean environment. OSRPs need not require specific supporting equipment and vessel types and quantities, but should require a general description of how sustained operations will be executed far from shore.

Rationale: Response operations for offshore oil spills that are far offshore face unique challenges that are not present in nearshore response operations. In the offshore and open ocean environment, transit times for fuel vessels, supply vessels, OSRVs, OSRBs, disposal of recovered oil, and source control are significantly increased. Response crews should have hoteling accommodations as it is too time-consuming to ferry them to shore every night, and emergency medical supplies and evacuation capabilities should be provided. As offshore oil development moves farther from shore, plan holders should demonstrate, in OSRPs, that they have plans in place to manage sustained response in the offshore and open ocean environment.

6.2 Regional Recommendations for the Gulf of Mexico

6.2.1 RCP and ACP Recommendations

GOM 1. BSEE should work with RRTs and Area Committees to develop strategic and tactical guidance for mechanical recovery to be included in RCPs and ACPs based on lessons learned from the Deepwater Horizon response efforts. This guidance is especially needed in the offshore and open ocean zones.

Rationale: Gulf of Mexico RCPs lack strategic and tactical guidance for mechanical recovery. There were many lessons learned during the Macondo response that have not been transferred to the ACP and RCPs. This may result in UC and Operations Section having to relearn these lessons if they are not captured and transferred to those e response guidance documents and available for use in strategic and tactical response planning in future spill events.

GOM 2. BSEE should work with RRTs and Area Committees to develop strategic and tactical guidance for in situ burning to be included in RCPs and ACPs. These strategies and tactics should be based on those used for in situ burning during the Macondo response (see Section 3.0). This guidance should also leverage the EBSP Calculator for estimating the removal potential of equipment staged in the region.

Rationale: The Gulf of Mexico RCPs and ACPs lack strategic and tactical guidance for in situ burning. Strategies and tactics can be found in "Fire Boom Performance Evaluation," Nere J. Mabile, November 9, 2010 and "Controlled Burns-After Action Report," Nere J. Mabile and Alan A. Allen, August 8, 2010.

GOM 3. BSEE should work with RRTs and Area Committees to encourage federal and state regulators to relax limitations on decanting. BSEE should consider policy options including pre-authorizing decanting in the offshore and open ocean zones and developing a decanting protocol for pre-authorized areas. Industry organizations, such as API, could be leveraged to assist in developing decanting protocols.

***Rationale*:** Decanting of oily water is critical for effective high volume mechanical recovery operations as it allows mechanical recovery platforms to use their on-board storage tanks more efficiently. Current regulations place significant limits on decanting in state and federal waters.

GOM 4. BSEE should work with RRTs and Area Committees to establish guidance for independent and accurate measurements of mechanically recovered oil during spill response, or incorporate similar requirements for verifying mechanical recovery equipment performance during a spill, into the OSRP regulations. This measurement should be taken when OSRVs offload to secondary storage tanks (either floating or shore-based).

Rationale: On August 15, 2010, Michael J. Utsler, a representative of BP Gulf Coast Restoration Organization wrote to BOEM regarding daily reporting of recovered oil and water. In this letter, Mr. Utsler stated that that while oil recovery data were a reasonable representation of daily recovery rates, data quality was hampered by inconsistent reporting protocols, variable timing of report submissions, and variable decanting frequencies. These problems can be addressed with the development of standard protocols to be described in RCPs and ACPs, or similar plan holder requirements in the OSRP regulations.

6.2.2 Surface-Applied Dispersant Capability Recommendations

GOM 5. BSEE should establish the requirements for dispersant application capabilities for EDSP shown in Table 111 and Table 112 for the Gulf of Mexico OCS Region. These requirements are for the first 36 hours of an incident; however, for continuous releases, the EDSP capability requirements for the 36 hour response time would be required to be available for each following day of the response until the discharge is secured.

Table 111: Recommended Surface Dispersants Response Times for WCDs <50,000 bbl/day in the Gulf of Mexico OCS Region

WCD Daily Flowrate Planning Volume < 50,000 bbl/day			
Response Time for EDSP (hrs)	EDSP (bbl/day oil treated using a 1:20 DOR)		
	0-20 miles from shore	20-150 miles from shore	150+ miles from shore
12	10,000	7,500	5,000
36	15,000	12,500	10,000

Table 112: Recommended Surface Dispersants Response Times for WCDs ≥50,000 bbl/day in the Gulf of Mexico OCS Region

WCD Daily Flowrate Planning Volume ≥ 50,000 bbl/day			
Response Time for EDSP (hrs)	EDSP (bbl/day oil treated using a 1:20 DOR)		
	0-20 miles from shore	20-150 miles from shore	150+ miles from shore
12	20,000	15,000	10,000
36	35,000	25,000	15,000

6.3 Regional Recommendations for the Pacific

6.3.1 Mechanical Recovery Recommendations

PAC 1. BSEE should closely review the levels and arrival times for secondary storage platforms necessary to support initial mechanical recovery operations in the Southern California planning area.

Rationale: The survey information provided by OSROs suggested that there will be delays in the arrival of the secondary storage platforms, especially during the first 12 hours of the response. While OSRVs could be on scene within 2-4 hours, they would have to travel to Santa Barbara to offload fluids during the initial operating periods. As these OSRVs have limited onboard storage, their skimming time during these initial operating periods would be significantly reduced by the lack of onsite secondary storage.

PAC 2. BSEE should require plan holders to use primarily Group "A" recovery equipment in this area.

Rationale: Group "A" mechanical recovery equipment is most often comprised of skimmers using oleophilic surfaces that are well suited for recovering more viscous oils. For equipment in this study, Group A was assigned an upper limit of 15,000 cp and Group C was set at 80 cp (See Table 10 for more detail). The SIMAP modeling for SM6683 simulated 31,363 bbl/day of Group C mechanical recovery equipment, however, Group C equipment did not achieve any oil removed throughout the simulation.

6.3.2 Surface-Applied Dispersant Capability Recommendations

PAC 3. BSEE should establish the requirements for dispersant application capabilities for EDSP shown in Table 113 and Table 114. These requirements are for the first 36 hours of an incident; however, for continuous releases, the EDSP capability requirements for the 36 hour response time would be required to be available for each following day of the response until the discharge is secured.

Table 113: Recommended Surface Dispersants Response Times for WCDs <50,000 bbl/day in the Pacific OCS Region

WCD Daily Flowrate Planning Volume < 15,000 bbl/day	
Response Time for EDSP (hrs)	EDSP (bbl/day oil treated using a 1:20 DOR)
12	4000
36	10,000

Table 114: Recommended Surface Dispersants Response Times for WCDs ≥50,000 bbl/day in the Pacific OCS Region

WCD Daily Flowrate Planning Volume ≥ 15,000 bbl/day	
Response Time for EDSP (hrs)	EDSP (bbl/day oil treated using a 1:20 DOR)
12	10,000
36	15,000

6.3.3 In Situ Burning Recommendations

PAC 4. Due to the limitations placed on in situ burning, BSEE should not allow mechanical recovery ERSP requirements to be offset with in situ burning equipment in the Southern California planning area.

Rationale: Conditions in this planning area are currently not conducive to in situ burning operations, due to prevailing weather conditions and air quality concerns.

6.4 REGIONAL RECOMMENDATIONS FOR THE ARCTIC

6.4.1 Arctic RCP and ACP recommendations

ARC 1. BSEE should work with Alaska RRT and the Subarea Committees to define strategy and tactical approaches for mechanical Recovery Systems in the offshore environment. The Alaska Unified Contingency Plan and Sub-Plans for Northwest Arctic and North Slope all consider mechanical recovery as the preferred oil spill response countermeasure, but do not give any guidance for a applicable offshore concept of operations on how such a response should be organized, deployed and supported.

Rationale: Offshore petroleum and exploration operations have occurred infrequently in the Beaufort and Chukchi Seas, and the RCPs and Subarea Plans for these areas have not fully integrated offshore response planning into their contingency plan documents.

ARC 2. BSEE should work with the Alaska RRT and others to establish response strategies and pre-authorization procedures for both surface and subsurface dispersants in the Chukchi and Beaufort Seas.

Rationale: There is currently no pre-authorization of surface or subsurface dispersants in Arctic OCS. Therefore, if it is decided that dispersants are needed for a spill in the Arctic, additional time will be needed to secure authorization for their use. The environmental conditions in the Arctic such as sea state and visibility can be unpredictable and effect vessels used for mechanical recovery, and aircraft used for dispersants in different ways. For example a high sea state and clear skies may be more suitable for aircraft, vs. foggy conditions and calm seas that could favor the use of vessels. Therefore ensuring that both vessels and aircraft are available for use in the Arctic will maximize opportunities for response.

6.4.2 Arctic OSRP Review Recommendations

ARC 3. BSEE should require plan holders to work with OSROs to include more information on the deployment, operation, management, and support of offshore recovery systems in their tactics manuals.

Rationale: The Alaska Clean Seas (ACS) Tactical Manual is referenced in the OSRPs as the basis for their planned response activities. The tactics manual; however, is oriented primarily toward providing guidance for response efforts in the nearshore, river, and shoreline environments, as well as covering oil recovery operations on ice. Although ACS and their members have some skimming devices that could be used for offshore applications, they do not have platforms that could effectively deploy those devices in the offshore environment.

ARC 4. BSEE should ensure that OSRPs for Arctic OCS facilities include response tactics for oil spill surveillance and tracking, mechanical recovery, in situ burning, and dispersants in both open water and in ice situations.

Rationale: The SIMAP Model was run using both Early Season and Late Season weather and sea conditions for both the Chukchi and Beaufort Sea scenarios, including the encroachment of ice during the late season runs. Those models showed fairly significant differences in the recovery rates and surface and shoreline oiling as a result of the spill starting at different points in the open water drilling season and encountering ice. As a WCD spill could occur at any point during a drilling operation, industry should be prepared for spills that must be cleaned up in both open water and in ice conditions. Since a majority of their response resources are transported into the Arctic subarea for the drilling season, those different resources should be included in the initial movement of response equipment into the Arctic.

ARC 5. BSEE should ensure that OSRPs include enough supporting resources to ensure that each recovery system planned for the response is completely functional for the operational period.

Rationale: A review of contingency plans developed for the offshore responses in the Arctic suggested that towing vessels will be a limiting resource that will be in short supply until additional task forces can arrive on scene 48 hours or more into the spill response. Even at that time, it appears that there will be shortfalls in the number of towing vessels needed to conduct boom deployment for enhanced encounter rate operations for mechanical recovery and in situ burning simultaneously.

ARC 6. BSEE should require plan holders to use only Group "A" mechanical recovery equipment in OSRPs for the Arctic OCS.

Rationale: Group "A" mechanical recovery equipment is well suited for recovering more viscous oils. These systems are most often comprised of belts, rope mops, brushes, barrels, and other skimmers that feature oleophilic surfaces. In this study, Group A recovery equipment was assigned an upper limit for oil viscosity of 15,000 cp (See Table 10 for more detail on Group Equipment Types and viscosity limits). The SIMAP modeling conducted for the Arctic OCS scenarios modeled the deployment of 44,783 bbl/day of Group C mechanical recovery equipment in the Chukchi Sea (P6912 WCD scenario) and 56,662 bbl/day of Group C mechanical recovery equipment in the Beaufort Sea (Fl6610 WCD scenario). In all cases, including both the early and late season simulations for both the Chukchi and Beaufort scenarios, Group C equipment did not achieve any oil removed at any time during the model runs. In contrast, Group A equipment, modeled in smaller quantities based on the OSRO survey inventories, were successful at recovering some portions of the discharged oil. For P6912, 17,531 bbl/day of ERSP removed a total of 18,138 bbl (early) and 16,324 bbl (late) of oil, For Fl6610, 119,155 bbl/day of ERSP removed a total of 11,489 bbl (early) and 11,587 bbl (late) of oil. While Group A equipment was more successful at removing oil in these conditions than Group C, it should be noted that mechanical recovery rates were still quite low for all Arctic simulations, this is likely a reflection of the mismatched proportions of Group A and Group C equipment that was deployed, as well as the additional weather restrictions that were placed on mechanical recovery equipment in the model assumptions (in effect 62.5% of the time). This restriction was in addition to downtime due to sea state and winds exceeding mechanical recovery parameters.

ARC 7. BSEE should closely examine resources identified in OSRPs that are cascading to the Arctic from other regions or nations with regard to the estimated time it will take to arrive and the supporting logistical requirements necessary to sustain those resources. In addition to the large distances between the spill sites, equipment depots, and transportation hubs, there is a lack of logistical infrastructure to support personnel, move, and store response assets once delivered.

Rationale: Logistic support in any response effort is important. In the Arctic, logistical support arrangements are critical due to the lack of shore-based infrastructure available in the Arctic or surrounding areas (see Table 115). Information regarding the handling of equipment and the arrangements necessary to get them from airports to marine facilities where they can be loaded for operations offshore should be required in the OSRPs. Although resources may be shipped into the Arctic by air, they still require platforms from which they can be deployed once onsite. The availability of adequate OSRVs, OSRBs, and VOOs for the Arctic is also a critical resource. This is especially of concern during the late season, as a response to any significant WCD incident will likely require ice strengthened platforms to support skimming operations in the vicinity of broken ice or ice flows. The OSRPs should identify the source of vessels that any recovery systems transported in will use as platforms and what their capabilities as recovery system platforms may be.

Table 115: Distance to Response Resource Depots from Arctic Scenario Locations, P6912, and FL6610

Location	P6912	FI 6610	Wainwright AK	Barrow AK	Prudhoe Bay, AK	Dutch Harbor, AK	Seattle, WA	Russia Nearest Point	Canada Nearest Point
P 6912	0	346	70	125	292	1,036	2,774	356	516
FI 6610	346	0	282	222	55	1,392	3083	702	130

6.4.3 Dispersant Capability Recommendations

ARC 8. BSEE should establish the requirements for dispersant application capabilities for EDSP shown in Table 116. These requirements are for the first 36 hours of an incident; however, for continuous releases, the EDSP capability requirements for the 36 hour response time would be required to be available for each following day of the response until the discharge is secured

Table 116: Recommended Surface Dispersants Response Time for the Arctic OCS Region

Response Time for EDSP (hrs)	EDSP (bbl/day oil treated using a 1:20 DOR)
36	10,000

ARC 9. BSEE should consider requiring plan holders to have an SSDI capability for offshore facilities conducting exploratory drilling with a subsea blowout preventer in the Arctic OCS.

Rationale: The SIMAP modeling for the Arctic scenarios showed extremely low removal rates for surface-based oil spill response countermeasures. SSDI was the most effective countermeasure employed in the simulations where SSDI was included (both late season simulations for the Chukchi and Beaufort Seas). In the Chukchi Sea, response countermeasures successfully removed 28% of the oil discharged, of which 15% was removed/treated by SSDI. In the Beaufort Sea, response countermeasures removed/treated 30% of the oil discharged, of which 22% was removed/treated by SSDI.

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8.0 APPENDIX A: RCP AND ACP SUMMARY TABLES

The following summary tables were used to collect information on the oil spill response strategies and tactics within RCPs and ACPs that cover the geographic areas that would be effected by any of the WCD scenarios in this study.

8.1.1 Gulf of Mexico OCS Region RCPs and ACPs

There are two Federal Regional Response Teams (RRTs) that supervise response operations in the Gulf of Mexico. Federal Region VI covers the western side of the GOM and its RCP, implemented by the Region VI RRT, covers Texas and Louisiana. Federal Region VI includes the GOM coastline from the international border with Mexico on the Southwestern side to its eastern boundary, which is the Louisiana and Mississippi state line. The region includes five U.S. Coast Guard (USCG) Captain of the Port (COTP) zones and their individual ACPs. Those ACPs are as follows: the ACP for Southwestern Texas Coastal Zone, Sector Corpus Christi, TX; the ACP for Central Texas Coastal Zone, Sector Houston/Galveston, TX; the Southeastern Texas/Southwestern Louisiana Coastal Zone, Marine Safety Unit (MSU) Port Arthur, TX; the ACP for South Central Louisiana, MSU Morgan City, LA; and ACP for New Orleans, LA, Sector New Orleans, LA.

Federal Region IV includes the eastern portion of the GOM from its western boundary with Region VI at the Mississippi and Louisiana State line to the southwestern tip of Florida at Key West. In addition to the RRT, which guides response activities for all of Region IV through the Region IV RCP, there are three ACPs that guide response for specific areas of the Mississippi, Alabama and Western Florida Coastal Zones: the ACP for Mississippi, Alabama and Northwest Florida Coastal Zone, Sector Mobile, AL; the ACP for the Central Western Florida Coast, Sector St. Petersburg, FL and the ACP for Southeastern/Southwestern Florida Coastal Zone, Sector Key West, FL.

Each RCP and ACP in the GOM indicates that mechanical recovery is the preferred option. They also provide a level of pre-authorization for in situ burning and use of dispersants by the Federal On-Scene Coordinator. The authorizations are provided should they consider additional treatment methods are needed to control the spilled oil and to minimize the shoreline impact. The summary table below details these pre-authorizations and limitations.

Table 117: Summary of Region VI (Texas and Louisiana) Regional Contingency Plan

Response Method	Reference	Content
Mechanical, including decanting	RCP Volume 1, Chapters VII & VIII	Does not provide specific guidance for offshore mechanical response strategy or tactics. RCP also does not address decanting
Dispersants	RCP Volume 1, Chapter VII and VIII; RCP Annex 7, 11, 12 & 34	Provides pre-approved authority to FOSC for deciding on use of dispersants in Federal waters and the parameters the FOSC is to follow in doing so. Pre-approved zone is offshore waters from 3 NM or 10 meter isobaths, whichever is farthest from shoreline, and the limit of the 200 NM EEZ. The region's southwestern boundary is the international boundary with Mexico and the eastern limit is the boundary between Region VI and Region IV. It also refers to the NRT Atypical Dispersant Guidance document for sub-surface dispersant decisions. Region VI RRT is in process of developing Annex 14, which will be dedicated to sub-sea dispersant applications.

Response Method	Reference	Content
In Situ Burning	RCP Volume 1, Chapter VII & VIII; RCP Annex 13	Provides pre-approved authority for FOSC to decide on use of ISB in Federal waters and parameters to be followed for doing so. Pre-authorized zone is generally 3 NM from shoreline to the 200 NM EEZ. Annex 13 also provides detailed guidance on ISB operations, including simultaneous operations with other recovery and treatment methods and nearshore operations approved by RRT.
Bioremediation	RCP Annex 15	Provides guidance on use of bioremediation and other treatments such as shoreline cleaning agents, surfactants, gelling agents and other such treatments. All such treatments require RRT approval. Suggests bioremediation as primarily a shoreline polishing treatment in final stages of cleanup.
Well Control	N/A	There is currently no guidance provided for well control or relief well drilling in the RCP. Annex 20 which will provide such direction is under development.
South Texas Coast (Sector Corpus Christi) ACP		
Mechanical, including Decanting	ACP Section 3230, 3260	ACP provides generic guidance such as mechanical being preferred the option for controlling oil spills. Aerial observation for directing skimmers is recommended. There is no specific guidance directed toward strategic or tactical operations. Decanting requires a permit and will be considered on a case-by-case basis.
Geographic Response Plans (GRP)	Texas GLO Spill Kit Website; Discussions with GLO & LOSCO	Texas GLO and Louisiana LOSCO have within the last year changed the format of their GRP program. The previously designed strategic and tactical approaches to the identified sensitive areas have been removed. Although basic strategy for each sensitive site, such as diversion deflection or encapsulation, is identified in the GRP, the strategy or tactic for carrying out the recommendation is left to the IMT on a case-by-case response basis depending on spill location and other factors that would influence the tactical approach.
Central Texas Coast (Sector Houston/Galveston) ACP		
Well Control	ACP Section 3240, 3242	This ACP provides detailed strategic and tactical guidance for well control activities, as well as good contractor and logistical information regarding well intervention operations.
Southeastern Texas/Western Louisiana Coast (MSU Port Arthur) ACP		
In Situ Burning (ISB)	ACP Section 1670; Annex 7, 11 &12;	Provides guidance on consultation with tribal governments. Also provides more detail on areas where ISB will not be allowed in more detail than other ACPs in this region.
Southeastern Louisiana Coast (MSU Morgan City) ACP		
In Situ Burning (ISB)	ACP Section 3270, 9000; Appendix C	Specifies additional details on pre-approval zone and suggests decision for pre-approval is from UC and not just the FOSC.
New Orleans (Sector NOLA) ACP		
The New Orleans ACE contained no additional information on response strategies and tactics		

Table 118: Summary of Region IV (Mississippi, Alabama, Western Florida) RCP

Response Method	References	Contents
Mechanical	RCP Sections A-Q	Decanting permission in Federal waters lies with FOSC and other members of UC
Dispersants	Region IV Dispersant Use Plan; Dispersant Use Operations Manual; and Memorandum for Dispersant Use in Ocean and Coastal Waters	Region IV Manuals provide detailed guidance and direction to FOSC and other UC members regarding dispersants, application platforms, safety, tactical considerations, monitoring protocols, and other aspects of dispersant use. Provides pre-authorization for FOSC to allow dispersant use in Zone 1 or "Green Zone." "Green Zone" is defined in RCP as 3 NM or 10 Meter Isobar, whichever is farther from shoreline and does not include "Yellow" (Zone 2) or "Red" (Zone 3) zones within 3 NM of operations. Requires RRT approval for any dispersant application within the yellow zone, which is generally considered state waters.
In Situ Burning	Region IV In Situ Burn Plan	Plan provides for detailed information regarding the 3 burn zones and the pre-authorization approval for Zone 1. In Situ Burn Plan provides guidance on safety tactics, monitoring and other aspects of ISB operation. "Yellow" or B Zones are described as state waters, Federal Marine Sanctuary waters and other environmentally sensitive areas in both Federal and state waters. No ISB operations are allowed even with RRT Approval in "Red" or "C" zones. There are currently no "Red" zones identified in Region IV.
Bioremediation	Region IV Bioremediation Spill Response Plan	FOSC will determine if Bioremediation is appropriate and practical for the specific incident. If deemed necessary, the FOSC must prepare the request and seek authorization from RRT. RRT is committed to provide decision within 24 hours.
Well Control	None	RCP does not provide guidance or direction regarding well control or relief well drilling.
Mississippi, Alabama, Northwest Florida (Sector Mobile, AL) ACP		
Well Control	ACP Section 1440.7.1, Section 9440.1; 7th District IODRP	ACP WCD Scenario provides detailed discussion on expectations regarding blowout prevention, relief well drilling, and well source control activities. Well Source Control activities include sub-sea well containment, assessment and debris removal, capping operations, capture and collection operations, and simultaneous operations. Calls for drilling of relief well to be implemented at beginning of WCD discharge and run simultaneously with other operations.
Central Western Florida Coastal (Sector St. Petersburg, FL) ACP		
In Situ Burning (ISB)	ACP Section 1650	Florida has a state ban on burning. Therefore, state permission must be obtained prior to initiating ISB operations within state waters. It should be noted that state waters in Western Florida extend out to 9 NM offshore.
Southwestern/Southeastern Florida (Sector Key West, FL) ACP		
Mechanical Recovery, Including Decanting		Due to Florida Keys National Marine Sanctuary covering large parts of this ACP's waters, it is doubtful that decanting will be authorized.

Response Method	References	Contents
In Situ Burning (ISB)	ACP Section 1650	Calls for FOSC to immediately notify EPA, DOI, DOC, and states if burning is authorized.

8.1.2 Pacific OCS Region RCPs and ACPs

As discussed in the previous Gulf of Mexico Section, the Region IX RCP and California ACPs for the California Central and Southern Coastal areas also indicate that mechanical recovery is the preferred option for response to an oil spill. However, they provide levels of pre-authorization for in situ burning and use of dispersants by the Federal On-Scene Coordinator (FOSC), if the FOSC considers additional treatment methods as being needed to control the spilled oil and to minimize the shoreline impact. The Federal Region IX RCP is the only contingency plan reviewed during this study that specifically indicated that pre-approval guidelines for dispersant use and in situ burning must follow the Net Environmental Benefit Analysis process. For more detail on Region IX pre-authorizations and limitations see the summary below.

Table 119: Summary of Region IX (California) Regional Contingency Plans and Area Contingency Plans

Response Method	Content	Reference
	Regional Contingency Plan	
Mechanical, including decanting	No specific strategic or tactical guidance for offshore response provided. Main objective presented is to minimize or prevent shoreline impact and reduce threat to wildlife. Indicates decanting may be authorized by FOSC outside of State and marine sanctuary waters. Decanting within those waters requires State or marine sanctuary supervisor approval.	RCP Section 2006.02.5
Dispersants	The FOSC is given pre-approved authority to use dispersants in the specific approved zone. The pre-approved zone is marine waters 3 to 200 NM from the coast or island shoreline, except for waters designated as part of a National Marine Sanctuary or within 3 NM of the border with Mexico on the south and the border with Oregon on the north. All other marine waters require RRT approval. The final 2010 RCP does not address sub-surface dispersant use, but it is under revision. The Sept. 2014 draft posted on the RRT website does address subsurface use of dispersants, which may be authorized on a case-by-case basis.	RCP Section 1007.05; Appendix 10, 12 and Annex I
In Situ Burning (ISB)	The FOSC is given pre-approved authority to use ISB in marine waters that are 35 to 200 NM offshore from the coastline. There is no E&P activity within the pre-approved zone. RRT consultation is required for all other areas.	RCP Section 1007.06; Appendix 13
Bioremediation	Bioremediation is considered a shoreline treatment only. Bioremediation and other treatments such as shoreline cleaners, gelling agents, and surfactants require RRT Approval for use.	RCP Section 1007-08; Appendix 10, 11 and 14.

Response Method	Content	Reference
Well Control	There is no reference to well control or relief well drilling in the RCP.	no reference
Central California Coast (Sector LA/LB) ACP		
Geographic Response Plans	Provides shoreline protection and recovery strategies for shoreline areas covered by the ACP, including recommended boom and equipment levels required for recommended tactical approaches.	ACP Volume II
Southern California Coast (Sector San Diego) ACP		
Geographic Response Plans	Provides shoreline protection and recovery strategies for shoreline areas covered by the ACP, including recommended boom and equipment levels required for recommended tactical approaches.	ACP Volume II

8.1.3 Arctic OCS Region RCPs and ACPs

The Alaska Regional Response Team (ARRT) has divided the State into ten sub-areas, each with its own ACP. This study reviewed the North Slope Sub-ACP, which covers the Beaufort Sea, and the Northwest Arctic ACP, which provides guidance for the Chukchi Sea. The U.S. Coast Guard (USCG) and Alaska Department of Environmental Conservation (ADEC) are assigned primary oversight of response activities for both the Chukchi and Beaufort Seas. The Commander USCG Sector Western Alaska (Anchorage) serves as Federal on Scene Coordinator (FOSC). ADEC representatives serve as State on Scene Coordinators (SOSC). The pertinent information obtained from the review of the Alaska RCP and ACPs is summarized in the table below.

Table 120: Summary of Alaska Unified Command Contingency Plan and Northwest Arctic and North Slope ACPs

Response Method	Content	Reference
Regional Contingency Plan		
Mechanical, including decanting	Mechanical is preferred response option. No discussion regarding offshore strategic or tactical response actions. No reference to decanting authority.	no reference
Dispersants	Dispersants are not pre-authorized in the Arctic. Unified Command (UC) must consult with RRT (EPA, DOI, DOC) for both surface and sub-surface applications.	RCP Annex F, Appendix 1
In Situ Burning (ISB)	UC has authority to authorize when mechanical is not capable of controlling the spill. Appendix also provides guidance for decision-making and zones where ISB can be used, including separation distances to be considered in UC burn decisions.	RCP Annex, Appendix 2
Bioremediation	RRT Approval required. Considered practical for only shoreline cleanup.	RCP Annex F, Appendix 3
Well Control	Well control and relief well drilling is not addressed in RCP.	No reference
North Slope Sub-ACP		

Response Method	Content	Reference
Mechanical	Calls for full Incident Management Team (IMT) to be in place within 96 hours. Discusses need for agreements to be made regarding sharing of equipment to reduce shortfalls. WCD scenario provides view of response strategy expected for offshore response. Refers to Alaska Clean Seas Cooperative Tactics Manual for guidance on tactical approaches to be used for both offshore, nearshore and ice conditions.	ACP-A-17, ACP F-1
Other Response Methods	No other substantive new information or guidance from that provided in RCP.	no reference
Geographic Response Plans	Provides charts showing sensitive areas to be protected, guidance on type and amount of boom to be used to carry out identified strategies, and location of equipment caches.	ACS Map Atlas Volume 2
Northwest Arctic		
Other Response Methods	No other substantive new information or guidance from that provided in Alaska RCP and North Slope ACP.	no reference
Geographic Response Plans	Provides shoreline protection and recovery strategies for shoreline areas covered by ACP, including recommended boom and equipment levels required for recommended tactical approaches.	ACP Section G

9.0 APPENDIX B: NATIONAL OIL SPILL RESPONSE REGULATIONS SUMMARIES

The following tables were used to collect information on oil spill response regulations from the eight countries that were studied for this report. The information in these tables was found in statutory, regulatory, and guidance documents found on government websites of these eight countries. The information in these tables was used as a basis for the analysis in Section 4.0, and some of the recommendations in Section 6.0 Oil Spill Response Capability Recommendations.

Table 121: Summary of Australia Oil Spill Response Regulations

<table>
<tr><th colspan="3">Regulatory Regime for Offshore Oil Spills in Australia</th></tr>
<tr><th colspan="2">Regulatory Categories</th><th>Details</th></tr>
<tr><td colspan="2">General Regulatory Approach</td><td>Performance-based approach that requires operators to reduce risks to "as low as reasonably practicable" (ALARP).</td></tr>
<tr><td colspan="2">Facility-Level Planning Document</td><td>Environmental Plan (EP) that contains an Oil Pollution Emergency Plan (OPEP).</td></tr>
<tr><td colspan="2">Operator Roles During Response</td><td>Operators are responsible for oil spill cleanup.

OPEP must detail when and how the operator will seek assistance from third party oil spill response organizations.

Once the operator’s OPEP is submitted to and approved by National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA), no permission is needed from government to carry out any oil spill response operations.</td></tr>
<tr><td rowspan="4">Risk Assessment and Scenario Planning</td><td>Oil Characterization</td><td>It is recommended that operators assess persistence, fate/weathering, and toxicity of oil.</td></tr>
<tr><td>Worst Case Scenario Volumes</td><td>NOPSEMA’s regulations do not make reference to worst case scenarios; however guidance documents indicate that NOPSEMA is unlikely to accept an Environmental Plan that has not considered a "high-consequence spill."</td></tr>
<tr><td>Modeling Requirements</td><td>Modeling is not required but is recommended to support the risk assessment. Modeling should:
• Show potential geographic extent of oil spills
• Show minimum time to shoreline impact
• Show maximum shoreline oiling quantities
• Use threshold values to display oil spill impacts (e.g., threshold surface oiling thickness)
• Model persistence of residual oil in the environment
• Model the accumulation of oil on shorelines and in the water column over time</td></tr>
<tr><td>Risk Assessment</td><td>The OPEP should include:
• Description of all oil and gas activities
○ Description of oil spill scenarios even if they are low-probability spills or if technologies to prevent those spills are effective
○ Source and release location of the oil pollution (e.g., subsurface/surface)
○ Hydrocarbon characteristics and properties relevant to determining risks (e.g., persistence, fate/weathering, toxicity)
○ Duration, flow rates, and volumes of oil that could be released
○ Possible extent of oil pollution</td></tr>
</table>

		• Description impacts
		  ○ Values and sensitivities of the environment that may be affected by any oil pollution and by the implementation of response strategies
		  ○ Potentially affected environmental receptors at sea, subsurface, and on shorelines
		  ○ Potentially affected social, cultural, and economic resources
		  ○ Potentially affected threatened species and ecosystems
		  ○ How protection of environmental resources will be prioritized
		• Description of oil spill response measures that will be used to reduce risks to "as low as reasonably practicable"
		  ○ Evaluation of the effectiveness of response measures in terms of functionality, availability, reliability, survivability, independence, and compatibility
		  ○ Demonstration that all reasonable and practical controls have been adopted and that adopting additional or alternative control measures is grossly disproportionate to additional cost or environmental benefit

Response Options	**General Guidance/ Principles/ Approach**	Environmental Performance Outcomes (EPOs) are the outcomes against which response operations are assessed and should address: • Why particular controls are being implemented • What constitutes an acceptable outcome Environmental Performance Standards (EPSs) are the standards by which response measures are assessed and should address: • How the control measure must perform • What level of performance is needed to effectively reduce overall risk Response arrangements should match the identified risk and be: • Performance based • Adaptable • Scalable • Executable • Sustainable • Clear in terms of identified roles and responsibilities OPEPs should include: • The capability to respond in a timely manner and for the duration of the event • When and how the titleholder will seek assistance from others • How responders will implement control measures ensuring the levels of performance required of adopted control measures will be met • Roles, responsibilities, and priority actions to guide an effective response The Australian National Plan for Maritime Emergencies identifies three levels of incidents: • **Level 1** Incidents are generally able to be resolved through the application of local or initial resources only (e.g., first-strike capacity) • **Level 2** Incidents are more complex in size, duration, resource management, and risk and may require deployment of jurisdiction resources beyond the initial response • **Level 3** Incidents are generally characterized by a degree of complexity that requires the Incident Controller to delegate all incident management

		functions to focus on strategic leadership and response coordination and may be supported by national and international resources
	Mechanical Recovery	The regulations have no specific requirements for mechanical recovery.
	Surface Applied Dispersants	Chemical and physical characteristics of dispersants should be considered in risk assessment and development of the OPEP.
	Subsurface Applied Dispersants	Chemical and physical characteristics of dispersants should be considered in risk assessment and development of the OPEP.
	In Situ Burning	The regulations have no specific requirements for in situ burning.
	Shoreline Protection	The only specific requirement for shoreline protection is to prioritize protection of sensitive environmental endpoints which could be located on shorelines.
Oil Spill Tracking	**Spill Tracking, Aerial Reconnaissance/ Surveillance & Remote Sensing**	Operators must have processes in place to monitor the effectiveness of control measures and to ensure EPSs for control measures are met. Adequate arrangements for monitoring oil pollution should include: • Capability to respond in a timely manner and for the duration of the petroleum activity • Maintaining responsibility for the incident • When and how the operator will seek assistance from others • How monitoring will be used to ensure that response measures meet relevant EPSs • Roles, responsibilities, and priority actions to guide an effective response • Where modelling is used to project where monitoring resources will be needed, this process should be described
Source Control and	**Relief Wells**	The regulations have no specific requirements for relief wells.
	Capping/ Intervention	The regulations have no specific requirements for capping or well intervention.

Table 122: Summary of Brazil's Oil Spill Response Regulations

Regulatory Regime for Offshore Oil Spills in Brazil		
Regulatory Categories		**Details**
General Regulatory Approach		Brazil's regulations are highly prescriptive.
Facility-Level Planning Document		Offshore facilities must have an Individual Emergency Plan (PEI) that describes oil spill prevention and response procedures for offshore oil drilling installations
Operator Roles During Response		In the event of a spill, Federal Environmental Agency (IBAMA) will usually devolve the clean-up response to the environment departments of the 18 coastal states and/or to operators. The role of On-Scene Commander would normally be played by either the relevant Port Captain, or an employee from the local IBAMA office, the State Environmental Agency concerned, or an operator.
Risk Assessment	**Oil Characterization**	Types of oil being stored or produced should be described.
	Worst Case Scenario Volumes	The following formulas should be used to calculate worst case discharge volumes:

and Scenario Planning		Worst case discharge volume= V1 + V2 V_1 = sum of the maximum capacity of all storage tanks and pipes on platform V_2 = estimated daily volume resulting from the loss of well control for 30 days • When the loss of well control does not threaten the integrity of the storage platform, worst case discharge volume can exclude $V_{1.}$ • Daily flow due to loss of well control should be calculated based on characteristics of the reservoir. If these characteristics are unknown, the characteristics of analogous reservoirs should be considered. • The estimated daily volume must be accompanied by technical justification.
	Modeling Requirements	• Modeling should be used in the vulnerability assessment or risk assessment to identify ecological and socioeconomic endpoints • Modeling should also be used to monitor and predict the fate and weathering of a spill once it has occurred • No specific technical requirements for modeling are provided in the regulations
	Risk Assessment	A risk assessment should consider possible effects of oil pollution incidents on human life and the environment based on potential site-specific oil spill scenarios. The risk assessment should include: • Type and volume of oil spilled • Areas likely to be impacted by oil • Sensitivity of these areas to the oil • The location of impacted areas will be determined by comparisons with previous oil spill incidents, if applicable, and the use of transport models and oil dispersion. PEIs should include procedures to update the following information used for risk assessment: • Hydrographic, hydrological, meteorological and oceanographic information • Description of impact including oil weathering, infiltration, and surface adhesion • Impacted ecological endpoints, such as mangroves, coral reefs, wetlands, estuaries, spawning, nesting, reproduction, feeding grounds and migratory wildlife, • Air quality monitoring
Response Options	**General Guidance/ Principles/ Approach**	PEIs must contain information on owned and contracted oil spill response equipment. The information required is: • Name, type and operational characteristics of each type of equipment • Quantity • Location • Estimated response time • Limitations of the use of equipment and materials

<table>
<tr><td></td><td></td><td>Contracts and other legal documents must be provided in Individual Emergency Plan to prove the availability of contracted response resources</td></tr>
<tr><td></td><td>Containment Boom</td><td>Operators must have available, through owned, or contracted resources, the quantities of containment boom required in the table below.
<table>
<tr><th>Strategy</th><th>Minimum quantity of boom</th></tr>
<tr><td>Full enclosure of spill source</td><td>3 x length of vessel or spill source</td></tr>
<tr><td>Containment of oil slick</td><td>According to calculation of CEDRO</td></tr>
<tr><td>Protection of rivers, canals, and other water bodies</td><td>The greater length of either 3.5 x width of the water body, in meters, and 1.5 + maximum current speed in knots x width of the water body, in meter to the limit of 1150 ft. or 350 m</td></tr>
</table></td></tr>
<tr><td></td><td>Mechanical Recovery - Open Water</td><td>Requirements for mechanical recovery
<table>
<tr><th>Volume of spill</th><th>Response time</th><th>Daily Effective Capacity of Oil Collection (CEDRO)</th></tr>
<tr><td>Small discharge is defined as ≤8 m^3 or ≤50 bbl.</td><td><2 hrs.</td><td>CEDRO must equal discharge volume</td></tr>
<tr><td>Medium discharge is the lower value of either 1258 bbl. (200 m^3) or 10% of the WCD</td><td><6 hrs. Timing may be extended based on technical justification.</td><td>CEDRO is 0.5 x discharge volume</td></tr>
</table>
In the case of platforms located beyond the Territorial Sea, CEDRO and response times may differ, based on a technical justification, provided it is accepted by the competent environmental agency
In the case of an oil discharge greater than 1258 bbl (200 m^3), the installation must submit a plan to ensure the continuity of emergency response.
Procedures for mechanically recovering oil should be described in Individual Emergency Plan.

Mechanical recovery response times and required Daily Effective Capacity of Oil Collection (CEDRO) for worst case discharges:
<table>
<tr><th>Response Times</th><th>Oil Recovery Requirements</th></tr>
<tr><td>Within 12 hrs.</td><td>Coastal Zone, lakes, dams and other lentic environments: CEDRO = 15,000 bbl/day, or 2,400 m^3/day</td></tr>
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<table>
<tr><td></td><td>Rivers and other lotic environments: CEDRO = 2000 bbl/day or 320 m^3/day

Sea waters beyond the Coastal Zone: CEDRO = 10,000 bbl/day or 1,600 m^3/day</td></tr>
<tr><td>Within 36 hrs.</td><td>Coastal Zone, lakes, dams and other lentic environments: CEDRO = 10,000 bbl./day or 1,600 m^3/day

Rivers and other lotic environments : CEDRO = 4,000 bbl/day or 640 m^3 /day</td></tr>
<tr><td>Within 60 hours</td><td>Coastal Zone, lakes, dams and other lentic environments: CEDRO =50,000 bbl/day or 8,000 m^3/day

Rivers and other lotic environments: CEDRO = 7,125 bbl/day or 1,140 m^3/day

Sea waters beyond the Coastal Zone: CEDRO = 40,000 bbl/day or 6,400 m^3/day</td></tr>
</table>
Formula for calculating Effective Daily Capacity of Oil Gathering (CEDRO):
CEDRO = 24hrs x Cn x fe
Cn = nominal capacity of the collector,
fe = efficiency factor, whose maximum value is 0.20
CEDRO may be calculated using alternative methods, provided it is approved by the appropriate environmental agency
Mechanical dispersion- a justification of equipment levels and response times should be provided to the appropriate environmental
Temporary storage - the available volume of temporary storage of mechanically recovered oil/water mixture should be equivalent to three hours of operation of the skimmer
Absorbents - The absorbents used for final cleaning of a spill area, for the locations inaccessible to skimmers and, in some cases, to protect vulnerable coastlines or other special areas shall be quantified according to the following criteria:
• absorbent barriers and blankets: the same length of the barriers used for containment boom (see table above)
• absorbent material in bulk: in an amount compatible with the response strategy
</td>
</tr>
<tr>
<td></td>
<td>Surface Applied Dispersants</td>
<td>Before the use of dispersants, it is recommended that operators describe:
• Geographical area being considered for dispersant application including the direct and indirect risk area</td>
</tr>
</table>

		• Distribution and seasonality of each ecosystem in the area • Socio-economic resources at risk • Coastal geomorphology and relative sensitivity of impacted environments; • Process for obtaining meteorological and climatological data • Process for obtaining hydrodynamic data and hydrographic conditions • Where the application of dispersants is recommended or not • Situations where dispersant application is more efficient and beneficial in minimizing the overall impact of an oil discharge that might reach environmentally sensitive areas, in order to ensure that the oil/dispersant mixture does compromise the coastal environment nor other important environmental assets; • Areas and specific situations not provided for in the previous items, provided they are duly authorized by the competent environmental agency. Chemical dispersants may be used: • In situations where other techniques, such as containment and collection of oil, are not efficient, due to the oil characteristics, the volume and environmental conditions • In situations where the oil slick is moving toward environmentally sensitive areas The chemical dispersants may not be used in: • Areas within 2,000 m (2,187 yards) of the shoreline • Sheltered coastal areas with low circulation where chemical dispersant on the oil mixture can stay concentrated or have a high period of residence • Estuaries, canals, rocky shores, sandy beaches, sludge or gravel, or sensitive areas such as mangrove swamps, marshes, coral reefs, lagoons, sandbanks, shoals exposed by the tide, protected areas, ecological parks and environmental reserves; • Areas detailed in sensitivity maps with upwelling, natural fish nursery and spawning, endangered species, populations of fish or seafood to commercial interests or aquaculture, migration and reproduction of wildlife, water resources for drinking or industrial purposes. • Oil or derivatives spills that have dynamic viscosity of less than 500 mPa.s, or more than 2,000 mPa.s at 10° C, because the effectiveness of dispersants on this type of oil is low or zero • Where the formation of water-oil emulsion has begun or, when the aging process of the oil mixture is visible. • Cleaning of port facilities in any type of vessel, as well as equipment used in the operation of oil spill or derivatives response.

<table>
<tr><td rowspan="3"></td><td></td><td>Monitoring of Dispersant Application
Aircraft should monitor spread of oil slick and provide guidance aerial application of dispersants
It is recommended that speedboats monitor dispersant efficiency. Agitation from speedboats may increase effectiveness of dispersants
It is recommended that samples of water and ocean organisms be collected in the early days of the spill, and at 30 and 90 days to assess environmental impacts
Wind and wave limits for effective dispersant application:
<table>
<tr><th></th><th colspan="2">Maximum values for effective and safe operations</th></tr>
<tr><th>Application System</th><th>Wind speed (knots)</th><th>Wave height (ft.)</th></tr>
<tr><td>Single engine plane</td><td>17-21</td><td>6-9</td></tr>
<tr><td>Helicopter</td><td>17-27</td><td>6-17</td></tr>
<tr><td>Large plane</td><td>30-35</td><td>17-23</td></tr>
</table></td></tr>
<tr><td>Subsurface Applied Dispersants</td><td>No information on subsurface dispersants in regulations</td></tr>
<tr><td>In Situ Burning</td><td>No information on in situ burning in regulations</td></tr>
<tr><td></td><td>Shoreline Protection</td><td>Individual Emergency Plans must describe procedures to protect ‘vulnerable areas’, but the regulations contain no information specifically related to shoreline protection</td></tr>
<tr><td>Oil Spill Tracking</td><td>Spill Tracking, Aerial Reconnaissance/Surveillance & Remote Sensing</td><td>The Individual Emergency Plan should include procedures for oil spill monitoring as appropriate including:
Visual monitoring
Satellite imagery
Photographs
Modelling
Monitoring efforts should describe the area, volume, pan, and weathering of the oil slick</td></tr>
<tr><td rowspan="2">Source Control and Subsurface Containment</td><td>Relief Wells</td><td rowspan="2">Individual Emergency Plan must include a description of how the flow of oil will be stopped, but the regulations contain no specific references to relief wells or well capping/intervention</td></tr>
<tr><td>Capping/Intervention</td></tr>
</table>

Table 123: Summary of Canadian National Energy Board Regulations in the Arctic

<table>
<tr><th colspan="3">Regulatory Regime for Offshore Oil Spills in the Canadian Arctic</th></tr>
<tr><th colspan="2">Regulatory Factors</th><th>Details</th></tr>
<tr><td colspan="2">Regulatory Categories</td><td>Canada’s National Energy Board (NEB) has a prescriptive regulatory regime.</td></tr>
<tr><td colspan="2">Facility-Level Planning Document</td><td>Environmental Protection Plan (EPP) and Contingency Plan (CP).</td></tr>
<tr><td colspan="2">Operator Roles During Response</td><td>Operators must notify Canadian Coast Guard (CCG) and Canada National Energy Board (NEB) in the event of a spill and have the responsibility to respond to oil spills using owned and contracted response resources.

Canadian Coast Guard (CCG) can assist with and direct response efforts, if needed.</td></tr>
<tr><td rowspan="4">Risk Assessment and Scenario Planning</td><td>Oil Characterization</td><td>CP requires characterization of oil for worst case scenario description (see "worst case scenario volumes" below)</td></tr>
<tr><td>Worst Case Scenario Volumes</td><td>CP requires description of a worst case scenario including:
• Estimated flow rate
• Total volumes of fluids
• Oil properties
• Maximum duration of a potential blowout
CP requires oil spill trajectory modeling to be used in worst case scenario description.</td></tr>
<tr><td>Modeling Requirements</td><td>CP must include description of:
• Oil spill trajectory modeling used
• Model’s features, limitations, and validation
• Model’s outputs for the worst case spill scenario planning
• Any three-dimensional capabilities used to simulate spill movements in or under ice cover in the Arctic environment
• Capability to implement an oil spill trajectory model, using real-time wind and current data to support response operations</td></tr>
<tr><td>Risk Assessment</td><td>Application to drill must include a project description with information on:
• Potential impacts to the environment, including potential impacts from accidents and malfunctions
• Socio-economic impacts arising from environmental effects
• Mitigation measures to protect the environment
• Arctic marine and land animals that would be particularly sensitive to a major oil spill
• Unique surface and subsurface features in the Arctic that would be particularly sensitive to an oil spill
• How marine protected areas and seasonal movements of marine animals (e.g., feeding, calving, and migration) will be addressed in the planned drilling activity
• How environmental factors in the Arctic, including extreme temperatures, darkness, polynyas, ice cover, ice movement, sea state, currents, shoreline features, and seafloor features, could potentially affect the project. Describe any knowledge gaps regarding the environmental setting of the project (e.g., biological, physical, and geological) and how these gaps will be addressed
• How results of ongoing research or information gathering initiatives will be incorporated into the project</td></tr>
</table>

		• Contingency measures if drilling unit, drilling rig, or equipment design or operating limits are exceeded

	Ice Management	Application to drill must include an Ice Management Plan with a description of: • Design and operating limits of the drilling system in the anticipated ice-ocean-atmospheric conditions in the operating area and at the drilling location • Conditions and ice features that would constitute hazards to the drilling system and its ability to stay at the location • Threshold used to identify conditions and ice features that could be a hazard, and a description of the conditions and ice features that would be at or above this threshold for the drilling system • How hazards will be identified and located including the use of ice detection systems and their effective range • How ice hazards will be predicted and tracked including specifications of the forecasting and tracking systems that would be used • How ice hazards will be managed including information on ice management system capabilities, reliability, and contingencies • How the drilling unit and well operations would be managed when ice hazards are predicted to exceed the ice management capability
Response Options	**General Guidance/ Principles/ Approach**	The CP must include a description of: • Process and procedures for chemical countermeasures and for containing and recovering spilled oil • Process for collection, handling, storage, and disposal of waste associated with spill response • Process and procedures to report and monitor spills and spill response progress • Criteria to be used for determining the appropriate oil spill countermeasures • Response strategies and methods for spill containment, monitoring, tracking recovery, and clean-up on surface water, the subsurface, shoreline, ice, and ice-infested waters • Operational limitations for each response method caused by Arctic environmental conditions such as wind, waves, ice, temperature, visibility, and daylight • Criteria and procedures to monitor the effectiveness of each response strategy and method • Inventory of dedicated and readily-deployable spill-response vessels, equipment, materials, and communications equipment and facilities, and expected mobilization and field deployment response times • Competent responder resources that would be brought to bear for each type of spill scenario
	Mechanical Recovery - Open Water	The regulations contain no requirements for mechanical recovery.
	Mechanical Recovery - Shoreline Cleanup	The regulations contain no requirements for mechanical recovery for shoreline cleanup.
	Surface Applied Dispersants	Use of surface applied dispersants must be approved by Environment Canada.

	Subsurface Applied Dispersants	Use of subsurface applied dispersants must be approved by Environment Canada.
	In Situ Burning	The regulations contain no requirements for in situ burning.
	Shoreline Protection	The regulations contain no requirements for shoreline protection.
Oil Spill Tracking	**Spill Tracking, Aerial Reconnaissance/ Surveillance & Remote Sensing**	The regulations contain no requirements for spill tracking/surveillance. Aerial surveillance and remote sensing are provided by Transport Canada and Environment Canada.
Source Control and	**Relief Wells**	CP must include a descript of: • Measures available to regain well control through same-well intervention, and by drilling a relief well. For each measure details should be provided on: ○ The sequence in which these measures would be implemented ○ The time it would take to implement each of these measures ○ Any constraints or limitations, including prevailing environmental conditions (e.g., ice encroachment, adverse weather) ○ The availability of sufficient people, equipment, drilling unit, and consumables • Capability to drill a relief well to kill an out-of-control well during the same drilling season. This is the Same Season Relief Well Policy. • Relief well plans, procedures, technology, and competencies required to kill an out-of-control well during the same drilling season, including: ○ Identification of the drilling unit that will be used, including mobilization details ○ Identification of a minimum of two suitable locations for drilling a same season relief well, including shallow seismic interpretation of the top-hole section ○ A hazard assessment for positioning the relief well close to the out-of-control well ○ Confirmation that the relief well drilling unit, support craft, and supplies are available and can drill the relief well and kill the out-of-control well in the same drilling season ○ Confirmation of the availability of well equipment and specialized equipment, personnel, services, and consumables to kill the out-of-control well during the same drilling season • Estimate of the time that it would take to drill the relief well and kill the out-of-control well in the same drilling season

	Capping/ Intervention	CP must include a description of: • Criteria that would be used to select the appropriate contingency measure to regain well control during Arctic offshore well operations notwithstanding the requirement to demonstrate same season relief well capability • Capping and containment methods and system proposed to appropriately respond to the worst case scenario • Plan for mobilization, deployment, and operation of the capping and containment system, including any clearance of debris or damaged pieces of sub-sea systems • Execution plan, resources, reliability, and redundancies of the capping and containment system in the unique Arctic environment • Required support systems, including vessels, icebreakers, riser system, and remotely operated underwater vehicles (ROV) • Testing and certification process of the capping and containment system, including qualification of new technology where applicable

Table 124: Summary of Oil Spill Regulations for Canada Nova Scotia Offshore Petroleum Board

Regulatory Regime for Offshore Oil Spills in Nova Scotia, Canada		
Regulatory Categories		**Details**
General Regulatory Approach		The Canada Nova Scotia Offshore Petroleum Board (CNSOPB) has a primarily performance-based regulatory regime.
Facility-Level Planning Document		Environmental Protection Plan (EPP) and Contingency Plan (CP)
Operator Roles During Response		Operators must notify the Canadian Coast Guard (CCG) and Canada Nova Scotia Offshore Petroleum Board in the event of a spill and have the responsibility to respond to oil spills using owned and contracted response resources. CCG can assist with and direct response efforts, if needed.
Risk Assessment and Scenario Planning	**Oil Characterization**	The regulations contain no requirements for oil characterization.
	Worst Case Scenario Volumes	The CP should describe oil spill scenarios including large-scale spills (e.g., blowouts) as well as small spills (e.g., from vessels).
	Modeling Requirements	Oil spill trajectory should be modeled for large scale spills (e.g., blowouts) at a minimum and should meet the following requirements: • Results should be reported for each month of the year • Analysis should continue until modelled oil slick is naturally dispersed, reaches a shoreline, or moves out of the model domain CP should also describe the capability to implement an oil spill trajectory model using real time wind and current data to support its response operations.
	Risk Assessment	CP should include information to be used to prioritize protection of environmental resources and should include: • Biological sensitivity charts that identify the areas containing spill-sensitive flora and fauna

		• Socio-economic sensitivity charts that indicate local human uses of the area potentially affected by oil spills • Physical sensitivity charts that identify shoreline types, coastal currents, ice forms and movement, and the nature of the littoral zone • Charts depicting operational resources and considerations EPP must include: • Summary of the studies undertaken to identify environmental hazards and to evaluate environmental risks • Summary of the means to avoid, prevent, reduce, or manage risks to the natural environment • An Environmental Assessment (EA) that includes identification of potential hazards to the environment, assessment of risks associated with these hazards, and identification of mitigation measures to reduce risk
Response Options	**General Guidance/ Principles/ Approach**	CP should demonstrate - quantitatively to the degree possible - the linkage between the types and quantity of response resources it provides to the spill scenarios it references. CP should include strategies that will be used for containment and cleanup in reference to the spill scenarios, including strategies for on-water response at and around the site, shoreline contamination, and response, and operations in any ice covered areas.
	Mechanical Recovery - Open Water	The regulations contain no specific requirements for mechanical recovery.
	Mechanical Recovery - Shoreline Cleanup	The regulations contain no specific requirements for mechanical recovery for shoreline cleanup.
	Surface Applied Dispersants	Environment Canada and CNSOPB must approve of the use of surface applied dispersants.
	Subsurface Applied Dispersants	Environment Canada and CNSOPB must approve of the use of subsurface applied dispersants.
	In Situ Burning	The regulations contain no requirements for in situ burning.
	Shoreline Protection	The regulations contain no requirements for shoreline protection.
Oil Spill Tracking	**Spill Tracking, Aerial Reconnaissance/ Surveillance & Remote Sensing**	The regulations contain no requirements for spill tracking/surveillance. Aerial surveillance and remote sensing are provided by Transport Canada and Environment Canada.
Source Control and	**Relief Wells**	CP requires operators to have a contingency plan for the identification and sourcing of a relief well drilling rig including: • Description of relief well rig's required operating capability, availability, and ancillary equipment • Schedule for mobilization of relief well rig to the well site Source of supply for backup wellhead system and all consumables required to set conductor and surface casing for relief well
	Capping/ Intervention	The regulations contain no specific requirement for capping/intervention.

Table 125: Summary of Denmark's Oil Spill Regulations

Regulatory Regime for Offshore Oil Spills in Denmark		
Regulatory Categories		**Details**
General Regulatory Approach		Denmark's regulatory regime is almost entirely performance based with very few prescriptive requirements.
Facility-Level Planning Document		Oil and Chemical Spill Contingency Plan (OCSCP)
Operator Roles During Response		Operator is responsible for responding to oil spills and notifying the Danish Environmental Protection Agency (EPA). Danish Ministry of Defense, Maritime Assistance Service (MAS) has primary responsibility for oil spill response.
Risk Assessment and Scenario Planning	**Oil Characterizatio n**	The regulations contain no requirements for oil characterization.
	Worst Case Scenario Volumes	The regulations contain no requirements for calculating worst case scenarios.
	Modeling Requirements	The regulations contain no requirements for modeling.
	Risk Assessment	The regulations contain no requirements for risk assessment.
Response Options	**General Guidance/ Principles/ Approach**	OCSCPs must contain details of the types, amounts, and locations of mechanical and chemical oil spill response measures available to the installation. OCSCPs must describe response actions in various oil spill scenarios including surveillance and temporary storage. Operators should have access to an amount of oil spill response resources that can "combat an oil spill similar to oil outflow from a production well." The regulations do not specify a time period for the maximum flow. Operators have access to some privately owned oil spill response resources, and MAS also owns oil spill response equipment that can be used to respond to spills from offshore installations.
	Mechanical Recovery - Open Water	Skimmers and oil spill response support/transport vessels must be able to operate in the following conditions: • Maximum wave heights of 2.5 meters (8.2 ft.) and/or a current of 1 knot • Air temperatures from 50 C to -20 C (122 F to -4 F) • Water temperatures from 40 C to -1 C (104 F to 30 F) OCSCPs must include information on temporary storage and disposal of oil/water mixture. Equipment must meet Danish EPA time constraints (information on specific time constraints was not found). In 2012, the Royal Danish Navy had the following equipment: • Seven specialized oil spill response vessels, 2 of which are ice class skimmers, 2 are non-ice class skimmers • Three barges used for storage of recovered oil In 2009, the Royal Danish Air Force had an unspecified number of aircraft to provide oil spill surveillance In 2009 the Danish Emergency Management Agency had the following equipment: • Equipment for nearshore and onshore response • 5 x 320 meters of ro-boom 1300

		Denmark does not maintain any dispersant stockpiles or aircraft with dispersant application capabilities.
	Mechanical Recovery - Shoreline Cleanup	The regulations contain no requirements for shoreline mechanical recovery.
	Surface Applied Dispersants	Dispersants are used as a last resort when mechanical recovery is not possible. Permission from Danish EPA must be granted before dispersants can be used. Danish Navy and Air Force have no aircraft capable of applying dispersants and do not maintain dispersant stockpiles[58]. Equipment must meet Danish EPA time constraints.
	Subsurface Applied Dispersants	Permission from EPA must be granted before dispersants can be used.
	In Situ Burning	Permission from Danish EPA must be granted before in situ burning can be initiated.
	Shoreline Protection	The regulations contain no requirements for shoreline protection.
Oil Spill Tracking	**Spill Tracking, Aerial Reconnaissance/ Surveillance & Remote Sensing**	The regulations contain no requirements for spill tracking.
Source Control and	**Relief Wells**	The regulations contain no requirements for relief wells.
	Capping/ Intervention	The regulations contain no requirements for capping/intervention.

Table 126: Summary of Greenland Oil Spill Regulations

Regulatory Regime for Offshore Oil Spills in Greenland		
Regulatory Categories		**Details**
General Regulatory Approach		Greenland's oil spill response regulations are mostly performance-based.
Facility-Level Planning Document		The following contingency plans must be submitted and presented as a minimum to the Bureau of Minerals and Petroleum (BMP) for approval: • Emergency preparedness plan for major accident • Oil spill contingency plan • Relief well drilling plan and program • Ice management plan
Operator Roles During Response		Operators initiate and coordinate response operations. Response equipment is owned and operated by third party oil spill response contractors.
Risk Assessment and Scenario Planning	**Oil Characterization**	The regulations contain no requirements for oil characterization.
	Worst Case Scenario Volumes	The regulations contain no requirements for worst case scenarios.

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	Modeling Requirements	An Environmental Impact Assessment (EIA) must be performed that includes oil spill trajectory modelling. As part of licensing and in addition to the EIA, operators must submit oil spill model results that simulate a spill over the course of seven days. This oil spill model must take into consideration the local wind and weather conditions.

	Risk Assessment	An EIA and Social Impact Assessment (SIA) must be completed for drilling operations.
		The EIA is comprised of:
		• Description of proposed activities including:
		    o Energy requirements
		    o Emissions
		    o Discharges of pollutants to water
		    o Plan for monitoring and reporting discharges
		• Description of probable impacts of proposed activity
		The SIA is comprised of:
		• Description of baseline social conditions in the area potentially affected by the project
		• Potential impacts of action
		• Analysis of possible alternatives
		• Mitigation of negative impacts
		• Monitoring and evaluation

Response Options	**General Guidance/ Principles/ Approach**	If there are significant changes in the stock of equipment and dispersants available to the operator, the operator must immediately inform BMP. BMP may require the operator to secure equipment and dispersants in another way for use on a possible oil spill. The government of Greenland owns the private oil spill response company, Greenland Oil Spill Response A/S. The company owns boom, temporary storage, and dispersant stockpiles that are available for oil spill response.
	Mechanical Recovery - Open Water	The regulations contain no requirement for open water mechanical recovery. The government-owned private company, Greenland Oil Spill Response, maintains: • 28 rope mop skimmers • 28 oleophilic disk skimmers • 28 mini-vac skimmers • 48 land-based temporary storage systems with volume of 7.5 to 10 m^3 (1,981 to 2,642 gallons) • 40,000 liters (10,567 gallons) of dispersant
	Mechanical Recovery - Shoreline Cleanup	The regulations contain no requirement for shoreline mechanical recovery.
	Surface Applied Dispersants	After an oil spill occurs, the use of dispersants must be approved by BMP and the National Environmental Research Institute (NERI), Denmark. Dispersant use will be approved if it is found, through a Net Environmental Benefits Analysis (NEBA), that the effects of dispersants are less harmful to the environment than if mitigation was limited to mechanical recovery or no measures at all.

	Subsurface Applied Dispersants	The regulations contain no requirements for subsurface applied dispersants.
	In Situ Burning	In situ burning must take place at least 10km (5.4 NM) from the coast of Greenland. The application will be approved if it is found, through a NEBA, that the effects of in situ burning are less harmful to the environment than if mitigation was limited to attempts at mechanical recovery or no measures at all.
	Shoreline Protection	The regulations contain no requirements for shoreline protection. The government-owned private company, Greenland Oil Spill Response, maintains 8,280 meters (27,165 feet) of protection boom
Oil Spill Tracking	**Spill Tracking, Aerial Reconnaissance/ Surveillance & Remote Sensing**	The oil spill contingency plan must contain a monitoring program to be initiated in the event of a large oil spill. The monitoring program must primarily cover the oil content in water and sediment.
Source Control and	**Relief Wells**	Operators must submit relief well contingency plans in accordance with Norsk Sokkels Konkuranseposisjon (NORSOK) Standard D-010. NORSOK is the industry association for Norwegian oil and gas operators. Drilling must occur in the presence of two drilling rigs so that relief well drilling can begin immediately in the event of loss of well control. If two or more operators are drilling, they may be able to share a third contingency rig.
	Capping/ Intervention	The regulations have no requirements for capping/intervention.

Table 127: Summary of New Zealand's Oil Spill Response Regulations

Regulatory Regime for Offshore Oil Spills in New Zealand		
Regulatory Categories		**Details**
General Regulatory Approach		New Zealand's regulatory regime is a mix of performance-based and prescriptive requirements. While guidance documents offer a range of prescriptive solutions to fulfill regulatory requirements, the regulations are largely performance based.
Facility-Level Planning Document		Discharge Management Plan (DMP) and Well Control Contingency Plan (WCCP)
Operator Roles During Response		Operators use owned or contracted response equipment to respond to Tier 1 spills (see Response Options, General Guidance below)
Risk Assessment and Scenario Planning	**Oil Characterization**	DMP must include a description of all oils on the offshore installation including: • Type of oil • Volumes stored on the installation and, where applicable, flow rates and volumes in pipelines • Fuel specifications sheets and full MSDS for each oil • Estimation of the frequency and volumes of oil transferred to or from the site

	Worst Case Scenario Volumes	Individual well worst case scenario volume is calculated based on maximum flow rate from hydrocarbon reservoir and the maximum time that it could take to stop the discharge of oil. New Zealand maintains the ability to respond to a one-in-one-hundred-year, or 3,500 metric tons, spill event. For spills larger than this, New Zealand will need to seek assistance from other countries via mutual aid agreements.
	Modeling Requirements	Oil spill trajectory modelling must be conducted to determine the impact of potential oil spills. Requirements for oil spill modeling: • Modelling must show fate and transport of potential oil spills • Stochastic modelling must be used to show where impacts could occur • Consideration of the depth of the release • Worst case flow rates must be run for at least 30 days • Modelling must use appropriate weather, current, and temperature data
	Risk Assessment	Risk assessment should prioritize and describe potentially impacted ecological, social, cultural, and economic endpoints including: • Shorelines • Fisheries • Aquaculture operations • Coastal environments that may be subject to oil pollution based on trajectory modelling The risk assessment should consider factors including: • Water depth • Distance from shore
Response Options	**General Guidance/ Principles/ Approach**	Oil Spill response is guided by a three tier framework: • **Tier 1** oil spills are responded to and resolved by the operator. The level of response includes the capacity to assist if there is an escalation to a Tier 2 or Tier 3 response. • **Tier 2** oil spills are generally those beyond the capability of the operator acting alone and the response is led and resolved by the local Regional Council. The specific capacity required by the regional council is based on the regional risks. • **Tier 3** oil spills are generally more complex, of longer duration and impact, and beyond the response capability of the regional council or operator. The response is nationally led and coordinated by Maritime New Zealand (MNZ). MNZ owns substantial stockpiles of response equipment including skimmers, boom, dispersant, and aircraft that are available for Tier 2 and Tier 3 oil spills The Well Control Contingency Plan should describe when and how an operator will seek spill response assistance from third parties including contractors.
	Mechanical Recovery - Open Water	The regulations have no specific requirements for mechanical recovery
	Mechanical Recovery - Shoreline Cleanup	The National Contingency Plan includes detailed guidance on how shoreline cleanup operations should be conducted, but includes no prescriptive requirements for timing or equipment levels

	Surface Applied Dispersants	Dispersant Testing: Any oil or condensate produced on an offshore installation should be tested against a range of dispersants to determine which dispersant(s) will be most effective if a spill does occur. Testing must be undertaken as soon as a sample of the oil or condensate is available. Dispersant Use Approval: During a spill, incident dispersants may not be used in New Zealand continental waters without approval from the On-Scene Commander. Dispersant Application Rates: The ratio of dispersant to oil required for effective dispersal varies between 1:5 and 1:30. Depending upon oil type and environmental conditions. As a general guide, a dispersant starting ratio, or dose rate, of between 1:20 and 1:30 is recommended.
	Subsurface Applied Dispersants	The regulations have no specific requirements for subsurface dispersants
	In Situ Burning	The regulations have no specific requirements for in situ burning
	Shoreline Protection	The regulations have no specific requirements for shoreline protection
Oil Spill Tracking	**Spill Tracking, Aerial Reconnaissance /Surveillance & Remote Sensing**	The regulations have no specific requirements for oil spill tracking
Source Control	**Relief Wells**	Where drilling one or more relief wells is identified as a potential control option, operators must: • Provide details of any contracts for implementing a relief well including contact information • Consider relief well design and location • Demonstrate a plan to source a mobile offshore drilling unit (MODU) if one is needed and include contact information with any associated third party contractors • Include a timetable for sourcing a MODU that includes cessation of current MODU operations and transport to relief well site. Also include a description of the complexities and uncertainties of sourcing a MODU and the impacts these could have on the timetable
	Capping/ Intervention	Where the use of a capping device is identified as a potential control option, operators must: • Have arrangements in place to implement well capping • Demonstrate that the capping device is suitable for use with the individual well • Include details of any well capping contracts including contact information • Include a timetable of the steps involved in deploying a capping device

Table 128: Summary of Norway's Oil Spill Response Regulations

Regulatory Regime for Offshore Oil Spills in Norway		
Regulatory Categories		**Details**
General Regulatory Approach		Norway's oil spill response regulations are entirely performance-based with no prescriptive requirements.
Facility-Level Planning Document		Plan for Development and Operation (PDO) and Plan for Installation and Operation (PIO).
Operator Roles During Response		Operator leads and coordinates response to minor spills with owned or contracted private equipment and resources. Regional or national authorities assume control of response operation if spill is too large to be addressed by private operators, or if it is unknown where the spill originated. Intermunicipal Boards for Acute Pollution (IUAs) lead response efforts on the regional scale. IUAs are responsible for responding to spills that are too large to be addressed by private operators, or where the origin of the spill is unknown. Each board is responsible for the creation and maintenance of a regional contingency plan and responds to minor spills from normal oil and gas activities. IUAs must assist the Norwegian Coastal Administration (NCA) during response to major oil spills. The NCA is responsible for oil spill response in areas not covered by private and regional preparedness, and assumes control of response efforts for all major oil spills. The NCA owns significant oil spill response equipment and resources.
Risk Assessment and Scenario Planning	**Oil Characterization**	Oil must be characterized with particular emphasis on oil fate and weathering properties. Oil properties should be taken into consideration for oil spill response preparedness.
	Worst Case Scenario Volumes	The regulations contain no information on worst case discharge scenarios.
	Modeling Requirements	"Recognized and suitable models, methods, and data" must be used when conducting the risk assessment.
	Risk Assessment	The risk assessment must: • Identify hazard and accident situations • Identify potential causes of accidents • Identify and analyses risk-reducing measures The risk assessment will be taken into consideration when making decisions including: • Selecting the type and amount of oil spill response measures • Establishing performance criteria for spill response Important information that should be considered when conducting environmental risk analyses includes: • Reservoir's discharge potential where relevant, and the offshore facility's discharge potentials • Likelihood of discharges from various facilities • Physical, chemical, and eco-toxicological properties of the pollution • Meteorological and oceanographic data on wind, temperature, and current • Drift and spread of the pollution • Weathering and degradation of the pollution • Vulnerability of the ecosystems

		• Environmental databases and environmental prioritization map covering vulnerable and prioritized resources and their extent in time and space Facilities must establish and maintain emergency preparedness plans that should include: • Description of organization, notification, mobilization, and communication • Description of facility and prioritized vulnerable environmental resources in that may be impacted by spilled oil • Description of the facility's spill response resources, area resources, regional resources, and external resources and equipment and response times • Instructions for emergency preparedness personnel • Any coordination procedures with other involved parties • Any cooperation procedures and agreements with other involved parties
Response Options	**General Guidance/ Principles/ Approach**	The Petroleum Safety Authority and the Climate and Pollution Agency can, within their respective jurisdictions, stipulate a requirement that standby vessels, including aircraft, shall be stationed at facilities or vessels participating in the petroleum activities. They can also stipulate requirements regarding the functions that a standby vessel shall be able to perform. The primary oil spill response organization is Norwegian Clean Seas Association For Operating Companies or NOFO. NOFO responds to oil spills using a "multiple barrier" approach. The barriers are: • **Barrie**r 1: response measure such as mechanical recovery and application of dispersants are carried out near the source of the spill. • **Barrier 2**: response measures such as mechanical recovery and application of dispersants are carried out in the open waters between the source and the shoreline. • **Barrier 3**: mechanical recovery takes place in coastal waters with wide variety of skimming systems including small vessels and vessels of opportunity. Response resources are directed by aerial surveillance to protect the most sensitive resources. • **Barrier 4**: shoreline cleanup is conducted using coordination among local, regional, and national resources.
	Mechanical Recovery - Open Water	The regulations contain no requirements for open water mechanical recovery. In 2011, IUAs maintained 3,000 oil skimming devices. In 2012 the NCA owned 5 skimming vessels and the NOCG owned 11 skimming vessels[59].
	Mechanical Recovery - Shoreline Cleanup	The regulations contain no requirements for shoreline mechanical recovery.
	Surface Applied Dispersants	Aircraft that are to be used in actions against acute pollution should be designed so that they can be used to carry out dispersion measures and so

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		that they can contribute to monitoring pollution and directing seagoing vessels that take part in the action.
	Subsurface Applied Dispersants	The regulations contain no requirements for subsurface applied dispersants.
	In Situ Burning	The regulations contain no requirements for in situ burning.
	Shoreline Protection	The regulations contain no requirements for shoreline cleanup. In 2011, IUAs maintained 70,000 meters (229,660 ft.) of lightweight boom. In 2012, the NCA maintained: • 10,000 meters (32,808 feet) of boom for use in the open ocean • 23,000 meters (75,459 feet) of boom for use in coastal waters • 10,000 meters (32,808 feet) of boom for sensitive water e.g., fjords
Oil Spill Tracking	**Spill Tracking, Aerial Reconnaissance/ Surveillance & Remote Sensing**	The operator shall establish a remote measuring system that provides sufficient information to ensure that acute pollution from the facility is quickly discovered and mapped so that the amount and spread can be determined. Regional plans shall be established for remote measurement of acute pollution on the open sea, along the coast, and in the beach zone. NCA owns one surveillance aircraft equipped with forward-looking infrared radiometer (FLIR), side-looking airborne radar (SLAR), and IR/UV imaging.
Source Control	**Relief Wells**	The regulations contain no requirements for relief wells.
	Capping/ Intervention	The regulations contain no requirements for capping/intervention.

Table 129: Summary of the United Kingdom's Oil Spill Response Regulations

Regulatory Regime for Offshore Oil Spills in United Kingdom	
Regulatory Factors	**Details**
General Regulatory Approach	UK approach is largely prescriptive.
Facility-Level Planning Document	UK Oil Pollution Emergency Plans (OPEPs) are developed by each offshore facility and contain information on the risks that oil spills pose to specific geographic areas and how to respond to oil spills. Facilities within 25 NM of the coast must have, as part of their OPEPs, Shoreline Protection Plans (see Shoreline Protection section below)
Operator Roles During Response	Responsibility for oil cleanup is based upon where oil pollution occurs (see table below) **Location of Pollution** → **Responsibility for ensuring clean up** On the water, jetties, wharves, structures, beach or shoreline owned by the harbor authority within the port/harbor area → Harbor Authority Shoreline → Local authority, or in some places, Northern Ireland Environment Agency

<table>
<tr><td colspan="2"></td><td><table><tr><td>Privately owned jetties, wharves, structures, beach or shoreline</td><td>Property owner</td></tr><tr><td>All other areas at sea inside the EEZ and the UK Continental Shelf</td><td>Maritime Coastguard Authority (MCA) or spill response contractors</td></tr></table>Operators of offshore installations hold contracts for oil spill response equipment. When operators need additional assistance responding to oil spills, they may supplement their contracted oil spill response capabilities with additional contractors or request national assets through the MCA.</td></tr>
<tr><td rowspan="4">Risk Assessment and Scenario Planning</td><td>Oil Characterization</td><td>The OPEP must detail the following oil characteristics:
• ITOPF grouping
• Specific gravity
• Viscosity
• Wax content
• Asphaltene content
• Pour point
For exploration wells where information may be limited, all known oil characteristics must be detailed and the OPEP updated once oil characteristics have been discovered.</td></tr>
<tr><td>Worst Case Scenario Volumes</td><td>The OPEP must contain a detailed calculation of the worst case discharge including worst case flow rates.</td></tr>
<tr><td>Modeling Requirements</td><td>The OPEP must include oil spill modeling using a minimum two-year data set of hydrodynamic and meteorological parameters.

The following oil characteristics should be used as inputs for the model:
• Specific Gravity
• Viscosity
• Wax content
• Asphaltene content
• Pour point
Stochastic modelling must be performed as follows:
• Using a minimum two year time series data-set
• At least 100 runs should be performed
• The duration of the release should be based upon the time anticipated to stop the release
• For production operations or operations extending over a year, modelling must be carried out for four seasons
• For temporary operations (e.g., drilling/well intervention) the season(s) during which the operation is to be undertaken must be used for modelling purposes.
• The model results must be displayed to an oil thickness of 0.3μm.
The OPEP must include stochastic model output maps showing minimum travel time to cross median lines and to reach shorelines. Shoreline oiling and median crossing probability must be shown to at least 1%.</td></tr>
<tr><td>Risk Assessment</td><td>The OPEP must contain a summary of the sensitive environmental endpoints at risk from an oil spill including:
• Seabirds
• Fisheries
• Marine mammals</td></tr>
</table>

Response Options	**General Guidance/ Principles/ Approach**	Oil spill are categorized into three tiers based on the size of response required to effectively combat the oil spill: • Tier 1 Local (within the capability of the offshore installation operator) • Tier 2 Regional (beyond the capability of the offshore installation operator or requires additional contracted response) • Tier 3 National (requires the use of national resources coordinated by the operator For all response resources identified, the OPEP must detail the time taken to deploy the resource on location.
	Mechanical Recovery - Open Water	The regulations contain no requirements for mechanical recovery.
	Surface Applied Dispersants	If dispersant use is identified as part of an oil spill response strategy the OPEP must provide the following for the relevant Tier of response: • Type of dispersant • Quantity (m3 / tonnes) • Confirmation within the OPEP that the chosen dispersant is suitable for application given the oil characteristics as detailed in the OPEP • Selection of dispersant type should be re-evaluated if the reservoir oils significantly change Tiers 2 and 3 – offsite dispersant stocks: • Confirmation within the OPEP that any additional dispersant held by the operator or obtainable from any contracted oil spill responder is suitable for application given the oil characteristics. • Selection of dispersant type should be re-evaluated should the reservoir oils significantly change. Where information regarding the characteristics of the oil does not exist (e.g., exploration drilling) the operator must justify the rationale for the chosen dispersant. Justification must be provided if dispersant is not selected as part of an oil spill response strategy. The use of dispersant under the following circumstances requires additional approval: • Within 1 NM of waters of 20 meters depth or less • Beneath the surface of the sea • If the oil spill treatment product is not being used in accordance with any government product approval, or the conditions of that approval.
	Subsurface Applied Dispersants	The operator may consider and plan for sub-surface application of dispersants; however, there are no response requirements specified in the regulations.
	In Situ Burning	Justification must be provided in the OPEP if operators plan to use in situ burning as a response option.
	Shoreline Protection	In sensitive locations where the risk of shoreline impact is likely to occur before the arrival of Tier 2/3 resources, operators should consider storing dedicated pre-positioned resources nearby. A Shoreline Protection Plan (SPP) must also be developed for all installations (including pipelines) operating in blocks wholly or partly within

<table>
<tr><td></td><td></td><td>40 km of the coast and pipelines coming ashore which have a potential for released oil to the shoreline.

The OPEP arrangements for any installation (not pipelines) located within 40 km of the shoreline should confirm that:
Dispersant can be applied within 30 minutes of a pollution incident
Sufficient dispersant stocks are available to treat a minimum oil release of 25 tonnes
Appropriate open-water and shoreline response resources can be available on scene in sufficient time to minimize the impact of any oil pollution</td></tr>
<tr><td>Oil Spill Tracking</td><td>Spill Tracking, Aerial Reconnaissance/ Surveillance & Remote Sensing</td><td><table>
<tr><td colspan="4">Aerial Resource Response Time Requirements</td></tr>
<tr><td>Oil Spill Verification</td><td>Oil Spill Quantification</td><td>Dispersant Test Spray</td><td>Large Scale Dispersant Application</td></tr>
<tr><td>Within 4 Hours*</td><td>Within 6 Hours*</td><td>Within 6 Hours*</td><td>Within 18 Hours*</td></tr>
</table>
* from time of mobilization request.
As a minimum, the following should be available on aircraft whose purpose is to detect the presence of oil:
Marine VHF radio
Digital still and video capabilities
Satellite telephone
Suitable navigation equipment including GPS to ensure the accurate display of search areas and dispersant spray patterns and to control the activities of other resources during counter-pollution operations
Suitably trained and experienced personnel to ensure an adequate, continuous response capability.
As a minimum, the following should be available aircraft whose purpose is the quantify spilled oil:
Marine and Aviation VHF radio
Digital still and video capabilities
Infrared imaging equipment
Ultra Violet imaging equipment
Satellite telephone
Suitable navigation equipment including GPS to ensure the accurate display of search areas and dispersant spray patterns and to control the activities of other resources during counter-pollution operations
Suitably trained and experienced personnel to ensure an adequate, continuous response capability
Crew change helicopters may provide details as to the size and location of pollution, but they cannot be used for formal verification and quantification of pollution.</td></tr>
</table>

Source Control and Subsurface Containment	**Relief Wells**	If the drilling of a relief well has been identified as a response option, the OPEP must detail the following: • Any specific drilling rig configuration required to drill the relief well (e.g., HP/HT, deep water) • Provide details if the limited availability of a suitably configured drilling rig may cause delays to the relief well operations A justification must be provided within the OPEP if a relief well is not deemed an appropriate response option. An estimation of the time required to complete the relief well operation must be included in the OPEP including an estimation of time required from the day the relief well operation is mobilized to the day the well is killed.
	Capping/ Intervention	If a well capping device has been identified as a source control option, the OPEP must contain the following: • Details of the capping devices deemed suitable for use • Confirmation that the suitability of the capping devices has been fully assessed and is compatible with the well infrastructure and is certified for the anticipated well pressures • Details of the specialist contractor(s) providing the devices • Contact details of the specialist contractors • A justification must be provided within the OPEP if a capping device is not deemed an appropriate source control option. • An estimation of the time required to complete the well capping operation must be included in the OPEP. This is an estimation of time required from the day the capping operation is mobilized to the day the well is successfully capped.

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10.0 APPENDIX C: TABLE OF ACRONYMS

ACP	Area Contingency Plan
BOEM	Bureau of Ocean Energy Management
BSEE	Bureau of Safety and Environmental Enforcement
EIA	Environmental Impact Assessment
ESI	Environmental Sensitivity Index
EUR	Estimated Ultimate Recovery
EVP	Elastic-Viscous-Plastic
EVT	Extreme Value Theory
GEBCO	General Bathymetric Chart of the Oceans
GIS	Geographic Information System
GODAE	Global Ocean Data Assimilation Experiment
GOM	Gulf of Mexico
GOR	Gas-To-Oil Ratio
HFO	Heavy Fuel Oil
HPHT	High Pressure-High Temperature
IFT	Interfacial Tension
IHO	International Hydrographic Organization
IOC	Intergovernmental Oceanographic Commission
ITOPF	International Tanker Owners Pollution Federation Limited
MD	Measured Depth
MMS	Minerals Management Service
MPD	Managed Pressure Drilling
NOAA	National Oceanic and Atmospheric Administration
NOGAPS	Navy Operational Global Atmospheric Prediction System
NRDA	Natural Resource Damage Assessment
NRDAM/CME	Natural Resource Damage Assessment Model For Coastal and Marine Environments
NRDAM/GLE	Natural Resource Damage Assessment Model For the Great Lakes Environments
NRT	National Response Team
NSIDC	National Snow and Ice Data Center
OCS	Outer Continental Shelf
OECM	Offshore Environmental Cost Model
OSRB	Oil Spill Response Barge
OSRO	Oil Spill Removal Organization
OSRP	Oil Spill Response Plan
OSRV	Oil Spill Response Vessel
NMFS	National Marine Fisheries Service
PA	Plugged and Abandoned
PAH	Polycyclic Aromatic Hydrocarbons

POM	Princeton Ocean Model
RCD	Regional Containment Demonstration
RCP	Regional Contingency Plan
ROV	Remote Operated Vehicle
RP	Responsible Party
RRT	Regional Response Team
SSDI	Subsurface dispersant injection; sometimes referred to as subsea dispersant injection
USCG	U.S. Coast Guard
USDOI	U.S. Department of the Interior
VOC	Volatile Organic Compound
VOO	Vessel of Opportunity
VOSS	Vessel of Opportunity Skimming System
WCD	Worst Case Discharge
WRRL	Western Response Resource List