Applications of science and engineering to quantify and control the *Deepwater Horizon* oil spill

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The unprecedented engagement of scientists from government, academia, and industry enabled multiple unanticipated and unique problems to be addressed during the *Deepwater Horizon* oil spill. During the months between the initial blowout on April 20, 2010, and the final well kill on September 19, 2010, researchers prepared options, analyses of tradeoffs, assessments, and calculations of uncertainties associated with the flow rate of the well, well shut in, killing the well, and determination of the location of oil released into the environment. This information was used in near real time by the National Incident Commander and other government decision-makers. It increased transparency into BP's proposed actions and gave the government confidence that, at each stage proposed, courses of action had been thoroughly vetted to reduce risk to human life and the environment and improve chances of success.

oil collection | science-based decision making | well control | Gulf of Mexico | spill of national significance

The *Deepwater Horizon* (DWH) ultra-deepwater semisubmersible oil drilling rig exploded and sank in the northern Gulf of Mexico on April 20, 2010, killing 11 crew members and initiating the largest marine oil spill in US history. According to federal law (ref. 1 and *SI Text* describe the responsibilities of various parties), the US Coast Guard (USCG) is the On-Scene Coordinator (OSC) for maritime discharges to ensure that the responsible party, here including BP, takes appropriate actions to limit releases and clean up spills. The National Oceanic and Atmospheric Administration (NOAA) provides scientific advice to the OSC, participates in responses executed by the OSC, and assumes significant responsibilities for damage assessment. By day 10 (see timeline, figure S1 in ref. 1), the DWH spill was declared the nation's first "spill of national significance" (*SI Text*), the USCG had established a National Incident Command, and President Obama named USCG Commandant Admiral Thad Allen as National Incident Commander (NIC). It became apparent that our nation's best scientific and engineering advice would be required to support the decisions of those people with the legal responsibility and authority to act on behalf of the American government. Although science is often conducted for the purpose of advancing the frontiers of discovery, the effort in DWH had to be accomplished under the intense pressure of time and public scrutiny to support proximate decisions and deliver evidence-based results with maximum understanding of what error might mean for the ocean environment and human wellbeing.

This paper summarizes some of the science and engineering undertaken to support best decisions for collecting the oil and killing the well. Science and engineering played a critical role in that decision-making; the NIC respected science and relied on scientific information to understand tradeoffs, because scientists were in lead roles in numerous relevant agencies and scientists in academia, industry and the Federal Government were willing to help in ways never before used in such a marine disaster. A summary of all of the important DWH events and science applications over a nearly 5-mo period is given in ref. 1.

DWH was unprecedented in numerous ways: an unknown amount of oil/gas gushing continuously from more than 1 mi beneath the ocean surface and in open, noncoastal waters was ongoing for months. Public and political interest across federal, state, and local governments and members of the public was intense, because the disaster played out quite publicly for 87 d. BP was unprepared for source control in the eventuality that the blowout preventer (BOP) would not work (2). The result was the first loss of ultra-deepwater well control in US history. Without direct human access to the well, all activities associated with well control required the use of remotely operated vehicles (ROVs). Although BP took immediate action to begin drilling relief wells, including a backup relief well, BP's initial approach to controlling the spill was to first try methods that had the lowest risk of harming the well or the BOP at the well head. Unfortunately, early methods deployed by BP—the coffer dam placed over the point of discharge and the Top Kill to force hydrocarbons back down the well with mud—both failed. With the relief wells not projected to reach their target until August, these failures eroded public and government confidence in the ability of the company to solve the problem in a quick and effective manner.

From the earliest days of the oil spill, the government had sent scientists and engineers to the Gulf region, including the incident command center in BP headquarters in Houston, Texas. Initially, the roles of these government representatives in Houston were very specific and distinct from the roles of the BP scientists and engineers. For example, Department of Energy (DOE) engineers were involved in mobilizing γ-ray imaging to determine the status of deployment of the BOP's rams to help resolve conflicting information about which of the rams in the BOP designed to cut off the flow from the well had successfully been triggered.

Secretary of Energy Dr. Steven Chu led one team, the Government-Led Science Team (GLST) (*SI Text*), and the members participated in both the well integrity and well kill teams and rotated in and out of BP headquarters in Houston. The GLST was designed to bring unconventional thinking to bear on DWH problems (in this case, stopping the flow of oil). GLST members were chosen for their critical

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thinking skills, broad knowledge of relevant science and engineering, and willingness to be available. The rationale was simple: BP had many specialists, but in a crisis that involved never before encountered modes of failure, fresh thinking could bring creative solutions.

After the failure of Top Kill, the role of this team changed. The US Government and the American public wanted more assurance that future well interventions had a high likelihood of success. In coordination with the NIC, the GLST in Houston began participating in reviews of proposed well interventions and proposed procedures, examining risks, proposing alternatives, asking questions, and making suggestions, alongside BP's scientists and engineers. At the request of the GLST, some of the more critical interventions were reviewed by experts from other major oil companies, a very unusual development (2). The result was substantial, comprehensive, and independent advice to the President and the NIC about the risks associated with proposed well control actions and options to increase the likelihood of success. The NIC, charged with oversight of the responsible party, had the authority to consider and transmit formal recommendations to BP.

This new relationship between the government scientists and engineers and the BP team increased transparency into the procedures that BP proposed, increased confidence that risks had been appropriately mitigated, and provided appropriate assurance that other candidate options had been thoroughly vetted. The GLST and the BP team reached consensus on a path forward from Top Kill onward to establish well integrity through the final well kill using the traditional methods of science and engineering to solve any disagreements: collect more information, conduct simulations, and reduce uncertainties.

The Federal Government had also established a number of other science teams to assist with aspects of the spill; work on flow rate and oil budget (i.e., where the oil went) is described here. (The work of other scientific teams is detailed in ref. 1, and a description of teams is in *SI Text*.)

Flow Rate

An accurate assessment of flow rate was important for predicting the likelihood for success of various well intervention strategies, planning containment capacity to capture the flow while relief wells were drilled, applying the proper amount of dispersant, and helping satisfy the need for the public to understand the scale of the crisis. The flow rate was first publicly estimated on day 5 by BP to be ~1,000 barrels per day (bpd). Experienced NOAA hydrocarbon scientists observing oil on the surface from planes quickly challenged that estimate, saying the flow had to be at least 5,000 bpd, and likely, it was much, much more. BP strenuously resisted the phrase "and much, much more." In the absence of firm information, the USCG announced a new flow rate of 5,000 bpd on day 9.

Subsequently, the media announced several higher estimates of flow rate: 60,000 bpd based on a number observed written on a white board in the NOAA Office of Response and Restoration and 20,000–100,000 bpd, which was derived from analysis of the first short video clips showing the plume of hydrocarbons escaping from the damaged riser (3). These estimates, although presaging higher flow rates, were not officially adopted as government estimates because of multiple uncertainties and the fact that the NIC was in the process of setting up an official team to take all approaches into account, resolve differences, and estimate flow (*SI Text*).

Using analysis of higher-quality video as well as other methods, on day 37, the Flow Rate Technical Group (FRTG) (*SI Text*) issued its first lower bound on the oil discharge rate of 12,000–25,000 bpd (4). Within a few weeks, better data and estimates from more methods confirmed higher flow rates: 57,000 ± 10,000 bpd from Woods Hole Oceanographic Institution (5) estimated just before the riser was cut and >40,000 bpd from several of the video analyses that used manual methods to track features (6). The particle image velocimetry technique for video flow-rate analysis influenced the early government estimates, especially because it could be applied rapidly; multiple teams adopted this approach (4). This method was later shown to underestimate flow rates for this particular application (6).

The GLST used an opportunistic shutdown in oil collection on day 48, 2 d after the Top Hat was installed, to estimate a lower limit to the flow. The GLST noted that ROV video records of oil leaking from the skirt (bottom) of the Top Hat during oil collection of 15,600 bpd and when collection was 0 bpd were indistinguishable. Assuming that one could discern by eye a change of at least one-half to one-third of the oil leaking from the Top Hat, they established a lower bound on the flow rate of 30,000–45,000 bpd. Based on this estimate, the NIC ordered BP to increase containment capacity to 60,000 bpd. [On June 8, day 50, BP presented a plan to Secretaries Salazar and Chu, documented in a letter on June 9, to contain "40–50,000 barrels of oil per day. In addition, the Discoverer Enterprise would remain in the field and could provide additional capacity (15–18,000 barrels of oil per day) ... In summary, we believe this plan is responsive to your order."]

The GLST proposed estimating the amount of flow not captured by surface collection (escaping through relief ports and gaps in the skirt where the Top Hat mated with the mounting flange) by measuring the differential pressure inside and outside the Top Hat. The higher the differential pressure, the higher the flux of the escaping flow. The calculation also depended on estimating the area available in the ports and skirt for fluid flow to escape. Three DOE National Laboratories performed calculations to estimate flow rates, combining the escaping flow to the surface collection at the time that the pressure measurement was made. Their estimates ranged from 72,000 to 83,000 bpd, with large uncertainty for two reasons. First, the gap area in the skirt was poorly known. Second, a lightning strike led to a production shutdown, increasing the flow through the Top Hat but no discernible change in differential pressure. This observation led several experts to become concerned that the measurement point for the differential pressure gauge was not representative.

The lower limit of the GLST and the estimates from the FRTG were merged on day 56 and released 1 d later as the last government flow-rate estimate provided before shut in of the well: 35,000–60,000 bpd (4, 6). Although the lower bound was considered a hard minimum value, the press release made clear that the upper bound was less certain.

The most definitive measurement of the flow occurred just before the well was shut in. On day 86, collection by surface vessels was partially interrupted, and the two working pressure gauges installed on the capping stack were able to record a reliable change in the pressure in the capping stack that was coincident with the change in flow. This record allowed the GLST to make a simple calculation that was largely insensitive to details of the capping stack geometry. The flow of the hydrocarbon mixture was also insensitive to the gas/oil ratio (other than the assumption that the ratio was constant before and after the change in flow). In addition, several DOE laboratories made detailed calculations to interpret the pressure readings as a function of flow through the capping stack before and after the well was shut in on day 87 (July 15, 2010). The result of these analyses produced an accurate flow rate, yielding consistent results that, at that time, the rate was 53,000 bpd ± 10% (6, 7). This latter calculation depended on the gas/oil ratio, which was well-determined by this time (8).

Quantification of the integrated flow from the time of the blowout benefitted from more detailed knowledge of the reservoir condition and the effect of possible BOP restrictions on the flow. Information on the former was obtained during the well integrity test. Modeling by Oldenburg et al. (9) on the phase interference of ascending oil and gas in the well suggested that restrictions in the BOP would not have a large effect on oil flow rates.

Well Integrity Test

Complete collection of oil through the Top Hat was impossible, because the system was only designed to accommodate 15,000 bpd oil and associated natural gas. An additional ∼9,000 bpd of oil and associated gas were produced through the choke line of the damaged BOP to the semisubmersible drilling platform, *Q-4000*, but the total collection through the two routes to the surface was inadequate. Deployment of a smaller BOP (capping stack) on top of the Lower Marine Riser Package, the top of the damaged BOP, would allow the collection of more than 80,000 bpd from the combination of the valved ports in the capping stack and additional lines from the BOP.

The deployment of the capping stack also allowed the possibility of shutting off the flow by closing the valves. The well could not be left shut in unless the well passed an integrity test (10) that showed that all rupture disks in the well casings and casing shoes had remained intact, despite the explosion. If it had not, shutting in the well would risk release of hydrocarbons to surrounding geologic formations and potential blowouts to the seafloor (Fig. 1), a much worse situation than the single point of exit through the damaged BOP. If the well passed the test, with the upward flow turned off, it would be possible to statically kill the well by injecting drilling mud down the well bore. The capping stack and BOP had to withstand the overpressure that would be generated by the Macondo well when the well was shut in and any additional pressure that would be needed in the static kill. The GLST's independent structural analysis raised concerns about the mechanical stresses that the capping stack would put on the flex joint of the BOP. The flex joint had been bent to its maximum tilt range by the drifting DWH before it sank. In part because of detailed GLST/DOE calculations of the elastomer vulnerabilities, BP restored the flex joint to vertical alignment before attaching the capping stack.

By mid-June, hurricane season was slowing the build-out of additional collection capacity and progress on the relief wells. Government and BP experts were weighing whether to proceed with the well integrity test (WIT) (10). Risks identified included (*i*) broaching of hydrocarbons to the seafloor through multiple subsea floor vents and (*ii*) sinking of the BOP into

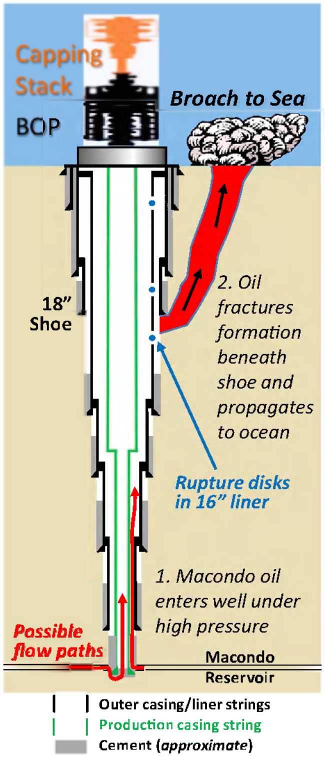

Fig. 1. Schematic of the Macondo well (11) and capping stack showing a possible broach situation through rupture disks in the 16-in liner after shut in with the capping stack. Although sand layers were present above the 18-in shoe, geologic analyses by the Well Integrity Team indicated that such layers were too thin or laterally discontinuous to be counted on for arresting or significantly delaying vertical fracture growth to the seafloor (10).

the seafloor through liquefaction of surrounding sediments by broaching oil (Fig. 1). Either situation might mean that the full flow of the Macondo well would discharge into the Gulf until the relief wells killed the well. The expert view of geologists from academia, government, and industry was that the former scenario would not be irrecoverable: if an incipient leak to the seafloor was detected within hours and the well was quickly reopened, the ductile seafloor sediments would heal fractures in the seafloor. The second scenario was viewed as unlikely after examining the details of well design and rock formation but given the high consequences, had to be avoided at all costs.

The GLST recommended that the well be shut in for specified intervals depending on the observed pressure on gauges installed at their request. The original reservoir pressure with a static head of well fluid would have yielded an estimated pressure of about 9,000 psi. Accounting for some well depletion since the beginning of the blowout, if the pressure was above 7,500 psi, the well could be shut for 48 h with low risk, and if the pressure was above 8,000 psi, the well most likely was not damaged. If the pressure was found to be less than 6,000 psi, the low pressure would indicate that the well was significantly damaged and would have to be opened quickly. Between 6,000 and 7,500 psi, the result would be ambiguous, but the well could be left shut in for 24 h based on the assumption that flow through ruptured disks of 20,000 barrels could be tolerated without irreversible harm (Fig. 2).

The well was to be shut in with the proviso that multiple surveillance methods would be used to search for a leak on or beneath the seafloor: multichannel seismic surveys, water column sonar, visual ROV camera surveys, and acoustic listening at the wellhead (10). Previously directed operations by BP to increase oil recovery capacity were stopped as necessary while critical seismic and acoustic runs were made through the area near the wellhead. It is noteworthy that this very complicated set of activities was accomplished without accident.

On day 87 (July 15), the final (choke) valve in the capping stack was closed in a sequence of steps. The pressure rose stepwise to 6,600 psi, squarely in the middle of the ambiguous zone (Fig. 2). Some members of the GLST advocated that the risk of inducing an uncontrolled release into the Gulf was too great and that BP should return to collecting oil until a relief well was completed. BP was reluctant to reopen the capping stack and argued that the low pressure was a sign of well depletion. The GLST leadership recommended that the shut-in test continue. The BP/NIC path chosen was to allow the WIT to continue initially for 24 h (the agreed-on guidance) and redouble the surveillance efforts.

US Geological Survey team members transmitted a cell phone photograph of the pressure changes vs. time when the capping stack was closed to Paul Hsieh at US Geological Survey in Menlo Park, California. Working through the night, Hsieh interpreted the data in terms of their implications for well integrity. In parallel, BP conducted a similar analysis. These analyses were crucial in providing a plausible argument for allowing the WIT to continue beyond the original 24 h. The decision to keep the well sealed was made every 8 h, but as the understanding of the well increased, the decision point was lengthened to 12 h and then, 24 h.

Both Hsieh and BP plotted the time dependence of the pressure in a Horner plot, where pressure is plotted vs. the log $[(t_P + dt)/dt]$ (t_P is the duration of the spill, and dt is the time since the well was sealed) (Fig. 3). On day 88, BP presented the first plot in a series of Horner plots showing a straight line trend of data up to 0000 h (7/16/2010). On the same day,

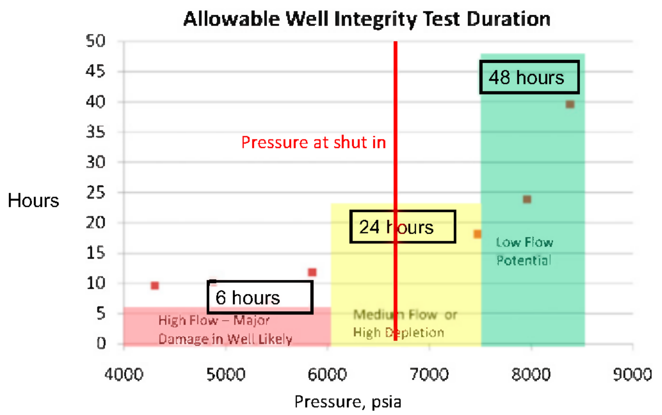

Fig. 2. Pressure ranges agreed to by the government-led science team and BP that would prompt different actions after well shut in as described in the text. Squares are a National Labs analysis of the allowable time for shut in using estimated flow rates at varying BOP pressures assuming 20,000 barrels of oil is the maximum allowable flow into formation. The red line shows the shut in pressure, approximately 6,600 psi on July 15, 2010.

Hsieh presented his model of a square reservoir, predicting that the data would follow the same straight-line trend but would begin to saturate 2 d after shut in. The linear trend continued for another day, but on day 90, the first hint of departure was seen. By 1900 h on day 91, BP presented data showing that the departure was unmistakable. Instead of saturating, the pressure line curved up. Hsieh immediately revised his reservoir model from a square reservoir to a channel (rectangular) reservoir. BP had made the same deductions, and in an 1100 h meeting the same day, BP and Hsieh presented their combined analysis that the data were consistent with a channel reservoir with no aquifer drive having an aspect ratio of roughly 8:1.

Confidence was growing that the well casings were intact, such that when Tropical Storm Bonnie came through on day 95, the NIC allowed the well to remain shut in without monitoring for the duration of the storm. After the storm passed, the GLST used the increased understanding of the reservoir to calculate the pressure depletion in the well since the beginning of the blowout. The shut-in pressure at the capping stack, by this time, was approaching 6,900 psi. Assuming no leak from the well and correcting for the static density of the hydrocarbon fluid in the well, the static pressure at the reservoir was estimated to be ~10,000 psi, roughly 1,800 psi lower than the static pressure of 11,800 psi measured by BP before the blowout. The reservoir model of Hsieh indicated that the pressure and flow had decreased linearly since the time of the blowout. Because the flow was determined to be 53,000 bpd on day 87, the GLST determined the flow rate at the beginning of the incident to be 62,000 bpd ± 10% after the ~5% step increase in flow after the riser was cut off. The integrated flow was calculated to be 4.9 million barrels (mb) of oil released from the well (7, 12), and ~0.8 mb were collected by the Top Hat, choke/fill flow, and the Riser Insertion Tube Tool.

Killing the Well

As confidence grew that the well had retained integrity, attention turned to possibly killing the well by injecting drilling mud to force the hydrocarbons in the well column back into the reservoir. The deeper of the two relief wells was still weeks away from reaching the base of Macondo. Until the final well kill from below, the risk of additional oil spilling could be reduced if pressure could be taken off the capping stack by injecting mud from above.

This method of killing the well was similar to the approach that had failed during Top Kill, but the well had been actively flowing at that time at ~60,000 bpd. The likelihood of killing the well under static conditions was greatly improved compared with a dynamic kill of a flowing well, where substantial upward hydrocarbon fluid momentum had to be overcome. A strong argument for proceeding with the static kill was that it would greatly reduce the internal pressure on the capping stack and require less monitoring as peak hurricane season approached. BP argued that the static balancing of exploratory wells is done routinely in normal operations, and an injectivity test (how much pressure is needed to overcome the skin impedance at the reservoir/well interface) would provide valuable information in preparation for the bottom kill.

The greatest risk to the well would occur during the initial pumping, when additional pressure would be added to the capping stack and BOP. The pressure at the BOP/capping stack was estimated by BP to rise from 6,900 to ~7,400 psi, within the limit of 8,000 psi developed by GLST. If the static kill was successful, BP proposed to follow the static kill by forcing a plug of cement into the bottom of the well and partially into the reservoir.

The discussions with BP and the GLST on whether to proceed with the static kill and cementing intensified soon after Tropical Storm Bonnie had passed. There was diversity of opinions within the GLST and outside industry experts over whether to proceed with a static top kill or take a more conservative approach of waiting for the relief well to be completed (2).

The possibility remained that a static kill would allow the well to be killed in the central casing but not the annulus, the space between the central well casing and the outer double wall. One of the flaws in the design of the Macondo well was that there was an unobstructed flow path from the bottom of the annulus (the 9.875-in shoe) to the hanger seal in the BOP. Only a few hundred feet separated the reservoir from this shoe, and if the intervening rock was fractured anytime during the drilling or blowout, oil could flow up the annulus. Normally, this flow is prevented by a hanger seal that isolates the annulus from the central casing. However, the locking mechanism for the hanger seal had not been installed before the blowout. If the blowout lifted the hanger seal up and it did not reseat properly, hydrocarbons could leak from behind the hanger seal. However, mud pumped in the static kill would be less likely to enter the annulus because of impedance differences for the mud pathways.

Although there were manageable risks to a hydrostatic balancing of the drill mud, a cement procedure from the top that failed to fully seal the well from the reservoir was viewed as an irreversible problem. A botched cement job might isolate hydrocarbons in the annulus that would not be hydrostatically balanced with the drilling mud when the relief well entered the Macondo, interfere with access to the reservoir for the cement from a bottom kill, and prevent fishing the drill pipe from the hole. Before proceeding with cementing, it was agreed that the pressure–volume response during the kill operation had to strongly favor that the flow path of the mud was through the casing or casing/drill pipe only. If there was any indication that flow was going into the annulus, cementing would be unacceptable.

After numerous discussions, the NIC authorized the static kill. On August 3 (day 106), base oil was injected into the well as the first part of the injectivity test. The pressure rise was only 35 psi, hundreds of psi below the most optimistic

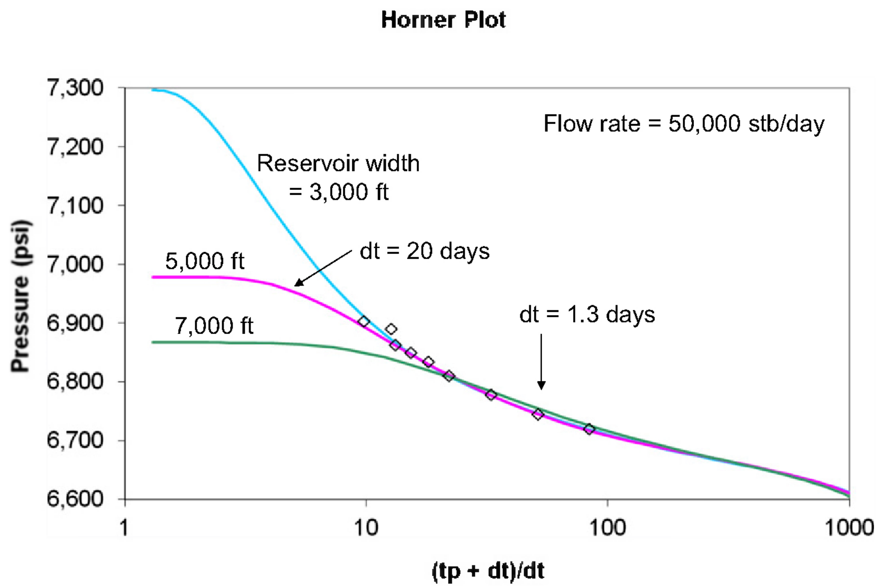

Fig. 3. Horner plot of measured pressure (publicly announced daily values–government team in Houston had more extensive proprietary data) from the Macondo well (diamonds; psi) plotted as a function of $(t_P + dt)/dt$, in which t_P is the duration of the spill (86 d) and dt is the time since the well was shut in. Horizontal axis is log scale. Arrow at dt = 1.3 d indicates data trend 1.3 d after the well was shut in. Arrow at dt = 20 d shows how the modeled pressure (solid line) predicts that, for a reservoir that is 5,000-ft wide, the pressure would stabilize (flatten) 20 d after shut in. Flattening of the pressure in the Horner plot is predicted to occur sooner for a 7,000-ft-wide reservoir and much later for a 3,000-ft-wide reservoir. Models assume porosity of 21%, thickness of reservoir of 90 ft, and area of reservoir of 85.3 million ft^2. Permeability, compressibility, and location of the well in the reservoir are fitted parameters. This plot was presented to BP and the GLST on July 26, 2010 (11 d after shut in) by Paul Hsieh. By this time, it was clear that a narrow, long reservoir that would trend to a higher eventual shut-in pressure was a better fit to the data. Industry proprietary seismic images of the Macondo reservoir confirmed this interpretation.

expectations of the lowest pressure rise needed to stop and then reverse the hydrocarbon flow. As the amount of base oil injected into the well increased, the rate of pressure decrease increased proportionally. When the injection stopped, the pressure flat-lined. This result meant that oil lurking in the annulus, ready to spring back when injection stopped, was essentially ruled out. The impedance to flow at the well–reservoir interface or elsewhere into the lower rock formation was very small. Mud injection would carry little risk, and observations of the volume of mud injected during the static kill helped narrow down likely mud paths that informed the decision on whether to cement the well. Permission to cement the well was given on the next day. Although the cementing job did not go exactly as planned, it passed rigorous and extended pressure tests.

After the successful static kill, attention turned to the relief well. A review had previously been held on day 71 that was attended by government and industry experts in Houston. BP followed many of the guidance recommendations, thereby mitigating the risks in the bottom-kill procedures. The bottom kill, at this point, was simply to "hammer the final nails in the coffin" of a well that had been trouble from the start, and on day 153 (September 19), 5 mo after the initial explosion, President Obama declared the well to be dead. After the intersection and cementing from the relief well, the NIC transferred the command authority back to the Minerals Management Service (now the Bureau of Ocean Energy Management and the Bureau of Safety and Environmental Enforcement). The GLST continued to be engaged with the Minerals Management Service until the final steps of the plug and abandonment operations that were largely over by day 106 (November 11, 2010).

Oil Budget

The efforts detailed above to quantify flow rate and total discharge of the Macondo well were the starting point for estimating an overall oil budget for DWH. Oil and gas released from a deep wellhead had numerous possible fates: (*i*) dissolution or dispersion and eventual decomposition in the water column either naturally or chemically with the aid of dispersants; (*ii*) accumulation at the surface; (*iii*) removal, skimming, or burning at the surface; (*iv*) evaporation into the atmosphere; (*v*) deposition along the shore or the seafloor; or (*vi*) direct recovery (in this case, from the riser pipe or choke line). An oil budget attempts to quantify these fates with the sole purpose of enabling response efforts to be targeted to recoverable oil.

An oil budget represents the amounts of oil estimated to be flowing or already flowed into the environment, the amount that has been recovered or degraded, and the remaining amount that could be recovered (13). It is typically developed for use by responders and updated frequently as new information is available. Estimating amounts of oil in various categories entails varying degrees of uncertainty. For example, calculating direct capture and burning has the least uncertainty, because these processes are measured on scene. At the other end of the spectrum are calculations of dispersion, which are based on limited data, theoretical considerations, and expert knowledge based on previous spills. Throughout the process, calculations and assumptions err on the side of achieving a conservative answer to avoid underestimating cleanup requirements. In most spills, the oil budget is not publicly available; it is simply a response tool. The DWH oil budget began with the methodologies developed during numerous previous spills (primarily in shallow waters) and adapted them for DWH conditions.

During DWH, the frequently updated oil budget calculator was maintained by the NIC. In response to public interest and support of the Administration's commitment to transparency, after determination of the discharge as 4.9 mb (±10%), the NIC released a preliminary oil budget on August 4 (day 107) (Table 1). Doing so proved highly controversial for multiple reasons. (*i*) Administration officials inadvertently mischaracterized conclusions from the estimated oil budget (saying "more than three-quarters of the oil is gone"), whereas in fact, the oil budget indicated—and the press release and press conference announcing it made clear—that roughly only one-half was gone (recovered, burned, skimmed, evaporated, or dissolved) (Table 1), with another one-quarter in the water column and one-quarter unaccounted for—with considerable error bars around each component estimate. (*ii*) There was considerable confusion about flow rates and subsurface oil—key parameters in the oil budget that, although accurate in the end, had not yet been generally accepted. (*iii*) It was difficult—especially after seeing daily video images of oil gushing from the riser pipe and beaches and birds covered with oil—for the public, policy-makers, the press, and most people to understand how even one-half of the oil could possibly have disappeared so quickly.

Initial calculations in the oil budget were dependent on parameters only poorly

Table 1. Comparison of August and November of 2010 (13) oil budgets intended to target response efforts to potentially recoverable oil based on the estimated release of 4.9 mb oil

Oil budget as of August of 2010		Final oil budget (technical report November 2010)		
Category	Percent of total	Category	Percent of total	Change (%)
Direct recovery	17	Direct recovery	17	None
Burned	5	Burned	5	None
Skimmed	3	Skimmed	3	None
Chemically dispersed	8	Chemically dispersed	16	8
Naturally dispersed	16	Naturally dispersed	13	−3
Evaporated or dissolved	25	Evaporated or dissolved	23	−2
Other	26	Other	23	−3

Direct recovery is oil recovered from the wellhead. Other is oil not accounted for after estimation of other categories and includes oil that is potentially recoverable (still on or just below the surface as light sheen and weathered tar balls, washed ashore or collected from the shore, or buried in sand and sediments). Response operations removed 25% of the oil (direct recovery and burned and skimmed). The 29% dispersed (in November budget) was either still in the water column or consumed by bacteria, but in either case, it was not amenable to restoration efforts.

understood at the onset of the spill, including the oil/gas mixture and the composition of the crude oil, which affects its volatility and the rate of microbial degradation. A final, extensively peer-reviewed estimated oil budget was released in November (Table 1) (13). With the exception of the amounts of oil dispersed naturally (16% as of August 4 vs. 13% in November) (Table 1) vs. chemically (8–16%), most of the oil budget released in August was later confirmed as accurate. Changes in the naturally vs. chemically dispersed categories reflected increased understanding of the dynamics of dispersion at deep depths and additional measurements taken during the interval. Across all categories, the final estimates had the benefit of significantly more information (extensive documentation is given in ref. 13). This final tally indicated that around one-quarter of the oil was unaccounted for as of November of 2010. This "Other" category includes oil on beaches, in tar balls, in shallow subsurface mats, and in deep-sea sediments—all of which are difficult to measure with any precision or estimate with much confidence.

Skimming and burning activities were conducted primarily in offshore waters north of the wellhead. Both removal methods require sufficient oil to be present in an area to be effective. The patchy nature of surface oil and the dynamic day-to-day movement (see animation in ref. 1, *SI Text*) made accurate intelligence about surface conditions essential. In the end and despite considerable effort, only about 8% of the oil was skimmed or burned. According to the final oil budget estimates, around 25% of the oil was removed (recovered, burned, or skimmed) by NIC-directed BP efforts and the federal response (*SI Text*).

Since release of the final oil budget estimates, published research on the fate of various oil components has generally confirmed the final oil budget results. Because of the relatively light composition of the Macondo oil (e.g., enriched in relatively low molecular-weight components) (13), a substantial portion of the oil was evaporated into the atmosphere (14, 15), dispersed as a result of the physical properties of the oil jet entering the ocean under extreme conditions of pressure and temperature (16), dispersed through the addition of chemical dispersants at the wellhead and surface (13), or consumed by bacteria able to metabolize gas and lighter components of the oil (17–21).

Oil budgets are predicated on the estimates of daily and cumulative oil flow, which were difficult to estimate for DWH initially. An important constraint on the final oil budget was the estimated total release of oil from the Macondo reservoir: 4.9 mb ± 10% (4, 12). This estimate is independent of the details of the flow rate on any particular day of the spill.

Conclusions

The need for scientific information to guide decision-making by federal officials charged with the legal responsibility of safeguarding environmental and personal safety during the DWH oil spill mobilized an unprecedented effort of government, academic, and industry scientists and engineers to answer questions never before encountered. The teams tackled questions of critical importance to helping the NIC oversee BP's response efforts by answering how fast the oil was flowing from the well, how much oil was recoverable throughout the event, and what strategies were likely to be successful in stopping the flow. Each of the three science teams described above included individuals from academia, government, and industry. Each team was created de novo to meet a specific need. Teams advised the NIC, who made decisions about response efforts, including directing BP to take certain actions.

The ability of government and BP scientists and engineers to work together and provide government scientists access to BP's proprietary information took time but eventually, produced results. The GLST (*i*) independently validated the range of well pressures that might arise at shut in and during static kill operations, (*ii*) thoroughly assessed the structural integrity of the capping stack and BP's assertion that the pressure inside the capping stack would be limited to 9,000 psi, (*iii*) independently analyzed the design of the WIT, and (*iv*) produced flow-rate information by means of methods that were used in conjunction with those methods used by the FRTG.

BP pursued options for oil containment, well control, and kill, under the government's oversight. Some political leaders had suggested that the government take over responsibility for stopping the oil spill after the failure of Top Kill. Given BP's skill at executing exceptionally difficult and complex operations in extreme environments, it would have been a mistake to remove BP from the response effort.

The FRTG used the full spectrum of approaches to resolve the raging controversies about the flow rate, be explicit about pros and cons of different approaches, bring credibility to final estimates, and provide guidance to response efforts that depended on knowledge of flow rate. During the process, new methodologies for estimating flow rates were developed (such as quantifying hydrocarbons in the air above the ocean surface) that may well be useful in the future.

The Oil Budget Team's primary contribution was assisting the response by calculating where cleanup efforts should be targeted. The fact that later information confirmed most of the estimates released in August is a tribute to the efforts of the team.

In all, the combined efforts of government, academic, and industry scientists were essential to the response effort.

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