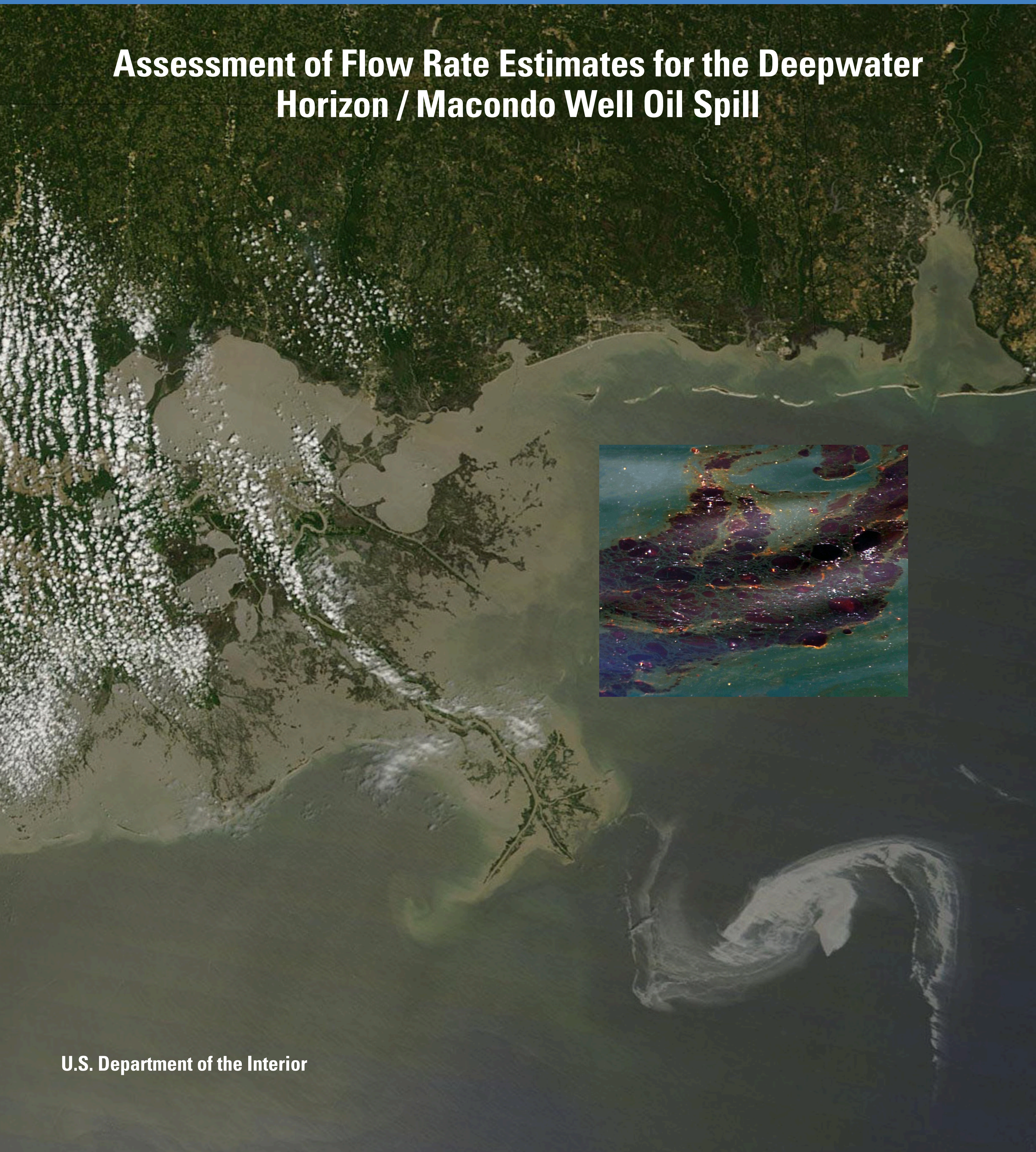
National Incident Command, Interagency Solutions Group, Flow Rate Technical Group

Assessment of Flow Rate Estimates for the Deepwater Horizon / Macondo Well Oil Spill



U.S. Department of the Interior

Cover: Satellite image of the oil spill in the Gulf of Mexico on April 29, 2010 (NASA Goddard Space Flight Center photo); oil floating on the surface of the water in the Gulf of Mexico on June 12, 2010 (photo by Petty Officer First Class Tasha Tully).

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Prepared by:

Marcia McNutt, U.S. Geological Survey: Flow Rate Technical Group Chair

Richard Camilli, Woods Hole Oceanographic Institution: WHOI Flow Rate Measurement Group Lead

George Guthrie, Department of Energy, National Energy Technology Lab: Flow Rate Technical Group, Nodal Analysis Team Lead

Paul Hsieh, U.S. Geological Survey, National Research Program

Victor Labson, U.S. Geological Survey: Flow Rate Technical Group, Mass Balance Team Lead

Bill Lehr, National Oceanic and Atmospheric Administration: Flow Rate Technical Group, Plume Analysis Team Lead

Don Maclay, Bureau of Ocean Energy Management, Regulation and Enforcement: Flow Rate Technical Group, Reservoir Modeling Team Lead

Art Ratzel, Department of Energy, Sandia National Laboratories: DOE-NNSA Team Lead

Mark Sogge, U.S. Geological Survey: Flow Rate Technical Group Deputy Chair

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Contents

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EXECUTIVE SUMMARY

The April 20, 2010, explosion on board the Deepwater Horizon drilling platform led to an 87-day blowout of the Macondo oil well nearly one mile deep in the Gulf of Mexico that was only partially contained through collection of up to 25,000 barrels per day of oil (plus natural gas) to surface ships during the latter portion of the incident. For a number of reasons related to the response effort, it was important to have an accurate estimate of the rate of release of hydrocarbons, especially oil, from the well, and yet no proven techniques existed for estimating the flow under such conditions. The National Incident Command (NIC), Interagency Solutions Group established the Flow Rate Technical Group (FRTG) and assigned it two primary functions: (1) quickly generate a preliminary estimate of the flow rate from the Macondo well, and (2) use multiple, peer-reviewed methodologies to later generate a final estimate of flow rate and volume of oil released. The purpose of this report is to describe the relative advantages of the different methods that were used to measure flow rate from the Macondo well, so that if this process needs to be used again in an emergency situation, quick decisions can be made to mobilize the techniques most appropriate to that future emergency.

Given the lack of precedents, the FRTG used all practical methodologies to estimate the flow rate (defined in this report as equivalent stock tank barrels of oil at sea level), each with its inherent strengths and limitations. One technique (mass balance) relied only on observations available on the ocean surface and yielded a flow rate of 13,000 to 22,000 barrels per day (BPD) early on in the incident. Two techniques (video and acoustic) acquired in situ observations from remotely operated vehicles (ROVs) of the oil plume as it exited the well in water 5067 feet deep at the wellhead. These techniques yielded fairly consistent flow rates of 25,000 to 60,000 BPD. An in situ hydrocarbon sample not only improved these flow estimates, but also was combined independently with surface collection data to yield a flow rate of 48,000 to 66,000 BPD. The final approach (reservoir and well modeling) needed no new observations but did rely on industry proprietary data (seismic data on the reservoir structure, rock and fluid properties, well logs, etc.) to constrain model parameters. This approach produced the largest range in estimated flow rates (from less than 30,000 to more than 100,000 BPD) and had the largest number of uncertain parameters. On June 15, 2010, using flow estimates available at the time (primarily video and acoustic), the government released an updated estimate of 35,000 to 60,000 BPD.

Three days after a capping stack was installed on the well on July 12, 2010, the choke valve was closed and oil stopped flowing into the Gulf. Three different teams from Department of Energy (DOE) labs used pressure measurements recorded as the valve was closed to yield the most precise and accurate estimation of flow from the Macondo well: 53,000 barrels/day at the time just prior to shut in. The teams assigned an uncertainty on that value of ±10% based on their collective experience and judgment. The flow rate immediately prior to shut in was then extended back to day one of the spill using a U.S. Geological Survey (USGS) model simulation for the rate of depletion of the reservoir calibrated by pressure data from the well integrity test to produce an estimate of the flow rate as a function of time throughout the incident. The net result was a time-varying flow rate, announced on August 2, 2010, that decreased over the 87 days from an initial 62,000 to a final 53,000 barrels per day, for a total release of 4.9 million barrels of oil, before accounting for containment. The estimated uncertainty on these flow values is also ±10%. In this report, the post-shut-in, time-dependent estimate announced on August 2, 2010 (the "August estimate"), is considered to be the ground truth against which the June estimates are compared to answer the question of which methods are best suited for measuring flow rate during an ongoing incident.

Based on attributes such as timeliness of the information and accuracy of the estimation, the technique that performed the best during the ongoing emergency was the acoustic technique (combining sonar to image plume size with acoustic Doppler to measure plume velocity). The video technique was deployed more rapidly and could be the first recourse to get a quick, initial flow rate if such an event were to be repeated. Various members of the video team used different analysis techniques, with some providing better matches to the August estimate than others. Every attempt should be made to get an in situ sample of produced reservoir fluids or repeated samples if the incident is not rapidly contained.

There were some scenarios of the reservoir and well models (typically the "most likely" scenario) that predicted flow rates close to the August estimate. Given the very large range of uncertainty in the well and reservoir conditions that existed prior to shut in, whether the flow predictions from these models could have been useful for decisionmaking had they been available sooner would have depended on the criteria for model selection from among a number of plausible alternatives. For example, the "worst case scenario" required a containment capacity for surface ships that was more than five times that of the "best case scenario" for flow rate. Of course, any future oil spill event would have certain unique features, and therefore each of these methods would have to be judged on its own merits for the situation at hand.

The mass-balance flow rate was significantly lower than the rate determined by the other methods and is not a reliable technique for estimating flow from deep-sea releases. Much environmental modification of the oil, especially in its ascent from a mile of water depth, had already happened by the time the surface slick was imaged by the airborne instrument; thus, the combined effects of dispersion, dissolution, and evaporation simply left too much oil unaccounted for. Expanded research on the physical, chemical, biological, and geological fate of oil released in the deep marine environment will aid in the response to future oil spills.

Assessment of Flow Rate Estimates for the Deepwater Horizon / Macondo Well Oil Spill

Background on the Macondo Well and Oil Spill Origin

The Macondo well is located in the Mississippi Canyon Block 252 (MC252) of the Gulf of Mexico, approximately 50 nautical miles (93 km) southeast of the Mississippi River delta (28.74°N, 88.39°W) (Figure 1). BP America purchased the mineral rights to this block in 2008, and in October 2009 drilling of the exploratory well began in water approximately 5000 ft (1500 m) deep. On April 20, 2010, an explosion occurred on the drilling rig Deepwater Horizon, which then burned and sank on April 22. This incident severely damaged the underwater riser – the pipe connecting the ocean floor well to the drilling platform – about 4000 feet (1200 m) of which fell back to the seafloor. The riser looped around back as it fell, such that its broken end was less than 2000 feet (600 m) from the wellhead.

The first news reports from the explosion and fire were that the well was not leaking oil. However, it was apparent to the remotely operated vehicles (ROVs) diving near the wellhead as early as April 22 that hydrocarbons were escaping from tears where the riser pipe was bent over at the wellhead, the so-called “kink” in the riser (Figure 2). At this time the ROVs had been dispatched to the seafloor to intervene with the blowout preventer (BOP) to activate the blind shear rams by directly plugging into the system hydraulics. However, this maneuver had no effect on the flow through the kink at the wellhead. The much larger flow from the well through two other leaks further up the riser was first discovered on April 24 by the ROVs with their scanning sonars, far beyond the region illuminated with their lights. Up through May 5 there were repeated efforts to directly activate various rams in the BOP. Only activation of the casing shears on April 29 had any effect at all, and it was a momentary hesitation in the flow through one of the leaks. On May 5 the problem of attempting to contain the flow from the damaged riser was simplified by cutting off the damaged end of the drill pipe at one of the leak points and capping it off such that all flow was channeled either through the kink in the riser at the wellhead or out the broken (open) end of the riser (Figure 2).

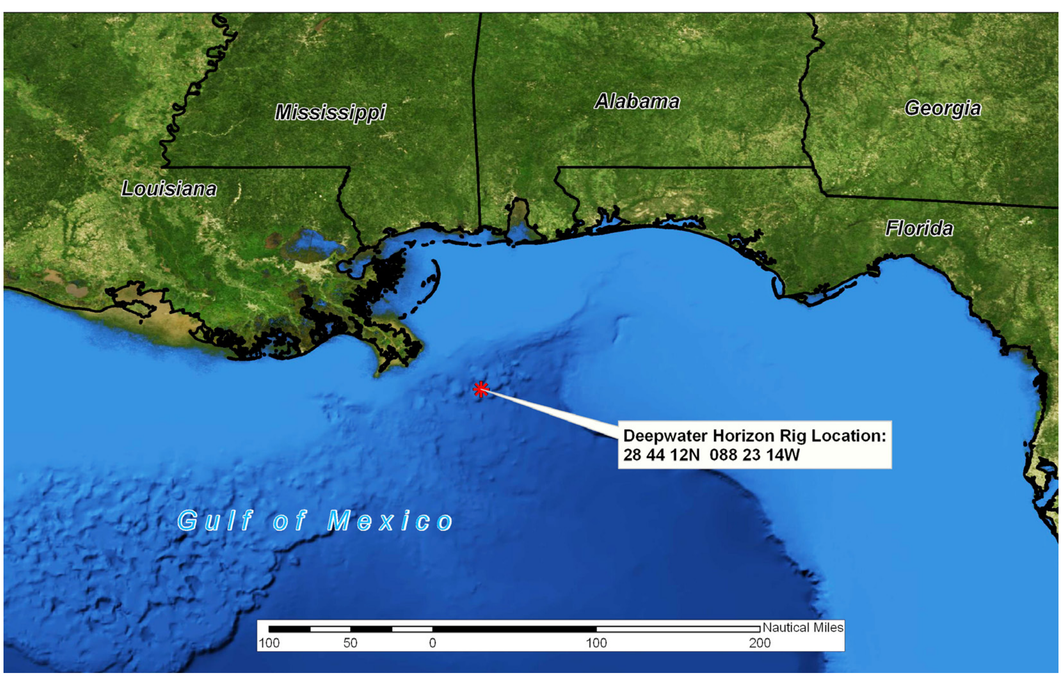

Figure 1. Location of the Deepwater Horizon / Macondo well oil spill, in the Gulf of Mexico approximately 50 miles (80 km) southeast of the Mississippi Delta. Source: U.S. Geological Survey.

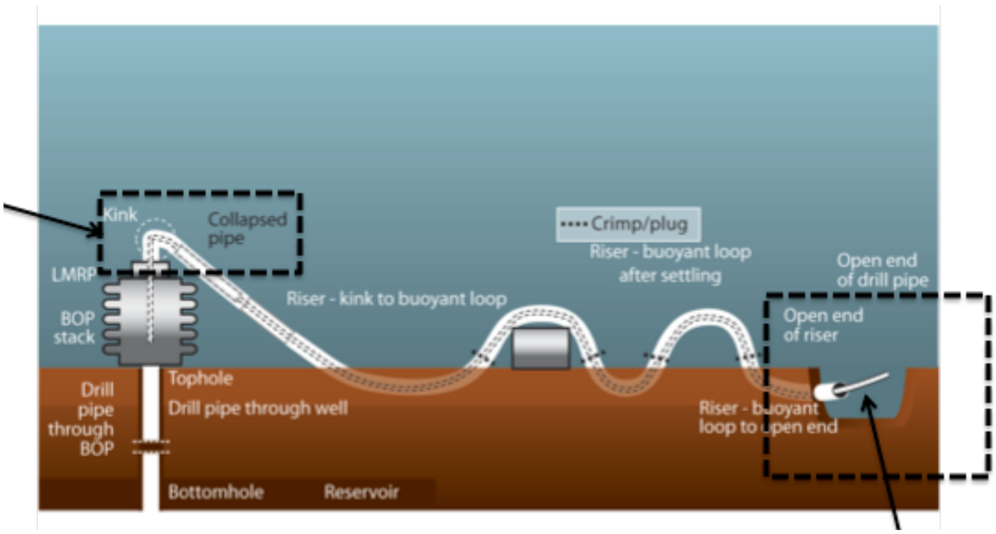

Figure 2. Diagram of damaged riser at the Macondo well spill site. Most hydrocarbon release occurred in the areas highlighted by black rectangles, emanating from the kink immediately above the Blowout Preventer (BOP) stack and the open end of the riser/drill pipe. LMRP refers to the Lower Marine Riser Package, which is at the top of the BOP stack. Source: BP web.

Subsequent Well Control Efforts

BP attempted additional control of the plume on May 8, when a large coffer dam (or "dome") was lowered to the seafloor over the broken riser end. This failed when the coffer dam filled with methane hydrates caused by the interaction of methane gas from the hydrocarbon plume with seawater. The icy hydrates changed the buoyancy of the coffer dam, threatening to make the large structure unstable. The hydrates would also have prevented hydrocarbon flow through the coffer dam and its riser up to the sea surface. On May 16, the Riser Insertion Tube Tool (RITT), a snorkel-type device, was placed in the broken riser end to capture some of the escaping oil (Figure 3). The rate of capture varied over time, peaking for short periods at a rate that, had it been sustained, would have yielded 8000 barrels per day (BPD). On May 26, BP attempted a "Top Kill" procedure by pumping heavy mud and some bridging material into the well through the BOP; this failed and the attempt was ended on May 29.

In order to consolidate the escaping flow into a single outlet and to set the stage for future control attempts, BP severed the riser just above the Lower Marine Riser Package (LMRP, the uppermost unit of the BOP stack) on June 3 (Figure 4). That same day, Top Hat #4 was placed on top of the LMRP and began recovering hydrocarbons from the severed Macondo well (Figure 5). The captured flow was transferred to the vessel *Discoverer Enterprise*; oil recovery rate ramped up over the next few days to peak at approximately 15,000 BPD. On June 11, additional capacity for hydrocarbon collection was brought on line by converting the manifolds that were used to pump mud in the Top Kill procedure to collect oil on the *Q4000* semi-submersible from the choke line of the BOP. Oil recovery rates for the *Q4000* proved to be quite reliable and robust, with a peak rate of approximately 9000 BPD. These two concurrent collection efforts failed to capture all of the hydrocarbon flow from the well; video from ROVs clearly showed hydrocarbons leaking through the vents and through the skirt in the Top Hat. In order to keep the work area at the sea surface free of volatile organic chemicals (VOCs), which are a human health hazard to the hundreds of workers in the immediate vicinity of the wellhead, subsea dispersant chemicals were added to the plume via a dispersant wand deployed from an ROV. These chemicals reduce the average oil droplet size, which aids dispersal into the water column and reduces the amount of oil reaching the surface.

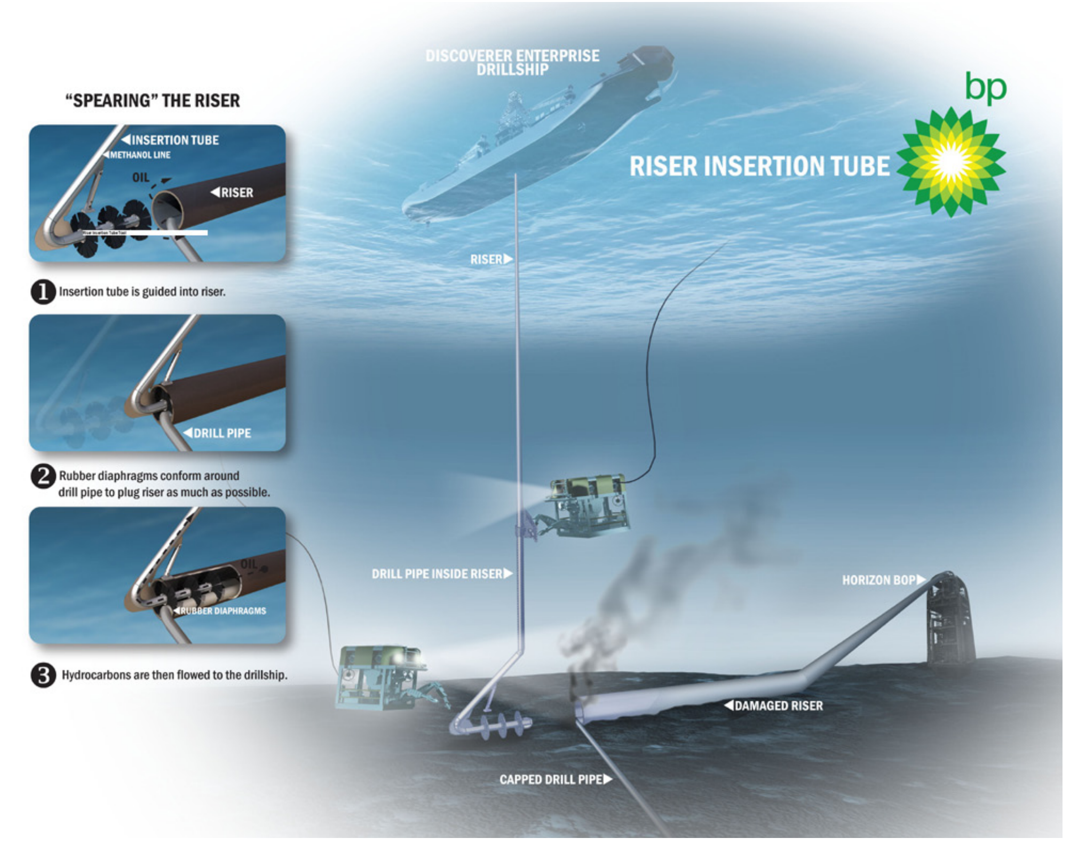

Figure 3. Diagram of Riser Insertion Tube Tool (RITT) that was used in mid-May to capture hydrocarbons being released from the open end of the damaged riser at the Macondo well spill site. Source: BP web.

On July 10, government researchers in Houston encouraged BP to accelerate a procedure to remove Top Hat #4 and replace it with a three-bore capping stack that would allow for greater containment of the flowing oil and potentially full closure of the well. After the capping stack was successfully installed, the National Incident Command (NIC) approved a well integrity test that would temporarily stop the oil flow by closing all valves on the capping stack. For the first time in 87 days, all oil from the Macondo well ceased flowing into the ocean at 14:20 CDT on July 15, 2010. Government and independent scientists carefully monitored the ocean and subsurface for any sign of hydrocarbons leaking from the well into surrounding rock formations or into the ocean via pressure and temperature gages and seismic, acoustic, sonar, and visual surveys using ships and ROVs. The monitoring progressively gave government officials confidence that the well had integrity and could remain shut in, such that no new oil/natural gas was released after July 15. On August 3, the Static Kill process was conducted and the well was filled with heavy mud, significantly reducing pressure at the wellhead. Cement was injected into the Macondo well from above on August 5, and on September 17 the well kill process was completed when cement was pumped into the annulus from the relief well drilled by the Development Driller III.

Motivation for Flow Estimates

Initially, BP’s estimate of the flow from the well was approximately 1000 BPD. On April 28, the National Oceanic and Atmospheric Administration (NOAA) released the first official government flow rate of 5000 BPD. At the time, this number was highly uncertain and based on satellite views of the area of oil on the surface of the ocean. After the May 12 public release of videos showing the plume of hydrocarbons escaping from the damaged riser in the deep sea, many scientists insisted that the flow rate was much higher than 5000 BPD. On May 14, 2010, the NIC

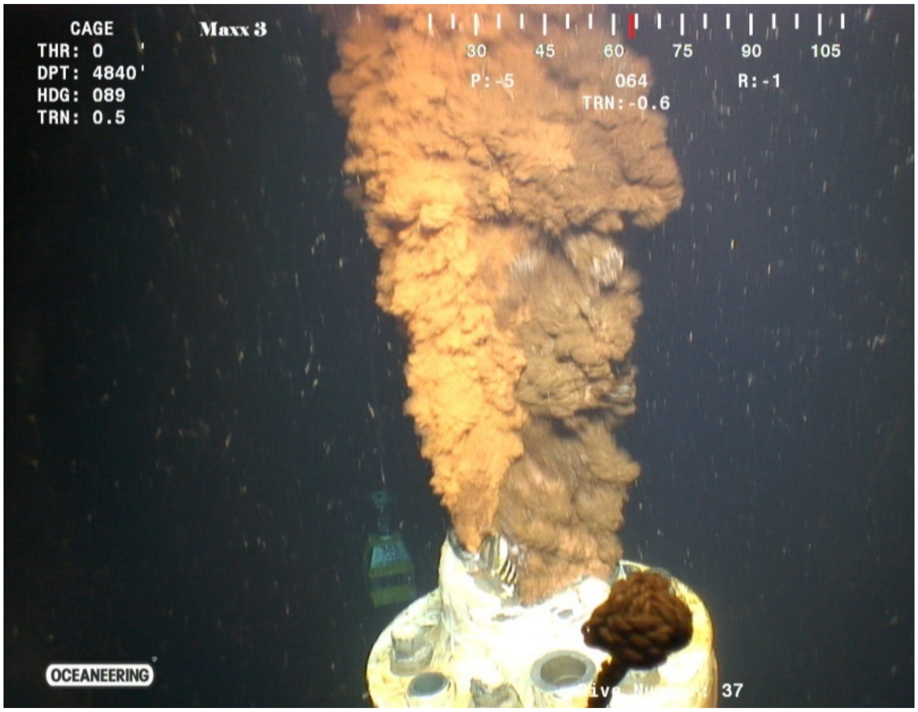

Figure 4. Hydrocarbons (oil and natural gas) escaping from the end of the riser tube, after it was severed on June 3 immediately above the Macondo well Blowout Preventer (BOP) stack. Source: BP video from Remotely Operated Vehicles (ROVs).

asked its Interagency Solutions Group (IASG) to provide scientifically based information on the discharge rate of oil from the well. In response, the NIC IASG chartered the Flow Rate Technical Group (FRTG) on May 19. Experts from many scientific disciplines were brought together to perform the FRTG's two primary functions: (1) as soon as possible, generate a preliminary estimate of the flow rate, and (2) within approximately two months, use multiple, peer-reviewed methodologies to generate a final estimate of flow rate and volume of oil released.

There are a number of reasons for needing a more accurate estimate of the flow rate, beyond the public's interest in the magnitude of the Deepwater Horizon incident. To begin with, a number of operations and interventions associated with the well were sensitive to flow rate. For example, higher-than-anticipated flow rates likely contributed to failure of the coffer dam, and the likelihood of success of the Top Kill was dependent on the flow rate from the well. The amount of dispersant that should be applied by the ROVs to prevent an oil slick and release of volatile organic compounds on the surface, where they posed a health hazard to hundreds of workers involved in well intervention, was proportional to the flow rate. The planning for containment of oil at the sea surface while the relief wells were being drilled required a realistic assessment of how much oil needed to be accommodated. The rate of depletion of the reservoir, which therefore determined the final shut-in pressure when the capping stack was closed, depended on the amount of oil withdrawn. Much discussion by the government science team in Houston immediately after the well was shut in centered on whether the low shut-in pressure was the result of high depletion of the reservoir (exacerbated by a high flow rate) or the effect of a well that was leaking below the sea floor. Ultimately, the impact of the oil on the environment depends primarily on the total volume of oil released.

General Approach to Flow Estimation

Despite the need for an accurate flow estimate, the challenge of providing such information should not be underestimated. Typically for oil spills that involve ship groundings, the amount of oil spilled is exactly known because the volume of oil in the tanks is measured before the ship sails. The Deepwater Horizon incident was unprecedented in terms of the water depth at which the blowout occurred, and no methods existed for measuring multiphase flow at these pressures and temperatures. The Ixtoc I blowout of a Mexican well in 1979 in the Gulf of Mexico is the nearest analogue, but the water was only about 160 feet (50 m) deep, thus completely avoiding the very serious methane hydrate complications. The official rates of flow for the Ixtoc I well were about a factor of two less than for the Macondo well and were estimated by Petroleos Mexicanos (PEMEX), the responsible party (Jernelöv and Lindén,1981). After the well was capped, PEMEX revised the flow rate and total release downward. Given the different conditions and the absence of peer-reviewed papers describing the methodology used to constrain the estimate, it is not possible to use Ixtoc I as an example for how to approach the problem of measuring flow rate from a deep-water blowout.

Acknowledging the challenges of measuring the flow from the Macondo well, the FRTG leadership concluded that the best way to deal with the research nature of the problem was to have multiple independent teams use different methods, each with its own inherent strengths and limitations. At the time that the FRTG was established, there was no guarantee that ground truth for the flow rate would ever be established. The goal was to find convergence from multiple methodologies on a flow rate with reasonable precision. At one point, it appeared that BP might contain all of the flow on surface ships, which would have provided an excellent final measure of flow rate (at least at that one point in time), but the flow rate proved too large for the available surface containment capacity prior to closure of the capping stack. Additional capacity was not brought on line prior to shutting in the well for good. Fortunately, when the choke valve in the capping stack was

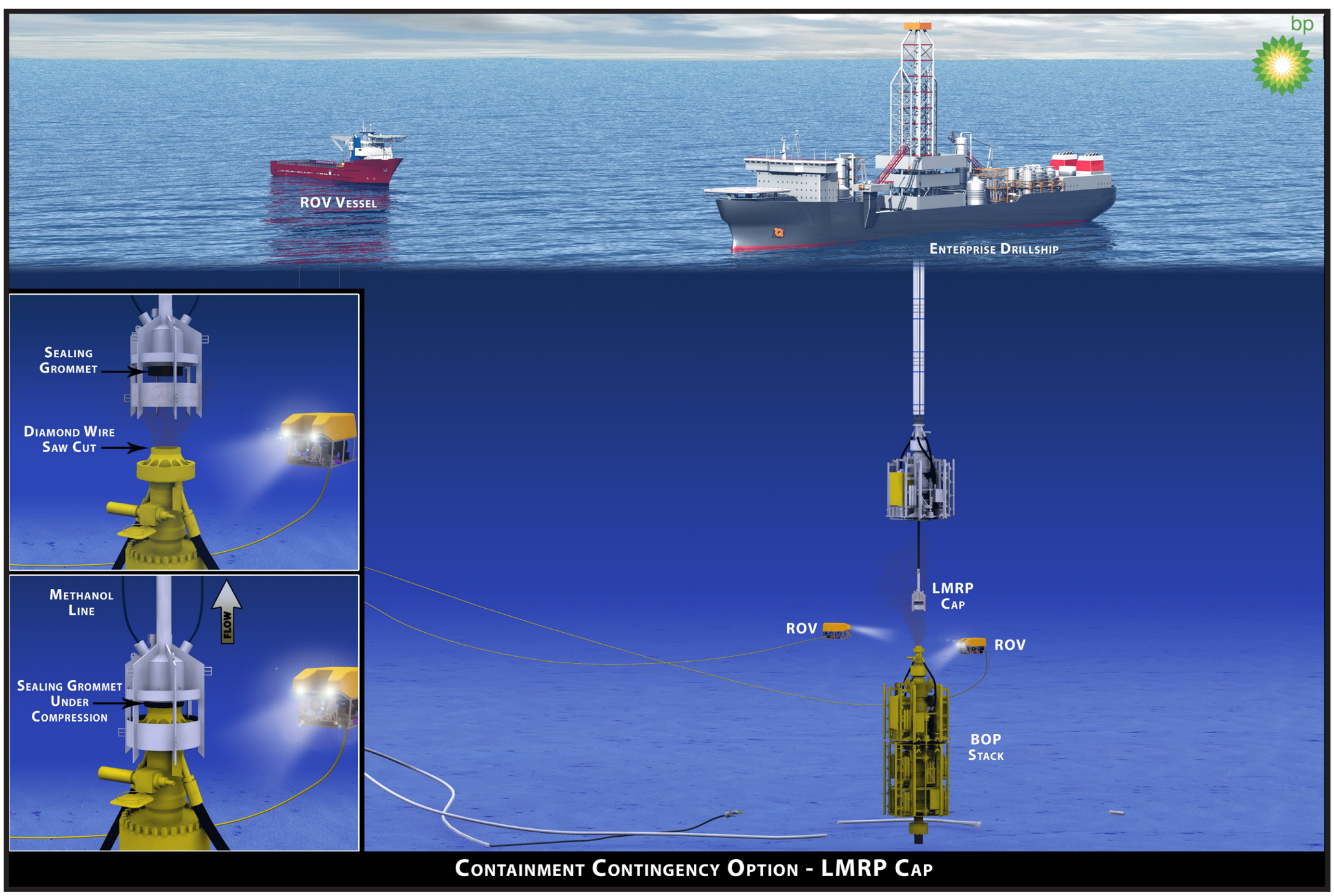

Figure 5. Diagram of LMRP Cap (a.k.a., Top Hat #4) that was used in June and early July to capture hydrocarbons being released from the Macondo well, after the damaged riser was severed immediately above the Blowout Preventer (BOP) stack. Source: BP web.

throttled back in a series of precisely controlled steps to close off the well, the pressure readings taken at the time were analyzed by three separate Department of Energy (DOE) laboratories to yield very consistent results for the flow rate of the well at the time of shut in: 53,000 BPD (Ratzel 2011). When combined with a U.S. Geological Survey (USGS) model for reservoir depletion as a function of time (Hsieh 2010; Appendix A), these post-shut-in results provided a flow rate estimate for the entire duration of the oil spill with reasonably high precision that confirmed the best of the June pre-shut in estimates. Based on this convergence of results, the Department of Interior (DOI) and DOE released, on August 2, 2010, a time-varying flow rate for the well as a function of time (Figure 6) that was estimated by the team of scientists to be accurate to ±10%. Although this figure does not represent a formal statistical error estimate, it approximately accounts for errors in the pressure readings (based on two redundant pressure gauges) and unmodeled multiphase effects. With a few discontinuities to account for changing resistance at the wellhead (i.e., removal of riser, addition of capping stack), the flow rate was estimated to have decreased from 62,000 BPD to 53,000 BPD over the 87 days of the incident, for a total release of 4.9 million barrels of oil. This includes the approximately 800,000 barrels of oil directly collected from the well that never reached the environment.

Strengths and Limitations of the Various Flow Estimation Methodologies

Below we review with the benefit of hindsight the issues with each of the methods used in the case of this particular incident. Each of the methods was reviewed in terms of the following three criteria: (1) how accurately it measured the flow rate assuming the August flow estimate as the ground truth; (2) the complexity and costs of deploying the method; and (3) the timeliness of results. Note that for any other oil spill the situation could be different depending on availability of subsurface equipment in the field, remote sensing equipment over the ocean, and geophysical/reservoir data from the various parties involved in developing the field.

Mass Balance Estimate (Labson et al. 2010; Appendix B): 13,000-22,000 BPD (Lower Bound)

The mass balance estimate took advantage of a novel NASA sensor, the Airborne Visible InfraRed Imaging Spectrometer (AVIRIS), to calculate the amount of oil on the ocean surface as of May 17, 2010. The advantage of this approach over the previous mass balance estimate of 5000 BPD is that AVIRIS measures not only the area of the ocean that is oiled, but also the thickness of the oil. The scientists then corrected the observed amount of oil by adding in the amount that was skimmed and burned plus estimates of the amount that was dispersed or evaporated up to that day after reaching the sea surface; this sum of all known oil represented an estimate of the amount that had been released to date. An average of daily flow was generated by dividing by the number of days of flow to the surface through May 17. The calculation based on mass balance is an average rate for the first 27 days of the spill, assuming that the 5 days that sea-bottom dispersants were being applied prior to May 17 did not contribute to the observable surface spill. The range in flow rates derived depended on how aggressively the scientists interpreted the sensor data in terms of oil in each pixel of ocean surface imaged. However, there is likely additional uncertainty in the estimates arising from the modeled effects such as evaporation and dispersion at the sea surface, and dissolution and dispersion within the subsea.

The mass balance method has the following strengths and limitations.

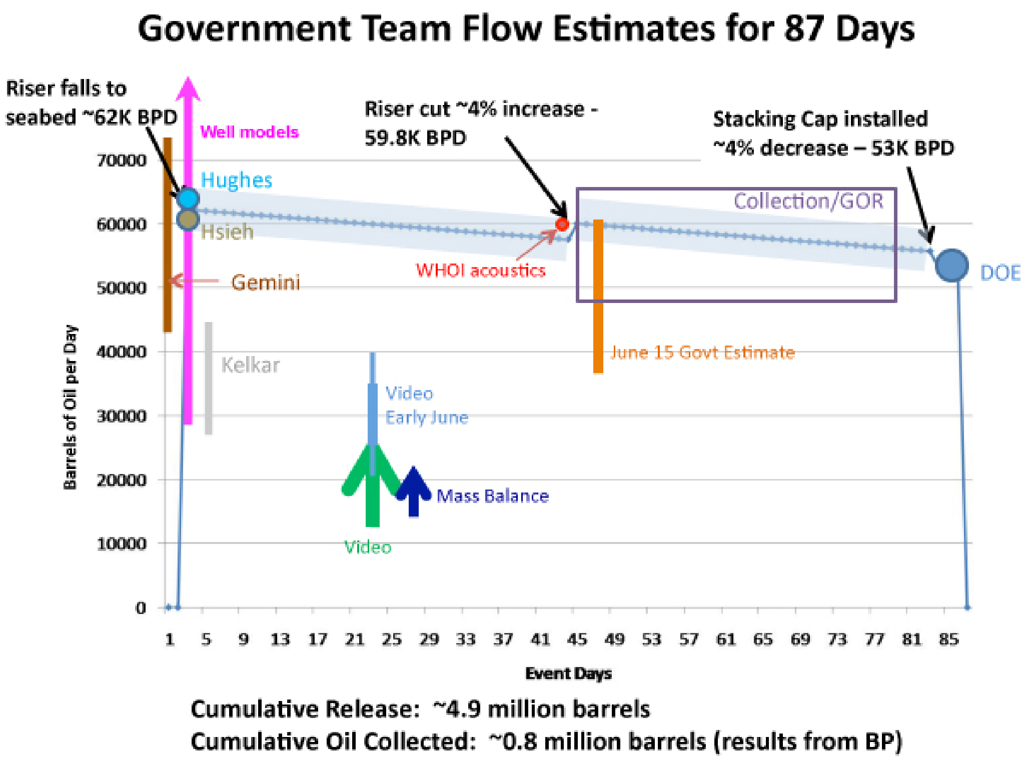

Figure 6. Summary of flow rate estimates. The continuous curve represents the best estimate of the evolution in flow rate throughout the oil spill incident (announced on August 2, 2010), obtained by extrapolating the 53,000 BPD estimate from Department of Energy at the time that the capping stack was closed (Ratzel 2011) back to the beginning of the incident using the reservoir depletion model of Hsieh (2010; Appendix A). In this extrapolation, a flow rate increase of 4% was estimated to have occurred when the riser was severed and a decrease of 4% when the capping stack was installed. The stippled band represents a +/- 10% uncertainty in the flow rate model. Compared to this August estimate are earlier estimates made as the incident was ongoing and discussed in the text, plotted as a function of the day that the data for that flow rate were collected. Flow rates were typically reported at later dates. The estimates from mass balance (dark blue) and video (green) were reported first, shown as arrows because both were lower bounds. The light blue bar indicates the later, improved video estimate before the riser was cut. The red circle is the pre-riser-cut flow rate from the Woods Hole Oceanographic Institute acoustics method. The orange bar is the government flow rate estimate, released on June 15, for the period immediately after the riser was cut (June 3), based on all available information at the time (video plus acoustic). Flow estimates made available after shut in were as follows: from reservoir modeling by Gemini, Kelkar and Hughes teams and by Hsieh (shown by the indicated symbols), well modeling (lavender arrow off chart to 118 BPD), trends in gas-oil ratio in surface collection (purple box to show range in dates of collection and values).

Strengths

- Measures oil likely to impact shorelines/wildlife because it focuses on oil on the ocean surface;
- Requires no subsea assets;
- Independent of oil/gas ratio;
- Assesses oil thickness as well as area to get true volume indication.

Limitations

- Misses an unknown amount of oil remaining in or returned to the subsurface;
- Would underestimate relatively large quantities of oil that may accumulate in tar balls;
- Requires a very specialized sensor deployed from an expensive platform (aircraft);
- Needs low sea state to obtain a reliable measurement;
- For large spills, cannot in one day get the synoptic view, so must interpolate assuming area imaged is representative.

The first limitation was considered by the mass balance team to be an important one: they missed a significant fraction of oil that either never made it to the surface from the mile-deep wellhead or was dispersed from the surface and sank. For that reason, the 13,000 to 22,000 BPD flow estimates were considered minimum or lower bound values.

Acoustics Analysis (Camilli 2010; Appendix C): 60,000 BPD

The U.S. Coast Guard (USCG) supported the work of researchers from the Woods Hole Oceanographic Institution (WHOI) to generate a flow rate estimate by deploying a 1.8 MHz multi-beam imaging sonar and a 1.2 MHz Acoustic Doppler Current Profiler (ADCP) from a work-class ROV. The field data were acquired on a “not to interfere” basis by placing oceanographic research equipment on ROVs that were under contract to BP to conduct well intervention and oil containment efforts.

On May 31, 2010, the WHOI team obtained their estimates of plume flow rates, using the imaging sonar to determine the cross sectional area of the plumes at the end of the riser and at the kink (Figure 2) and the ADCP to measure the velocity of the flow field. The flow velocity and area estimates were then multiplied to produce an ensemble estimate of the total volumetric flow rate (oil plus gas) of 0.25 m^3/s. The acoustics group did not give a formal uncertainty on its estimate because the natural variability of the turbulent jets exceeded the statistical uncertainty of instantaneous velocity and cross section measurements.

On June 21, 2010, the WHOI team returned to the field with a pressure-qualified sample bottle and gathered 100 mL of uncontaminated discharge of hydrocarbons inside Top Hat #4 as they exited the well. This sample allowed the best estimate of the volumetric oil fraction at ambient seafloor conditions (150 atm and 4.4 ° C): 42.8% liquid petroleum hydrocarbons (pentane and higher), 57.2% gas (natural gas, condensates, and non-hydrocarbon gases) (Chris Reddy, WHOI, pers. comm.).

Based on WHOI’s early results, an oil flow rate was initially estimated to be 59,000 BPD (described in Richard Camilli’s September 27, 2010, testimony to the National Commission and in Appendix C). This flow rate estimate has since been updated to explicitly account for turbulent jet source and expansion characteristics, improved measurement of the inside diameter of the riser after it was recovered from the seafloor, and to account for natural gas, hydrocarbon condensates, and non-hydrocarbon gas contributions to the bulk flow, as detailed in the previous paragraph. As a result, since Appendix C was prepared, the liquid petroleum hydrocarbon (pentane and higher hydrocarbons) flow rate has been revised upward to 60,000 BPD for May 31, 2010.

The acoustic analysis method has the following strengths and limitations.

Strengths

- Measurement is taken near the wellhead before the plume is dispersed and so captures the full flow;
- Allows for a full 3-D image of the plume velocity field;
- Measurement can be repeated for different periods to get time variation;
- Independent sensors measure both plume cross-section and velocity.

Limitations

- Requires specialized oceanographic equipment that is uncommon for work-class ROVs;
- Requires access to the deep sea;
- Depends on knowing the oil/gas ratio (which must be measured or estimated).

The certification requirement which required extra time and effort for deploying the specialized fluid sampling gear from the contractor's ROV could have been alleviated had it been possible to bring in an additional research-class ROV and oceanographic support vessel. However, in this particular instance, the workspace above the wellhead was so congested with ships supporting the well control and oil containment efforts throughout the duration of the incident that bringing in additional vessels dedicated to the problem of measuring flow rate was not a priority. All data gathering had to be accomplished on a "not to interfere" basis given the importance everyone, from the public to the highest officials, placed on stopping oil from flowing into the Gulf of Mexico.

Video PIV Analysis (Plume Calculation Team 2010; Appendix D): 25,000 to 30,000 BPD (pre-riser cut), 35,00 to 50,000 BPD (post-riser cut)

A relatively large group of scientists examined underwater video of the oil plumes and estimated flow rates. Three of the teams used a fluid dynamic technique called Particle Image Velocimetry (PIV), while other individuals used video analysis methods that tended to produce higher flow rates than the PIV results. The video data examined were either opportunistic from work-class ROVs working in and around the incident site or specifically commissioned by the video team to be collected by an ROV for flow-rate analysis. In the PIV method a flow event (e.g., an eddy or other identifiable feature) is observed in two consecutive video frames. Distance moved per time between frames gives a velocity, after adjustment for viewing angle and other factors. This process is repeated at multiple interrogation points and on different scale flow features to characterize the plume velocity field. These velocities correspond to fluid velocities at the surface of the plume and were acquired close to the point of exit to minimize buoyancy effects. The conversion of surface velocity of the flow to mean velocity within the plume is then based on a model. For the measurements at the open end of the sheared riser (Figure 2, right hand side) or at the top of the LMRP after the riser was cut off, surface velocities were used to estimate centerline velocities at the exit, which were then multiplied by a scaling factor and the plume cross-sectional area to get volumetric fluxes. For flow at the kink in the riser, a velocity profile based on the development of a round turbulent jet was used to correlate these surface velocities with volumetric fluxes.

The PIV analysis yields only an estimate of total volumetric flow of hydrocarbons. As with the acoustics analyses discussed above, some assumption must be made about the gas-to-oil ratio in order to estimate the fraction of liquid oil relative to all of the hydrocarbons released from the well. Early on, in the absence of independent information, the scientists used BP's pre-accident estimate that 29% by volume of the reservoir fluid was liquid oil at seafloor conditions (based on early samples). There was some indication based on the color of the discharge that the riser was acting as a gas/oil separator, such that the gas-to-oil ratio in the plumes varied widely both in time and space. Later on, when the collection system associated with Top Hat #4 started to provide consistent data about the oil and gas collection at the surface, a liquid oil fraction of 41% was used to convert the measurements of total volumetric flow rate at the wellhead to equivalent stock tank barrels at the surface.

Initially, the team analyzed May 17 video from both the end of the riser where the majority of the flow was escaping (prior to insertion of the RITT) and from the kink in the riser where a smaller amount exited through narrow slits where the riser bent over the top of the LMRP. This analysis was more complicated on account of the multiple exit points and resulted in flow rate estimates of 20,000 to 40,000 BPD with a best estimate of 25,000 to 30,000 BPD. Later analysis was based on video taken from the single flow point immediately after the riser was cut just above the LMRP on June 3 and yielded best-estimate flow rates between 35,000 and 45,000 BPD from PIV analysis, but possibly as high as 50,000 BPD based on other methods.

This video analysis method has the following strengths and limitations.

Strengths

- Video data are relatively easily acquired from any number of manned or unmanned deep sea systems;
- PIV is a common technique that is widespread with many practitioners who can provide peer review;
- The measurement is taken right at the wellhead before the fluid dissipates and so captures the full flow;
- Observations can be readily repeated at multiple periods to get time variation of flow.

Limitations

- Dependent on assumed oil-to-gas ratio;
- More successful with high-quality, clear video data from a stationary viewing platform, which can be challenging to obtain;
- Dependent on assumed relation of flow on surface of plume to flow within plume interior;
- Requires access to the deep sea.

Reservoir and Well Modeling

Two groups were involved in reservoir and well modeling exercises, one concentrating on modeling the evolution of the producing reservoir at 18,000 feet (5500 m) below sea surface and the other on the various possible flow paths up through the well. Unlike the previous approaches, neither of these teams required access to the field or new data acquisition. However, both required access to industry proprietary data in order to constrain model parameters (for example, fluid and reservoir properties). The two model approaches can be considered in some sense complementary, in that results from the reservoir model can be expressed as a bottom-hole pressure that would then be input to the well model, to simulate flow up through the well to the sea. In fact, the original intent was for the two teams to work together. However, the time needed to get contracts and non-disclosure agreements in place for the reservoir modeling groups delayed the initiation of the research. This meant that each group was required to make some simplifying assumptions concerning the other part of the model in order to meet required deadlines. Hence, the reservoir modeling group considered some simplified well flow paths (i.e., hydrocarbons traveling up the annulus around the production tubing or within the production tubing itself), and the well modeling group considered bottom-hole pressures as a function of flow rate derived from simplified reservoir models. Even though modeling activities were expedited to the greatest degree possible, because of the complexity of the task, the results were not delivered until after the June flow rate estimate was announced.

Reservoir Modeling (Reservoir Modeling Team 2010; Appendix E) : 27,000 to 102,000 BPD

Three independent groups of researchers in the field of reservoir simulation calculated the rate at which oil and gas can be produced from the sands penetrated by BP's Macondo well. The reservoir geometry was prescribed by maps generated from 3-D seismic data interpreted by Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEMRE) geophysicists. The models were constrained using Macondo reservoir rock and fluid properties derived from open-hole logs; pressure transient tests; pressure, volume, and temperature measurements; core samples; and reservoir data from an analogous well drilled 20 miles (32 km) away. The researchers populated computer models and determined flow rates from the targeted sands in the well as a function of bottom-hole pressure. This provided an estimate of the rate at which oil could theoretically flow into the well. Permeability assumptions significantly impacted the results. In addition, the particular flow path through the well was as important as any reservoir parameter in determining the final flow rate. On account of time constraints, the modelers concentrated on two scenarios: the maximum flow (worst case) conditions and the most likely flow scenario. The Hughes team (Louisiana State University) estimated most likely peak flows of 63,000 to 66,000 BPD after a 10-day ramp up period following the blowout, with worst case assumptions about reservoir structure (aside from permeability) increasing flow rates by only 1400 BPD. The Kelkar team (University of Tulsa) had systematically lower peak flow rates (which in its model occurred in the first day after the blowout): 27,000 to 32,000 and 37,000 to 45,000 BPD for the most likely and maximum scenarios, respectively, with the range in each scenario dependent on the flow path through the well (tubing versus annulus), size of the restriction in the BOP choke, and pipe roughness. Gemini Solutions Group, an industry team, produced the most simulations. The most likely (base case) scenario predicted an initial flow rate of 58,000 BPD. The range of initial flow rates for the majority of its simulations was 41,000 to 73,000 BPD, depending primarily on the well flow path and to a lesser extent on reservoir permeability. For these models, the time history also predicted that after 87 days of flow, the rate would drop from about 60,000 BPD to about 50,000 BPD, in agreement with trends predicted by Hsieh (2010). Gemini also produced a worst case scenario of initial flow ~102,000 BPD in the case of tubing plus annular flow.

Well Modeling (Guthrie et al. 2010; Appendix F): 30,000 to 118,000 BPD

Five DOE National Labs used different but comparable methodologies to estimate hydrocarbon flow from the reservoir through the well to the surface; the National Institute of Standards and Technology (NIST) then performed a statistical synthesis of these results. This Nodal modeling is based on pressure drops from the reservoir to the ocean floor that result from restrictions to flow through the well-BOP-riser system. The team used input from various reservoir models (including pressure, temperature, fluid composition and properties over time) and pressure and temperature conditions at the exit points on the seafloor, along with details of the geometries of the well, BOP, and riser (when applicable) to calculate fluid compositions, properties, and fluxes from each exit point. This provided an estimated range of possible flows, based on differing scenarios of how the fluid was flowing through the well. The flow into the base of the system was prescribed as bottom-hole pressure.

Many of the lab teams considered a number of different time periods for the flow as different resistance was present at the wellhead. All teams considered the flow conditions that existed after cutting of the riser but prior to emplacement of the Top Hat, which is considered the base case. Three flow scenarios were modeled (Figure 7; also Appendix F):

1. flow in the annulus surrounding the 9-7/8" x 7" production casing, exiting the well predominately through the BOP;
2. flow inside the production casing, exiting the well through the BOP and drill pipe;
3. flow initiating in the annulus surrounding the production casing that breaches into the production casing higher up the well, exiting the well through the BOP and drill pipe.

The modelers consistently found that flow paths 1 and 3 produced the lowest (and similar) flow rates, while flow path 2 produced the highest rates. Models for the base case considering flow paths 1 and 3 ranged from 30,000 to 64,000 BPD, while for flow path 2 base case rates had a larger spread among the various teams: 44,000 to 118,000 BPD.

The most significant factor impacting the model results was the bottom-hole pressure (i.e., flow into the bottom of the well), although choice of flow paths 1 and 3 versus flow path 2 had a very big effect as well. The model results from the various teams for the base case clustered into two probability distributions such that the choice was bimodal: with a best estimate for flow rate either around 84,000 BPD for flow path 2 or around 50,000 BPD for flow paths 1 and 3. Without additional information on the flow path, it would have been difficult to choose between these two rates.

The overall reservoir/well modeling effort had the following strengths and limitations.

Strengths

- Required no new field experiments or data collection;
- Owing to widespread expertise in these disciplines and accepted analysis techniques, could involve numerous academic, government, and commercial experts for internal consistency checks and model validation;
- Can ask "what if" questions about well interventions going forward in time to predict impact on flow;
- Can model entire history of reservoir/well/resistance to predict time variation of flow.

Limitations

- Strongly dependent on access to industry proprietary data, especially reservoir/fluid properties and details on wellbore construction;
- Many unknowns (dominant well flow path, wellhead restrictions, extent of formation damage) with no way to constrain them;
- Hard to choose among equally plausible model outcomes.

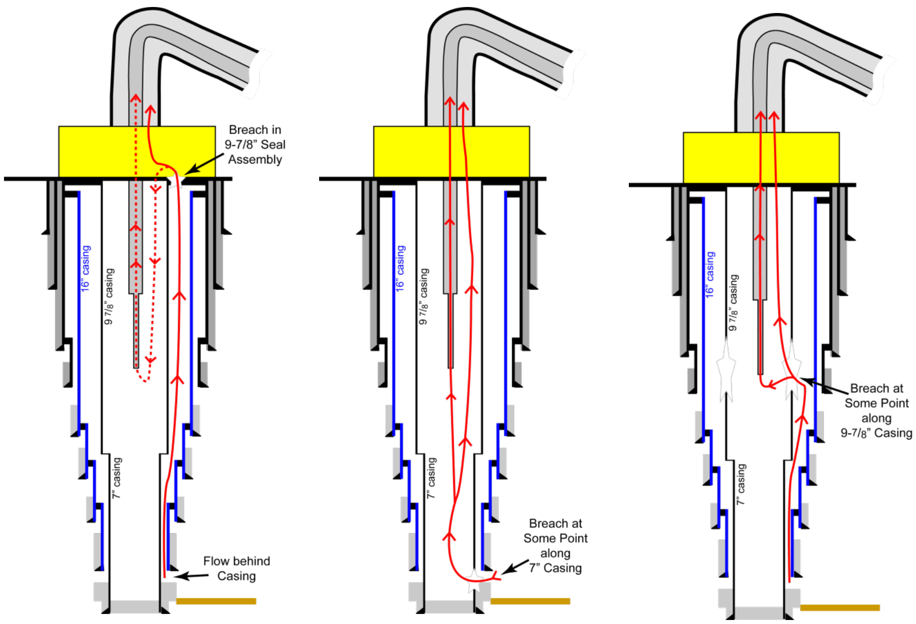

Figure 7. Schematic diagram of possible well flows modeled by the Nodal Analysis team. Scenario 1 (left): Flow initiates in the annular space between liner and casing, flowing through a breach at the top (in the seal assembly) into Blowout Preventer (BOP) and then riser; depending on flow restrictions in BOP, some flow may re-enter the casing to flow down to enter the drill pipe. Scenario 2 (middle): Flow initiates in a breach of the 7" casing, flowing up the casing. Some flow enters drill pipe, some continues up the casing to BOP. Scenario 3 (right): Flow initiates in the annular space between liner and casing, entering a breach in 9-7/8" casing and continuing to flow upward inside the casing. Some flow enters drill pipe, some continues up the casing to BOP. From Guthrie et al. 2010 (Appendix F).

Convergence of Gas-Oil Ratio (GOR) from Surface Collection to Deep-Sea Value: 48,000 to 66,000 BPD

After the riser was severed from the top of the LMRP, BP was able to collect hydrocarbons through Top Hat #4 and a riser system to the *Discoverer Enterprise* recovery vessel at the ocean surface where gas and oil were separated and their volumes measured. Surface collection was later increased via the BOP choke and kill lines to the *Q4000* and *Helix Producer 1* (*HP1*), respectively. Comparing the gas-oil ratio (GOR) of the hydrocarbons collected on surface ships to the GOR value from a seafloor sample provided an additional technique to estimate oil flow rate.

Statistical analysis of the GOR values as recorded on the sea surface during the recovery period strongly supports the hypothesis that most of the scatter in the GOR observations is a result of the hydrocarbon recovery process, rather than a reflection of inherent variability in the GOR of the fluids escaping from the well. As a particularly clear example, on June 24, 2010, the GOR for fluids recovered from the BOP choke line to the *Q4000* recovery vessel underwent an abrupt increase. *Q4000* daily GOR values from the time periods before and after this date (1814 ±71 and 2380 ±59, respectively) indicate statistically different means and distributions with a greater than 99% level of confidence. In contrast, hydrocarbons captured simultaneously by the Top Hat #4 to the *Discoverer Enterprise* recovery vessel, from the same well through the same riser, do not exhibit a statistically significant change in daily GOR values. Therefore, we assume that the apparent temporal variability in daily GORs collected by these surface vessels is attributable to the collection, separation, and metering processes, not actual variability in end member GOR.

Although the recorded daily GOR data from the *Discoverer Enterprise* and *Q4000* are variable, both indicate a decreasing GOR (i.e., the overall yield at the surface became more oily) as a greater percentage of the total hydrocarbon flow was produced to the surface. There is no trend in daily GOR data for the *HP1* surface vessel because BP assumed a static GOR of 2380 based on *Q4000* data, apparently the average from the time period exclusively after June 24, 2010 (post-GOR shift). *Q4000* trends for the two time periods (pre and post-GOR shift) indicate slope trends similar to the *Discoverer Enterprise* data but with differing offsets. The explanation for this trending behavior is that the collection devices were linked to the well in an open configuration with the BOP choke line and LMRP Top Hat #4 riser acting as gas/oil separators, causing the lighter gas component to be preferentially favored at lower production rates. The recorded daily GOR trends suggest that if the entire flow were captured, the GOR recorded by the surface vessels would match the true GOR of the well.

The availability of the in situ hydrocarbon sample obtained by the WHOI team on June 21, 2010, not only provided a direct measurement of the well fluid's oil volume fraction at seafloor conditions but when combined with surface collection data also allowed for an independent estimate of flow rate. Figure 8 shows the *Discoverer Enterprise* daily GOR (recovered from Top Hat #4) plotted as a function of oil produced, as reported by BP from June 5 through July 11, 2010. The horizontal line at a GOR of 1600 is the surface GOR equivalent of the IGT-8 sample taken by WHOI on June 21, which was also obtained from within the Top Hat #4 at the LMRP. This in situ sample was collected at the point of exit at the wellhead and thus indeed represents the true GOR of the well. If we assume that the daily GOR data acquired at the surface would trend linearly to the actual GOR (IGT-8 end member), then the intercept should indicate the total oil flow rate. The intercept of this best-fitting linear trend with the actual GOR indicates that had BP been able to

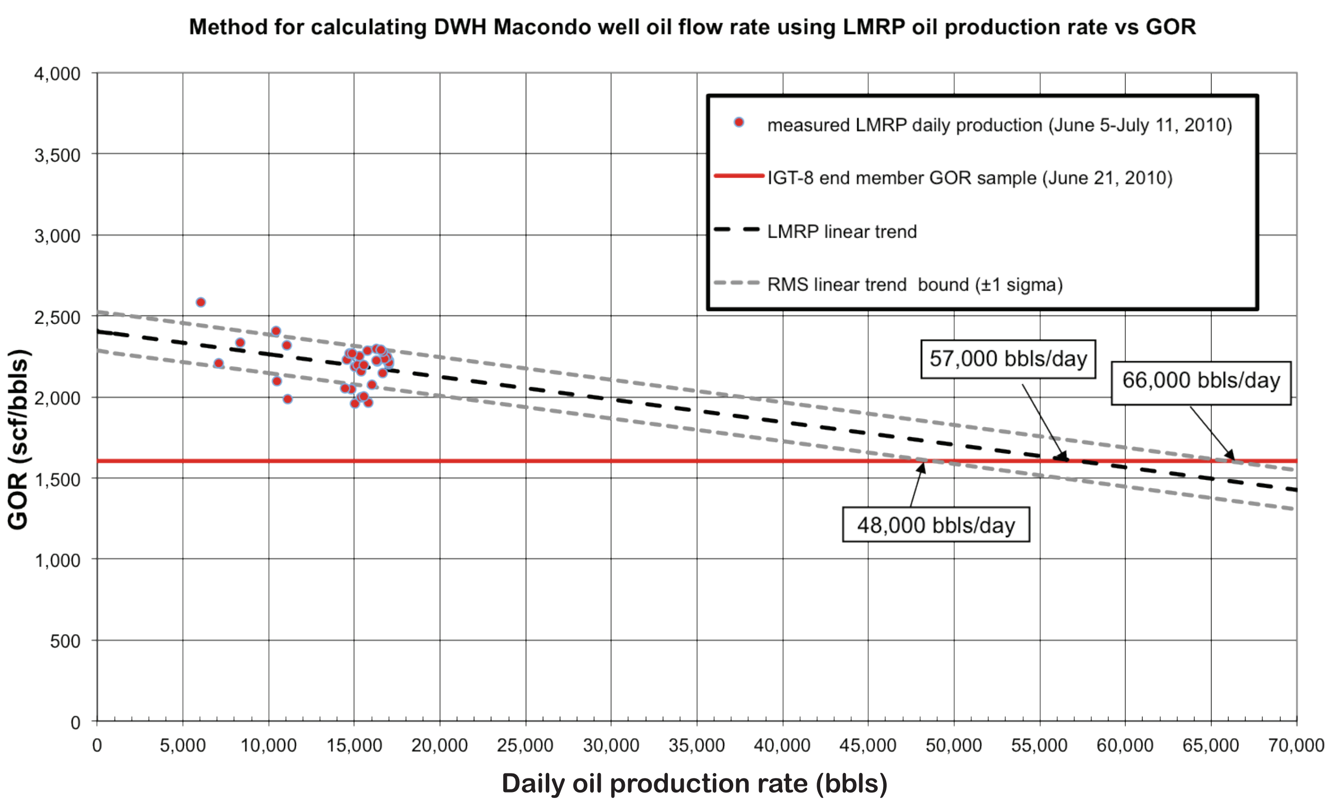

Figure 8. The daily gas-oil ratio (GOR) at the ocean surface as reported by BP, plotted as a function of oil produced. The general trend indicates that the GOR drops as a greater percentage of the total flow is produced to the surface but with considerable scatter. If the entire flow were captured, the GOR would match the true GOR of the well. The horizontal line at a GOR of 1600 is equivalent to the surface GOR of the IGT-8 sample taken by Woods Hole Oceanographic Institute on June 21, which was obtained at the point of exit at the wellhead, and is taken to represent the true GOR of the Macondo reservoir fluids escaping from the well. Assuming that GOR samples acquired at the surface would trend linearly to the actual GOR (IGT-8 end member), then the intercept should indicate the total oil flow rate on June 21. The best-fitting linear trend to the GOR data as a function of surface oil yield indicates that had BP been able to capture the total flow at a GOR of 1600, the oil captured would have been 57,000 BPD on June 21. The one-standard-deviation uncertainty on the best-fitting line to the GOR data allow the flow rate at the GOR of 1600 to lie between 48,000 and 66,000 BPD.

capture the total hydrocarbon flow from the well, the oil capture rate would have averaged 57,000 BPD for the period from June 5 through July 11, 2010. The one-standard-deviation uncertainty (calculated as the root mean square deviation from the best-fitting line to the GOR data) allows the average flow rate to lie between 48,000 and 66,000 BPD.

The GOR/collection method for estimating flow rate has the following strengths and limitations.

Strengths

- Does not require imaging of plume;
- Makes very few assumptions (i.e., linear approach to true GOR);
- Relatively independent estimate of flow rate that can be used to check other methods.

Limitations

- Unlikely to produce an early estimate of flow rate due to complex sample collection effort;
- Difficult to resolve temporal variations in flow rate;
- Requires access to deep-sea in situ hydrocarbon sample.

Discussion

Figure 6 compares the best estimates of the various methods used by the FRTG against the post-shut-in estimate released on August 2, 2010. Note that most of the methods used by the FRTG did a credible job of predicting the flow rate from the well, although some clearly with less uncertainty than others. Any of the methods were adequate to determine that the true flow was many times greater than the 1000 BPD or 5000 BPD early estimates, concern over which had led to the formation of the FRTG and the initiation of other flow studies.

The acoustic method acquired the most comprehensive data set (plume size, velocity profiles, and oil fraction) under the most challenging flow geometry (riser flow plus kink flow) and resulted in an excellent match to the August estimate. The video (PIV) approach was easier to execute and reported more timely results. It provided reasonable agreement with the August estimate, especially when the flow geometry was simple (post riser cut). The PIV method, however, tended to produce flow rate estimates that were 20–50% lower than flow rates obtained by other methods observing the flow during the same time period.

The FRTG would have concluded on the basis of the reservoir and well modeling results alone that the best estimate for flow rate of the Macondo well was in the range of 50,000 BPD rather than 5000 BPD, albeit with larger uncertainty than the deep-sea methods. For situations in which direct access to the flowing well might be precluded for data gathering for whatever reason, such modeling would indeed be a useful exercise. Furthermore, reservoir and well modeling provides the capability to run “what if” scenarios into the future to answer questions such as:

- How quickly will the flow rate ramp down as the reservoir depletes itself?
- What happens to the flow rate if the riser is removed?
- If production is begun in a relief well, how much will that reduce the flow in the well?
- How would leakage below the seafloor (i.e., loss of well integrity) be manifest in wellhead pressure?

Therefore, reservoir and well modeling is an excellent adjunct to field programs and well remediation even if it is not needed as the only source of flow rate information.

The great utility of pressure readings from the capping stack during well shut in for refining models of reservoir behavior (Hsieh 2010; Appendix A) suggests that the task of the reservoir and well modeling groups would have benefitted from the availability of reliable pressure measurements during the period of oil discharge. During the majority of the oil spill, the only pressure reading came from one highly erratic pressure gage at the base of the BOP, designed to be accurate only to ±400 psi. In contrast, the capping stack installed on July 12 had two redundant pressure gages providing much more accurate information.

It is perhaps not surprising that the flow rate derived from mass balance, which used as its input oil on the ocean surface, was significantly lower than the rate determined by the other methods. Soon after the mass-balance flow rate was released, oceanographers discovered plumes of oil underwater that never reached the surface. Certain crude components (e.g., benzene, toluene, ethylbenzene, and xylenes and other less hydrophobic aromatics) will dissolve into the water column and not contribute to surface expression. The physics and chemistry of oil dispersion and dissolution, particularly when the release is a mile beneath the ocean surface, are poorly known. Furthermore, in a highly dynamic canyon setting, oil can be entrained in sediments and over time can concentrate in tar balls and thus become virtually invisible to airborne and satellite remote sensing. Improving the understanding of behavior of oil underwater should clearly be a high priority for future oil spills. The mass balance method was far better suited for helping response coordinators assess the location and amount of oil likely to impact shorelines and wildlife than for estimating flow rate.

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Appendices

Appendix A – Hsieh 2010; Reservoir Depletion Report

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Appendix B – Labson et al. 2010; Mass Balance Team Report

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Appendix C – Camilli 2010; Woods Hole Oceanographic Institution Acoustics Analysis Report

Camilli, R. 2010. Final Oil Spill Flow Rate Report and Characterization Analysis, Deepwater Horizon Well, Mississippi Canyon Block 252. Woods Hole Oceanographic Institution report to the U.S. Coast Guard. August 10, 2010.

Appendix D – Plume Calculation Team 2010; Particle Image Velocimetry Report

Plume Calculation Team. 2010. Deepwater Horizon Release, Estimate of Rate by PIV. Plume Team report to the Flow Rate Technical Group. July 21, 2010.

Note: Due to the length of the full Plume Calculation Team report, this appendix includes only the summary section. The full report can be downloaded at: http://www.usgs.gov/oilspill/ and http://www.doi.gov/deepwaterhorizon/index.cfm

Appendix E - Reservoir Modeling Team 2010; Reservoir Modeling Report

Reservoir Modeling Team. 2010. Flow Rate Technical Group Reservoir Modeling Team Summary Report. August 11, 2010.

Note: This report was not previously released as a separate document.

Appendix F – Guthrie et al. 2010; Nodal Analysis Team Report

Guthrie, G., R. Pawar, C. Oldenburg, T. Weisgraber, G. Bromhal, and P. Gauglitz. 2010. Nodal Analysis Estimates of Fluid Flow from the BP Macondo MC252 Well. Nodal Team report to the Flow Rate Technical Group.

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National Incident Command, Interagency Solutions Group, Flow Rate Technical Group—**Assessment of Flow Rate Estimates for the Deepwater Horizon / Macondo Well Oil Spill**—March 10, 2011