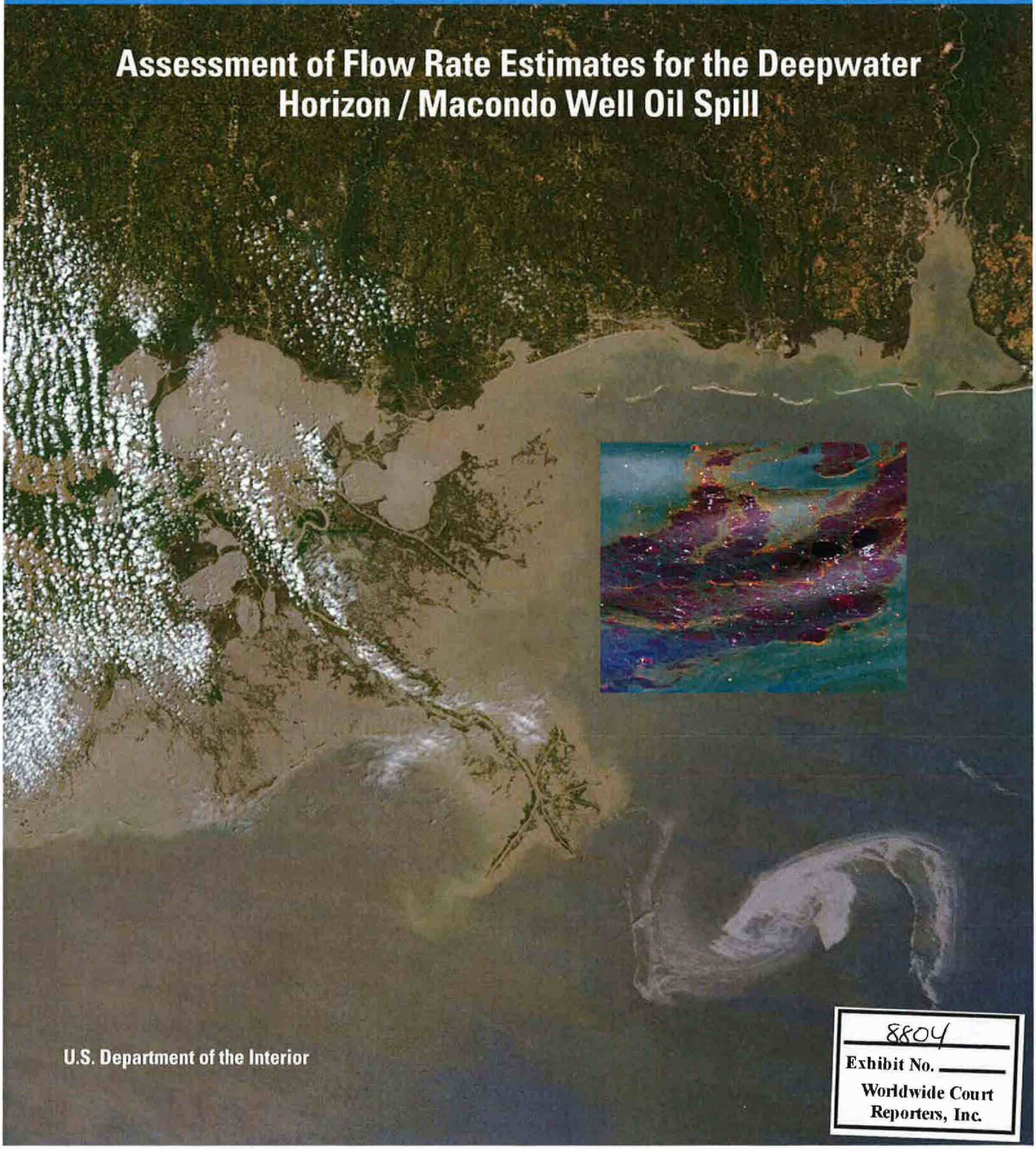
National Incident Command, Interagency Solutions Group, Flow Rate Technical Group

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



U.S. Department of the Interior

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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).

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

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

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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.

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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.

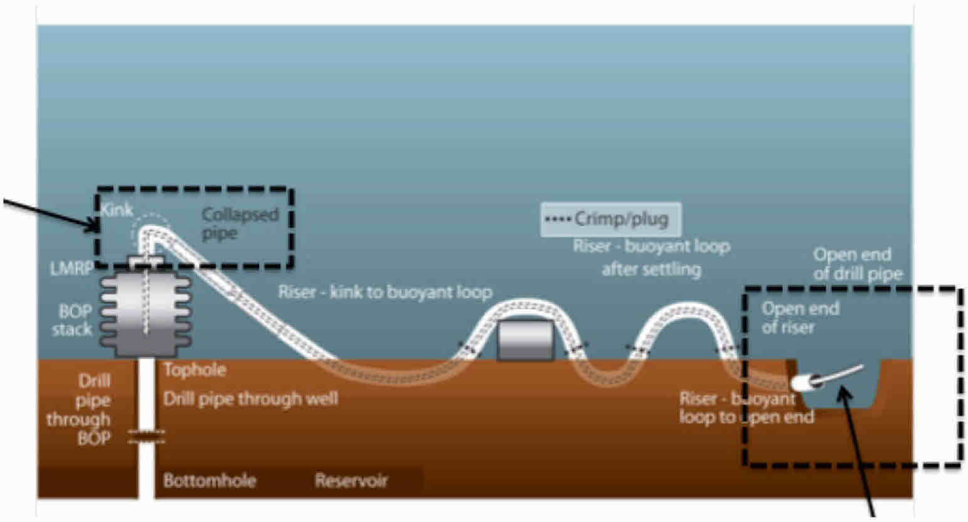

Figure 2. Diagram of damaged riser at the Macondo well spill site. Most hydrocarbon release occurred in the areas highlighted by black rectangles, emanating from the kink immediately above the Blowout Preventer (BOP) stack and the open end of the riser/drill pipe. LMRP refers to the Lower Marine Riser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

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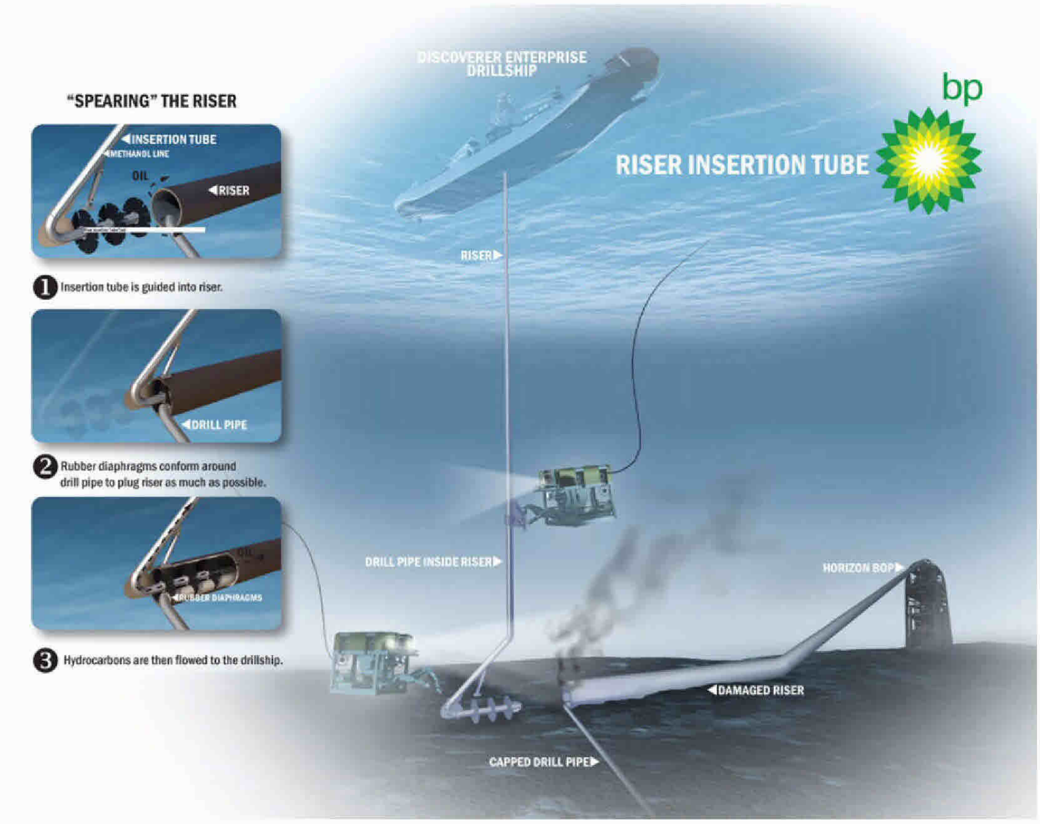

Figure 3. Diagram of Riser Insertion Tube Tool (RITT) that was used in mid-May to capture hydrocarbons being released from the open end of the damaged riser at the Macondo well spill site. Source: BP web.

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

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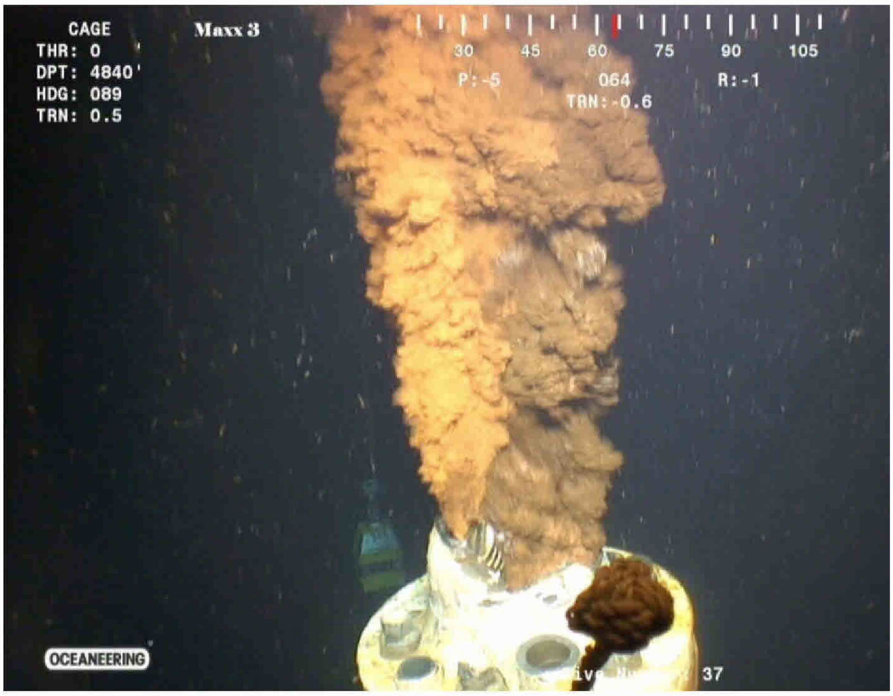

Figure 4. Hydrocarbons (oil and natural gas) escaping from the end of the riser tube, after it was severed on June 3 immediately above the Macondo well Blowout Preventer (BOP) stack. Source: BP video from Remotely Operated Vehicles (ROVs).

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

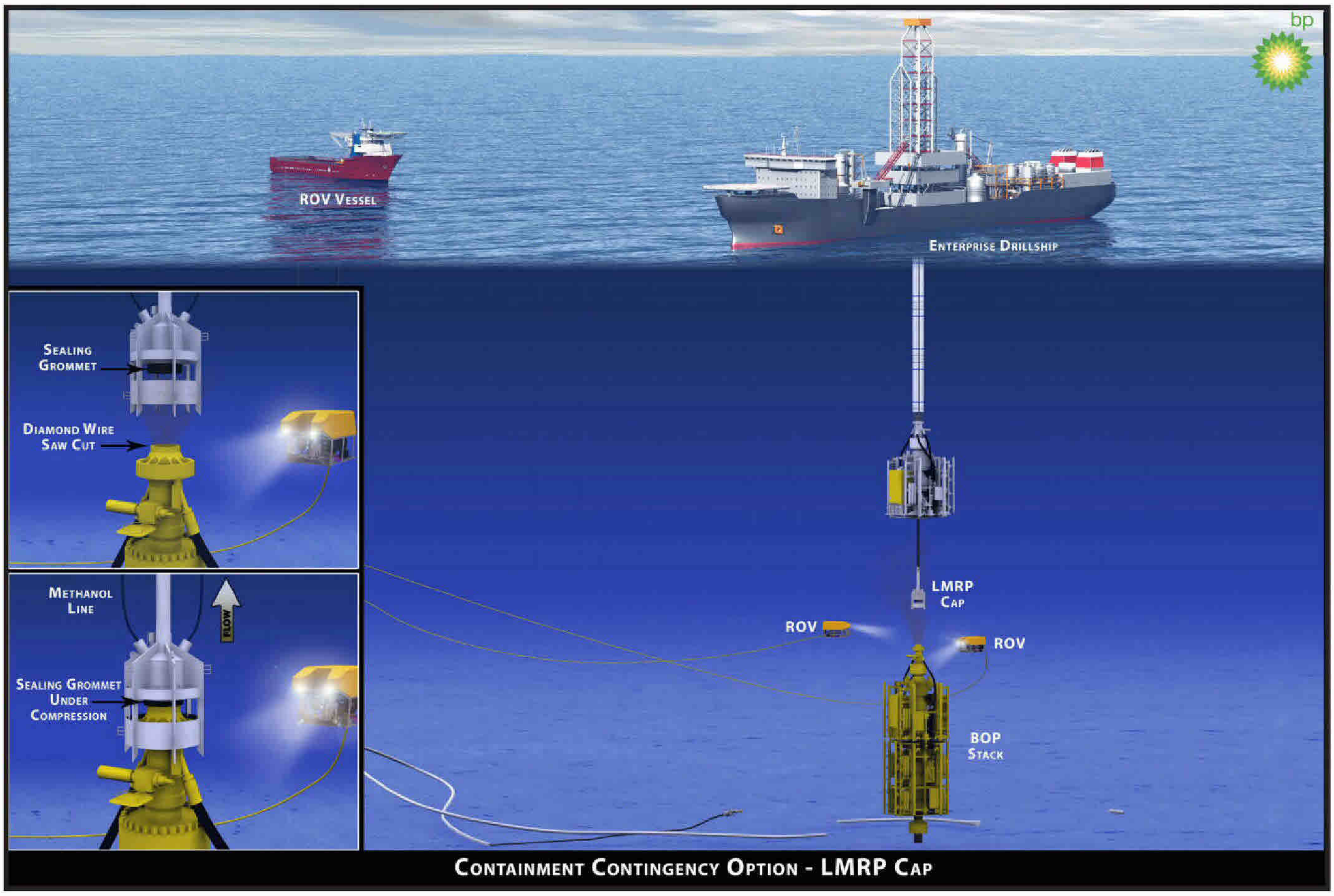

Figure 5. Diagram of LMRP Cap (a.k.a., Top Hat #4) that was used in June and early July to capture hydrocarbons being released from the Macondo well, after the damaged riser was severed immediately above the Blowout Preventer (BOP) stack. Source: BP web.

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.

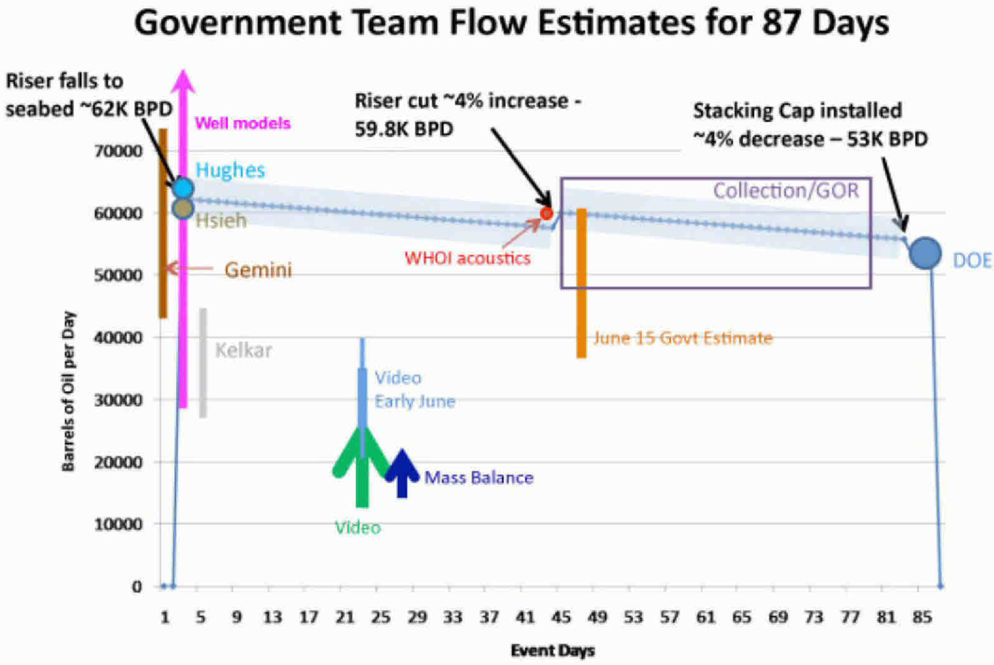

Figure 6. Summary of flow rate estimates. The continuous curve represents the best estimate of the evolution in flow rate throughout the oil spill incident (announced on August 2, 2010), obtained by extrapolating the 53,000 BPD estimate from Department of Energy at the time that the capping stack was 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.

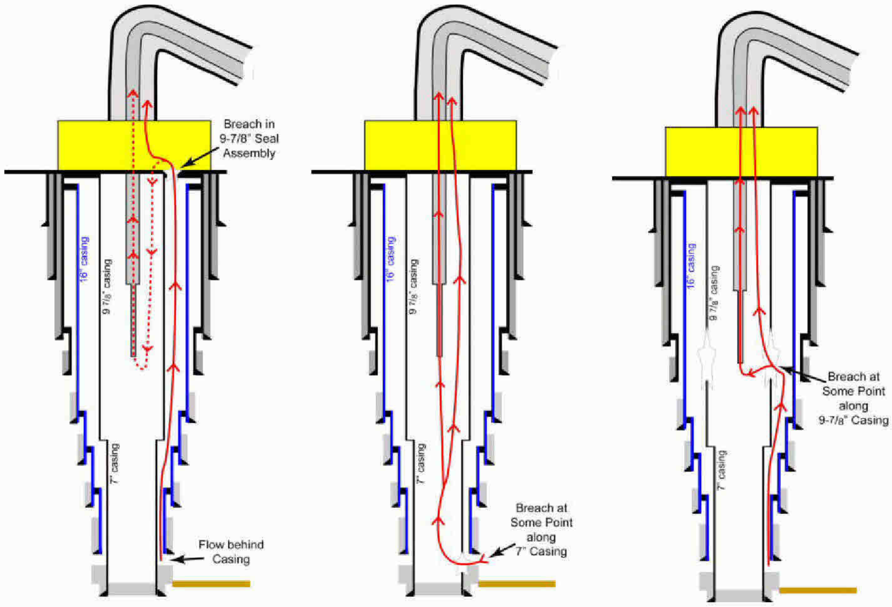

Figure 7. Schematic diagram of possible well flows modeled by the Nodal Analysis team. Scenario 1 (left): Flow initiates in the annular space between liner and casing, flowing through a breach at the top (in the seal assembly) into Blowout Preventer (BOP) and then riser; depending on flow restrictions 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

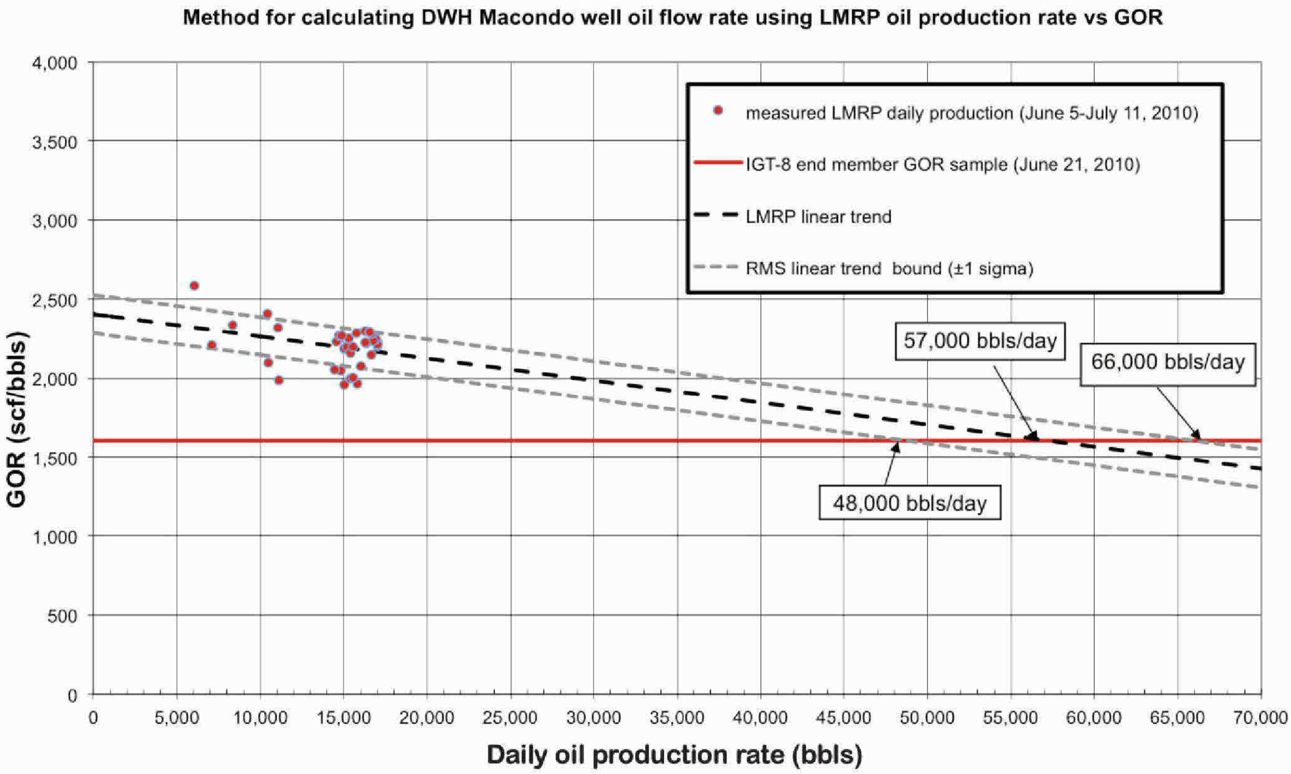

Figure 8. The daily gas-oil ratio (GOR) at the ocean surface as reported by BP, plotted as a function of oil produced. The general trend indicates that the GOR drops as a greater percentage of the total flow is produced to the surface but with considerable scatter. If the entire flow were captured, the 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.

Acknowledgements

The results and insights presented in this report were derived from the dedicated efforts of a large and diverse team of scientists and engineers from Federal agencies, universities around the country, and independent organizations. This team included representatives from the U.S. Geological Survey, National Oceanic and Atmospheric Administration, Department of Energy (DOE), Bureau of Ocean Energy Management, Regulation, and Enforcement, and the National Institute of Standards and Technology. Seven DOE National Labs were involved, including Los Alamos National Laboratory, Lawrence Berkeley National Laboratory, Lawrence Livermore National Laboratory, National Energy Technology Laboratory, Pacific Northwest National Laboratory, Oak Ridge National Laboratory, and Sandia National Laboratories. Members also included staff of the Woods Hole Oceanographic Institution (WHOI) and academic researchers from Clarkson University, John Hopkins University, Massachusetts Institute of Technology, Purdue University, University of California (UC) Berkeley, UC San Diego, UC Santa Barbara, University of Georgia, University of Texas, and University of Washington. The National Aeronautics and Space Administration and its Jet Propulsion Laboratory provided invaluable assistance with AVIRIS instrumentation and data collection. Our scientific activities were greatly aided by a talented pool of administrative, science support, and communication professionals from numerous agencies and organizations. David Rainey, Cynthia Yielding and others at BP Inc. provided invaluable assistance in acquiring data that were critical to the analyses and estimates described in this report. Getting the WHOI team in the field required great cooperation from BP, the contractors, the U.S. Coast Guard, and the researchers. It was through the good will and extra efforts of all involved that the necessary cross-referencing of safety standards was made and the equipment safely deployed. Charlotte Barbier, Barbara Bekins, Catherine Enomoto, David Hetrick, and Steve Hickman provided insightful reviews of earlier drafts of this report, improving its accuracy and exposition. Paul Cascio and Lara Schmit provided assistance formatting this document.

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Appendices

Appendix A – Hsieh 2010; Reservoir Depletion Report

Hsieh, Paul A. 2010. Computer Simulation of Reservoir Depletion and Oil Flow from the Macondo Well Following the Deepwater Horizon Blowout. USGS Open-File Report 2010-1266.

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

Labson, V.F., R.N. Clark, G.A. Swayze, T.M. Hoefen, R. Kokaly, K.E. Livo, M.H. Powers, G.S. Plumlee, and G.P. Meeker. Estimated Minimum Discharge Rates of the Deepwater Horizon Spill – Interim Report to the Flow Rate Technical Group from the Mass Balance Team. USGS Open-File Report 2010-1132.

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.

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

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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

TREX 008804.0029

science for a changing world

Computer Simulation of Reservoir Depletion and Oil Flow from the Macondo Well Following the Deepwater Horizon Blowout

By Paul A. Hsieh

Open-File Report 2010–1266

U.S. Department of the Interior
U.S. Geological Survey

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Contents

Tables

Figures

Conversion Factors

Oil Field Units to SI

Multiply	By	To obtain
foot (ft)	0.3048	meter (m)
gallon (gal)	0.0037854	cubic meter (m^3)
Barrel[1] (bbl)	0.15899	cubic meter (m^3)
pound per square inch (psi)	6.8948	kilopascal (kPa)
pound per gallon (ppg)	119.83	kilogram per cubic meter (kg/m^3)
centipoise (cP)	0.001	pascal-second (Pa·s)
millidarcy (mD)	9.8692×10^{-16}	meter squared (m^2)

SI to Oil Field Units

Multiply	By	To obtain
meter (m)	3.281	foot (ft)
cubic meter (m^3)	264.17	gallon (gal)
cubic meter (m^3)	6.2898	Barrel[1] (bbl)
kilopascal (kPa)	0.14504	pound per square inch (psi)
kilogram per cubic meter (kg/m^3)	0.0083454	pound per gallon (ppg)
pascal-second (Pa·s)	1,000	centipoise (cP)
meter squared (m^2)	1.01325×10^{15}	millidarcy (mD)

[1] Oil volume under reservoir conditions is measured in terms of reservoir barrels. Oil volume under surface conditions (60°F and 14.7 psi, or 15°C and 101.325 kPa) is measured in terms of stock tank barrels. When a quantity of oil is brought from reservoir conditions to surface conditions, the change in temperature and pressure and the release of gas bubbles cause the oil volume to decrease. The ratio of the oil volume under reservoir conditions to the volume under surface conditions is known as the formation volume factor and is denoted by *B*.

Temperature in degrees Fahrenheit (°F) may be converted to degrees Celsius (°C) as follows:

°C=(°F-32)/1.8

Computer Simulation of Reservoir Depletion and Oil Flow from the Macondo Well Following the Deepwater Horizon Blowout

By Paul A. Hsieh

Abstract

This report describes the application of a computer model to simulate reservoir depletion and oil flow from the Macondo well following the Deepwater Horizon blowout. Reservoir and fluid data used for model development are based on (1) information released in BP's investigation report of the incident, (2) information provided by BP personnel during meetings in Houston, Texas, and (3) calibration by history matching to shut-in pressures measured in the capping stack during the Well Integrity Test. The model is able to closely match the measured shut-in pressures. In the simulation of the 86-day period from the blowout to shut in, the simulated reservoir pressure at the well face declines from the initial reservoir pressure of 11,850 pounds per square inch (psi) to 9,400 psi. After shut in, the simulated reservoir pressure recovers to a final value of 10,300 psi. The pressure does not recover back to the initial pressure owing to reservoir depletion caused by 86 days of oil discharge. The simulated oil flow rate declines from 63,600 stock tank barrels per day just after the Deepwater Horizon blowout to 52,600 stock tank barrels per day just prior to shut in. The simulated total volume of oil discharged is 4.92 million stock tank barrels. The overall uncertainty in the simulated flow rates and total volume of oil discharged is estimated to be ±10 percent.

Background

The computer simulation described in this report was undertaken to supplement the work of the Flow Rate Technical Group, a group of scientists and engineers led by U.S. Geological Survey (USGS) Director Marcia McNutt to estimate the flow of oil from the Macondo well following the Deepwater Horizon blowout on April 20, 2010. Much of the work of the Flow Rate Technical Group was carried out prior to July 15, 2010, the date when the Macondo well was shut in to begin the Well Integrity Test. The computer simulation described in this report was carried out to analyze the shut-in pressure data obtained during the Well Integrity Test in order to gain additional knowledge of the Macondo well and the oil reservoir. Simulation results of particular interest include (1) the assessment of reservoir depletion resulting from oil flow during the 86 days from blowout to shut in, (2) the estimate of oil flow rate from the well, and (3) the estimate of total volume of oil discharged.

A significant amount of data used in the development of the reservoir model described in this report were provided by BP personnel at meetings in Houston, Texas, during late June to early August 2010. Much of these data are considered proprietary and by Government regulation cannot be released. Although the proprietary data were included in the draft version of this report for USGS technical peer review, they are not included in this final release version in accordance with Government regulation.

Reservoir Model

Reservoir Geometry and Conditions

The Macondo well produces oil from an oil reservoir known as M56. According to the BP investigation report of the Deepwater Horizon blowout (BP, 2010, Appendix W, p. 17, fig. 1.6), the M56 oil reservoir consists of three oil-producing sand layers. The top of the reservoir is penetrated by the Macondo well at a depth of approximately 18,000 ft below sea surface. The combined pay thickness of the three oil-producing sand layers is approximately 90 ft. The initial reservoir pressure is 11,850 pounds per square inch (psi). The reservoir temperature is approximately 240°F. As the bubble point of the oil in the reservoir is approximately 6,500 psi (BP, 2010, Appendix W, p. 11), the reservoir is believed to be under single-phase (liquid oil) condition. Table 1 shows the reservoir and fluid properties used in the model. However, property values are not given in this report owing to their proprietary nature.

To construct the reservoir model, the bulk volume of reservoir containing the oil is estimated by

$$V_b = \frac{V_o B}{\phi(1 - S_w)}, \tag{1}$$

where

V_b is the bulk volume of reservoir containing the oil [L^3],

V_o is the volume of original oil in place [L^3],

B is the formation volume factor [dimensionless],

ϕ is porosity [dimensionless], and

S_w is water saturation [dimensionless].

The sedimentary history of the Gulf Coast in the vicinity of the Macondo well suggests that the oil-producing sands composing the M56 reservoir are submarine channel fills (Posamentier, 2003). In the model, the oil reservoir is assumed to be a long, narrow channel having a rectangular cross section (fig. 1). The vertical thickness (b) of the channel is 90 ft. The horizontal length (L) and width (W) are initially unknown and are estimated by history matching of the Well Integrity Test. However, because $L \times W \times b$ must equal V_b, L and W are related by

$$L \times W = \frac{V_b}{b} = \frac{V_b}{90\,\text{ft}} \quad . \tag{2}$$

The reservoir is assumed to be a closed system. In other words, all six faces of the channel are impermeable boundaries. Within the reservoir, the Macondo well location is defined by the coordinates (x_w, y_w), which are initially unknown and are estimated by history matching.

Mathematical Formulation

The equation of oil flow in the reservoir is given by (after Matthews and Russell, 1967, p. 7, equation 2.12)

$$\frac{\partial^2 p}{\partial x^2} + \frac{\partial^2 p}{\partial y^2} = \frac{\phi \mu c}{k} \frac{\partial p}{\partial t} , \tag{3}$$

where

p is pressure [M/(L·T^2)],

c is the system compressibility [L·T^2/M],

k is permeability [L^2],

μ is oil viscosity [M/(L·T)],

x, y are Cartesian coordinates in the horizontal plane [L], and

t is time [T].

In applying equation 3 to the reservoir, the following conditions are assumed:

1. Flow of oil is under single-phase and isothermal conditions.
2. Reservoir properties (permeability, porosity, and compressibility) are homogeneous.
3. Permeability and viscosity are independent of pressure.
4. Permeability is isotropic.

Additional assumptions are given by Matthews and Russell (1967). These are standard in the analysis of pressure buildup and flow tests in wells and include assumptions that the reservoir is

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horizontal, the fluid compressibility is small and constant, and that pressure gradients within the reservoir are sufficiently small for Darcy's law to apply.

The system compressibility is computed as (after Matthews and Russell, 1967, p. 135, note 1)

$$c = (1 - S_w)c_o + S_w c_w + c_f \,, \tag{4}$$

where

c_o is oil compressibility [$L \cdot T^2/M$],

c_w is water compressibility [$L \cdot T^2/M$], and

c_f is effective formation (or pore) compressibility [$L \cdot T^2/M$].

Except for permeability, values of reservoir and fluid properties used in the reservoir model are assumed to be known (table 1). Permeability is estimated by history matching.

The volumetric flow rate of oil from the reservoir through the Macondo well and exiting the blowout preventer is modeled by the equation (see fig. 2)

$$Q^2 = C(p_w - p_e - \rho_o gH) \,, \tag{5}$$

where

Q is the volumetric flow rate of oil at reservoir conditions [L^3/T],

C is a coefficient of pressure loss through the well [L^7/M],

p_w is the reservoir pressure at the well face [$M/(L \cdot T^2)$],

p_e is the ambient pressure at the exit point of the blowout preventer [$M/(L \cdot T^2)$],

ρ_o is oil density [M/L^3],

g is gravitational acceleration [L/T^2], and

H is the elevation difference between the M56 reservoir and the exit point at the blowout preventer [L].

Equation 5 is similar to the Darcy-Weisbach equation (De Nevers, 1970), which relates the head loss due to friction along a given length of pipe to the square of the flow rate through the pipe. The value of the coefficient C in equation 5 is initially unknown and is estimated by history matching. In the reservoir simulation, C is kept constant for the entire period of well flow. This assumes that the changes in outlet configuration, such as cutting of the riser pipe, do not significantly impact the oil flow rate. For the Macondo well flow calculation, the ambient pressure at the exit point of the blowout preventer (p_e) is 2,190 psi and H is 13,000 ft. The volumetric flow rate of oil at surface (stock tank) conditions is computed by dividing Q by the formation volume factor, B.

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MODFLOW Implementation

The U.S. Geological Survey model known as MODFLOW-2000 (Harbaugh and others, 2000) is used to simulate oil flow in the M56 oil reservoir. Although MODFLOW-2000 was originally designed to simulate the flow of groundwater in aquifers, it can be readily adapted for simulating flow of oil in reservoirs under single-phase and isothermal conditions. The fluid flow equation solved by MODFLOW-2000 is analogous to equation 3, and can be written as

$$\frac{\partial^2 h}{\partial x^2} + \frac{\partial^2 h}{\partial y^2} = \frac{S_s}{K}\frac{\partial h}{\partial t}, \tag{6}$$

where

h is hydraulic head [L],

K is hydraulic conductivity [L/T], and

S_s is specific storage [1/L].

For simulating oil flow, the quantities h, K, and S_s are computed as

$$h = \frac{p}{\rho_o g} + z, \tag{7}$$

$$K = \frac{\rho_o g k}{\mu}, \tag{8}$$

$$S_s = \rho_o g \phi c, \tag{9}$$

where

z is the vertical elevation above a reference datum [L].

A modified version of the General-Head Boundary Package is used to simulate flow through the Macondo well, as expressed by equation 5. In its original version, the General-Head Boundary Package (see McDonald and Harbaugh, 1988, chapter 11) can be used to implement equation 5 if the exponent of the Q term were 1 instead of 2. To implement the Q^2 term, the Fortran source code of the General-Head Boundary Package is modified and the program recompiled.

Figure 3 is a map view of an example finite-difference grid of the oil reservoir, which is represented by a single 90-ft thick model layer. The cell containing the Macondo well has a horizontal dimension of 1 ft by 1 ft. The cell size increases away from the well to a maximum size of 100 ft by 100 ft. During history matching, the grid is reconstructed as the well coordinates (x_w, y_w) are varied. The simulation time step is 0.2 day. Well shut in is simulated by setting the coefficient C in equation 5 to zero.

History Matching

The parameter estimation program PEST version 10 (Doherty, 2004) is used to perform history matching—the adjustment of model parameters so that simulated pressures match measured pressures. (This procedure is also known as model calibration.) The estimated model parameters are shown in table 2. PEST implements a nonlinear least-squares regression method to estimate model parameters by minimizing the sum of squares of the differences between measured and simulated pressures:

$$\Phi = \sum_{i=1}^{N} (p_i^{mea} - p_i^{sim})^2 \quad (11)$$

,

where

N is the number of measurements [dimensionless],

p_i^{mea} is the i^{th} measured pressure [$M/(L \cdot T^2)$], and

p_i^{sim} is the i^{th} simulated pressure [$M/(L \cdot T^2)$].

PEST uses the Gauss-Marquardt-Levenberg method to minimize Φ. Details of this method are given in the PEST user's manual (Doherty, 2004).

The pressure data used for history matching were measured during the Well Integrity Test, which began on July 15, 2010. At 2:20 p.m. Central Daylight Time, the final turn on the choke was closed and the Macondo well was shut in. Shut-in pressure was measured continuously by two pressure gages installed in the capping stack. Pressure data from the PT-3K-1 transducer were nearly identical to pressure data from the PT-3K-2 transducer, except the former gave a pressure reading that was approximately 100 psi lower than that from the latter. For history matching, shut-in pressures measured by the PT-3K-2 transducer are used. The simulated shut-in pressure in the capping stack is calculated by subtracting $\rho_o gH$ from the simulated reservoir pressure at the well face to adjust for the elevation difference between the M56 reservoir and the pressure gage in the capping stack. The Well Integrity Test ended on August 3, 2010, when heavy mud was injected into the Macondo well to initiate the "static kill" operation.

Figure 4 is a Horner plot showing the simulated shut-in pressures in the capping stack. The horizontal axis of the Horner plot shows the quantity $(t_p + \Delta t)/\Delta t$, where t_p is the period of oil flow (86 days), and Δt is the elapsed time since shut in. Note that on the horizontal axis, time increases to the left. The simulated pressures closely match the continuously measured pressures—the standard error of the residuals (differences between simulated and measured pressures) is 2.3 psi. However, the continuously measured pressures used for history matching are not shown in figure 4 owing to their proprietary nature. Instead, figure 4 shows only those pressure readings that were announced in daily Government press releases (http://www.restorethegulf.gov/news/press-releases) and in BP technical briefings (http://www.bp.com/sectiongenericarticle.do?categoryId=9034442&contentId=7063846).

Simulation Results

Reservoir Depletion

Figure 5 shows the simulated reservoir pressure at the Macondo well face. The origin of the time axis corresponds to April 20, 2010, the date of the Deepwater Horizon blowout. The initial reservoir pressure is 11,850 psi. Immediately after the blowout, the simulated pressure drops rapidly to approximately 11,000 psi and then follows a steady decline to 9,400 psi on day 86, just prior to shut in. After shut in, the simulated pressure recovers and eventually stabilizes at 10,300 psi. The pressure does not recover back to the initial pressure owing to reservoir depletion from 86 days of oil discharge.

Oil Flow Rate

Figure 6 shows the simulated volumetric flow rate of oil for surface conditions (expressed in stock tank barrels per day). Note that this flow rate is obtained by dividing the simulated flow rate under reservoir conditions, Q, by the formation volume factor, B. The simulated initial volumetric flow rate of oil is 63,600 stock tank barrels per day. As the reservoir depletes, the flow rate decreases to 52,600 stock tank barrels per day on day 86, just prior to shut in. The simulated total volume of oil discharged over the 86-day period from blowout to shut in is 4.92 million stock tank barrels.

Uncertainty Analysis

After history matching, the program PEST is run in "predictive analysis mode" to assess the predictive uncertainty of the reservoir model (see Doherty, 2004, chapter 6). In this context, a "prediction" is simply a model-simulated quantity that is not measured—there is no implication that the simulated quantity is to occur in the future. Three simulated quantities are of particular interest: (1) the initial oil flow rate, just after the blowout; (2) the final oil flow rate, just before shut in; and (3) the total volume of oil discharged. Table 3 gives the predictive uncertainty of these simulated quantities in terms of 95-percent prediction intervals. Note that all three intervals are relatively narrow—the upper or lower limits are no more than a few percent higher or lower than the corresponding simulated value. The narrow intervals are largely due to the close match between simulated and observed pressures and the low degree of nonuniqueness in the estimated parameters.

The prediction intervals given in table 3, however, do not fully characterize the uncertainty in the simulated values. In calculating these intervals, it is assumed that the values of the reservoir and fluid properties given in table 1 are known. However, quantities such as original oil in place are, in fact, best estimates and are subject to uncertainty. To evaluate the impact of parameter uncertainty on the simulated flow rates and total volume of oil discharged, each reservoir or fluid property in table 1 is varied by ±25 percent, except for oil density, which is varied by ±10 percent (because a ±25-percent variation in oil density is considered too extreme). For each parameter variation, history matching is re-performed, and the simulation results are tabulated in table 4. As shown by the table, the impact of the parameter variation ranges from 0 (no impact) to ±25 percent of the simulated flow rates and total volume of oil discharged. On the basis of these results, the overall uncertainty in the simulated flow rates and total volume of oil discharged is estimated to be ±10 percent.

Conclusions

The reservoir model presented in this report simulates oil discharge from the Macondo well following the Deepwater Horizon blowout and pressure recovery after the well was shut in. During the 86-day period of oil discharge, the simulated reservoir pressure at the well face declines from the initial reservoir pressure of 11,850 psi to 9,400 psi. After shut in, the simulated reservoir pressure recovers to a final value of 10,300 psi. The pressure does not recover back to the initial pressure owing to reservoir depletion from the oil discharge. The simulated oil flow rate declines from 63,600 stock tank barrels per day just after the Deepwater Horizon blowout to 52,600 stock tank barrels per day just prior to shut in. The simulated total volume of oil discharged is 4.92 million stock tank barrels. Analysis of the predictive uncertainty of the reservoir model suggests that the 95-percent prediction intervals of the simulated flow rates and total volume of oil discharged are relatively narrow—the upper or lower limits are no more than a few percent higher or lower than the corresponding simulated value. However, these prediction intervals do not fully characterize the uncertainty in the simulated values. If uncertainties in reservoir and fluid properties are taken into account, the overall uncertainty in the simulated flow rates and total volume of oil discharged is estimated to be ±10 percent.

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Table 1. Reservoir and fluid properties used in the reservoir simulation model.
[Property values used in the reservoir model are not given in this report owing to their proprietary nature]

Reservoir or fluid property
Original oil in place
Formation volume factor, B
Porosity, ϕ
Effective formation (or pore) compressibility, c_f
Oil viscosity, μ
Oil compressibility, c_o
Oil density, ρ_o
Water saturation, S_w
Water compressibility, c_w

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Table 2. Model parameters that are estimated by history matching.
[See figure 1 for definition of L, W, x_w, and y_w. Estimated values are not given in this report because they are derived from proprietary data]

Model parameter
Horizontal length of reservoir, L
Horizontal width of reservoir, W
X-coordinate of Macondo well, x_w
Y-coordinate of Macondo well, y_w
permeability, k
Coefficient of pressure loss in well, C

Table 3. Simulated oil flow rates and total volume of oil discharged along with 95-percent prediction intervals computed by PEST predictive analysis.

Simulated quantity	Simulated value	95-percent prediction interval Minimum	Maximum
Initial oil flow rate (stock tank barrels/day)	63,600	62,800	64,200
Final oil flow rate (stock tank barrels/day)	52,600	51,900	53,100
Total volume of oil discharged (stock tank barrels)	4.92×10^6	4.85×10^6	4.97×10^6

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Table 4. Impact of ±25-percent variation in parameter value on simulated initial flow rate, final flow rate, and total volume of oil discharged.
[%, percent]

Parameter being varied	Impact of ±25% variation in parameter value on		
	Initial flow rate	Final flow rate	Total volume
Original oil in place	±25%	±25%	±25%
Formation volume factor, B	0	0	0
Porosity, ϕ	0	0	0
Effective formation (or pore) compressibility, c_f	±12%	±12%	±12%
Oil viscosity, μ	0	0	0
Oil compressibility, c_o	±13%	±13%	±13%
Oil density, ρ_o	±20%*	±20%*	±20%*
Water saturation, S_w	±1%	±1%	±1%
Water compressibility, c_w	±0.3%	±0.3%	±0.3%

*Oil density varied by ±10 percent.

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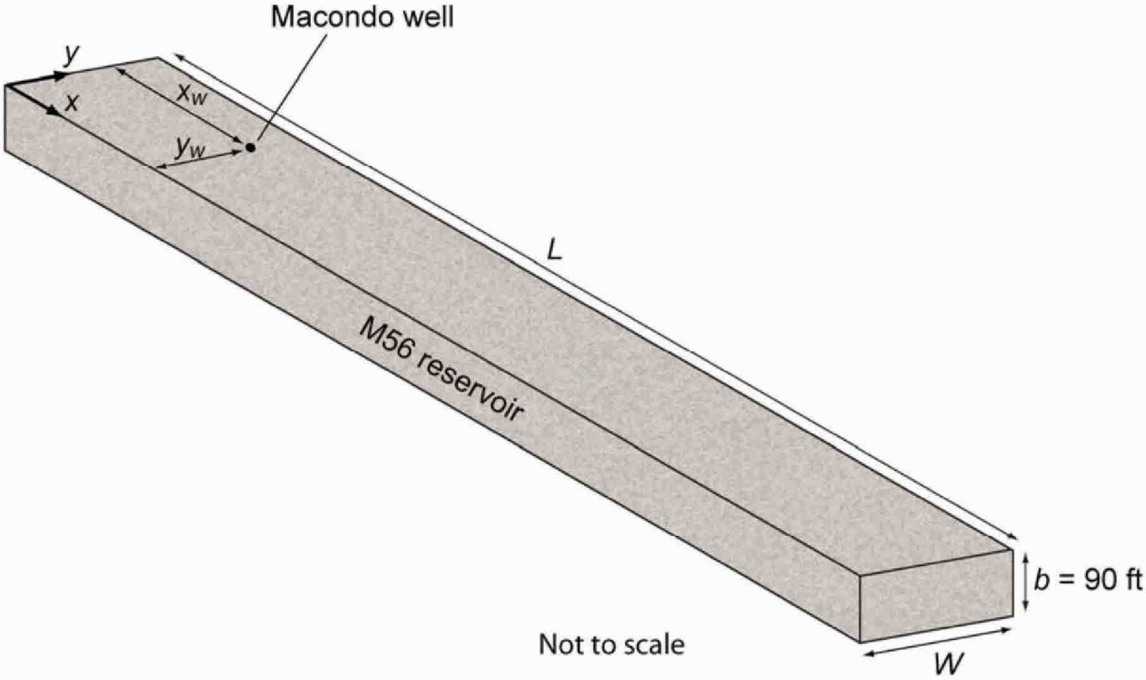


Figure 1. Oblique schematic view of the M56 oil reservoir.

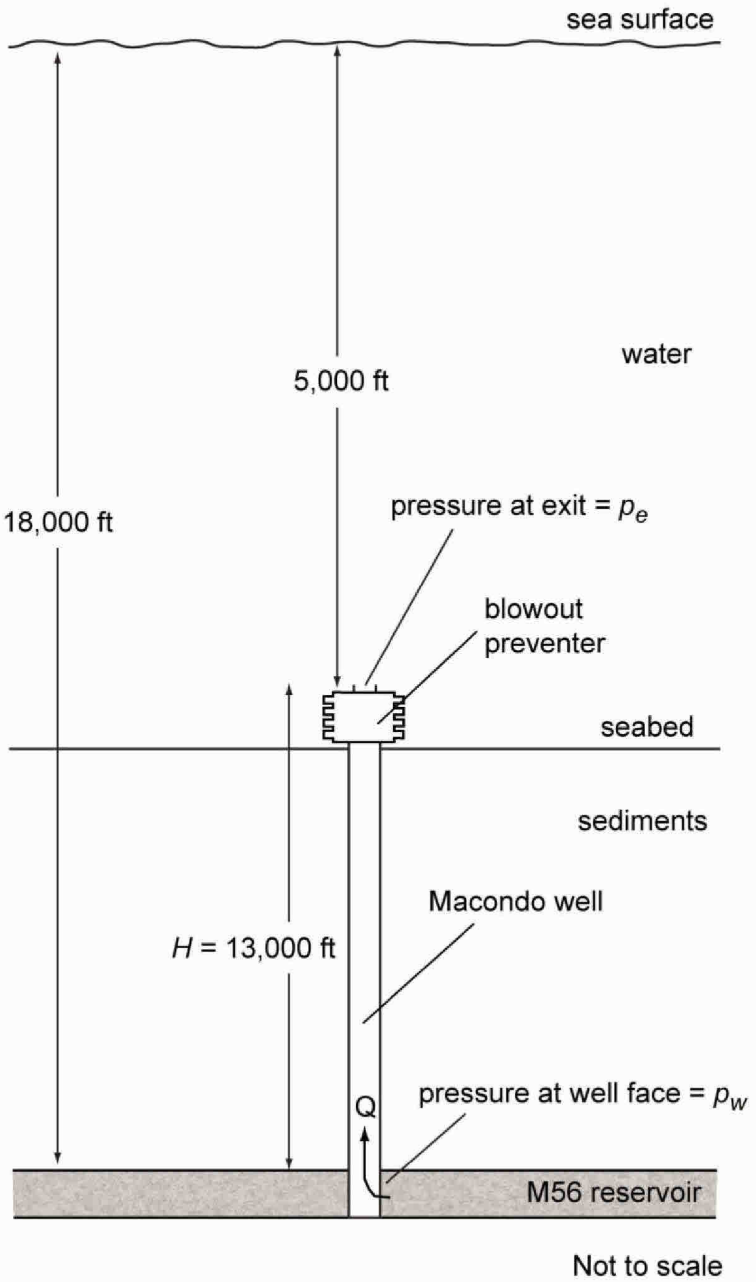


Figure 2. Schematic vertical section showing flow of oil from M56 reservoir through the Macondo well and exiting at the top of the blowout preventer.

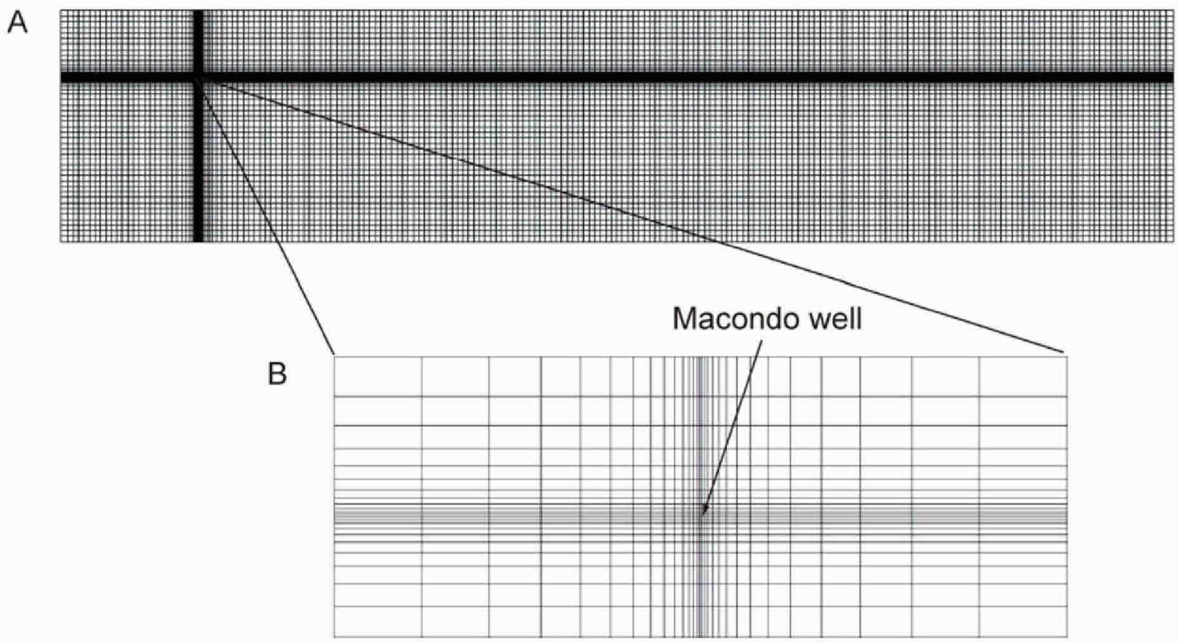


Figure 3. Map view of an example finite-difference grid of the oil reservoir. *A*, Entire grid. *B*, Detailed view of a small portion of the grid in the vicinity of the Macondo well.

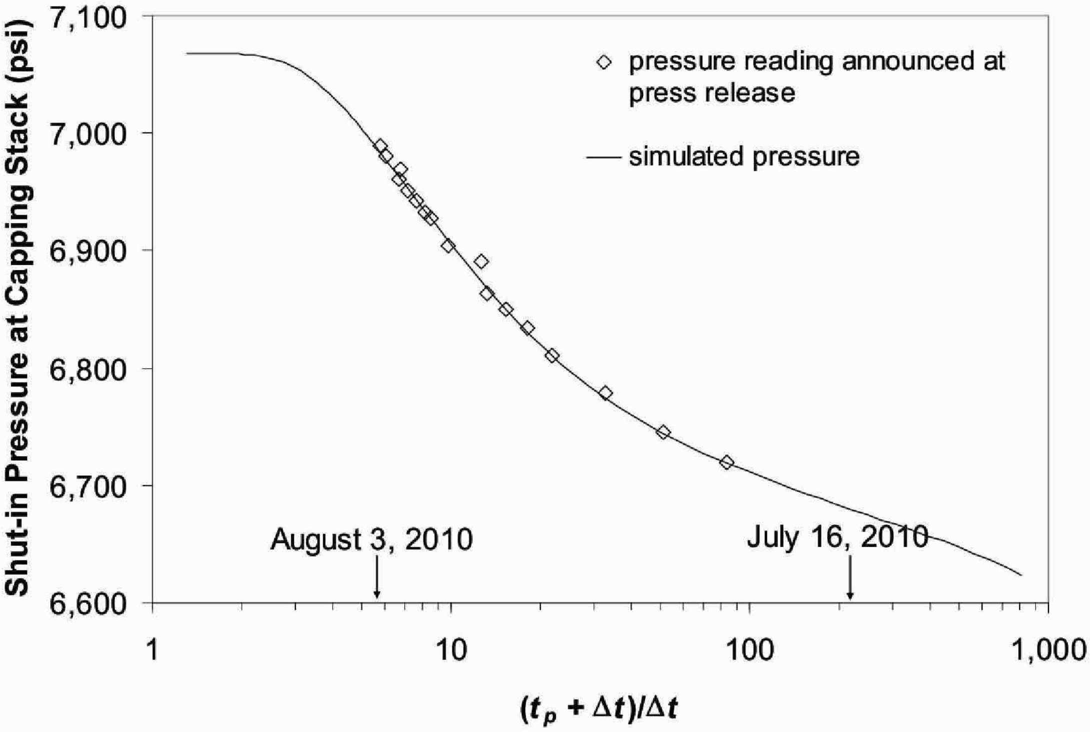


Figure 4. Horner plot of shut-in pressure in the capping stack of the Macondo well. t_p is the period of oil flow, which is 86 days. Δt is elapsed time since shut in. Note that time increases to the left on the horizontal axis. The solid line shows the simulated shut-in pressure in the capping stack. The simulated pressures closely match the continuously measured pressures, which are not given in this report owing to their proprietary nature. Instead, the diamond symbols show pressure readings that were announced in daily Government press releases and in BP technical briefings.

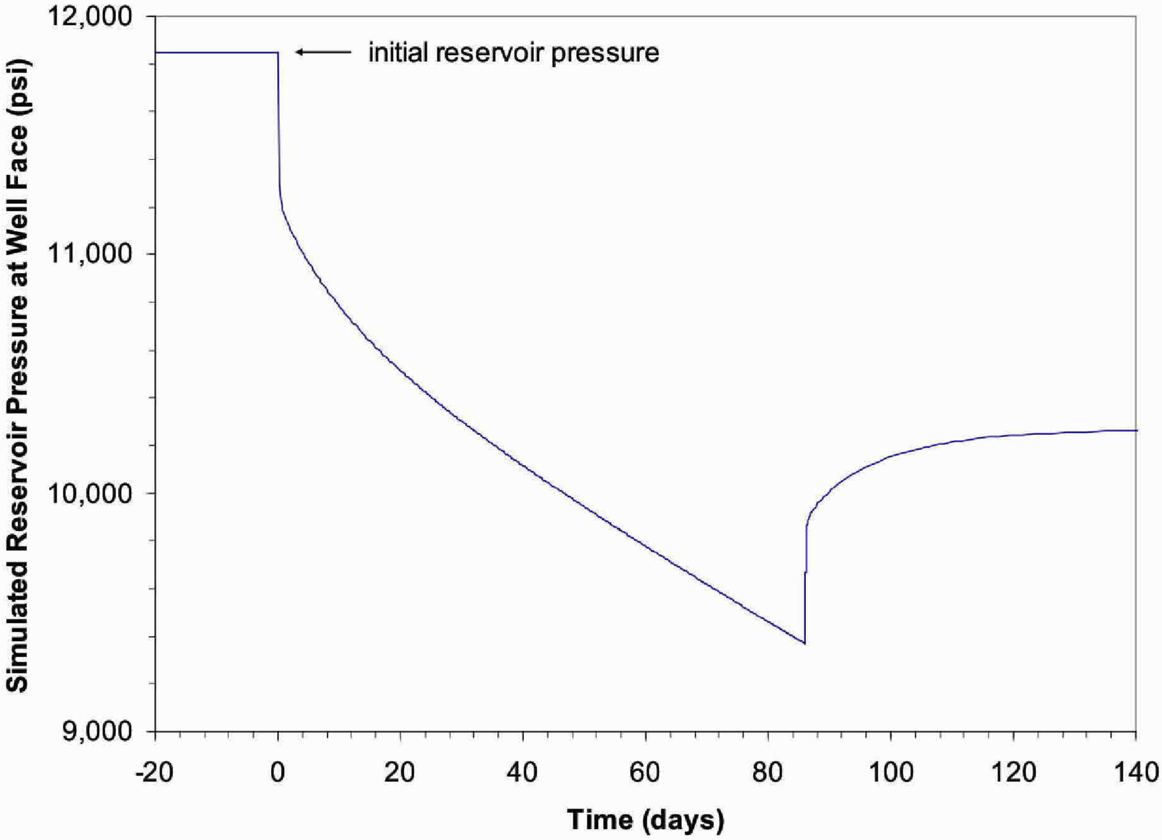


Figure 5. Simulated reservoir pressure at the Macondo well face. The origin of the time axis (t = 0) corresponds to April 20, 2010, the date of the Deepwater Horizon blowout.

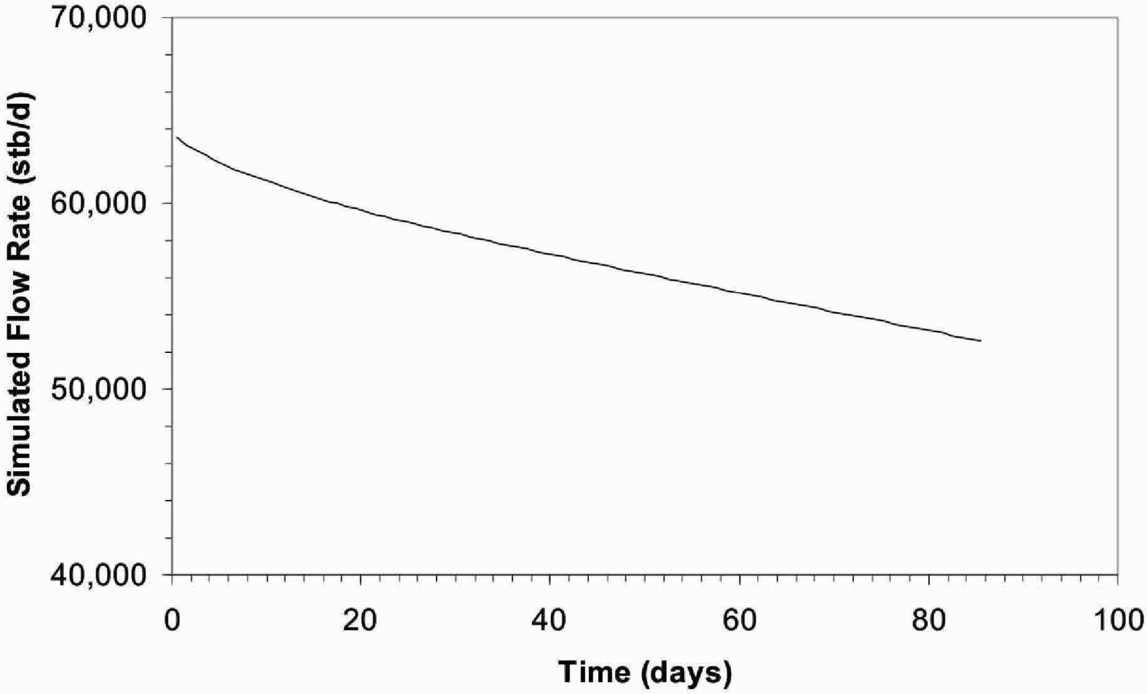


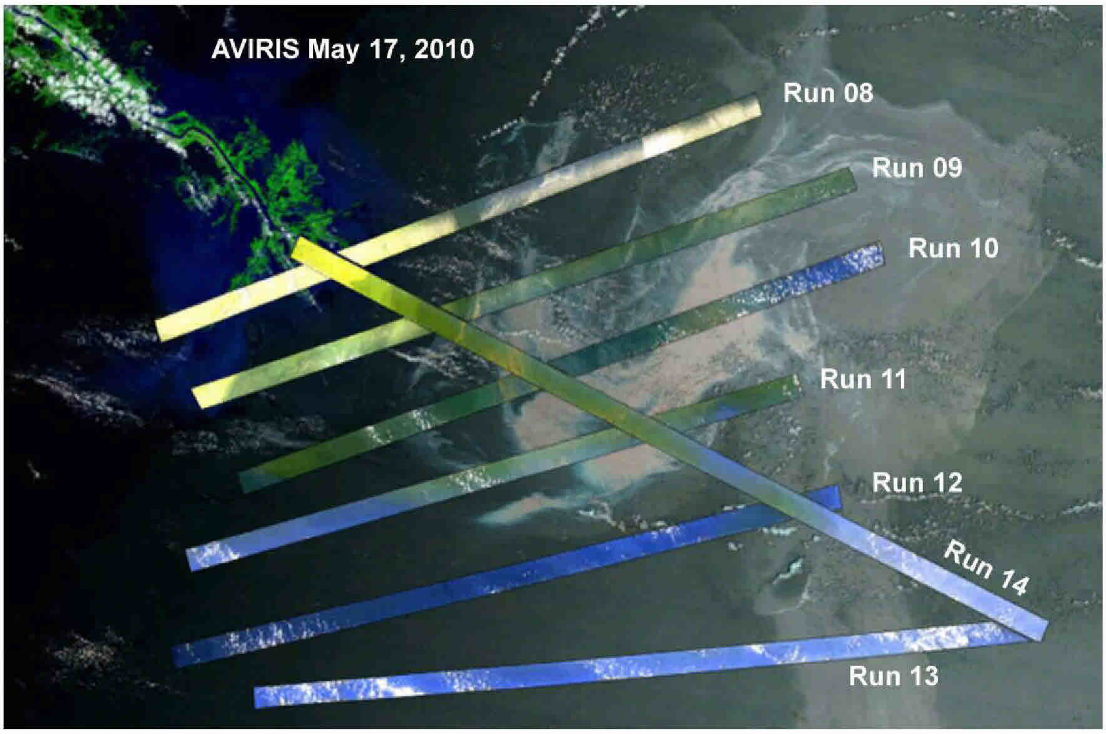
Figure 6. Simulated volumetric flow rate of oil from the Macondo well in stock tank barrels per day (stb/d). This flow rate is obtained by dividing the simulated flow rate under reservoir conditions (*Q*) by the formation volume factor (*B*). The origin of the time axis (t = 0) corresponds to April 20, 2010, the date of the Deepwater Horizon blowout.

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

Labson, V.F., R.N. Clark, G.A. Swayze, T.M. Hoefen, R. Kokaly, K.E. Livo, M.H. Powers, G.S. Plumlee, and G.P. Meeker. Estimated Minimum Discharge Rates of the Deepwater Horizon Spill – Interim Report to the Flow Rate Technical Group from the Mass Balance Team. USGS Open-File Report 2010-1132.

Estimated Minimum Discharge Rates of the Deepwater Horizon Spill—Interim Report to the Flow Rate Technical Group from the Mass Balance Team

By Victor F. Labson, Roger N. Clark, Gregg A. Swayze, Todd M. Hoefen, Raymond Kokaly, K. Eric Livo, Michael H. Powers, Geoffrey S. Plumlee, and Gregory P. Meeker



Open-File Report 2010–1132

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Contents

Conversion Factors

Inch/Pound/Gallon/Barrel to SI

Multiply	By	To obtain
Length		
inch (in.)	2.54	centimeter (cm)
foot (ft)	0.3048	meter (m)
mile (mi)	1.609	kilometer (km)
yard (yd)	0.9144	meter (m)
Area		
acre	4,047	square meter (m^2)
acre	0.4047	hectare (ha), which is 10,000 m^2
square foot (ft^2)	0.09290	square meter (m^2)
square mile (mi^2), a section or 640 acres	259.0	hectare (ha) [1 ha = 10,000 m^2]
square mile (mi^2)	2.590	square kilometer (km^2)
Volume		
gallons (gal)	3.7854	liters (l)
barrels (bbl)	158.99	liters (l)

SI to Inch/Pound/Gallon/Barrel

Multiply	By	To obtain
Length		
centimeter (cm)	0.3937	inch (in.)
meter (m)	3.281	foot (ft)
kilometer (km)	0.6214	mile (mi)
meter (m)	1.094	yard (yd)
Area		
hectare (ha)	2.471	acre
square kilometer (km^2)	247.1	acre
square meter (m^2)	10.76	square foot (ft^2)
hectare (ha)	0.003861	square mile (mi^2), a section or 640 acres
square kilometer (km^2)	0.3861	square mile (mi^2)
Volume		
liters (l)	0.26417	gallons (gal)
liters (l)	0.00629	barrels (bbl)

TREX 008804.0056

Estimated Minimum Discharge Rates of the Deepwater Horizon Spill—Interim Report to the Flow Rate Technical Group from the Mass Balance Team

By Victor F. Labson, Roger N. Clark, Gregg A. Swayze, Todd M. Hoefen, Raymond Kokaly, K. Eric Livo, Michael H. Powers, Geoffrey S. Plumlee, and Gregory P. Meeker

Purpose

All of the calculations and results in this report are preliminary and intended for the purpose, and only for the purpose, of aiding the incident team in assessing the extent of the spilled oil for ongoing response efforts. Other applications of this report are not authorized and are not considered valid. Because of time constraints and limitations of data available to the experts, many of their estimates are approximate, are subject to revision, and certainly should not be used as the Federal Government's final values for assessing volume of the spill or its impact to the environment or to coastal communities. Each expert that contributed to this report reserves the right to alter his conclusions based upon further analysis or additional information.

Summary

An estimated minimum total oil discharge was determined by calculations of oil volumes measured as of May 17, 2010. This included oil on the ocean surface measured with satellite and airborne images and with spectroscopic data (129,000 barrels to 246,000 barrels using less and more aggressive assumptions, respectively), oil skimmed off the surface (23,500 barrels from U.S. Coast Guard [USCG] estimates), oil burned off the surface (11,500 barrels from USCG estimates), dispersed subsea oil (67,000 to 114,000 barrels), and oil evaporated or dissolved (109,000 to 185,000 barrels). Sedimentation (oil captured from Mississippi River silt and deposited on the ocean bottom), biodegradation, and other processes may indicate significant oil volumes beyond our analyses, as will any subsurface volumes such as suspended tar balls or other emulsions that are not included in our estimates. The lower bounds of total measured volumes are estimated to be within the range of 340,000 to 580,000 barrels as of May 17, 2010, for an estimated average minimum discharge rate of 12,500 to 21,500 barrels per day for 27 days from April 20 to May 17, 2010.

Description of Approach

The Mass Balance Team approach combined remote-sensing-based estimates of oil volumes at the sea surface with estimates provided to the group by NOAA (National Oceanic and Atmospheric Administration), NASA (National Aeronautics and Space Administration), and USCG on volume of oil skimmed, volume of oil burned, and percentage of oil evaporated or dissolved in seawater.

The remote sensing estimates of oil volumes at the ocean surface were determined from analysis of data obtained from space and airborne sensor measurements of the surface oil in the Gulf of Mexico on May 17, 2010. A multichannel MODIS (MODerate-resolution Imaging Spectroradiometer) satellite image (250×250 meter pixels) from that day was used to estimate the total surface area of oil on the water (about 17,725 km2). The determination was based on higher surface signal return to the sensor from areas with oil sheens, slicks, and floating plumes of oil/water emulsion than from average baseline clean ocean areas.

The percentages of total ocean surface oil coverage considered to be "thick" (2 percent), "dull" (10 percent), or "sheen" (88 percent) were provided by NOAA and the USCG. Applying these percentages to the total estimated ocean surface oil coverage area on May 17, 2010, resulted in 350 km2 of "thick," 1,775 km2 of "dull," and 15,600 km2 of "sheen."

Thick Oil (2 Percent of Surface Oil Coverage Area)

Aircraft-based AVIRIS (Airborne Visible/Infra-Red Imaging Spectrometer, 224 channels, 8.5×8.5 meter pixels) imaging spectroscopy data were also collected over 967 km2 of the oil coverage area on May 17 and were used to map and characterize thicker emulsion-bearing regions. The higher resolution of the AVIRIS data allows a more refined estimate than MODIS of the thicker oil emulsions that commonly occur in wispy or ropy patterns on the sea surface, separated by substantial areas of much thinner oil accumulations. Laboratory reflectance measurements of oil/water emulsion samples ("thick" oil) collected on a traverse of the spill on May 7 were used to develop an algorithm for conversion of AVIRIS response to oil volume per pixel. These values were extrapolated from the 967 km2 AVIRIS coverage to the full estimated 3,363 km2 of MODIS-derived emulsion-bearing regions. This procedure, described in a report in preparation (R.N. Clark and others, written commun., 2010), provided an estimated range of 66,000 to120,000 barrels of oil in the emulsion-bearing regions. The total area recognized by the AVIRIS algorithm as "thick" oil, when compensated for the total emulsion-bearing region covered by AVIRIS, results in a measurement of 1.83 percent of the total surface oil coverage area showing "thick" oil. This is independent of the percentage assignments provided by NOAA and USCG, and allows a confident assignment of this AVIRIS minimum estimate to the expected 2 percent surface area of "thick" oil.

The two numbers (66,000 and 120,000) represent a range of the minimum volume of oil determined from less and more aggressive assumptions built into the AVIRIS estimation algorithm for detecting surface oil between 25 micrometers (μm) and 20 millimeters (mm) in thickness. The thickness of oil that can be detected with infrared spectroscopy (AVIRIS) varies with the oil-to-water ratio (R.N. Clark and others, written commun., 2010). As the oil fraction increases, the oil layer becomes dark, limiting the light energy penetration depth. The AVIRIS algorithm varies oil volume on the basis of pixel value response according to oil thickness and oil:water ratios for determined thicknesses up to 4 mm. Only the more aggressive calculation includes oil volumes for regions with thicknesses greater than 4 mm, and only with an assumption of 20 mm thickness when the oil-to-water ratio is less than or close to 2 percent. The volume of oil below the upper 4 mm of more oil-rich emulsions (where oil-to-water ratio is greater than 2 percent) was not evaluated with AVIRIS and could substantially increase the oil volume values reported herein. As noted below, estimated "dull" oil volumes are due to surface oil thickness in the range of 3 to 6 microns. Surface oil volumes due to oil thicknesses greater than 6 μm and less than 25 μm, or thicknesses greater than 20 mm, could also be significant and are not included at all in this estimate.

Dull (10 Percent Surface-Oil Coverage Area) and Sheen Oil (88 Percent Surface-Oil Coverage Area)

The amount of oil in the 1,775 km2 of "dull" area and the 15,600 km2 of "sheen" area was estimated assuming a range of oil thickness for each area that falls within color-based thickness ranges assigned by an ASTM standard method (American Society for Testing and Materials, 2006) for visually estimating oil spill thickness on water. For the "dull" area the assumed thickness range was 3 to 6 µm, and for the "sheen" area the assumed thickness range was 0.3 to 0.6 µm. This resulted in estimated oil volume ranges for the spill of 33,500 to 67,000 barrels in thin "dull" areas and 29,500 to 59,000 barrels in thin "sheen" areas. Summing the "thick," "dull," and "sheen" volumes gives a minimum surface oil estimate over the MODIS-determined area of the spill on May 17, 2010, of 129,000 to 246,000 barrels of oil.

Oil Skimmed, Burned, Evaporated, Dissolved, and Dispersed

Additional estimates of oil volumes were provided to the group and included 23,500 total barrels of oil skimmed as of May 17 (USCG data), 11,500 total barrels of oil burned as of May 17 (USCG data), and 40 percent of surface oil evaporated or dissolved (NOAA data). To determine the amount of oil prior to evaporation or dissolution in seawater, the amounts skimmed and burned are added to the range of amounts estimated present on the surface on May 17. The sum is considered to be about 60 percent of the total oil volume reaching the surface, which is calculated by dividing the observed, skimmed, and burned sum by 0.6. The difference between the total and observed amounts yields a range of evaporation and dissolution volume from 109,000 to 185,000 barrels.

Subsea dispersants were applied for a total effective time of 5.3 days over the 27 days from the start of the leak and May 17 (Jeffrey Hohle, BP, written commun., 2010). We therefore do not include subsea-dispersed volume in our surface oil sum, and have accounted for this by dividing our volume totals by 21.7 days rather than 27 days. We further assume that, due to the lack of significant wave action over the period when dispersants were applied on the surface (USCG data), the remote-sensing measurements include surface oil treated with dispersants.

Estimated Discharge Rates Based on Observed and Calculated Volumes

We estimate that a minimum of 273,000 to 466,000 barrels of oil discharged over 21.7 days. This results in a minimum estimated average oil discharge rate per day of 12,500 to 21,500 barrels. The values in barrels are summarized in the following table.

Low minimum	High minimum	Explanation
66,000	120,000	2 percent area "thick" oil from imagery
33,500	67,000	10 percent area "dull" oil
29,500	59,000	88 percent area "sheen" oil
129,000	246,000	Total observed on surface
23,500	23,500	skimmed oil
11,500	11,500	burned oil
164,000	281,000	Subtotal as of May 17, 2010
109,000	185,000	40 percent evaporation and dissolution
273,000	466,000	Total estimated as of May 17, 2010
12,500	**21,500**	**Daily average per 21.7 days**
67,000	114,000	assumed subsea dispersion
340,000	580,000	estimated leaked as of May 17

This summary includes the best available information as of this writing and is a refinement of previous estimates. We are continuing to refine these estimates by gathering further information that will help reduce potential sources of uncertainty in several parts of the mass balance calculations.

References Cited

American Society for Testing and Materials, 2006, Standard guide for visually estimating oil spill thickness on water: ASTM International F2534 – 06, 4 p. Accessed May, 2010 from *http://www.astm.org/Standards/F2534.htm*

Peer Review of "Estimated Minimum Discharge Rates of the Deepwater Horizon Spill – Interim Report to the Flow Rate Technical Group from the Mass Balance Team" by VF Labson, RN Clark, GA Swayze, TM Hoefen, R Kokaly, KE Livo, MH Powers, GS Plumlee, and GP Meeker.

With nine authors, all scientists with independent publication records, this report went through extensive review and revision among the authors prior to submission to the peer reviewers. Nonetheless, the authors greatly appreciate both reviewers for contributing excellent comments with valid points leading to a substantially improved report.

Reviewer 1:

I have reviewed the Mass Balance OFR and found it to be technically sound and a logical approach to estimating the amount of oil (volume) on the surface or near surface.

Author Response:

Thank you.

Reviewer 1:

In the next iteration of the OFR, I would like to see a comparison of the amount of surface oil detected with other sensors such as: WorldView 2, RadarSat 2, TerraSAR-X, SPOT.

Author Response:

We agree that this comparison is of interest and are working with other data and experts to develop it for future reporting as need determines. This report mentions only use of MODIS and AVIRIS for total surface area of detected oil, as these were the primary tools applied. Landsat7 data also were used to improve the final area, but with limited effect warranting no mention to retain brevity.

Reviewer 1:

Title "Estimated Lower Bound"- but then the paper gives a range of estimates - is it really an estimate for the observable oil at the surface?

Author Reponse:

Oil volume amounts were included for oil burned, skimmed, evaporated, dissolved, and dispersed in addition to the oil observed on the surface. The paper estimates a minimum discharge rate based on a total amount of oil accounted for on May 17, and not just an estimate of oil observable on the surface (although this amount is critical to the extended estimation). The method of summing oil observed and calculated through known physical processes can only determine a minimum amount, as unseen and unconsidered oil is not included (such as possible amounts in subsea suspension, biodegraded, deposited with natural sedimentation, etc.). The AVIRIS surface oil volume estimation algorithm for thick oil is conservative by design, and the range of volume estimation is due to slightly more or less conservative assumptions, yielding a range of minimum volume amounts.

Reviewer 2:

Concerning title "...Lower Bound for Leak Rates...": 1. "Lower Bound" seems like jargon. What's wrong with "Minimum?" 2. "Leak"—We don't know who will see this report, but it's not hard to imagine a news organization getting the report and saying that "DOI reports oil spill is only a leak." Maybe "leak" has a technical meaning here in terms of petroleum science, but the rest of the world does not see this as a leak. My recommendation is that the title of the report be changed to "Estimated Minimum Discharge Rates...".

Author Response:

Agreed with both points. Changed "lower bound for leak rates" to "estimated minimum discharge rates" in title and throughout paper.

Reviewer 2:

Summary paragraph, regarding "other processes may contribute significant volumes" and use of term "suspended tar balls": Contribute to what? What about "Volumes of oil associated with... and other processes may be significant...." This mention of tar balls seems to be minimizing the reported subsea plumes. Should the reports of these plumes be mentioned?

Author Response:

Changed sentence to read, "…and other processes may indicate significant oil volumes beyond our analyses, as will any subsurface volumes such as suspended tar balls or other emulsions that are not included in our estimates." Reports of "subsea plumes" at the time of writing were not substantiated with data on oil concentration levels above a few parts per billion. Reports of tar balls in general were substantiated on beaches, and these are known to exist in suspension in the water column, but the volume of oil involved was unknown. We chose wording to accurately describe concern for unknown amounts of suspended oil in the water column, without referring to undocumented stories.

Reviewer 2:

In Description of Approach, regarding "mass balance approach": In the strictest sense, this is not a "mass balance approach" because there is no balance, i.e., your calculations are not "balanced" against another measurement or estimate. The approach is a summation of the observed/estimated quantities of oil in the system.

Author Response:

Changed sentence to read, "The Mass Balance Team approach…"

Reviewer 2:

"Surface Spill Area" is a bit of an ambiguous term. What you mean (I think) is the total area with oil on the surface, but the "surface spill area" might also be considered to be the total area bounded by the outer edges of the spill, which is a much larger area. The term used in the previous paragraph (surface oil coverage area) is more precise.

Also, I think it might be helpful to note up front the total areas associated with each of the 3 oil coverages . . . maybe add in the previous paragraph, as noted *above. These will be numbers of considerable interest, but are difficult to find in the report.*

Author Response:

Used "surface oil coverage area" throughout report. Placed coverage area amounts for all three areas at start of discussion.

Reviewer 2:

Regarding "...determination was based on higher signal return...": "Higher" than what?

Author Response:

Changed sentence to read: "The determination was based on higher surface signal return to the sensor from areas with oil sheens, slicks, and floating plumes of oil/water emulsion than from average baseline clean ocean areas."

Reviewer 2:

Regarding "...data were also collected over the area on May 17...": Should the area be specified, particularly because, from following sentences, it appears that the AVIRIS data did not cover the entire spill area?

Author Response:

Changed to "…data were also collected over 967 km2 of the oil coverage area on May 17…".

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.

Final Oil Spill Flow Rate Report and Characterization Analysis
Deepwater Horizon well
Mississippi Canyon Block 252

by
Dr. Richard Camilli
Woods Hole Oceanographic Institution
Department of Applied Ocean Physics and Engineering
Deep Submergence Laboratory

August 10, 2010

submitted to the
United States Coast Guard
Research and Development Center
contract # HSCG3210CR0020
Dr. Richard Camilli and Mr. Andrew Bowen
Task 3.3; Deliverable #4

The analysis and findings described here were authored by the WHOI Flow Rate Measurement Group: Richard Camilli (WHOI), Andrew Bowen (WHOI), Dana Yoerger (WHOI), Alexandra Techet (MIT), Daniela Di Iorio (UGA), Louis Whitcomb (JHU);along with chemical analyses and documentation by Christopher Reddy (WHOI), Jeff Seewald (WHOI), Sean Sylva (WHOI), and Robert Nelson (WHOI). Additional operations and technical support was provided by Weatherford Pipeline Services, Teledyne RDI, SoundMetrics Corp, and Oceaneering.

TREX 008804.0065

Executive Summary:
At the direction of the United States Coast Guard (USCG) Research and Development Center, the Woods Hole Oceanographic Institution (WHOI) was contracted to undertake on-site data collection and analysis of the DEEPWATER HORIZON oil spill. This report has been submitted in fulfillment of USCG contract # HSCG3210CR0020 Deliverable #4. This analysis effort employed acoustic technologies mounted to a remotely operated vehicle (ROV) to directly measure flow rates of oil from the MC252 Deepwater Horizon (Macondo) well. Direct samples of hydrocarbons were collected from within the well riser to determine the gas-oil ratio. Both the flow rate analysis and sample collection were conducted on a non-interfere basis, wherein all operations were performed as time and equipment availability permitted during containment activities at the well site. This provided only a minimum time window to carry out measurement, under less-than optimal measurement conditions.

Flow rate estimates for the riser and BOP were constructed from acoustic Doppler velocity and sonar multibeam cross sectional estimates of each plume. Acoustic measurements were recorded after the top-kill attempt had ended and before the riser was cut, during beginning on May 31, 2010 and extending the early morning hours on June 1, 2010. The ROV was operated by Oceaneering International and supplied by BP. Velocity measurements were recorded at two distinct sites, above the riser pipe and at the kink above the BOP. Flow estimates were derived from three different Doppler velocity view angles above the riser pipe and three Doppler velocity view angles above the BOP during *MAXX*3 ROV Dive #35. Plume cross section measurements were completed using an imaging multibeam sonar on *MAXX*3 ROV Dive #35 and #36.

Hydrocarbon composition was determined based on end member samples collected using isobaric gas-tight samplers integrated onto the Millennium 42 ROV Dive #70. This collection was completed on June 21, 2010, approximately three weeks after the flow measurements. At this time of collection the kinked riser section directly above the BOP had been cut off and the 'top hat' containment system had been placed over the riser stub.

The cross sectional area of each plume was integrated with its respective average velocity and then normalized using the measured oil fraction coefficient. Due to the inherently high variability of flow within these turbulent jet plumes, the flow estimates were calculated as average values using ensembles of statistically large sample populations. Over 16,000 Doppler velocity measurements and 2,600 multibeam sonar cross sections were used to calculate the flow rates of these plumes.

Estimated flow rates on May 31, 2010:

Gas-oil ratio:	**56.3% gas and 43.7% oil**
Riser:	**40,700 bbl oil/day**
BOP kink:	**18,500 bbl oil/day**
Total flow rate:	**59,200 bbl oil/day**
Cum well release	**5 million bbls**
Net spill volume	**4.2 million bbls**

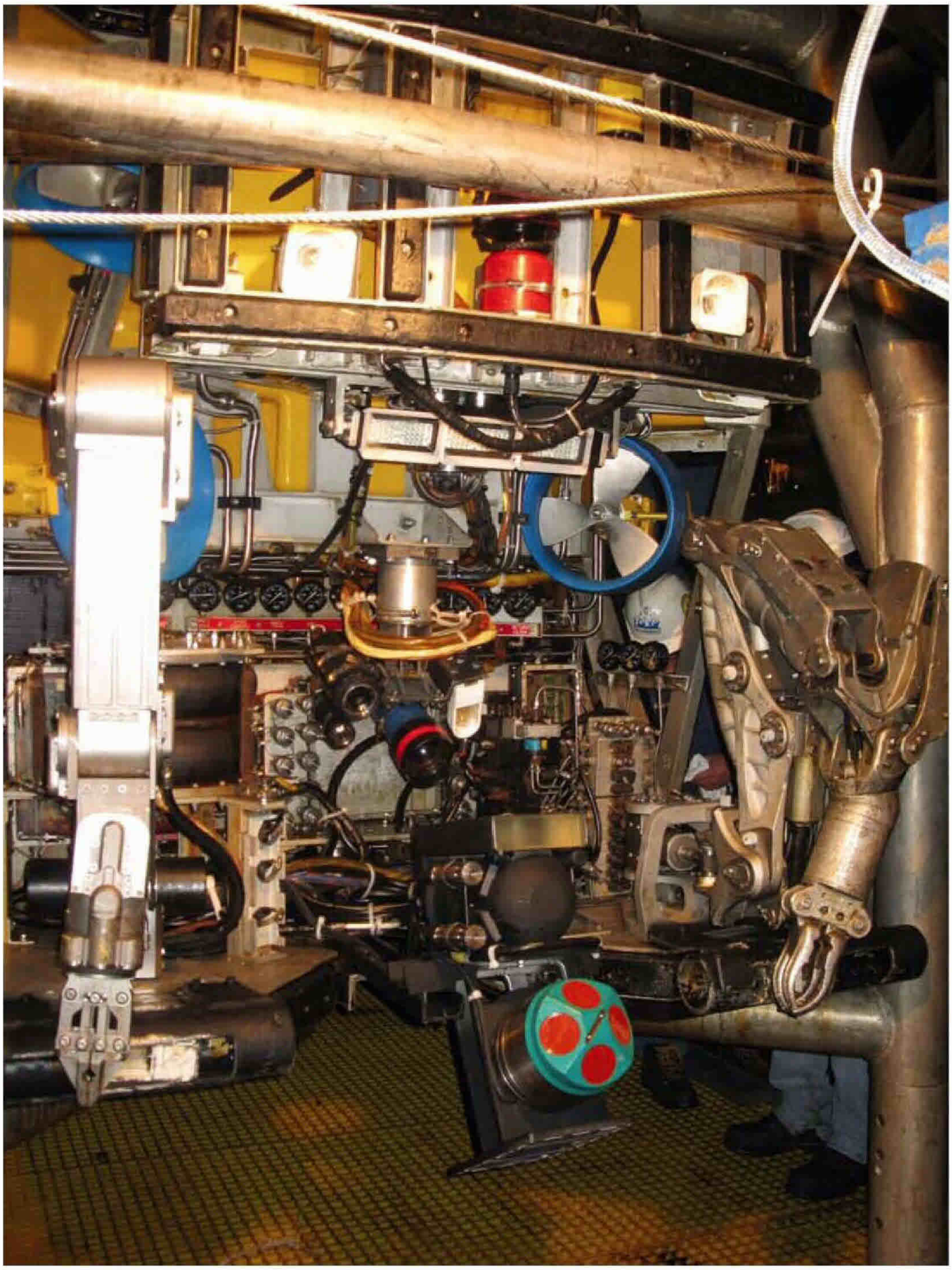


Fig 1: Photo of *MAXX*3 ROV prior to acoustic flow rate survey operations. The ROV is equipped with a forward-looking 1.2MHz ADCP (visible as green object with four red piezo-acoustic disks), and a 1.8MHz acoustic multibeam imaging sonar (visible as yellow rectangular and black circular object directly above the ADCP).

TREX 008804.0067

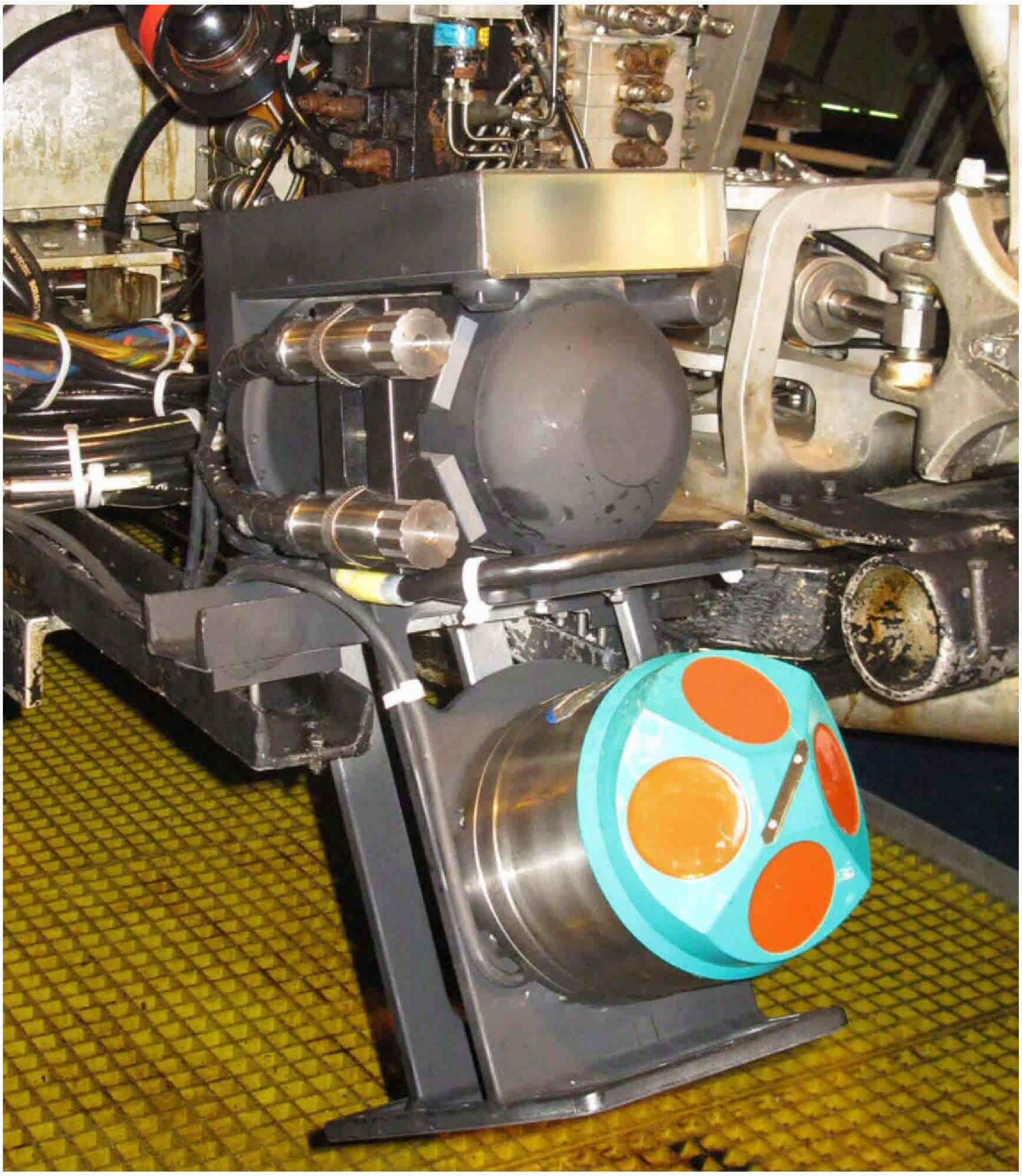


Fig 2: Close-up photo of forward looking ADCP and imaging multibeam sonar mounted on the Oceaneering *MAXX*3 ROV.

TREX 008804.0068

ADCP measurements
Flow velocity measurements of the rising plume were obtained with a 1,200 kHz Acoustic Doppler Current Profiler (ADCP) manufactured by Teledyne RD Instruments, San Diego, CA. Figs 1&2 are photographs of the ADCP unit mounted on the *MAXX3* ROV. This instrument measures fluid velocity parallel to each of four independent sonar beams at regular spatial intervals along the length of each beam. This instrument has four independent sonar beams oriented 30° from the instrument axis on a 90° plan. The instrument was mounted on the front of the *MAXX3* ROV with the instrument axis tilted 30° above horizontal. Fig 3 is a drawing depicting the sonar installation showing acoustic beam #4 oriented horizontally, beam #3 oriented 60° above horizontal, and beams #1 and #2 oriented above the horizontal to, respectively, starboard and port.

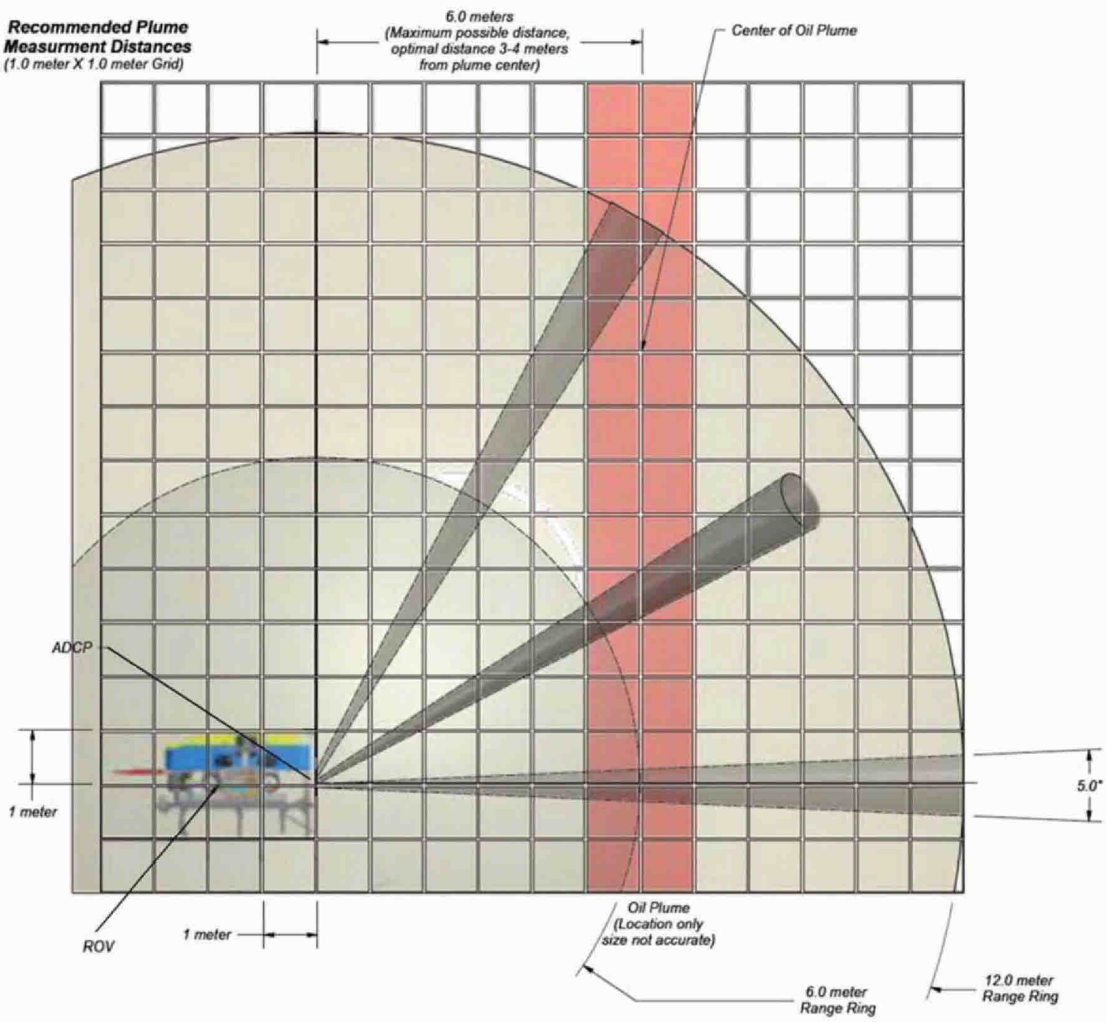


Figure 3: Schematic showing ADCP, as configured on the ROV, with maximum possible beam range at 6 meters offset from plume center.

For the measurements reported herein, the unit was configured to report velocities for each beam at locations up to 15 m from the instrument at fixed intervals along each beam. The ADCP was configured to generate ping ensemble data records at regular interval in several different modes as indicated in Fig 4. The ADCP measurement of the flow velocity along the direction of each beam at each bin interval is specified by the manufacturer to have an expected single acquisition measurement error standard deviation that varies from 9.33 cm/s (for Setup #1) to 2.75 cm/s (for Setup #4 and #5). The expected variation in the measurement standard deviation varies with bin size. Larger bins result in smaller standard deviation but decreased spatial resolution, whereas greater pings per ensemble and greater sample populations result in smaller standard deviation but decreased temporal resolution. For this work the naturally high turbulence of the source plumes made it necessary to use statistically larger sample numbers; thus lower temporal resolution was deemed an acceptable tradeoff for decreased measurement error.

ADCP sonar data of the oil leak plumes at two leak sites: the riser end leak site, and the BOP leak site. At each site, the *MAXX3* ROV was positioned facing the rising oil plume at three locations with the vehicle heading of, respectively, 120°, 240°, and 360°. The lateral ADCP standoff distance from the plume was typically between 2 to 4 m, depending on field of view obstructions. At each station, ADCP sonar data was obtained for durations of approximately 5 minutes in one or more of the configurations given in Fig. The flow velocity data were post-processed and combined with ROV navigation position estimates to compute the instantaneous velocity of each ping ensemble within the 3D coordinate frame. The riser plume velocity measurements used a total of 42,270 ADCP measurements (Fig 5), and the BOP kink plume used a total of 42,894 ADCP measurements as the initial sets of data points. A subset of these velocity measurements (8,372 and 7,763 data points for the riser and BOP kink, respectively) were defined as being within the plume, were then back-projected down to the imaging sonar plane. These back-projected points were then averaged together to produce a time-averaged vertical velocity of the flow at each leak site.

ADCP Setup	Pings Per Ensemble	ADCP Bin Size (m)	Number of Bins	Nearest Bin (m)	Farthest Bin (m)	Ensemble Standard Deviation (cm/sec)	Ensemble Period (sec)
#1	1	0.25	59	0.79	15.29	9.33	1.5
#2	1	0.25	59	0.79	15.29	9.33	1.5
#3	3	0.25	59	0.79	15.29	5.39	1.5
#4	1	0.50	30	1.01	15.51	4.76	0.9
#5	3	0.50	30	1.01	15.51	2.75	0.9

Fig 4: ADCP Configurations

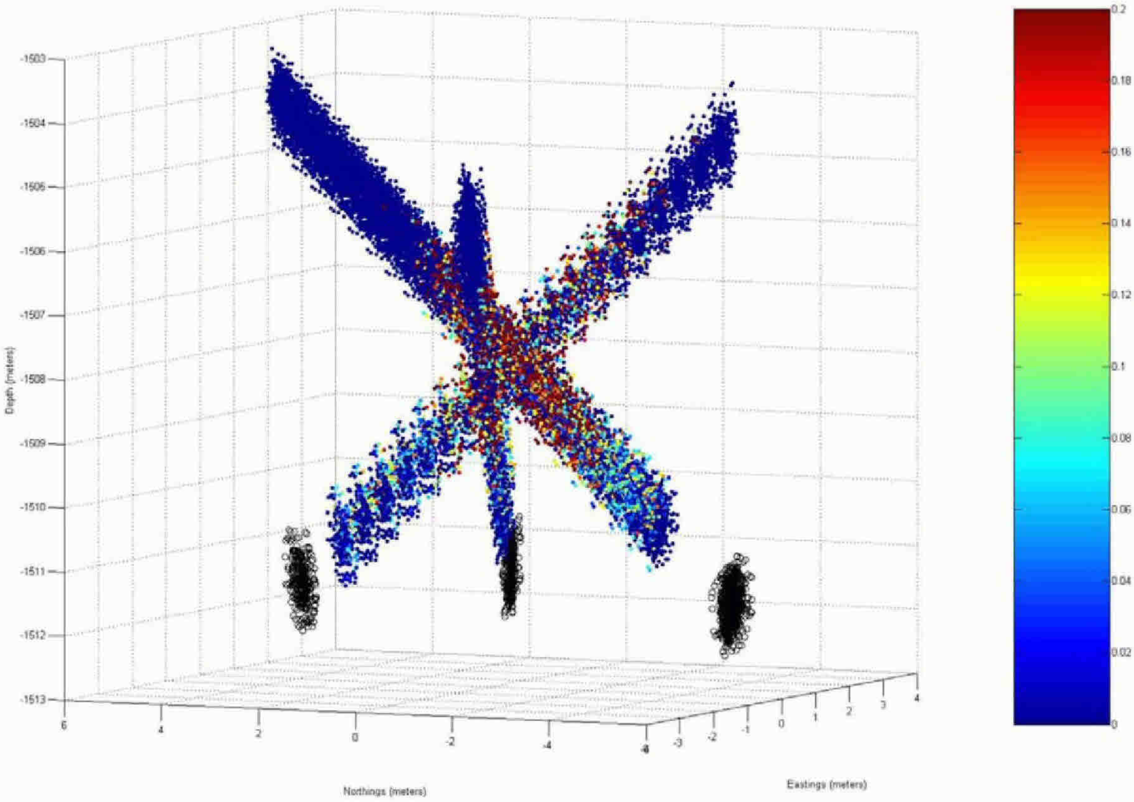


Fig 5: 3D reconstruction of over 42,000 ADCP velocity field measurements recorded at the riser leak site. Each dot represents the location of a Doppler ping ensemble, with the dot color describing the estimated velocity in m/s. The black circles indicate the location of the ADCP instrument during this measurement process.

Acoustic multibeam imaging

Acoustic multibeam imaging was performed at the riser and BOP kink leak sites using a Didson 3000 dual frequency imaging multibeam sonar operating at 1.8MHz. The theoretical resolution at this frequency is on the order of a centimeter. A series of over 1,000 plume cross sections were recorded above each of the leak locations (1089 and 1500 cross sections for the riser and BOP kink, respectively) wherein the sonar imaging plane was positioned at a lateral standoff distance of between 4 and 7 meters, with a height greater than 5X above the source diameter. These sonar cross section measurements were recorded at approximately 7Hz and required between 3 and 4 minutes of acquisition time per leak site.

Cross section calculation was based on inter-frame motion tracking of acoustic returns greater than or equal to 6dB above background noise and areas of plume flow were counted only if the contiguous area was equal to or greater than $100cm^2$ (Fig 6). Because the sonar was mounted to the ROV with an upward viewing angle of 10° the cross-section estimates were normalized by cosine 10°. The average area cross sections of the leak plumes at the riser and BOP kink were calculated to be 0.87 m^2 and $0.61m^2$, respectively.

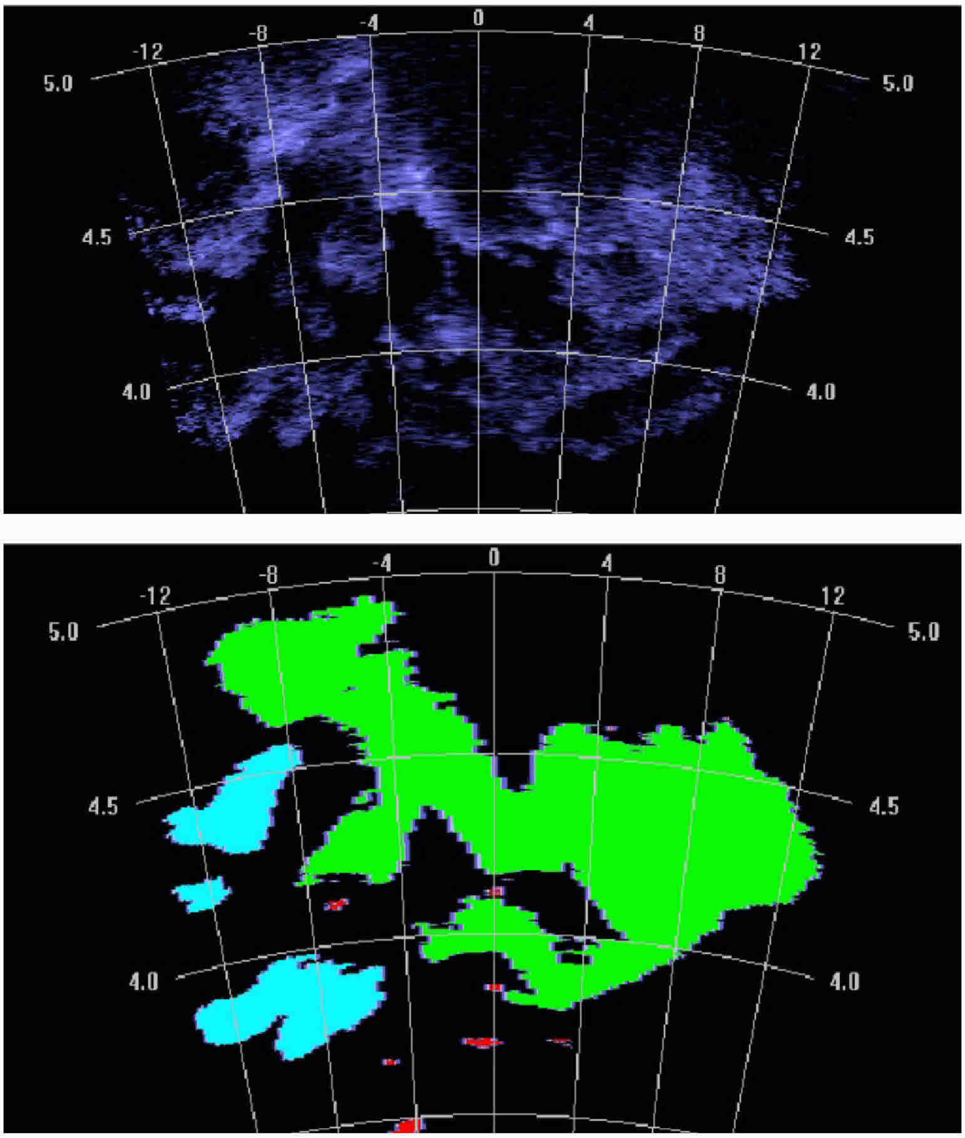


Fig. 6: Upper image shows an example acoustic cross section of plume, lower image shows plume area calculation using motion tracking with a 6dB threshold.

Oil Composition

To determine the gas/oil ratio flowing out of the well, we employed an isobaric gas-tight sampler (IGT; Fig 7) This device was designed for collecting hydrothermal vent fluids and hydrocarbon gases at temperatures up to 400 ºC and capable of preserving the integrity of samples for months until lab-based analysis. More traditional oceanographic water sampling equipment would not be able to prevent degassing during ascent to the ocean surface.

On June 20, 2010, some time after placement of tophat #4 on the riser stub, we collected a sample with a remotely operated vehicle deployed from the *Ocean Intervention III* (Fig 8). Briefly, the snorkel on the sampler was inserted immediately above the riser pipe into the flow of oil and gas. The thermistor attached next to the tip of the snorkel read a temperature of 100 ºC during sampling (with an ambient temperature of 4.4 ºC).

Once the sampler was removed from the ROV on the deck of the *Ocean Intervention III*, its pressure was measured at >2000 psi, consistent with the pressure of the water depth of collection. Following strict chain-of-custody procedures, the sampler was returned to Woods Hole, MA and secured.

The contents of the IGT were then determined by depressurizing the sampler into a custom-built system for collecting the oil and gas (Fig 9). The internal pressure of the sampler measured at WHOI prior to analysis was the same as when measured weeks earlier, indicating no leaks. By measuring the total volumes of oil and gas recovered, a gas/oil ratio of 309 at room temperature and atmospheric pressure was determined. For in-situ calculations, the measured laboratory gas volume was translated to a theoretical volume at 150atm and 4.4 °C. At this temperature and pressure propane and higher chained hydrocarbons were estimated to be in the form of a liquefied condensate and only methane and ethane were assumed to be in gas form at each of the leak sites. Gas analysis of the sample indicated that methane and ethane represent approximately 85.4% of the gas. Thus, the oil fraction at ambient seafloor pressure (150 atm) and temperature (4.4 °C) is 43.7% of the bulk flow.

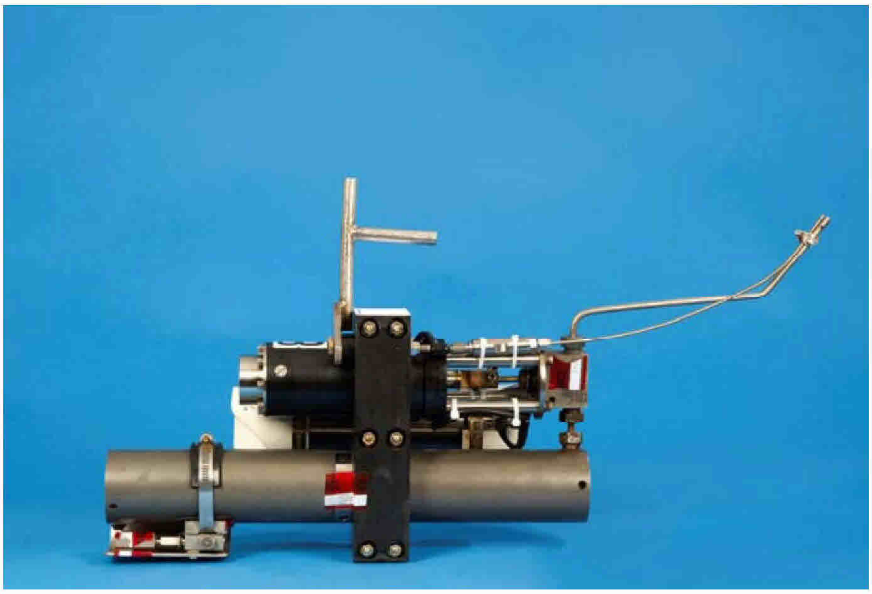


Fig 7: Image of the isobaric gastight (IGT) sampler. The snorkel and thermistor are in the upper right-hand side of the device.

Fig. 8: Image of the IGT sampler prior to integration onto the Millennium 42 ROV on June 20-21, 2010.

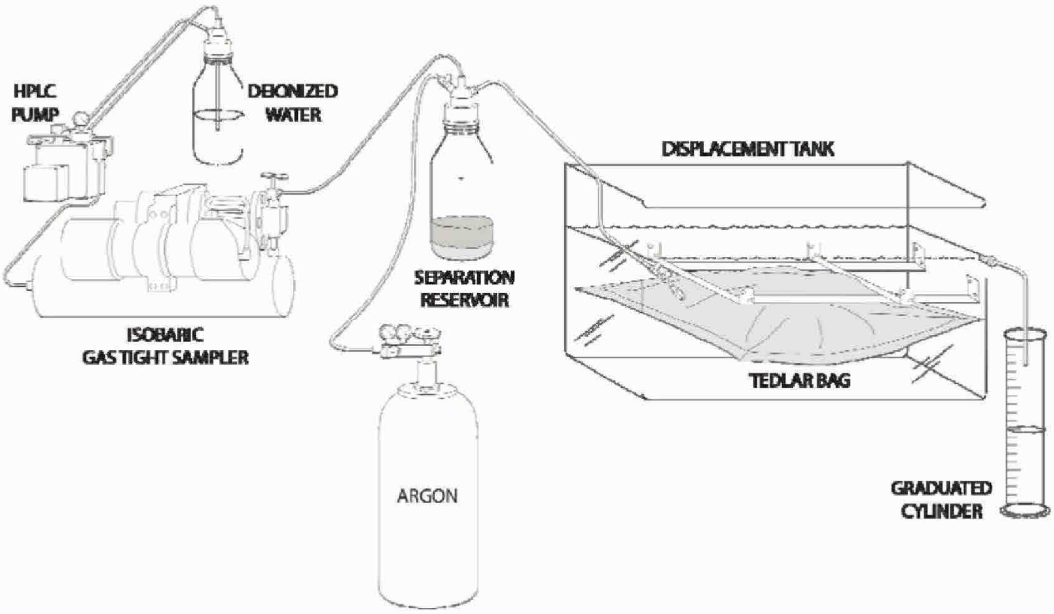


Fig 9: Schematic of system used to depressurize the IGT in the laboratory in Woods Hole to determine the gas/oil ratio from the sample collected within top hat #4.

TREX 008804.0076

Oil flow rate model

Based on empirical data for a wide range of free round jets emanating into a quiescent fluid, in the region where the jet is fully developed, velocity profiles obey laws of similarity such that the fluid velocity profile for a cross section of the jet maps identically to those at increasing distances from the source, once jet growth is accounted for. The distance x_c beyond which the jet velocity profiles become self-similar can change with the velocity profile at the orifice, depending on the boundary layer development inside the pipe leading up to opening. Well beyond x_c the initial jet velocity profile at the orifice becomes inconsequential.

To estimate the flow from the riser leak data obtained using an acoustic Doppler current profiler (ADCP) was combined with cross-sectional area measurements obtained using the imaging sonar system mounted to the Maxx3 ROV. The measured water depths of the riser leak source and BOP kink leak source were estimated to be 1513.9 meters and 1503.5 meters, respectively and using ROV data. The imaging sonar cross sections were measured at 1510.3 meters for the riser jet and 1502.2 meters for the BOP jet.

The four beams of the ADCP were arranged with beam 4 horizontal and co-planar with the Imaging sonar and Beam 3 pointing upwards at 60 degrees. Fig. 10 shows a schematic of the measurement setup. Data was binned to obtain velocities within the jet. The jet was defined based on the equivalent radius of the plume cross section and augmented by an expansion coefficient 0.11 times the distance traveled. Figs 11 and 12 show the velocity measurements defined as being within the plume radius. Each of these velocity values within the plume radius were then back-projected downward to the imaging sonar plane using the equation

$$u_1 = u_2\,(1+ \Delta x/x_1)$$

where u_1 is the calculated velocity at the sonar imaging plane, u_2 is the measured velocity at a height of Δx above the imaging sonar plane, and x_1 is the sonar imaging plane's height above the source.

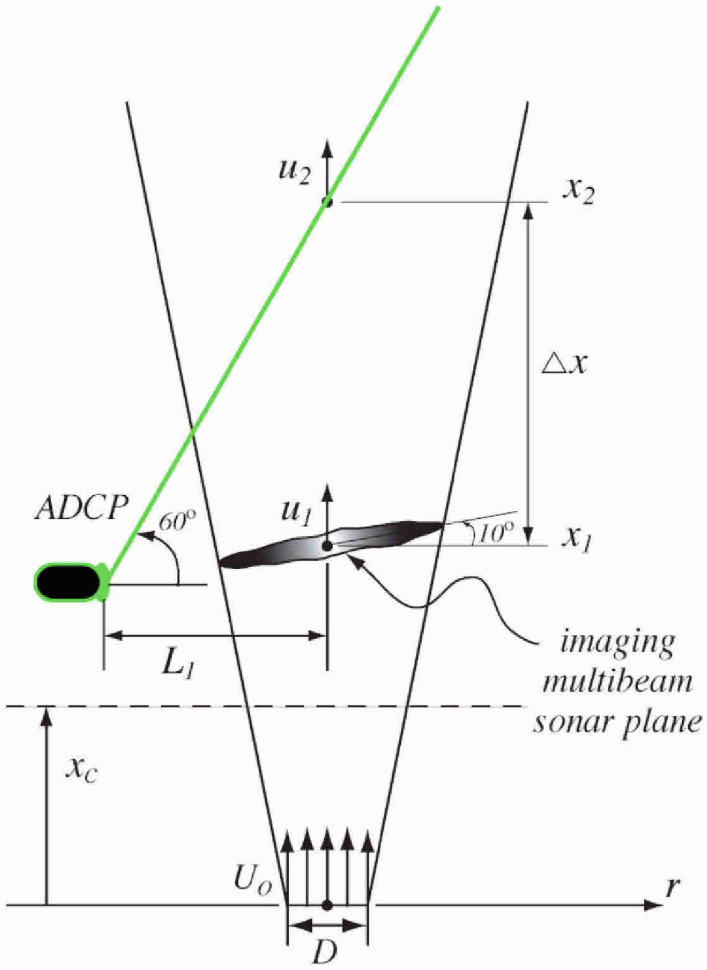


Fig 10: Diagram of computational model used to calculate flow rate using measured cross sectional area estimates and velocity measurements.

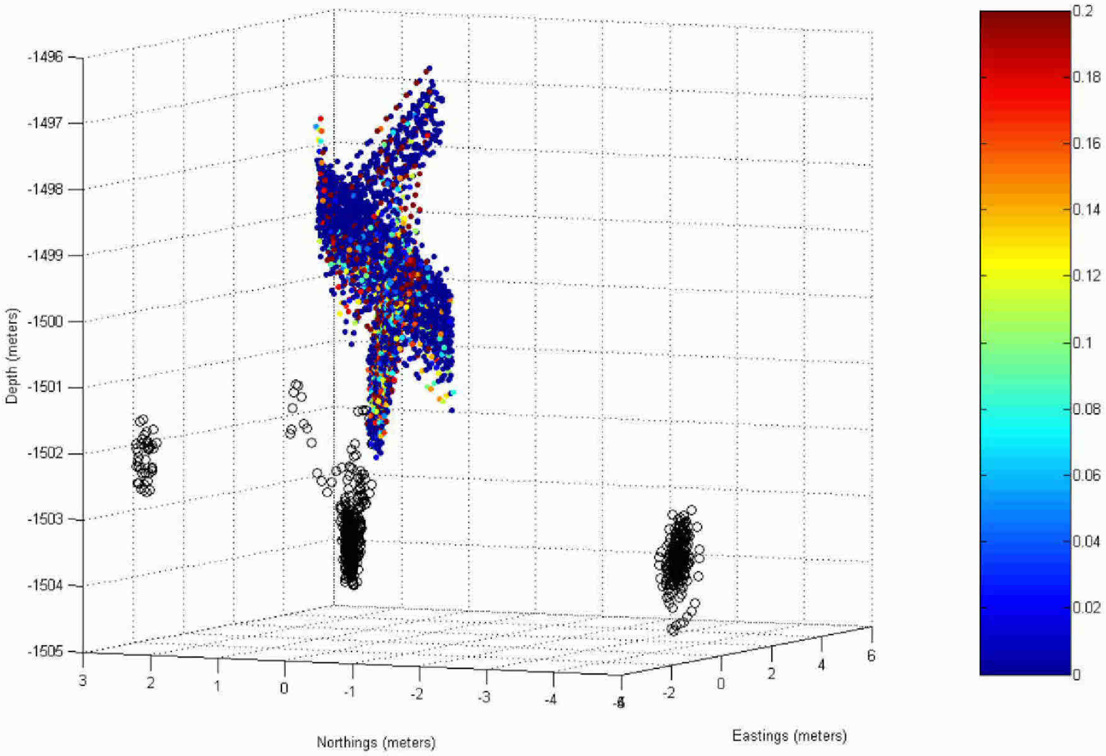


Fig 11: 3D reconstruction of the plume velocity field measured above the BOP kink, only including points defined as being within the plume radius. Colors indicate velocity in meters per second. The black circles indicate ROV positions.

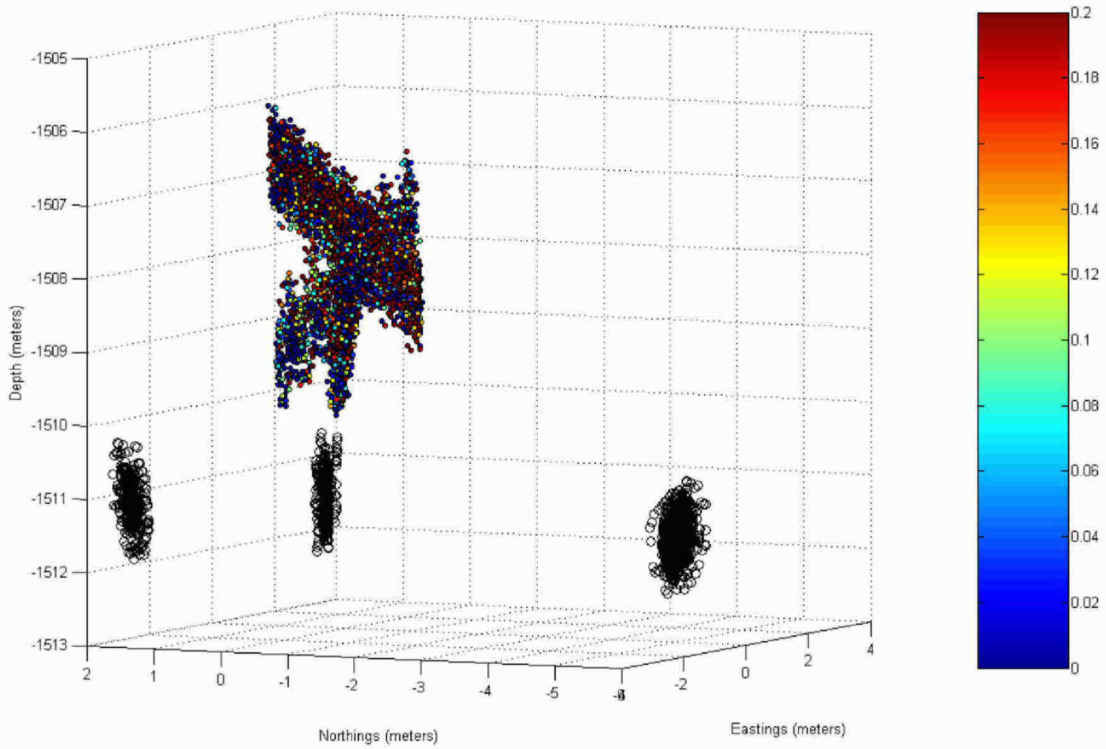


Fig 12. 3D reconstruction of the plume velocity field measured above the riser section, only including points defined as being within the plume radius. Colors indicate velocity in meters per second. The black circles indicate ROV positions.

To calculate the (total) bulk volume flow rate the average cross sectional area (S_1) measured by imaging sonar is multiplied by the average u_1 vertical velocity at the sonar plane. This bulk flow was then multiplied by the oil fraction (previously defined as 0.437) to yield an oil flow rate in m/s. This method yields a volumetric oil flow rate on 5/31/2010 of 0.0781 m^3/s from the leak at the BOP kink, and 0.171m^3/s from the leak at the end of the broken riser. This converts to a rate of 40,700 bbl oil/day from the end of the broken riser and 18,500 bbl oil/day from the BOP kink, or a total flow rate of 59,200 bbl oil/day on 5/31/2010.

Based on this 5/31/10 flow estimate and the DOE Tri-Lab Flow Modeling Team's WIT shut-in estimate (53,000 bbls/day), a linear flow rate trend is extrapolated for the interval between 4/20/10 and 7/14/10. The summation of each day's flow rate is then used to calculate a cumulative total flow from the well. This approach is consistent with the hypothesis that flow rate decreases approximately linearly with time as a result of well pressure decrease. Using this linear fit, a cumulative release of approximately 5 million barrels is estimated to have leaked from the well. Net leak to the ocean can be calculated as the cumulative release minus the oil collected by BP using the RITT, tophat, and BOP lines, or approximately 4.2 million barrels (Fig 13).

TREX 008804.0080

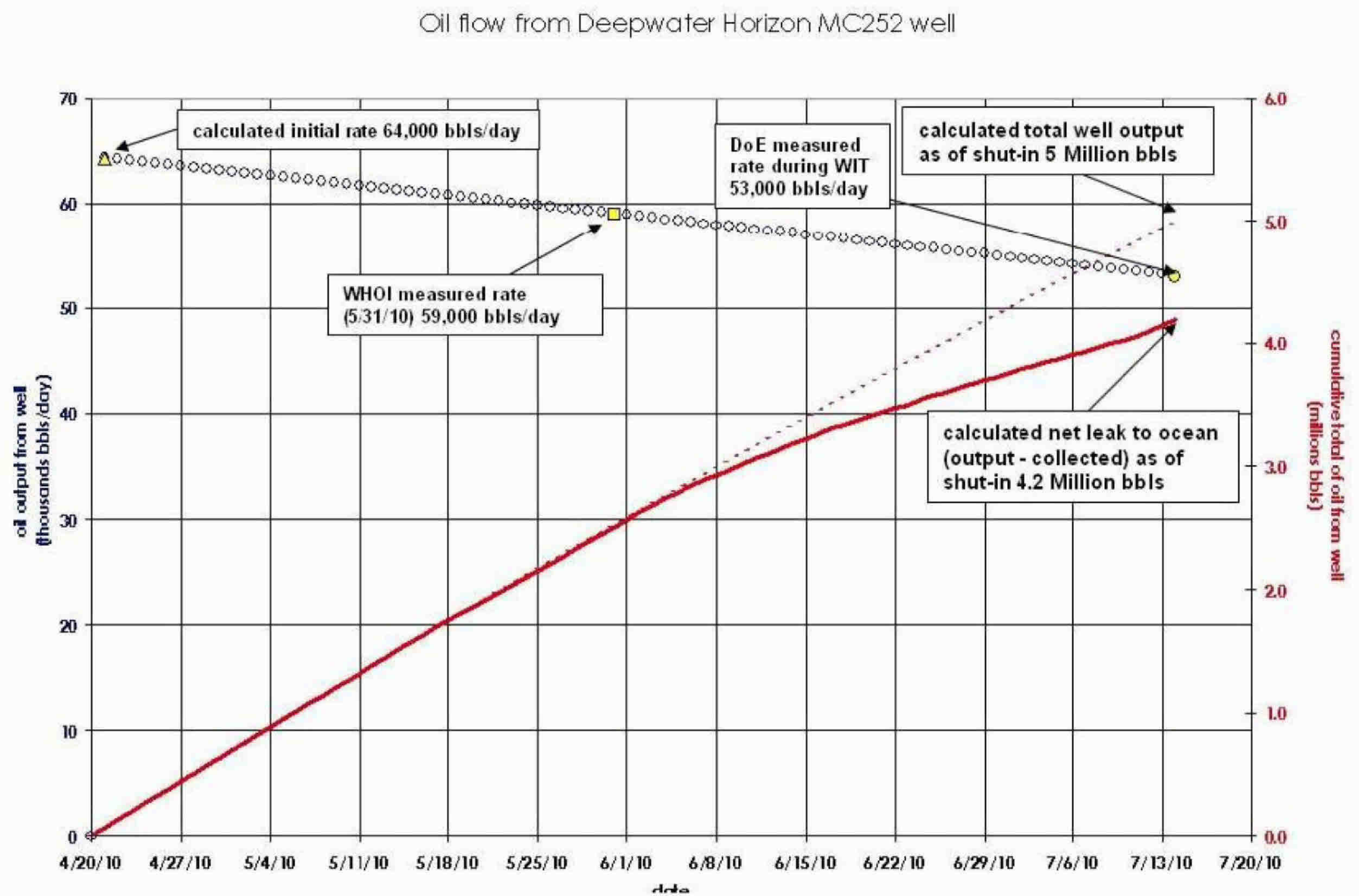


Fig 13: flow estimates of the Deepwater Horizon well

TREX 008804.0081

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

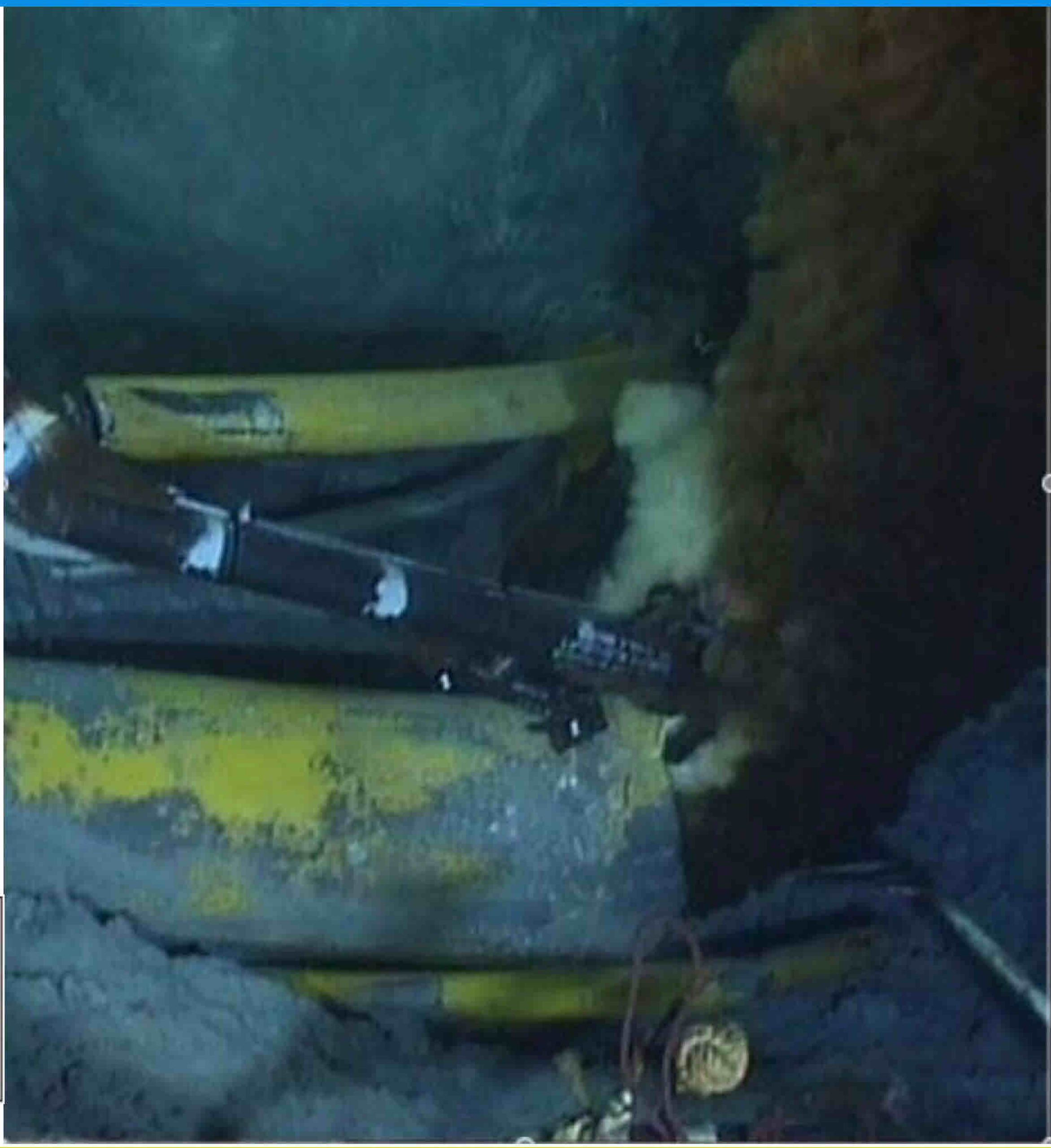
Plume Calculation Team. 2010. Deepwater Horizon Release, Estimate of Rate by PIV. Plume Team report to the Flow Rate Technical Group. July 21, 2010.

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

Deepwater Horizon Release Estimate of Rate by PIV

July 21, 2010

Plume Team - FRTG



Report to

Dr. Marcia Mcnutt, USGS Director and Science Advisor to the Secretary of the Interior
Lead to the National Incident Command Flow Rate Technical Group

Prepared by

Plume Calculation Team

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Yapa, Poojitha	Professor of Civil and Environmental Engineering, Clarkson University

All the calculations and conclusions is this report are preliminary, and intended for the purpose, and only for the purpose, of aiding the response team in assessing the extent of the spilled oil for ongoing response efforts. Other applications of this report are not authorized and are not considered valid. Because of time constraints and limitations of data available to the experts, many of their estimates are only approximate, subject to revision, and certainly should not be used as the federal government's final values for assessing volume of the spill or its impact to the environment or to coastal communities. Each expert that contributed to this report reserves the right to alter his conclusions based upon further analysis or additional information. Note that this version of the report was modified post-July 21, 2010 to correct a typographic error on page 3 and clarify a point about the DOE team data on page 16.

TREX 008804.0084

Table of Contents

TREX 008804.0085

Executive Summary

The plume modeling team observed video both before and after the cutting of the riser pipe. The 'before' video looked at the end of the original riser leak and from the kink in the riser and from the kink leak above the Blowout Preventer (BOP). The later video examined the leakage shortly after the severing operation but before any capping operation.

The main method employed to make estimates was a common fluid dynamic technique called particle image velocimetry (PIV). While difficult in practice, it is simple in principle. A flow event, e.g., an eddy or other identifiable item, is observed at two consecutive video frames. Distance moved per time between frames gives a velocity, after adjustment for viewing angle and other factors. Repeated measurement over time and space give an estimated mean flow. Flow multiplied by cross-section area of the plume gives a volume flux.

Because of time and other constraints, only a small segment of the leakage time was examined, and assumptions were made that may through later information or analysis be shown to be invalid. For example, the Team assumes that the average flow between the start of the incident and the insertion of the Riser Insert Tube Tool (RITT) was relatively constant and the time frames that were included in the examined videos were representative of that average. If this were not true, then the actual spillage may differ significantly from the values stated below.

Most of the experts, using the limited data available and with a small amount of time to process that data, concluded that the best estimate for the average flow rate for the leakage prior to the insertion of the RITT was between 25 to 30 thousand bbl/day. However, it is possible that the spillage could have been as little as 20,000 bbl/day or as large 40,000 bbl/day. Further analysis of the existing data and of other videos not yet viewed may allow a refinement of these numbers.

The video of the post-cut was of higher quality than earlier video. The best estimate of the PIV experts was for a flow of 35,000 to 45,000 bbl with the possibility that the leak could be as large as 50,000 bbl/day. After consultation with groups from the Department of Energy that were using pressure readings from inside the Top Hat to estimate flow, a joint estimated range of 35,000 to 60,000 bbl was provided to the National Incident Command (NIC).

TREX 008804.0086

Deepwater Horizon, on fire after the explosion

Background

When the Deepwater Horizon drilling unit sank in the Gulf of Mexico, initial loss estimates were given as 1000 bbl/day. By April 26, it was obvious that this estimate was too low. Based upon visual observations of oil on the surface, a working number of 5000 bbl/day was adopted. However, the large amount of surface oil, the volume recovered or burned, and a re-examination of the pipe leakage, convinced the National Incident Command (NIC) that it was necessary to revisit the 5000 bbl/day number.

On May 19, the NIC Interagency Solutions Group established the Flow Rate Technical Group that has as one of its subgroups the Plume Team represented in this report. Experts on fluid dynamics, subsurface well blowouts, petroleum engineering and oil spill behavior were assembled as part of a larger effort to improve spill size estimation. The team consists of both government scientists and leading scholars at academic institutions throughout the United States.

On May 27, the Team issued an Interim Report that established an estimated range for the minimum possible spillage rate but did not issue an estimate for a possible maximum value because the quality and length of the video data could not support a reliable calculation. Instead, they requested, and received, more extensive videos from British Petroleum (BP). See Table 1.

Table 1: List of Video Segments on BP-Provided Hard-Drive

subsea 7 — **DVR REGISTER**

Project Title	Deepwater Horizon	Project No.	TC1024
Archive Name	BP_Deepwater_Horizon	Client	BP
Vessel	Skandi Neptune		
Transmittal	TC1024/BPDW/TRANS/007	To S. Dietz	24/05/2010
Seagate 500Gb Drive Contents			

Directory Name	Start KP	End KP	Dive	Date	Time Start	Time End	Remarks
On First RAID Drive, Retrieved from LTO4 tapes 4 and 6							
A.Plume_Monitoring	NA	NA	H14/005	11/05/2010	07:22	08:22	Large Plume Monitoring, Measurement Ops
A.Plume_Monitoring	NA	NA	H14/006	12/05/2010	08:03	08:33	Large Plume Monitoring
A.Plume_Monitoring	NA	NA	H14/006	12/05/2010	10:04	11:04	Large Plume Monitoring
Retrieved from Second RAID Drive (In use on Skandi Neptune as of 24/05/10)							
A.Plume_Monitoring	NA	NA	H14/006	13/05/2010	19:08	19:50	Large Plume Monitoring
A.Plume_Monitoring	NA	NA	H14/006	13-14/05/2010	20:38	06:28	Large Plume Monitoring
D.Chemical_Dispersing_Ops	NA	NA	H14/006	14/05/2010	15:27	16:30	Dispersion at Large Plume
D.Chemical_Dispersing_Ops	NA	NA	H8/033	14/05/2010	15:54	16:17	Dispersion at Large Plume
J.Plume_Test_with_OS	NA	NA	H14/006	14/05/2010	16:50	20:25	Plume testing with OS
A.Plume_Monitoring	NA	NA	H14/006	14-15/05/2010	20:25	01:33	Plume Monitoring
I.Dredging_Ops	NA	NA	H8/032	15/05/2010	01:22	02:52	Dredging Ops
D.Chemical_Dispersing_Ops	NA	NA	H8/032	15/05/2010	02:52	03:42	Dispersion at Large Plume
D.Chemical_Dispersing_Ops	NA	NA	H14/007	15/05/2010	03:45	14:28	Dispersion at Large Plume
I.Dredging_Ops	NA	NA	H8/032	15/05/2010	03:53	05:25	Dredging Ops
I.Dredging_Ops	NA	NA	H8/034	15/05/2010	09:32	10:11	Dredging Ops
I.Dredging_Ops	NA	NA	H8/035	15/05/2010	12:45	14:31	Dredging Ops
H.Special Task\C.Hose Installation	NA	NA	H14/007	15/05/2010	14:36	15:50	Second 6\3 hose installation
A.Plume_Monitoring	NA	NA	H14/007	15-16/05/2010	16:50	01:15	BOP Monitoring (First 1/2 hour is debris)
K.Debris_Inspection	NA	NA	H8/035	15/05/2010	18:58	19:31	Debris Inspection
A.Plume_Monitoring	NA	NA	H8/035	15-16/05/2010	22:58	01:15	BOP Monitoring

After May 16, the Riser Insert Tube Tool (RITT) was placed into the riser at the main leak point, reducing the oil being released into the environment from this source. The recovery rate of gas and oil for the tube between the insertion and May 25 is shown below.

Table 2: Gas and Oil Flow Rates from the Riser Insert Tube Tool

Date	Oil (bo)	Gas (mmcf)	Oil + Gas (boe)	Gas Portion (%)	High Oil (bopd)	Low Oil (bopd)	High Gas (mmcf/d)	Low Gas (mmcf/d)
16-May-2010	290	0.9	440	34%				
17-May-2010	1,410	3.5	2,015	30%				
18-May-2010	1,930	10.4	3,721	48%	2,191	1,066	12.5	5.3
19-May-2010	3,014	17.5	6,025	50%	4,102	1,521	23.2	10.5
20-May-2010	2,185	15.6	4,882	55%	5,389	44	32.4	4.4
21-May-2010	2,173	4.9	3,025	28%	3,599	646	7.6	1.8
22-May-2010	1,361	7.1	2,586	47%	4,531	0	14.7	2.0
23-May-2010	1,120	2.9	1,616	31%	3,103	0	5.6	2.0
24-May-2010	6,078	9.8	7,771	22%	8,961	2,523	16.1	2.0
25-May-2010	2,596	15.8	5,316	51%	7,337	877	30.4	9.4
Total	22,158	88.4	37,397	41%	8,961	0	32.4	1.8
Average	2,430	9.7	4,106	40%				

As can be seen from Table 2, the amount of oil and gas fluctuated significantly. Part of this fluctuation was due to movement of the end of the RITT in the riser due to tidal effects and the natural separation of the oil from the gas in the riser (gas tends to rise to the top). However, examination of the videos also shows significant intermittency in the gas fraction of the flow.

During the time period of the videos examined by the Team, there were two main leak points, shown in Figure 1. The figure also displays the ultimate fate of the released fluid and gas. The main leak, until the most recent severing operation, came from the broken end of the riser, some distance away from the Blowout Preventer (BOP). The leakage was only from the annulus (inside pipe diameter of nineteen and a half inches) surrounding an interior drill pipe (pipe diameter of six and five eighth inches). According to BP, the mouth of the riser was damaged in the initial incident, reducing the cross-sectional area by 30%. Figure 2 shows the damaged riser. After May 1, and perhaps earlier, a second leak source appeared in the kinked riser above the BOP. The number of holes and leakage volume in the kink has increased over time, as BP has attempted to stop oil release by such operations as the RITT and Top Kill.

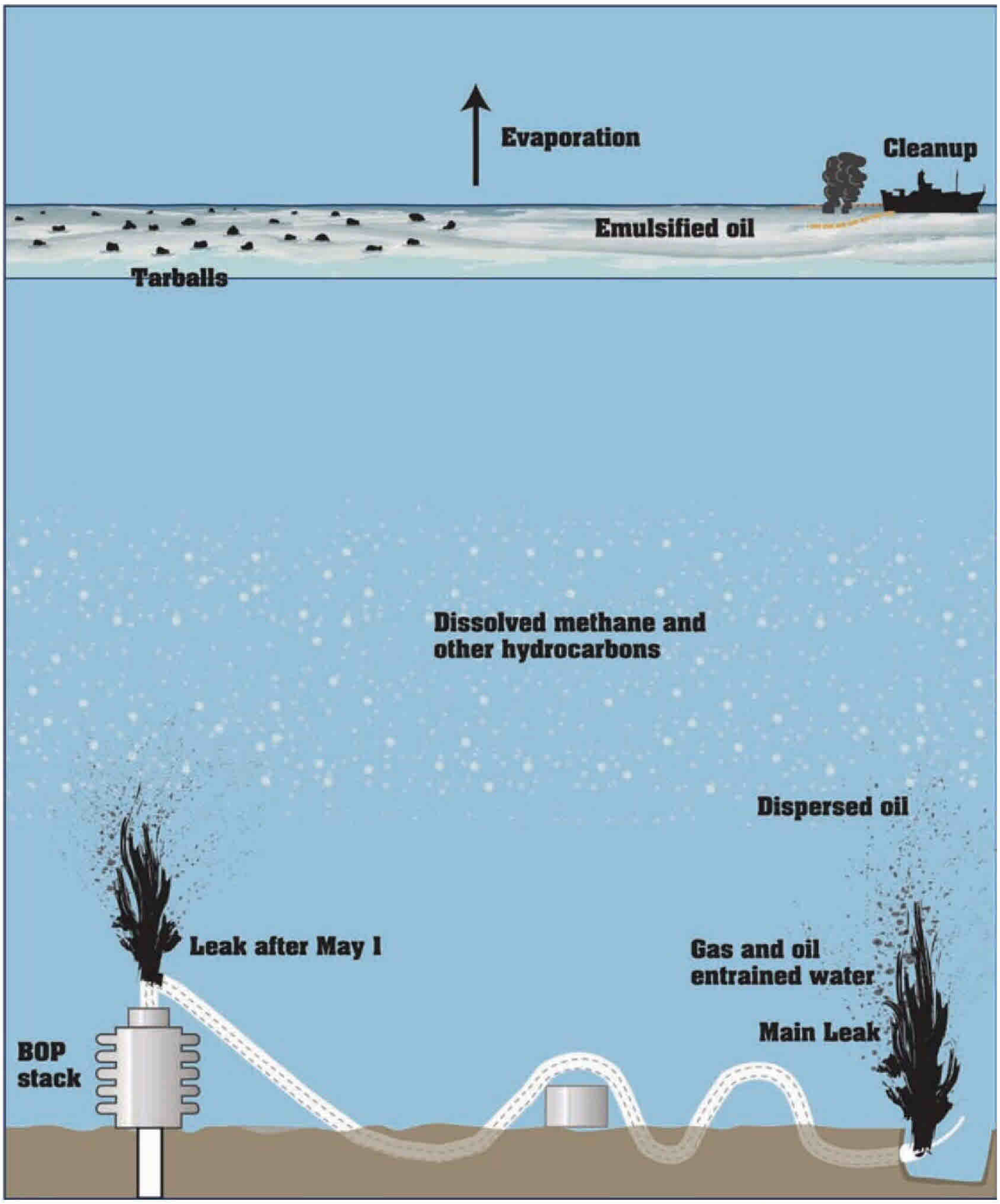

Figure 1: Graphic Showing Leaks and Oil Fate

At certain times, a dispersant wand was inserted in the plume and dispersant added. These chemicals are designed to lower surface tension and reduce the average oil droplet size. Unfortunately for flow rate estimation, they add an additional component to the flow and produce a less defined plume. Measurements were not done using video while dispersant was being applied

While particle image velocimetry (PIV), described in the next section, was the main approach to estimating the leak rate, alternative approaches were used to provide an additional credibility check on the results from the PIV method. These included looking at expected flow based upon properties of the reservoir and reservoir fluid, comparison of this release with a controlled experiment in the North Sea, using well-established similarity characteristics of turbulent jets, and calculating a possible release size, based upon surface oil and oil recovered or burned. Appendix 2 describes an estimate made using one of these alternative methods. Some of these same methods will be or are being examined by other Flow Rate Technical Group teams.

Figure 2: Riser Outlet Showing Its Reduced Cross-Sectional Area

Particle Image Velocimetry

The term particle image velocimetry was first proposed in 1984 by R. J. Adrian, a reviewer of this report. While difficult in practice, PIV is simple in principle. In this method a flow event, e.g., an eddy or other identifiable item, is observed at two consecutive video frames. Distance moved per time between frames gives a velocity, after adjustment for viewing angle and other factors. Repeated measurement over time and space give an estimated mean flow. Flow multiplied by cross-section area of the plume gives a volume flux.

Many researchers were drawn to PIV because it provided a new way to study turbulent flow structure. Turbulence is a phenomenon that is characterized by multiple length scales. To measure turbulent flow, therefore, the method must be able to operate at different scales with possible flow movement in all directions. True PIV uses small, solid particles illuminated by laser light and recorded under very short time exposures. In this instance, natural markers in the flow were employed. These markers themselves changed over time, increasing the complexity of the problem.

Figure 3 illustrates the approach. Because the flow velocity is not uniform throughout the plume, multiple locations, known as interrogation spots, must be sampled to estimate and average velocity. Similarly, the cross-sectional area is time and spatially dependent as well as having diffuse boundaries so that an average cross-section, dependent upon the location of the interrogation spots, needs to be calculated. A further challenge for measuring the flow in this case is that it is not spatially or temporally uniform in mixture of gas and fluid.

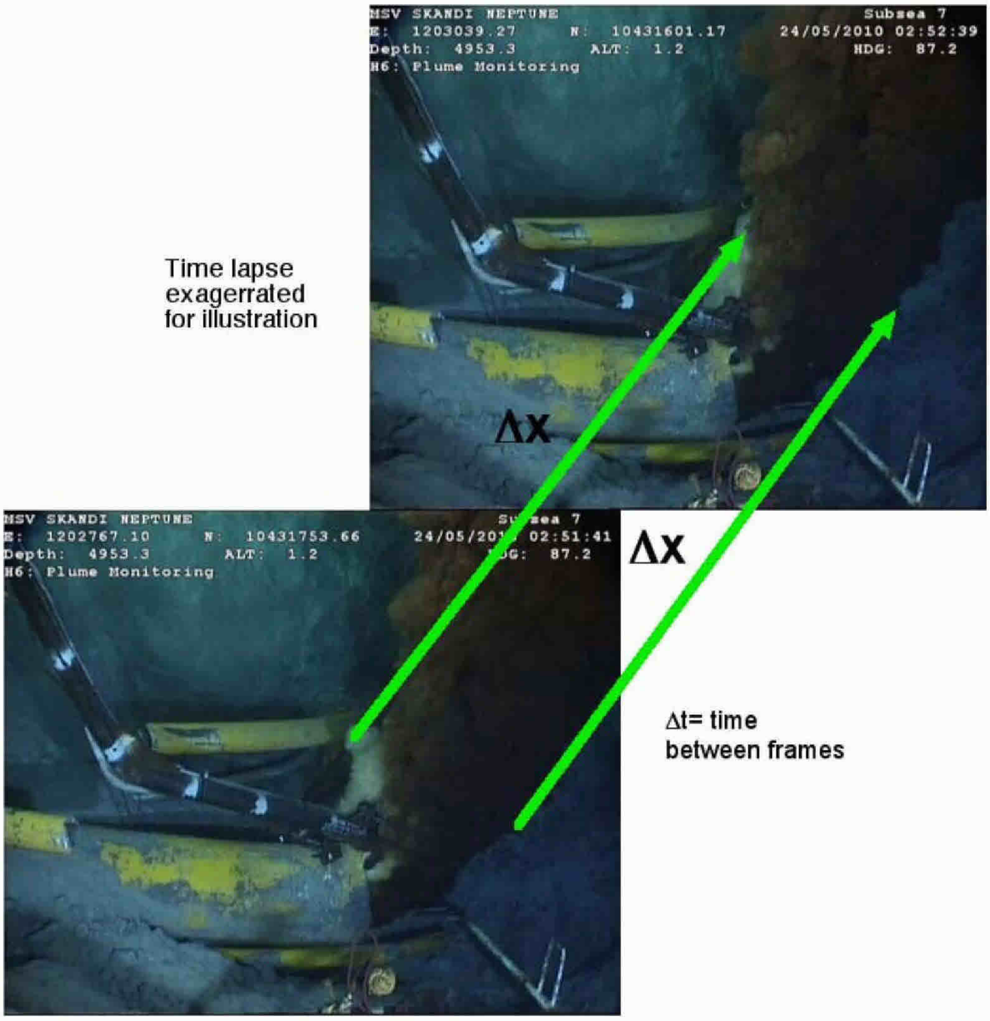

Figure 3: Illustration of Particle Image Velocimetry

For each of the interrogation sites a vector velocity $\Delta X/\Delta t$ is computed. The vector average of these velocities provides an average velocity. Combined with an average cross-section area, this yields a net flux of both gas and oil. A key parameter was this average ratio of gas to liquid. This term seemed to vary over the time period of the spill and during the time of the video clips. Increasing gas increased the velocity of the plume but decreased the mass flow. Analysis of the available short movies of the riser flow shows the existence of periods when the flow oscillates from pure gas to seemingly pure oil. This could be an indication of Slug Flow Regime. These periods of gas-oil flow fluctuation are in the range of minutes. Longer periods may also exist but would require examination of longer clips to determine.

Another key question was the fluid velocity at the interior of the jet, something that obviously could not be directly observed. The different PIV experts approached this problem in different ways. Most assumed a correction factor for the interior velocity, usually two or two multiplied by the square root of two. One expert chose larger scale structure that he believed would feel the interior flow directly so that no correction was necessary.

Kink Leak

The Kink leak began sometime around May 1. The Team has requested clarification of the exact date from BP. The number of holes in the riser pipe at the kink increased on or before May 15. The team believes that the amount of escaping oil from this source increased as the holes widened, increased in number, and as the RITT insertion placed more upstream pressure on the riser. Estimation of the flow from the kink was challenging because only one plume, labeled J1 below, was clearly visible and unobstructed in the video.

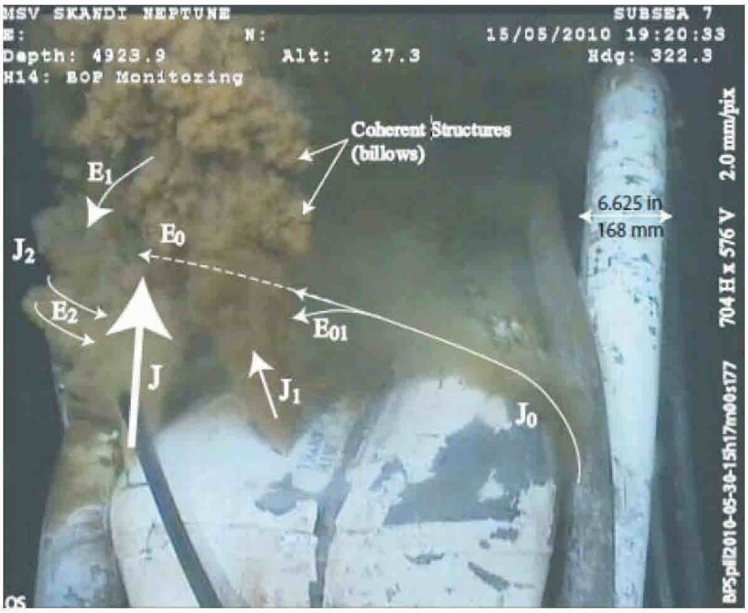

Figure 4: Kink Leak (Annotations by Savas)

New Leak at Severed Riser

By June 3, BP had severed the riser just above the BOP. According to the oil company estimates, this was expected to increase the total leak rate by approximately 20%. Surprisingly, the interior of the riser pipe contained not one, but two pieces of drill pipe inside (Figure 5). One team member speculated that the drill pipe snapped during the accident into several segments that would fit side by side inside the riser. The team requested from BP videos of the leak after the cut but before the installation of a dome designed to capture part of the flow. The damage to the riser during cutting complicated the task of estimating flow cross section.

Figure 5: Cut Riser Showing Two Pipes Inside

The quality of the video was much better for the severed riser flow than the video used for earlier estimates. This allowed for greater confidence in calculated flow. The PIV experts were able to use the visible flange and bolts as references although parallax adjustments were required. There was a noticeable difference in the color of the two distinct plumes emanating from the cut riser. BP attributed this to greater gas content in the lighter plume.

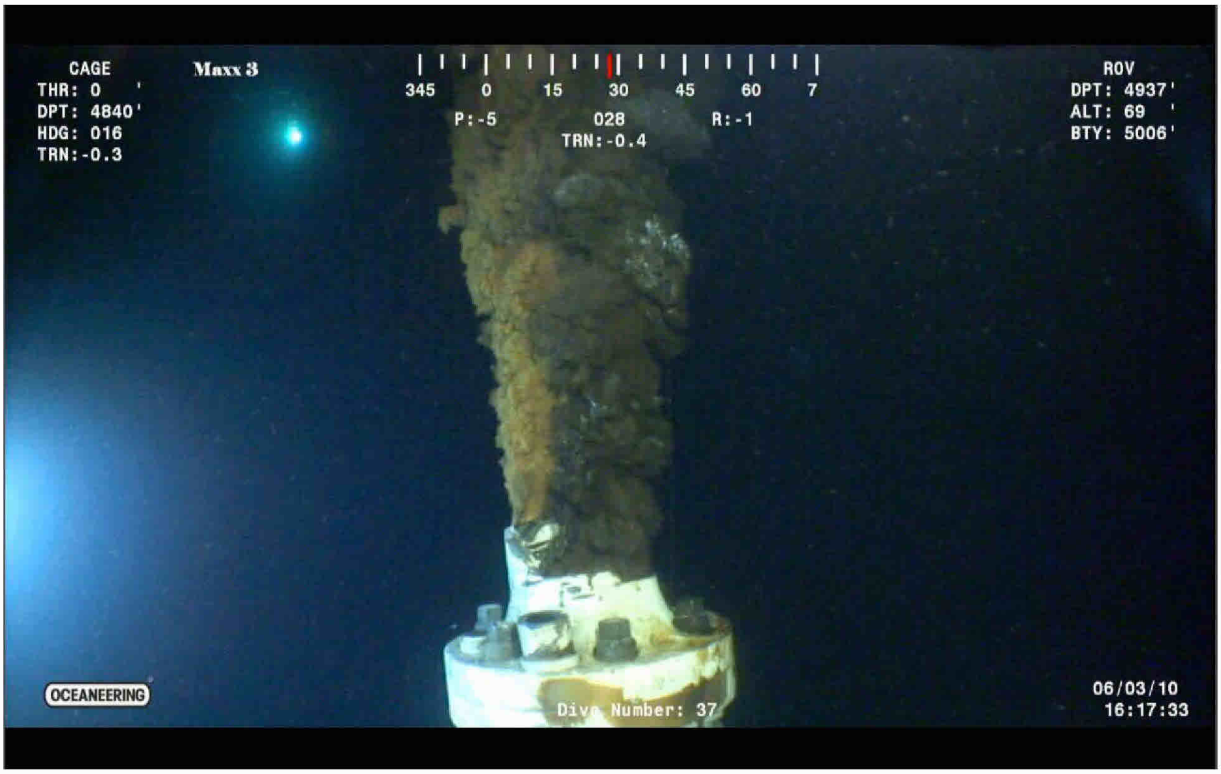

Figure 6: Cut Riser Leak

Shortly after the cut, BP placed a 'Tophat' over the riser stub, allowing the capture of some of the oil. This Tophat had vents that could be equipped with a pressure gauge, allowing an alternative method to estimate the flow. Teams affiliated with the Department of Energy, using the subsequent pressure readings to estimate flow, pooled their findings with the Plume Team results to produce a common estimate for operation purposes to the National Incident Command.

Conclusions

As with earlier estimates, the conclusions in this report are only to aid the Response, not to determine the final Federal estimate of spillage. Because of time and other constraints, only a small segment of the leakage time was examined, and assumptions were made that may through later information or analysis be shown to be invalid. For example, the Team assumes that the average flow between the start of the incident and the insertion of the RITT was relatively constant and the time frames that were included in the examined videos were representative of that average. If this were not true, then the actual spillage may differ significantly from the values stated below.

Most of the experts have concluded that, given the limited data available and the small amount of time to process that data, the best estimate for the average flow rate for the leakage prior to the insertion of the RITT is between 25 to 30 thousand bbl/day. However, it is possible that the spillage could have been as little as 20,000 bbl/day or as large 40,000 bbl/day. Further analysis of the existing data and of other videos not yet viewed may allow a refinement of these numbers.

For the time period after the riser cut, most of the experts concluded that the likely range for the flow was between 35,000 and 45,000 bbl/day but could be as high as 50,000 bbl/day.

The Plume Team then met with other experts from the Department of Energy, who employed non-PIV methods to estimate flow rate. The combined groups reached a consensus estimated flow range of 35,000 bbl/day to 60,000 bbl/day.

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.

Flow Rate Technical Group
Reservoir Modeling Team
Summary Report

August 11, 2010

CONTENTS

1. Overview

The Reservoir Modeling Team (Team) was established within the Flow Rate Technical Group (FRTG) to develop an independent assessment of the rate at which oil and gas can be produced from the sands penetrated by BP's Macondo well. Using open-hole logs; pressure, volume, and temperature data; core samples; and analog reservoir data; the Team directed the development of reservoir models from three independent groups of researchers from academia and other experts in the field of reservoir simulation. The researchers populated computer models and determined flow rates from the targeted sands in the well as a function of flowing bottomhole pressure.

The Nodal Analysis Team of the FRTG used reservoir modeling data (including pressure, temperature, fluid composition and properties over time), pressure and temperature conditions at leak points on the sea floor, along with details of the geometries of the well, BOP, and riser to calculate production rates from BP's well. The results of the Reservoir Modeling - Nodal Analysis study represent a scientific methodology that is independent of other FRTG methodologies that are being used to develop flow rate estimates.

2. Team Members

The Team is made up of engineers from the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) from the New Orleans Region Office and the USGS in Denver. BOEMRE personnel were responsible for obtaining proprietary rock, fluid and well data from BP and geologic interpretations of the target sands from BOEMRE geoscientists. The BOEMRE Team members were also responsible for conducting market research, assisting in developing formal federal contracts for the studies, assessing bid packages for the contracts, recommending selection of the researchers, and reviewing the deliverables for the Contracting Officer and FRTG. The BOEMRE members are Don Maclay, Gerald Crawford, David Absher and other Gulf of Mexico Region staff petroleum engineers.

The Team's representative from the USGS is Dr. Mahendra K. Verma, Research Petroleum Engineer at the USGS Energy Resources Science Center in Denver, CO. Dr. Verma's expertise in reservoir engineering and simulation allowed him to serve as an advisor in the area of reservoir simulation and as peer reviewer of the output data from the researchers.

3. Independent Researchers

Federal contracts were awarded to three independent research groups to conduct studies for the FRTG. These contracts were developed and executed in accordance with all federal acquisitions regulations which was required before work could begin by the research teams. This contracting process generally takes several months to complete; however, to expedite the process, a market research was preformed by the Team to justify other than full and open competition (JOFOC). By using the market research/JOFOC methodology, the time needed to award the contracts was reduced to three weeks.

The researchers selected for the project were as follows:

(1) Kelkar and Associates (University of Tulsa Group):
Dr. M. Kelkar, Professor, University of Tulsa, PhD Chemical Engineering, University of Pittsburgh,
Dr. H. Ates, Senior consultant, PhD Petroleum Engineering, University of Tulsa,
Dr. A. Bahar, Principal Consultant, PhD Petroleum Engineering, University of Tulsa.

(2) R.G. Hughes and Associates (LSU Group):
Dr. R.G. Hughes, Associate Professor, Louisiana State University, PhD Petroleum Engineering, Stanford University.

(3) Gemini Solutions (independent reservoir simulation firm):
Dr. J. Buchwalter, PhD Chemical Engineering, Rice University,
Dr. R. Calvert, PhD Biophysics, University of Houston.

The time given the researchers for their analysis, one to two weeks, was limited due to the timeline established by the FRTG. After allocating time for input data review, model construction, output data review and report writing, the researchers were left with only a few days to actually run the simulations. This was an extremely challenging schedule; however, the researchers were successful in providing the contracted deliverables as required.

BOEMRE supplied the input data, and due to the time constraints, required the researchers to focus on most-likely and worst case scenarios. The research teams were free to develop other scenarios testing sensitivities to a variety of reservoir parameters if time permitted. The research conducted by each team was independent of the other teams' analyses; the teams were not made aware that other groups were involved with the same project through BOEMRE. This was done to maintain a high level of independence among the research teams.

4. Input Data

The Team compiled and reviewed all pertinent reservoir and fluid information needed to perform reservoir simulation studies for the FRTG. The information included reservoir rock data, rotary core data, PVT data, bottom hole pressure transient data, the wellbore schematic listing all critical dimensions and depths, flow assurance wax and asphaltene analyses, geochemical analysis, mud log and CMR log analysis and raw log data. The same items listed above were also compiled and reviewed for an analog well drilled 20 miles away.

Data developed by BOEMRE, Office of Resource Evaluation, engineers and geoscientists include petrophysical analyses and 3-D seismic interpretations of the target sands. This information along with the data obtained from BP was transferred to the researchers once contracts were awarded and Data/Information Security Agreement forms were signed and returned to BOEMRE. The data were also uploaded to a secure ftp site developed by NOAA for the sharing of information between NOAA, DOE and BOEMRE.

5. Methodology

The researchers used different software packages to simulate reservoir performance and incorporated a variety of approaches to establish a range of possible outcomes. In addition, a detailed wellbore configuration provided by BOEMRE was incorporated into the models in order to develop a tubing lift curve to initiate production from the simulator.

Kelkar
Kelkar and Associates (Kelkar) used Schlumberger's Eclipse simulator to model reservoir performance. Kelkar developed sensitivities to several reservoir parameters and potential flow paths. One set of cases utilized base case/mean reservoir parameters with variations in flow path, choke size and pipe roughness. A second set of cases was developed using maximum reservoir parameters. Kelkar's forecasts also incorporated the effect of the installation of the Lower Marine Riser Package. Reservoir performance was simulated out to 116 days.

Hughes
R.G. Hughes and Associates (Hughes) used CMG's IMAX simulator to model reservoir performance. Hughes focused on developing sensitivities to structural interpretation using a fairly strong aquifer. Also, an initial blowout ramp up period was incorporated into these cases to reflect falling flowing bottomhole pressures during the first several days as the wellbore deteriorated. The flow path was assumed to be between the open hole and casing, and between the various casing strings. Reservoir performance was simulated out to 122 days.

Gemini
Gemini Solutions (Gemini) used GSI's Merlin simulator to model reservoir performance. Gemini developed sensitivities to reservoir parameters, potential flow paths and location of the OWC. In addition, the effects of 2-phase vertical flow correlations were investigated. The results of an absolute worst case scenario which reflected flow through multiple paths were also reported. Reservoir performance was simulated out to 10 years.

6. Results

The three independent researchers developed reservoir models for the targeted sands in BP's Macondo well and reported flow rates with associated bottomhole pressures and average reservoir pressures. The effects of reservoir and aquifer size, permeability variations and flow path were included in the analyses. In addition, all three researchers incorporated the initial wellbore configuration into their models and assumed annular flow as the base case. The range of possible outcomes reported for initial production rate is 27,300 to 102,607 BOPD.

Kelkar

Kelkar developed two sets of cases; one set using maximum values of fluid and reservoir parameters and the other using base case fluid and reservoir parameters. Each set includes 5 cases reflecting differing flow paths (tubing versus annular flow), choke diameters (2" versus 4" choke) and pipe roughness (smooth versus rough pipe). The range of values reported for initial flow rate is 27,300 to 45,400 BOPD (note: Kelkar's maximum production rates occur on the first day of the incident). The base case set forecasts rates between 27,300 and 31,500 BOPD and the maximum case set estimates initial rates between 36,800 to 45,400 BOPD.

In sensitivities developed by Kelkar, the researchers found that vertical flow performance curves based on assumed tubing and annular flow scenarios are more important than any static reservoir description parameter. Varying flow paths and choke sizes, resulted in a production rate impact of 9,000 BOPD, with rock, fluid and structural parameters held constant. After flow path, permeability was shown to influence rate significantly. Increasing permeability by 50 percent increased initial flow rate by 5,000 BOPD. Kelkar also reports that porosity and rock compressibility sensitivities had very little impact on production performance.

Hughes

Hughes developed two cases based on different reservoir structural assumptions. These cases assume different reservoir extents (sheet sand versus channel/levee complex) and fairly strong aquifer support. The flow path simulated was between the open hole and casing. The results show maximum flow rates from 63,157 to 65,531 BOPD (note: Hughes' maximum flow rates occur after a 10 day ramp up period). The flow path assumed by Hughes was also the same one incorporated into the other researchers' models and represents their most-likely flow scenario.

The results of Hughes' structural/stratigraphic interpretation sensitivity also showed that static reservoir parameters, apart from permeability, have a minimal impact on initial flow rate. Hughes' maximum case interpretation increased rate by only 1,400 BOPD.

Gemini

The data presented by Gemini includes a base case and 26 total sensitivities to structure, permeability, flow path and tubing flow correlations. The base case, assuming an infinite aquifer and an annular flow path, estimates an initial flow rate of 58,352 BOPD. The range of initial production rates reported is 40,564 to 102,607 BOPD (note: Gemini reports all production rates as daily average rates for a given week; maximum production rates provided are the daily average flow rate during the first week following the blowout. The output data were formatted in this manner due to the length of the simulation runs – 10 years).

Sensitivities to rock compressibility, aquifer size and location of OWC resulted in initial production rate changes of less than 1,000 BOPD, although a high permeability sensitivity increased rate by 2,000 BOPD and a low permeability case decreased rate by 7,000 BOPD. These results show that apart from permeability, variations in reservoir properties do not significantly affect initial production rate.

A sensitivity to reservoir extent supported Hughes' findings that showed little impact to initial production rate. Running the simulation out several years, however, showed that at 2 years, the case assuming a regional sheet sand had a daily production rate double that of the more limited case assuming a channel/levee complex with stratigraphic flow boundaries on two sides.

Gemini also ran several cases to test the model's sensitivity to four different flow correlations. Three of the correlations resulted in flow rates within 2,200 BOPD to each other (Hagedorn & Brown, Duns & Ross and Orkiszewski), while the fourth (Beggs and Brill) was ~14,000 BOPD greater than the others; the Beggs and Brill case predicted an initial rate of ~73,000 BOPD. The results of this analysis were used to determine the appropriate flow correlation for the base case; Gemini selected the Orkiszewski correlation.

Sensitivities to the flow path (annulus versus shoe failure) resulted in initial rate differences of over 16,000 BOPD, and the one high rate case which assumes all possible flow paths combined, generated a rate approximately 44,000 BOPD higher than the base case.

Reservoir Modeling Team

The reservoir Modeling Team developed Inflow Performance Relationship (IPR) curves for all cases submitted. These curves represent the relationship between flow rate and flowing bottomhole pressure at a specific time in the reservoir's life, and reflect fluid and rock properties at that time. The curves are designed to be used with outflow curves (tubing performance curves) to determine flow rate from the well. Discussions with the Nodal Analysis Team indicated that IPR curves were required for day 28 and day 56 after the blowout. These two curves were developed for each case and the data uploaded to the NOAA sftp site.

A preliminary statistical review of the results of the 39 cases submitted was conducted using Microsoft Excel. This analysis shows the 10th percentile at 32,688 BOPD and the 90th percentile at 63,432 BOPD.

One caveat concerning the production data generated by the researchers is that the data do not necessarily reflect changing tubing, drill pipe, BOP or riser configurations developed by the Nodal Analysis Team; this was not a necessary component of this project. The required output from this research was to generate data that could be used to develop inflow performance relationships for a variety of reservoir conditions. This requirement was fulfilled by the research teams.

6. Conclusions

1. Variations in reservoir properties such as rock compressibility and porosity, and OWC location, did not significantly affect initial production rate. Production rate variations of less than 1,000 BOPD were reported for these sensitivities.

2. Permeability uncertainties were shown to significantly affect production rate. A low permeability sensitivity resulted in decreasing the reservoir's productivity index (PI, *BOPD/psi*) by 50 percent; a high permeability case resulted in doubling the reservoir's PI.

3. Aquifer size variation had little impact on initial production rate; even after two years of production, significant variation between aquifer size cases was not observed. At five years, however, an infinitely acting aquifer case was forecasted to produce at a rate 50% greater than a 6:1 aquifer case; after 10 years, six times greater.

4. Different structural/stratigraphic interpretations impacting reservoir extent did not show a significant difference in initial flow rates. After 6 months, however, the two cases (sheet sand versus channel/levee complex) begin to diverge significantly; the sheet sand case forecasted a production rate 17 percent higher than the channel/levee complex case.

5. Four tubing flow correlations were tested in this study. Three of the methods (Hagedorn & Brown, Duns & Ross and Orkiszewski) showed similar results; one method (Beggs and Brill) resulted in a 24 percent higher initial production rate.

6. The variable with the greatest impact on flow rate from the Macondo well is the flow path. An annular flow path resulted in approximately 16,000 BOPD higher initial production rate (+38 percent) than a tubing/drill pipe flow model. When flow through all possible paths was considered, initial rate increased by 75 percent over the base case.

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.

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

Nodal Analysis Estimates of Fluid Flow from the BP Macondo MC252 Well

Conducted for the Flow Rate Technical Group (FRTG)
of the National Incident Command

23 July 2010, R2

George Guthrie (NETL; nodal-team lead), Rajesh Pawar (LANL team lead),
Curt Oldenburg (LBNL team lead), Todd Weisgraber (LLNL team lead),
Grant Bromhal (NETL team lead), Phil Gauglitz (PNNL team lead)

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1.0 Executive Summary

The Nodal-Analysis Team estimated flow rate for various time periods based on modeling by five different DOE national labs, each using different approaches.

The estimated flow rates[1] for two key time periods were:

- 40,000–91,000 STB/day (95% confidence interval) with a corresponding best estimate of 65,000 STB/day for the time period following partial closure of the BOP but prior to capping of the drill pipe (25 April – 5 May)
- 35,000–106,000 STB/day (95% confidence interval) with a corresponding best estimate of 70,000 STB/day for the time period following cutting of the riser and drill pipe but prior to placement of the top hat (1–3 June)

These represent reconciled ranges based on independent estimates from multiple national labs using a statistical analysis by NIST.

The estimates for these time periods were also analyzed with respect to two end-member scenarios for flow in the wellbore, which resulted in a bimodal distribution of estimates.

The wide spectrum of approaches used to estimate flow exhibited good agreement on a benchmarking scenario (*e.g.*, with a standard deviation of ~6% on estimated rates).

The large range in the estimates of flow related primarily to uncertainty associated with the well failure mechanism and, hence, the flow scenario within the well. Specifically, estimates were highly dependent on whether flow occurred primarily inside the casing or in the annular space outside the casing.

In addition, several uncertain and/or variable parameters were important in the estimation of flow, including bottom-hole pressure (which relates in part to flow in the reservoir), resistance in the blowout preventer, casing roughness, and gas-oil ratio. The Nodal-Analysis Team flow estimates include considerations of these parameters.

2.0 Background

The Nodal-Analysis Team is part of the Flow Rate Technical Group (FRTG), which was asked to estimate the flow rates from the Deepwater Horizon MC-252 well. The Nodal-Analysis Team was tasked with providing an estimate of flow rate by nodal analysis of the flow from the reservoir to the release points; another team (the Reservoir-Modeling Team, led by Minerals Management Service or MMS[2]) was tasked with estimating flow within the reservoir.

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1 As with all estimates in this report, these estimates assume a constant reservoir pressure over time.

2 MMS has become Bureau of Ocean Energy Management or BOEM.

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Nodal-Analysis Summary

The Department of Energy was asked by the FRTG to lead the Nodal-Analysis Team, so DOE's Assistant Secretary for Fossil Energy engaged a team of five DOE national labs that have been collaboratively addressing other fossil-energy challenges. These labs are:

- LANL—Los Alamos National Laboratory
- LBNL—Lawrence Berkeley National Laboratory
- LLNL—Lawrence Livermore National Laboratory
- NETL—National Energy Technology Laboratory
- PNNL—Pacific Northwest National Laboratory

Experts at a sixth national lab (ORNL—Oak Ridge National Lab) were engaged to provide a peer-review of the work (as requested by the FRTG). As the DOE-FE lab, NETL was asked to lead this multi-lab effort. Statistics experts at the National Institute of Standards and Technology (NIST) provided an analysis of the pooled estimates for some time periods in order to arrive at a single estimate for each time period.

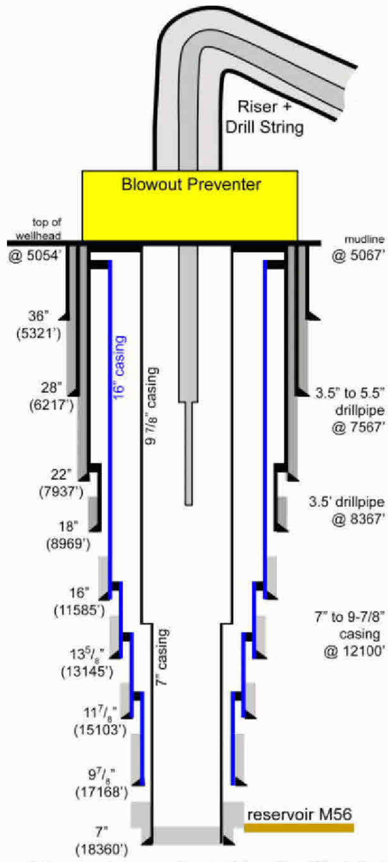

Figure 1: Schematic diagram of the system evaluated by the Nodal-Analysis Team (based on well schematic details from BP as available on http://www.energy.gov/open/oilspilldata.htm).

Using five different but comparable methodologies, the Nodal-Analysis Team focused on an estimate of fluid flow (including oil flow) from the reservoir to the release point(s), based on pressure drops from the reservoir to the ocean floor that result from restriction to flow through the reservoir-well-BOP[3]-riser system (Fig. 1). As noted, the MMS-led Reservoir-Modeling Team conducted detailed analysis of the reservoir flow; these results were used to inform the Nodal-Analysis Team with respect to some details of reservoir processes. Specifically, the link between reservoir and well relates to the coupling of flow rates out of the reservoir as a function of bottom-hole pressure, which is in turn a function of flow conditions in the well. To address this coupling, reservoir flow was incorporated into each of the nodal-analysis models to varying degrees and using different approaches. In addition, predictions from the Nodal-Analysis Team were made for a wide range of bottom-hole pressures to allow flexibility in comparisons with anticipated Reservoir-Modeling Team results.

3.0 General Approach

The five DOE national labs comprising the Nodal-Analysis Team used a diverse set of approaches to predict fluid flow (including two-phase flow, as relevant) through the various parts of the system. Each lab engaged a diverse team of its scientists and engineers, resulting in five separate teams estimating the flow.

Detailed discussions occurred across the Nodal-Analysis Team with respect to conceptual descriptions of the system, data needs, computational approaches, etc., providing an element of inter-lab peer review. Each individual lab team estimated flow rates independently. After the individual lab teams had conducted their analyses, flow estimates were discussed across the Nodal-Analysis Team to develop the conclusions as outlined in this summary report.

3.1 Data

Data used in the estimates[4] included a set of proprietary reports provided by MMS:

- Reservoir data included pressure (P), temperature (T), depth range, permeability, and porosity. Data sources included a wellbore schematic prepared by BP (now publicly available; listing depths and T), a report prepared for BP by Weatherford Laboratories (listing permeability/porosity at various depths), a wire-line log (which included porosity and permeability as a function of depth), a report prepared for BP by Schlumberger (listing reservoir pressures and temperatures), and verbal communication from MMS (confirming reservoir pressure and temperature).
- Fluid data included chemical analysis and fluid properties of the produced hydrocarbon (including component hydrocarbon percentages, gas-to-oil ratio, density, viscosity, compressibility, Pressure-Volume-Temperature (PVT) relationships for reservoir fluids, API gravity, properties at reservoir conditions, bubble-point pressure). Data sources included reports prepared for BP by Schlumberger and Pencor. Each team developed its own method to describe fluid

[3] BOP: Blowout Preventer

[4] Details of the data are discussed in confidential reports from each of the individual lab teams; these proprietary data are *not* described in detail in this Summary Report.

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properties throughout the system, consistent with the observed properties as reported.

- Well geometry data included the depths and sizes of casings and liners, cement zones, depths and sizes of drill pipe, T as a function of depth, and geometry of the BOP. The primary data source was a schematic prepare by BP (now publicly available).
- BOP data included a report on pressure measurements made at various points in the BOP on 25 May 2010.[5] This information was used to establish potential pressure drops associated with the BOP at one-point-in-time for a given set of conditions.

3.2 Computational Models

All five approaches accounted for the physics of two-phase fluid flow (as necessary).

Three of the five approaches (LANL, LLNL, and NETL) utilized models of the well system that accounted for reservoir coupling through the relationship between bottom-hole pressure and flow rate (Inflow Performance Relationship, or IPR). A preliminary IPR was calculated by NETL (Fig. 2) based on a black-oil model and a 17-layer reservoir model using site characteristics from a wire-line log. Two of the five approaches (LBNL and PNNL) utilized a coupled reservoir–well model.

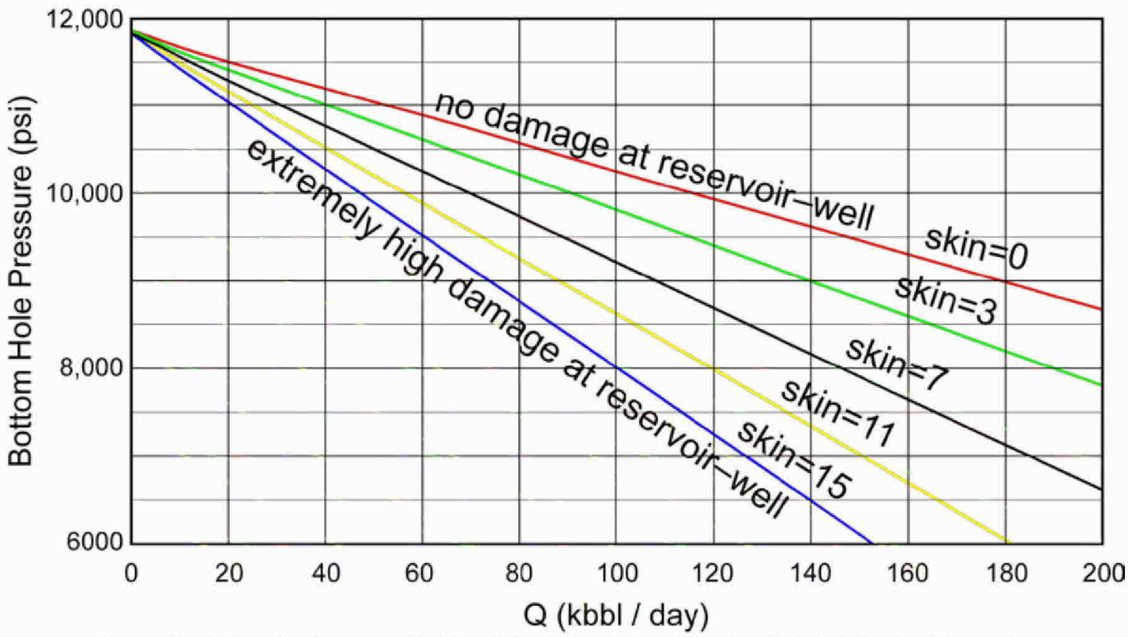

Figure 2: Inflow Performance Relationship at simulation day 15 calculated for the Deepwater Horizon site based on a black-oil simulator and a 17-layer reservoir model built in CMG. Skin factor is a parameter used to account for resistance between the reservoir and the well, usually associated with damage at the interface. A skin of 0 corresponds to no damage, whereas a skin of 15 corresponds to extremely high damage. A skin of 3 would be a commonly expected value.

[5] As reported on http://www.energy.gov/open/oilspilldata.htm.

A summary of the different approaches follows:

- LANL—a parametric engineering model to predict volumetric two-phase flow rates of oil and gas through both known and postulated restrictions in the wellbore system and associated pressure losses; flow estimates were calculated as a function of bottom-hole-pressure; oil properties were described following Dindoruk & Christman (2004) along with data from Schlumberger for the Macondo MC 252 well; gas properties were described following Peng-Robinson (1972) and Jossi et al. (1962).[6]
- LBNL—a coupled wellbore-reservoir flow model based on the Drift-Flux Model and modified to handle oil-gas systems and to handle uncertainty quantification and sensitivity analysis
- LLNL—a two-phase flow model based on BP oil property data for flow within the well system, including the effects of heat transfer to the surrounding rock, and reported pressure drops across the BOP; flow estimates were calculated as a function of bottom-hole pressure
- NETL—a parametric facility model (including well, BOP, riser, and drill pipe) developed using Pipesim™ and tied to the reservoir through an IPR curve to describe the behavior of flow in the reservoir (*i.e.*, flow estimates were calculated as a function of bottom-hole pressure)
- PNNL—a coupled reservoir-well model to estimate the frictional pressure drop(s) within the wellbore system using the revised Beggs and Brill two-phase flow model, given an assumed stock oil production rate; oil properties were described following Standing's correlation for bubble point, Glaso for dead oil, Begg-Robinson and Vasquez-Beggs for saturated oil; gas properties were described following Dranchuk and Abu-Kassem for compressibility and density and the Lee-Gonzalez-Eakins method for viscosity.

3.3 Time Periods with Different Flow Conditions

The well has experienced different flow conditions over several time periods that were considered by the various teams (Table 1). In addition, some simulations were done by each team for a hypothetical situation representing no BOP (i.e., no ΔP across the BOP).

[6] See Appendix for references: *Report on Estimation of Oil Flow Rate from British Petroleum (BP) Oil Company's Macondo Well* prepared by Los Alamos National Laboratory.

Table 1: Comparison of Simulations Conducted for Different Modeling Periods/Flow Conditions

Time Period	*Description*	*Dates*	*LANL*	*LBNL*	*LLNL*	*NETL*	*PNNL*
1	After explosion prior to rig collapse	20 Apr–22 Apr	X				
2	Post rig collapse but prior to partial closure of BOP	22 Apr–25 Apr	X				
3	Post partial closure of BOP but prior to capping of drill pipe	25 Apr–05 May	X		X	X	
4	Post capping of drill pipe but prior to cutting of riser	05 May–01 Jun	X			X	
5	Post cutting of riser but prior to placing top hat	01 Jun–03 Jun	X	X	X	X	X
6	Post cutting of riser with top hat in place	03 Jun–				X	

3.4 Conceptual Flow Models

The Nodal-Analysis Team assumed that the well was not originally open to flow from the reservoir (based on reports that it had not been perforated). Hence, uncertainty exists as to the mechanism by which hydrocarbon fluids enter the well system. Based on expert opinion, we considered various plausible flow scenarios that could represent flow paths of fluids exiting the riser after entering the well-BOP-riser system either through: (a) the wellhead seal assembly at the top of the well, (b) the 7” casing at the bottom of the well, or (c) the 9-7/8” casing along the well. These scenarios result in two end-member flow conditions: (1) dominantly annular flow outside of the completion casing (Fig. 3a) or (2) dominantly pipe flow inside the completion casing (Fig. 3b). We also considered an intermediate scenario where flow initiates in the annular region and then enters the completion casing at a point along the well (Fig. 3c). Some of the teams simulated all three well-flow scenarios; some teams simulated one of the scenarios.

Flow conditions within the BOP were not modeled in detail. Instead, the effect of restrictions in the BOP was modeled either as a uniform pressure drop across the BOP or as a very small diameter pipe. Pressure measurements reported for the BOP on 25 May 2010 provided a baseline for the ΔP at one point in time. However, due to the potential for variation in the BOP pressure drop over time, teams assessed flow over a range in BOP pressure drop.

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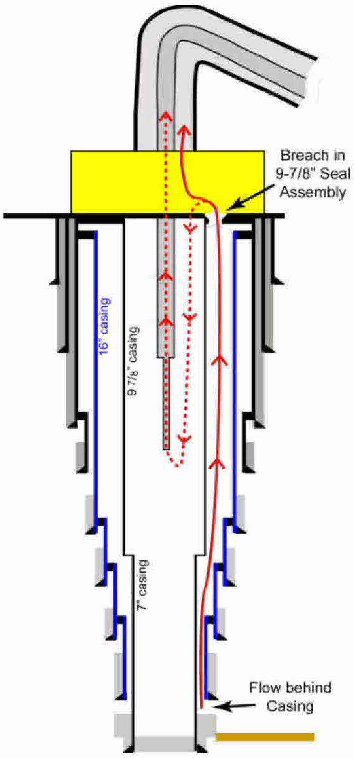

Figure 3a: Schematic diagram of well flow for Scenario 1. Flow initiates in the annular space between liner and casing, flowing through a breach at the top (in the seal assembly) into BOP and then riser; depending on flow restrictions in BOP, some flow may re-enter the casing to flow down to enter the drill pipe.

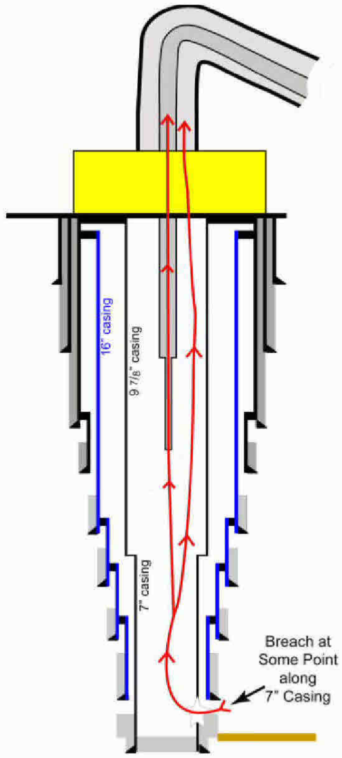

Figure 3b: Schematic diagram of well flow for Scenario 2. Flow initiates in a breach of the 7" casing, flowing up the casing. Some flow enters drill pipe, some continues up the casing to BOP.

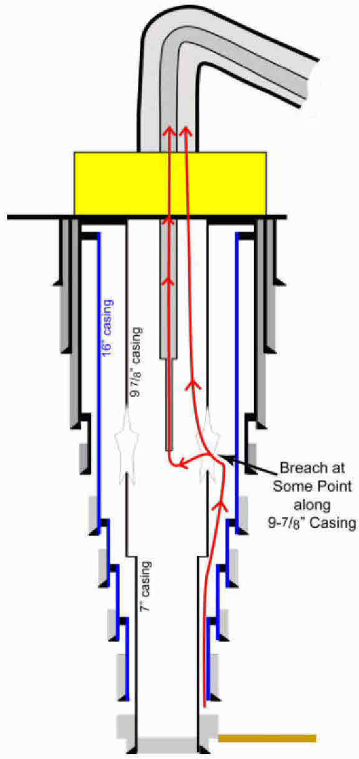

Figure 3c: Schematic diagram of well flow for Scenario 3. Flow initiates in the annular space between liner and casing, entering a breach in 9-7/8" casing and continuing to flow upward inside the casing. Some flow enters drill pipe, some continues up the casing to BOP.

4.0 Conclusions

4.1 Flow Dynamics in Well

All models predicted two-phase flow in the upper portion of the well, which is consistent with reported bubble point pressures for the reservoir hydrocarbon and with the reported pressure of 4400 psi measured at the bottom of the BOP on 25 May 2010.[7] Determining and accounting for the vertical distribution of single phase and two-phase flow was important to estimating the flow rates.

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[7] See "Pressure Data Within BOP" at http://www.energy.gov/open/oilspilldata.htm (filename: "4.2_Item_1_BOP_Pressures_07_Jun_1200_Read_Only.xls")

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4.2 Choice of Conceptual Flow Model

Teams that compared scenarios found that flow scenario 2 (Fig. 3b) resulted in the highest flow rate by a factor of 1.5–2 over flow scenarios 1 or 3. Additionally, scenarios 1 & 3 produced roughly the same flow estimates.

4.3 Consensus Flow Rates

To develop a consensus flow rate, the Nodal-Analysis Team recognized the variety of potential flow scenarios and time periods, as well as the variety of estimation approaches used by the individual lab teams. This variability precluded the development of a consensus flow rate based simply on comparison of predicted ranges reported by each team. Instead, a set of Nodal-Analysis Team flow rates was developed based on considerations discussed below. In addition, the Nodal-Analysis Team engaged statistical experts at the National Institute of Standards and Technology (NIST) to assist in developing a set of flow rates consistent with the various estimation results from each lab team for time periods where multiple teams made estimates of flow.

The Nodal-Analysis Team concluded that two primary factors should be considered in assessment of flow rates: choice of time period (Table 1) and choice of flow model within the well (Figs. 3a–3c):

- The Nodal-Analysis Team concluded that flow rates for the different time periods would likely differ due to fundamental differences in the flow characteristics of the system. Consequently, flow rates should be considered specifically for each time period. Time period 5 (post cutting of the riser and prior to installation of the top hat) was the only time period for which all teams assessed rates. Consequently, this time period was initially used for comparing the various estimation approaches. In addition, it was concluded that estimates of flow rates for other time periods would be determined using estimates from subsets of the Nodal-Analysis Team (as available).
- With respect to choice of flow pathway, the Nodal-Analysis Team had little basis upon which to evaluate whether any one of the three flow scenarios considered were most likely. However, the clear difference in rates between scenario 2 and scenarios 1 & 3 was used as a consensus observation by the Nodal-Analysis Team to exploit in developing the definition for a consensus rate. Specifically, it was agreed that an estimate for the lower bound of flow rate should be based on the lower bound for scenarios 1 and/or 3, whereas an estimate for the upper bound of flow rate should be based on of the upper bound for scenario 2.

In addition, the Nodal-Analysis Team chose to determine these lower and upper bounds using an expert-elicitation process, whereby each team would be treated as a separate expert group and report its estimated rates using the following guidance:

- A lower bound should represent the 5th percentile level, whereas an upper bound should represent the 95th percentile level. In cases where no Monte Carlo analysis was done, these values were based on expert judgment within the individual lab team on rates corresponding to conditions consistent with a 90% confidence interval. Individual lab teams then reported low and high values independently, and these were then analyzed in composite to arrive at a consensus range of rates for the 90% confidence interval.

Table 2 shows the results of this composite analysis.

Table 2: Summary of (composite) flow estimates** for various time periods (Table 1).

		Low Estimate	*High Estimate*	*Assumptions*
Time Period 1	LANL	*55,000*	112,000	Low estimate is lowest value of 5th percentiles for scenarios 1 & 3; high estimate is 95th percentile value for scenario 2
Time Period 2	LANL	49,000	100,000	Low estimate is lowest value of 5th percentiles for scenarios 1 & 3; high estimate is 95th percentile value for scenario 2
Time Period 3	LANL	42,000	90,000	Low estimate is lowest value of 5th percentiles for scenarios 1 & 3; high estimate is 95th percentile value for scenario 2
	LLNL	45,000	83,000	assuming low/high values of skin (0/15) and roughness (dimensionless roughness = 0.0002/0.002)
	NETL	45,000	87,000	5th and 95th percentile using populations derived from extensive parametric study
Time Period 4	LANL	39,000	81,000	Low estimate is lowest value of 5th percentiles for scenarios 1 & 3; high estimate is 95th percentile value for scenario 2
	NETL	(N/A)	80,000	95th percentile using population derived from extensive parametric study
Time Period 5	LANL	46,000	96,000	Low estimate is lowest value of 5th percentiles for scenarios 1 & 3; high estimate is 95th percentile value for scenario 2
	LBNL	(N/A)	120,000	based on 500 M-C simulations of the system with well screened across entire thickness of the reservoir and no BOP pressure losses
	LLNL	46,000	85,000	assuming low/high values for skin (0/15) and roughness (dimensionless roughness = 0.0002/0.002)
	NETL	45,000	100,000	5th and 95th percentile using populations derived from extensive parametric study
	PNNL	30,000	110,000	based on expert opinion: using lower values than median calculation for scenario 3; estimating higher possible flows from plausible ranges of input parameters for scenario 2

** Results are presented to two significant figures.

Table 2a: Summary of flow estimates** for time periods 3 and 5.

		Scenarios 1/3		*Scenario 2*		
		Low Estimate	*High Estimate*	*Low Estimate*	*High Estimate*	*Assumptions*
Time Period 3	LANL	42,000	54,000	67,000	90,000	Low/high estimates are lowest/highest value of 5th/95th percentiles for scenarios 1 & 3 and for scenario 2
	LLNL	45,000	55,000	64,000	83,000	Low/high estimates assume high/low values for skin (15/0) and roughness (0.002/0.0002 inches)
	NETL	46,000	63,000	61,000	86,000	Low/high estimates are lowest/highest value of 5th/95th percentiles for scenarios 1 & 3 and for scenario 2; slight variations from numbers in Table 2 reflect updated calculations based on new information from MMS
Time Period 5	LANL	46,000	56,000	73,000	96,000	Low/high estimates are lowest/highest value of 5th/95th percentiles for scenarios 1 & 3 and for scenario 2
	LBNL	(N/A)	(N/A)	90,000	118,000	Based on 37-m open borehole
	LLNL	46,000	56,000	66,000	85,000	Low/high estimates assume high/low values for skin (15/0) and roughness (0.002/0.0002 inches)
	NETL	45,000	64,000	62,000	96,000	Assuming min/max values for cases examined corresponded to P_{01}/P_{99} values of a Gaussian distribution; standard deviation was based on a standard normal table, with mean taken as average of P_{01}/P_{99} (symmetric) and where P_{01}/P_{99} correspond to a Z-value of 2.33 (Freund, 1992, Mathematical Statistics)
	PNNL	30,000	55,000	44,000	110,000	Low for scenarios 1/3 is reduction in lowest case by 20% to account for uncertainty; low for scenario 2 is low permeability/high BOP pressure loss case with 2000 psi breach pressure loss (which was judged to be sufficiently conservative that no further reduction was made for uncertainty in other parameters); high values represent a 30% increase in high permeability/high BOP pressure loss case to account for potential lower BOP losses, tendency of the model to underpredict flow rate, and uncertainty in GOR

** Results are presented to two significant figures.

For those time periods where multiple lab estimates were made (time periods 3 and 5), NIST developed a single, reconciled estimate using a statistical procedure for pooling results from multiple assessments. Using this procedure, NIST calculated the following:

- 40,000–91,000 STB/day has a 95% probability of including the true value of the flow rate for time period 3, with a corresponding best estimate of 65,000 STB/day
- 35,000–106,000 STB/day has a 95% probability of including the true value of the flow rate for time period 5, with a corresponding best estimate of 70,000 STB/day

An additional analysis was done to break out the estimates for time periods 3 and 5 into separate estimates for scenarios 1/3 and scenario 2 (Table 2a), thus providing more granularity to the estimates. This breakout was based on the recognition that these scenarios represent end-member cases reflecting flow that is dominantly in the annular space between the completion casing and the outer casing (blue in Fig. 3) or flow that is dominantly inside the completion casing. These end-member scenarios resulted in two distinct distributions in flow estimates. Using the same procedure described above, NIST calculated the following (Figs. 4ab):

- 42,000–62,000 STB/day has a 95% probability of including the true value of the flow rate for scenarios 1/3, time period 3, with a corresponding best estimate of 51,000 STB/day
- 61,000–90,000 STB/day has a 95% probability of including the true value of the flow rate for scenario 2, time period 3, with a corresponding best estimate of 75,000 STB/day
- 33,000–62,000 STB/day has a 95% probability of including the true value of the flow rate for scenarios 1/3, time period 5, with a corresponding best estimate of 50,000 STB/day
- 53,000–120,000 STB/day has a 95% probability of including the true value of the flow rate for scenario 2, time period 5, with a corresponding best estimate of 84,000 STB/day

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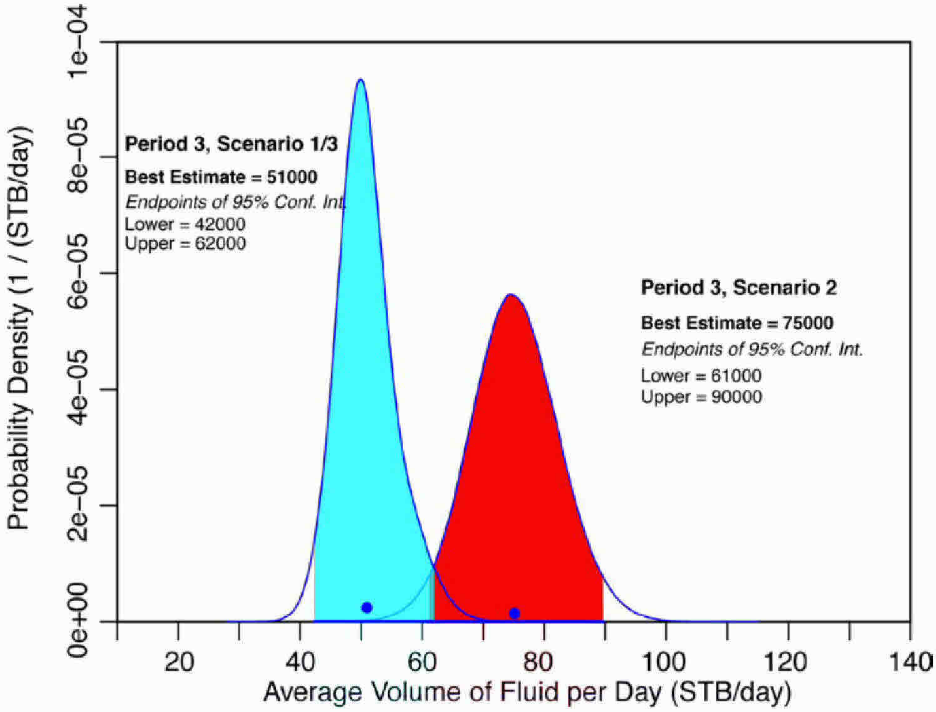

Figure 4a: Summary of NIST results for pooled estimates of flow for end-member cases (scenarios 1/3 and scenario 2) for time period 3.

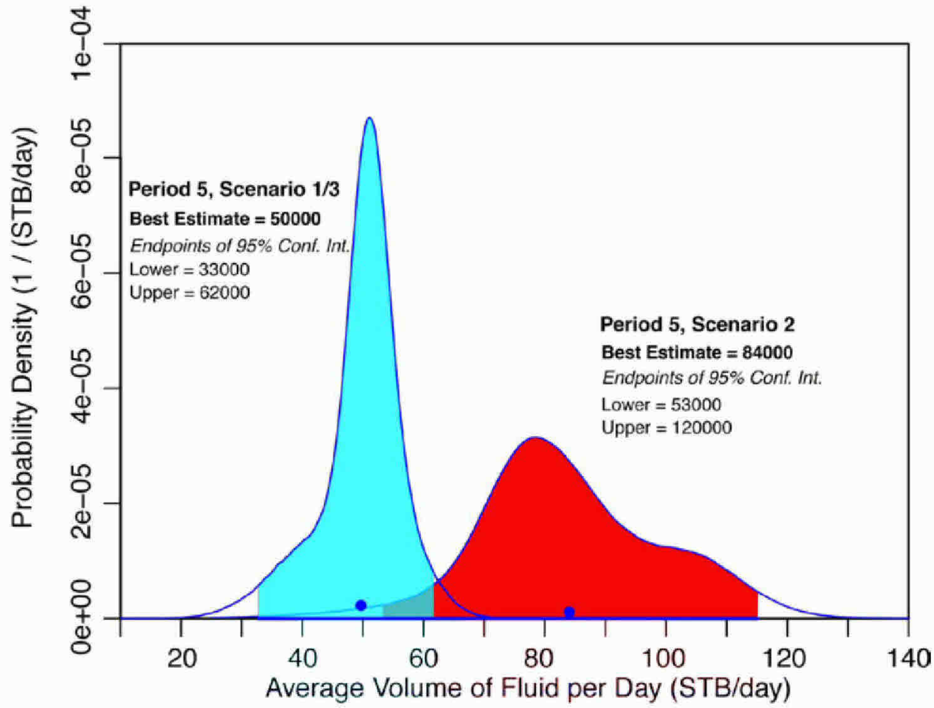

Figure 4b: Summary of NIST results for pooled estimates of flow for end-member cases (scenarios 1/3 and scenario 2) for time period 5.

4.4 Sensitivity Analysis for Key Parameters

4.4.1 Benchmark Case

One scenario was chosen as a standard for comparing the independent modeling approaches. It was not selected to indicate any conclusion or consensus by the Nodal-Analysis Team that these particular conditions and resulting flow rates were more or less likely than any other. Rather, a set of conditions common to existing calculations by one of the teams (PNNL) were chosen for calculations by three of the other teams in order to provide a set of calculations for comparison. For the benchmarking runs, key variables were set to values consistent with the site; these included: API gravity, specific gravity of gas, ocean pressure and temperature (at the release point), reservoir temperature, bubble point, gas-oil ratio, bottom-hole pressure, pipe roughness, and pressure drop (ΔP) across the blowout preventer.

Further, a sensitivity analysis for critical uncertain and/or variable parameters (gas-oil ratio or GOR, BOP pressure drop, BHP,[8] and roughness) was conducted by each of the teams using a distribution of values around those used in the initial benchmarking case. Distributions used in the sensitivity analysis were determined by Nodal-Analysis Team based on expert judgment and available data on MC252. Although some labs conducted sensitivity analyses as part of their initial detailed investigations, these analyses investigated a variety of flow conditions and/or ranges in parameters (in some cases, large ranges whereas in other cases smaller ranges). This variability precluded an integrated sensitivity assessment by the Nodal-Analysis Team based, so this additional sensitivity analysis was undertaken.

Four of the five labs[9] performed simulations at or near the benchmark case conditions. The results from the benchmarking study are shown in Table 3. Model predictions agreed very well for this case, with a standard deviation of ~6%. The lab reporting the highest estimate used slightly different input values, one of which (GOR) would have biased their results upward (as based on the sensitivity analysis described below).

[8] BHP=Bottom hole pressure (in the well)

[9] LBNL was unable to participate in this set of benchmarking simulations or in the associated sensitivity analysis, although LBNL (as well as each of the lab teams) performed an independent uncertainty and sensitivity analysis.

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Table 3: Benchmarking results**

	Oil Flow Rates for Benchmark Case (STB/day)
LANL	73,000
LLNL*	75,000
NETL	70,000
PNNL	65,000
Mean	71,000
σ	4,300
σ/Mean	6%

* LLNL results correspond to values for some of the fluid properties that are comparable to those used by the other teams but differ slightly

** Results are presented to two significant figures

Table 4: Results** for sensitivity analysis around benchmark case. Values are in STB/day. "Low" and "High" correspond to the values determined using the low and high value of the parameter investigated (respectively), as defined in Table 3.

Parameter	*LANL*		*LLNL**		*NETL*		*PNNL*	
	Low	*High*	*Low*	*High*	*Low*	*High*	*Low*	*High*
GOR	80,000	72,000	n/a	n/a	78,000	69,000	73,000	65,000
BOP	84,000	69,000	86,000	71,000	82,000	66,000	76,000	61,000
BHP	50,000	88,000	61,000	86,000	49,000	85,000	40,000	81,000
Roughness	77,000	72,000	79,000	75,000	74,000	69,000	69,000	64,000

* GOR was not varied. All other parameters were as listed in Table 4 footnote.

** Results are presented to two significant figures.

Table 5: Percent change for flow rate going from low end of parameter range to high end of range.

Parameter (range)	*LANL*	*LLNL*	*NETL*	*PNNL*
GOR (2300–3150 scf/STBO)	10%	n/a	11%	11%
BOP (1000–2500 ΔP, psi)	17%	17%	19%	20%
BHP (8500–11500, psi)	–77%	–40%	–73%	–103%
Roughness (0.001–0.002 inches)	6%	5%	6%	7%

Nodal-Analysis Summary

Table 4 shows the results of a sensitivity analysis performed around the benchmark case for the four critical parameters. "Low" and "High" values denote flow rates that correspond to the minimum and maximum values of the ranges for the varied parameters (not the minimum and maximum flow rates themselves). Table 5 shows the percent change in the flow rates for the high value of the parameter relative to the low value. Conclusions drawn from the values in Tables 4 and 5 are only strictly valid for the range of parameters.

4.4.2 *Impact of Gas-Oil Ratio (GOR)*

All teams found that changing the GOR had a noticeable impact on the flow rate estimate. Higher GOR produced lower flow estimates. For the range of GOR studied in the sensitivity analysis, the flow rates for each model only varied by 10–11% (Table 5), suggesting only a moderate impact on the flow rate estimates for that range. In contrast, LBNL (in its separate sensitivity analysis) found that GOR was the second most important variable in determining flow rate, albeit LBNL's analysis spanned a much larger range (1000–3017 scf/STBO).

4.4.3 *Impact of Blowout Preventer (BOP)*

All teams found the resistance (or the resulting ΔP) across the BOP impacted flow rate. Higher resistance in (or ΔP across) the BOP produced lower flow estimates. For the range of pressure drops studied in Table 3, the flow rates for each model varied by 17–20% from lowest to highest, suggesting that the pressure drop across the BOP has a fairly substantial effect on the flow rate estimates for the range of values used. The relatively high sensitivity to BOP partly reflects the broad range over which BOP pressure drop was varied in the sensitivity study (given that it was one of the most uncertain parameters). One model (LBNL) predicted a relatively low sensitivity to BOP over this range (albeit not at the exact conditions of the benchmarking case). LBNL concluded that the reason for this lack of sensitivity to BOP pressure under two-phase conditions is the phase interference caused by gas. Specifically, as the pressure at the bottom of the BOP decreases (less constriction), the ΔP from reservoir to seafloor increases, which should increase oil flow rate, but at the same time more gas exsolves, which inhibits oil flow.

4.4.4 *Impact of Bottom Hole Conditions*

All teams determined that the bottom-hole conditions had a significant impact on the estimates of oil flow rate. In the flow estimation, each team varied these conditions in different ways, either through reservoir pressure, permeability, skin factor, length of open interval (effective screen), or directly through bottom-hole pressure (BHP). In the sensitivity study, bottom-hole pressure was used. Higher BHP produced lower flow estimates. Of the four variables studied in the sensitivity analysis, BHP clearly has the greatest effect on the results. This finding underscores the importance of accurately capturing reservoir conditions in the nodal analysis results.

The importance of bottom-hole flow conditions was also found by LBNL in its separate sensitivity analysis using a different set of parameter ranges and a coupled wellbore-

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reservoir model. In LBNL's assessment reservoir permeability (as a controlling factor in bottom-hole flow conditions) was the most important parameter in estimating flow rate for scenario 2.

4.4.5 Impact of Roughness Parameter for Pipes

All teams found that the value for roughness used to account for frictional pressure loss along the well had an impact on estimates of flow rate. Higher roughness produced lower flow estimates. In the calculations used to estimate flow as reported in Table 2, slight variations were used in the simulations by each team:

- LANL—simulations used a roughness of 0.00138 inches; to assess impact on flow rate, simulations using a roughness of 0 showed an increase in flow rate of ~20% for scenarios 1 & 3 and ~25% for scenario 2
- LBNL—simulations used a roughness of 4.5e–5 m (0.00177 inches)
- LLNL—simulations used a dimensionless roughness of 2e–4 in the well, drill pipe, and riser; simulations using a roughness of 0 indicated an increase in flow of ~20%; for the well, 2e–4 corresponds to roughnesses of 0.001219 inches for an ID of 6.094" (7" casing) and 0.001725 inches for an ID of 8.625" (9-7/8" casing)
- NETL—simulations used a roughness of 0.001 inches
- PNNL—simulations used a roughness of 0.0018 inches in the drill-pipe and casing; for the annular region in the lowest section of scenario 3 (from the entry point to the bottom of the 9-7/8" liner at ~17,168'), roughness was a weighted average of steel (0.0018 inches) and concrete (0.12 inches) to account for exposed rock along the outer wall of the well.

In the sensitivity analysis, the range of values assessed spanned the range used by the teams in the flow estimation; over this range, the effect of roughness was 5–7% on the flow estimates.

4.4.6 Impact of Riser + Drill Pipe

With respect to components of the system downstream of the BOP (*e.g.*, bent riser and drill pipe assembly), the most significant assumptions related to the nature of the kink in either the riser or the drill pipe. The Nodal-Analysis Team addressed this by reducing the effective cross-sectional area in the two flow paths at the point of the kink.

Although this factor was not specifically considered in the sensitivity analysis around the benchmarking case, a qualitative assessment based on the team results in the flow estimation suggested that the pressure drop was generally small across the kink in the riser, and across the riser in general. However, the pressure drop due to the kink in the drill pipe was more significant if a substantial restriction were assumed (i.e., a restriction ≥90%). Nevertheless, the overall pressure drop summed over the riser and drill pipe assembly was relatively minor, as can be assessed by comparing flow estimates for time period 5 (post cutting of the riser and drill pipe) with time periods 3 and 4 (Table 2).

4.5 Assessment of Results from Reservoir Modeling Team

Results from the Reservoir Modeling Team included a range of IPR curves representing different conditions (Fig. 5).

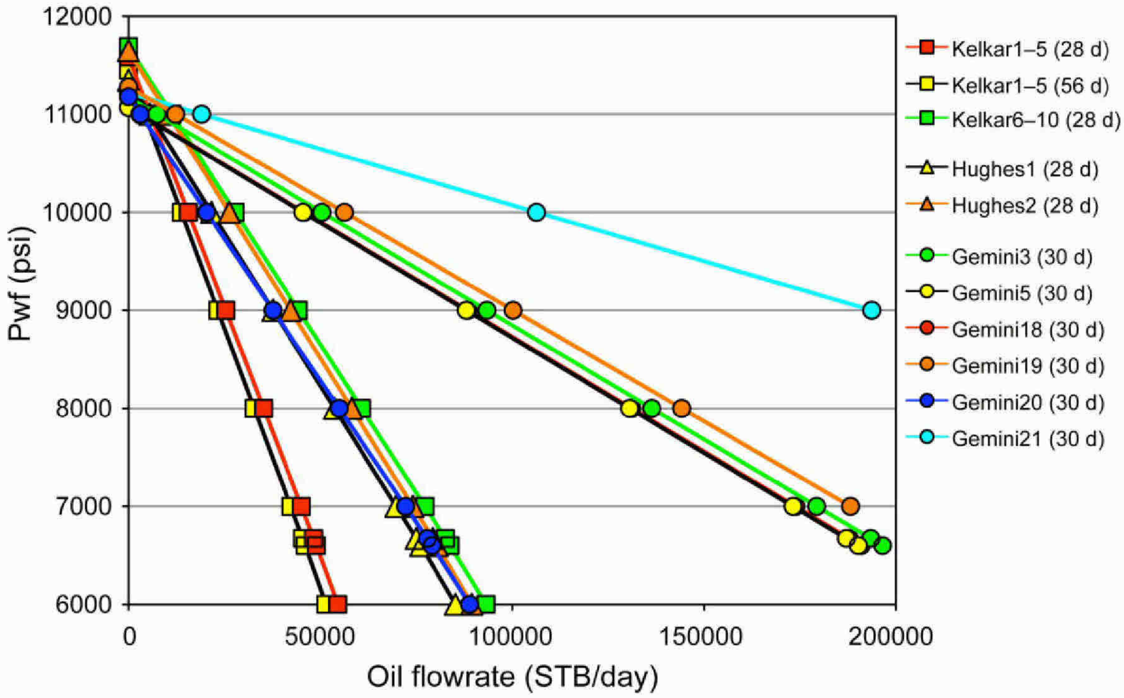

Figure 5: Inflow Performance Relationships (IPRs) from the Reservoir Team models. Gemini=Gemini Solutions; Kelkar=Kelkar and Associates; Hughes=R.G. Hughes and Associates. Pwf=Pressure while flowing.

The IPRs from the Reservoir Modeling Team fell into four general groups:

1. A group of curves that include Gemini-3, -5, -18, and -19. These used a base-case permeability for the reservoir.
2. An upper curve corresponding to the Gemini-21 IPR, which used a permeability twice that used in the base case.
3. A group of curves that include Gemini-20 as well as Kelkar IPRs for cases 6–10 and the two Hughes IPRs. For the Gemini and Kelkar IPRs, this group corresponded to a permeability roughly 40% lower than the Gemini base cases. For the Hughes IPR, this corresponded to an oil-wet system but using absolute permeability values comparable to the Gemini base case.
4. The lowest group of IPR curves that include the Kelkar IPRs for cases 1–5 using Kelkar's base case permeability values, which were roughly 65% lower than those in group 3 or ~25% lower than the Gemini base case values (group 1).

In general, several observations can be made in comparing the Reservoir Modeling Team IPRs with the NETL developed IPRs used by the Nodal Analysis Team (Fig. 2):

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- The Gemini 21 curve was comparable to the NETL IPR for skin 0. This Gemini curve corresponded to an upper end for reservoir permeability (slightly higher than that used by the NETL model[10]) and an infinitely behaving reservoir (*i.e.*, the maximum anticipated case for reservoir flow). Based on this, the Nodal Analysis Team concluded that the results from the Reservoir Analysis Team do not significantly impact the nodal estimates of the high end of the flow rate ranges.
- The Reservoir Modeling Team results demonstrate that reservoir permeability has a major impact on estimates of flow rate, confirming the LBNL sensitivity analysis using a coupled reservoir-well model that found permeability to be one of the two most important controls on flow rate.
- The primary factors driving the groups of IPR curves from the Reservoir Modeling Team related either to (a) assumptions of lower absolute permeability in the reservoir or (b) assumptions consistent with an oil-wet system (as opposed to a water-wet system). Assumptions by the Nodal Analysis Team were based on measured properties reported for one core from the reservoir (i.e., the assumptions used were consistent with information available to the team). However, incorporation of the full range of properties explored by the Reservoir Modeling Team would decrease the lower estimates of flow based on nodal analysis.
- Several of the other Gemini curves (e.g., 3, 5, 18, 19) assessed reservoir boundary effects. These IPRs showed only a slight depression for smallest reservoir size considered by Gemini (based on detailed reservoir information). These Reservoir Modeling Team results suggest that the Nodal-Modeling-Team assumption of an infinitely acting reservoir was reasonable and relaxing that assumption would not have a big impact on estimates of rate.

[10] Specifically, the product of absolute permeability and net-pay-zone thickness for the NETL IPR was only a factor of ~1.5 larger than this product for the Gemini-21 IPR. The NETL IPR was based on air permeability measurements as reported by a core analysis provided by MMS and assuming they represented midpoints of flow units along the core; the Gemini IPRs used three different permeabilities taken from within the range of reported air permeability measurements and applied these to the net pay zone thickness as determined by MMS. The relative permeability curves for oil were comparable between the NETL and Gemini cases.

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5.0 Flow-Estimate-Team Bios

5.1 LANL—Los Alamos National Laboratory

Dr. Rajesh Pawar is a Senior Project Leader in the Earth & Environmental Sciences Division at Los Alamos National Laboratory. His research interests are in the area of sub-surface fluid flow simulations as applied to oil & gas reservoir simulations, CO_2 sequestration, and enhanced oil recovery.

Dr. John Bernardin is a Scientist in the Mechanical and Thermal Engineering Group in the Applied Engineering and Technology Division at Los Alamos National Laboratory. He has a Ph.D. in Mechanical Engineering from Purdue University. His Ph.D. thesis is in the area of boiling heat transfer and two-phase flow. During his 14 years at LANL he has specialized in heat transfer and fluid mechanics including both experimental techniques and numerical modeling. He has over 60 peer-reviewed publications on various topics within the field of Mechanical Engineering. He is currently an Adjunct Professor at the University of New Mexico – Los Alamos and also President of Engineering & Technology Instruction, LLC.

Mr. Richard Kapernick is a Scientist in the Nuclear Design and Risk Analysis Group at Los Alamos National Laboratory. He has worked on the thermal-hydraulic design of nuclear reactors since 1968 at General Atomics and more recently at LANL. For 20 years, he was the manager of a reactor thermal-hydraulic design group, a reactor internals group and for core startup at the Fort St. Vrain reactor. At LANL, he has worked primarily on designs for small fast reactors for space and terrestrial applications.

Dr. Bruce Letellier is a Scientist in the Nuclear Design and Risk Analysis Group at Los Alamos National Laboratory. He has a Ph.D. in Nuclear Engineering from Kansas State University. He has performed accident-phenomenology and health-consequence modeling for facility and weapon safety studies, and most recently PAR of geologic CO2 sequestration. His past work has included interior- and atmospheric-transport modeling of aerosols and gases.

Dr. Robert Reid joined the technical staff at Los Alamos National Laboratory in 1986. Over his career he has work in areas such as convective two phase boiling enhancement, high temperature high pipes, thermoacoustic refrigeration, and fission reactor thermal hydraulic design for deep space missions. He received a Ph.D. in Mechanical Engineering from Georgia Tech and is a licensed professional engineer.

5.2 LBNL—Lawrence Berkeley National Laboratory

Dr. Curtis M. Oldenburg is a Staff Scientist and Program Lead for LBNL's Geologic Carbon Sequestration Program. Dr. Oldenburg received his PhD in geology from U.C. Santa Barbara in 1989, and has been working at LBNL since 1990. His area of expertise is numerical model development and applications for coupled subsurface flow and transport processes. He has worked in geothermal reservoir modeling, vadose zone hydrology, contaminant hydrology, and for the last ten years in geologic carbon sequestration. Dr. Oldenburg contributes to the development of the TOUGH codes.

Dr. Barry Freifeld is a Mechanical Engineer at the Lawrence Berkeley National Laboratory, where he is the principal investigator for numerous projects relating to CO_2 sequestration and arctic hydrology. He is an expert in the development of well-based monitoring instrumentation and techniques. His recent innovations include the U-tube geochemical sampling methodology, as well as thermal perturbation fiber-optic monitoring techniques for understanding subsurface processes. He has also received a U.S. patent for a portable whole-core x-ray computed tomography imaging system used at continental drill sites and on drilling vessels.

Dr. Karsten Pruess is a Senior Scientist at LBNL. He has conducted research in multiphase, non-isothermal, and chemically reactive flows in porous media, including mathematical modeling, analysis of field data, and laboratory experiments. His interests include geothermal energy recovery, nuclear waste isolation, oil and gas recovery and storage, environmental remediation, and geologic storage of carbon. He is the chief developer of the TOUGH family of general purpose simulation codes.

Dr. Lehua Pan has been working at LBNL since 1997 and is an expert in computer modeling of Earth systems and processes. Dr. Pan's research interests are in the area of new approaches to modeling fluid flow and transport in saturated and unsaturated soils, and porous and fractured media. Dr. Pan develops software to incorporate new approaches in subsurface modeling using cutting-edge IT techniques.

Dr. Stefan Finsterle is a Staff Scientist with research interests in inverse modeling of nonisosthermal multiphase flow systems; fracture and unsaturated zone hydrology; hydrogeophysics; test design and data analysis; optimization; error and uncertainty analysis; and geostatistics. He is currently the Platform and Integrated Toolsets Deputy for Advanced Simulation Capability for Environmental Management (ASCEM) and is the main developer of the iTOUGH2 nonisothermal multiphase inverse modeling code.

Dr. George J. Moridis is a Staff Scientist at LBNL and is the Deputy Program Lead for Energy Resources and is in charge of the LBNL research programs on (a) hydrates and (b) tight gas, and (c) leads the development of the new generation of LBNL codes for the simulation of flow and transport in the subsurface. He is the author and co-author of over 45 papers in peer-reviewed journals, of over 145 LBNL reports and book articles, and of three patents. He is a SPE Distinguished Lecturer for the 2009-2010 period.

Dr. Matthew T. Reagan is a Geological Research Scientist with research focus on the thermodynamics, transport, and chemistry of aqueous systems in the subsurface, including research on the thermodynamics of gas hydrates, gas production from methane hydrate systems, the coupling of methane hydrates and global climate, carbon sequestration via subsurface CO_2 injection, data reduction and uncertainty quantification using statistical methods, and "tight gas" simulation and engineering. Built and maintain online tools for physical property estimation and numerical simulation.

5.3 LLNL—Lawrence Livermore National Laboratory

Dr. Todd Weisgraber is a staff engineer in the Center for Micro and Nano Technology at Lawrence Livermore National Laboratory. His research interests in computational physics span a variety of application disciplines, including underground coal gasification, rheology, polymer physics, and microfluidic systems.

Dr. Thomas Buscheck is the Group Leader of Geochemical, Hydrological, and Environmental Sciences in the Atmospheric, Earth, and Energy Division at Lawrence Livermore National Laboratory (LLNL). His research involves scientific/engineering model analyses of nonisothermal reactive flow and transport phenomena in fractured porous media, applied across a range of energy and environmental challenges, including underground coal gasification, geologic CO_2 storage, enhanced geothermal energy systems, and radioactive waste management.

Dr. Christopher Spadaccini is a member of the technical staff in the Engineering Directorate and the Center for Micro and Nano Technology at Lawrence Livermore National Laboratory. His primary research interests are thermal and fluid aspects of microsystems and porous media, microsensors for detection applications, and advanced transport phenomena.

Dr. Roger Aines leads LLNL's Carbon Fuel Cycle Program, which takes an integrated view of the energy, climate, and environmental aspects of carbon-based fuel production and use. It supports DOE projects in sequestration technology development for capture, and underground coal gasification.

5.4 NETL—National Energy Technology Laboratory

Brian J. Anderson has served as the Energy Resources Thrust Area Leader of the NETL Institute for Advanced Energy Solutions. He is the Verl Purdy Faculty Fellow and an Assistant Professor in the Department of Chemical Engineering at West Virginia University. He holds Masters and PhD degrees in Chemical Engineering from the Massachusetts Institute of Technology and a BS from West Virginia University. Dr. Anderson's research experience includes sustainable energy and development, economic modeling of energy systems, and geothermal energy development as well as molecular and reservoir modeling of energy-relevant systems such as natural-gas hydrates.

Dr. Grant S. Bromhal is the Research Group Leader of the Sequestration, Hydrocarbons, and Related Projects group in NETL's Geosciences Division. As such, he leads a team of researchers focused on modeling, experiments, and field research related to carbon sequestration and hydrocarbon recovery. Dr. Bromhal received his PhD in civil and environmental engineering from Carnegie-Mellon University and his BS/BA in civil engineering and math from West Virginia University. He is the recipient of the 2007 Hugh Guthrie Award for Innovation at NETL.

Dr. George Guthrie is the focus area leader for geological and environmental systems at the National Energy Technology Laboratory (NETL). Dr. Guthrie received his PhD in mineralogy from Johns Hopkins and his AB in geology from Harvard before working at Los Alamos National Laboratory for 19 years. Since joining NETL, he leads research activities across a range of fossil-energy related challenges, including CO_2 storage and unconventional fossil fuels (including environmental aspects related to oil/gas production).

Dr. W. Neal Sams joined NETL in 1987 and designs reservoir simulators and has extensive experience utilizing them in a wide range of applications, including carbon sequestration/enhanced coal bed methane production. He is the author of MASTER, a miscible flood simulator, and NFFLOW, a discrete fracture gas reservoir simulator. Sams holds B.S and Ph.D. degrees in physics from the University of Houston.

Dr. Doug Wyatt is the Focus Area Manager for Geological and Environmental Sciences for NETL and has ~30 years of experience in fossil energy exploration and production, the management of multidisciplinary teams responsible for energy research and policy support, and the geoscience and environmental evaluation of high hazard facilities. Wyatt is currently on the Executive Committee of the Division of Environmental Geology for the American Association of Petroleum Geologists. He is a Certified Petroleum Geophysicist. Wyatt holds an appointment as Research Professor and Lecturer in the Department of Biology and Geology at the University of South Carolina - Aiken and is an Adjunct Assistant Professor of Environmental Engineering and

Earth Sciences at Clemson University. Dr. Wyatt has over 150 papers, presentations, and federal research reports.

Roy Long is NETL's Technology Manager for its Ultra-Deepwater and Unconventional Resources Program. He is a published Petroleum Engineer and well known within industry and the geoscientific community from his long association with technology development related to drilling and completion technologies. He is a 1970 graduate of the US Air Force Academy and received his MSc in Petroleum Engineering from the Colorado School of Mines. He is a member of many professional societies in the geosciences and has been a member of the Society of Petroleum Engineers for over 30 years.

5.5 PNNL—Pacific Northwest National Laboratory

Dr. Gauglitz joined PNNL in 1992 and is currently a project manager in the Fluid and Computational Engineering group in the Energy and Environment Directorate. He has led a variety of research and technology development projects, represented the laboratory to major clients, and has served as a technical group manager in the Environmental Technology Directorate for the Electrical and Chemical Processing and Thermal Processing groups and served as a technical group manager in National Security Directorate for the Radiation Detection and Nuclear Sciences group. A primary theme of his research interests has been the behavior of bubbles in non-Newtonian slurries, pastes, and porous media. Prior to joining PNNL, Dr. Gauglitz spent more than ten years investigating bubble behavior in porous media for enhanced oil recovery and in other oil field applications and worked for Chevron Oil Field Research Company. Dr. Gauglitz received a Ph.D. in 1986 from the University of California at Berkeley and a B.S. in 1981 from the University of Washington, both in Chemical Engineering.

Ms. Mahoney joined PNNL in 1989 and is a research engineer in the Fluid and Computational Engineering group in the Energy and Environment Directorate. She has played a central role in studies of waste retrieval through dissolution, flammable gas retention by in-tank waste, interpretation of data from waste pre-treatment processes in the test vitrification plant, definition of simulant compositions for a variety of tank waste studies, and computational modeling of chemical and flow systems.

Ms. Bamberger is a senior research engineer II in the Fluid and Computational Engineering group. Her research in multi-phase flow has focused on development and application of in-situ real-time instrumentation to characterize physical and rheological properties of particulate-laden fluids and multi-phase suspensions in both vessels and pipelines and developing fluids based technologies for remediating waste tanks. Ms Bamberger has an MS in Mechanical Engineering from The Pennsylvania State University and is a licensed Professional Engineer in the State of Washington.

Jeremy Blanchard joined PNNL in 2009 as a member of the Fluid and Computational Engineering group in the Energy and Environment Directorate. He has been involved in a number of diverse research projects including aerosol transport, multiphase pipe flow, flow in porous media, heat cycle analysis and building energy efficiency. His research interests are in experimental fluid mechanics and heat transfer applied to energy related projects. Specifically, he is focused on research relating to alternative energy and increasing building energy efficiency. Mr. Blanchard received a M.S. and B.S. in Mechanical Engineering from the University of New Hampshire in 2008 and 2006, respectively.

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Dr. Bontha is a Senior Research Engineer and a team-lead within the Radiochemical Science and Engineering group at PNNL. He has over 15 years experience in fluid dynamics, multi-phase slurry transport and mixing, and separations. Dr. Bontha has a Ph.D. in Chemical Engineering from Tulane University, New Orleans.

Mr. Enderlin has a Bachelor and Master's in Mechanical Engineering. Mr. Enderlin has a broad variety of project work experience including, experimental multi-phase fluid mechanics design and testing of systems, equipment for the mobilization mixing, transport, sampling of slurries as well as complex fluids and numerical simulation of thermal hydraulic systems. He has had International collaborations for spent fuel analyses equipment design and testing, performed analyses in the areas of: heat transfer and fluid mechanics, mechanical and system design, experimental design, data analysis, course development, and equipment evaluations. Mr. Enderlin has also developed test strategies, designed test setups, and directed test programs with both Newtonian and non-Newtonian fluids.

Dr. Fort is a staff engineer in the Fluid and Computational Engineering group at Pacific Northwest National Laboratory. His research activities are primarily in the area of computational modeling of fluid flow and heat transfer, with projects including natural convection cooling spent nuclear fuel storage casks, mixing of nuclear waste, Joule-heated glass melters, induction heated melters for reactive metals, and drag-reducing fairings for drill string risers suspended from off-shore oil drilling platforms. His dissertation research was a model of a supersonic propulsion application using hydrogen-air combustion.

Dr. Perry Meyer is a Staff Scientist in the Fluids & Computational Engineering Group with 18 years experience at PNNL. His academic area of specialization was high speed flow and nonequilibrium thermodynamics. He is an expert in areas of fluid mechanics including jet mixing, gas dynamics, multiphase flow, energy conversion, computational and experimental fluid dynamics, and mathematical modeling. While at PNNL, Dr. Meyer has been a principle investigator on projects relating to jet mixing, safety-related accident and hazard analysis, micro-scale energy conversion, liquid metal magnetohydrodynamics, and aerodynamic testing and design. Dr. Meyer has made significant contributions to the Hanford site in resolving key technical issues associated with tank waste physics and closure of the Tank Waste Safety Issue. Dr. Meyer received a Ph.D. from the University of Washington in 1992 in Aeronautics and Astronautics.

Dr. Yasuo Onishi works at the Pacific Northwest National Laboratory and is an Adjunct Professor of Civil and Environmental Engineering Department, Washington State University. He was a member of the National Academy of Sciences' committee on oil spill and the oil dispersant use, and is an adjunct member of the National Council of Radiation Protection and Measurements. He has conducted field, laboratory flume, and modeling studies of the heated water and contaminants released to surface waters.

Dr. David M. Pfund is a Senior Research Engineer at the Pacific Northwest National Laboratory. He has a Ph.D. (1989) in Chemical Engineering from the University of Oklahoma, where he applied liquid structure theories to the study of solvation in supercritical fluids. At PNNL he applied X-ray, NMR and IR spectroscopies to similar problems. His recent work has focused on the development of anomaly detection methods for low-count gamma sources. He has publications in the Journal of Chemical Physics, the Journal of Physical Chemistry, Langmuir, the AIChE Journal, Ultrasonics, Applied Radiation and Isotopes and the IEEE Transactions on Nuclear Science.

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Dr. Rector is a staff scientist in the Fluid and Computational Engineering group. He has had 30 years of experience in the computational simulation of fluid systems using such methods as lattice-Boltzmann, lattice kinetics and conventional computational fluid dynamics. Dr. Rector is currently involved in the development of computer programs, based on the PNNL developed implicit lattice kinetics methods, for predicting the flow behavior of multiphase systems, most notably the ParaFlow program for large-scale parallel computers.

Mr. Mark Stewart joined PNNL in 2003. His previous work experience has ranged from process simulation at a startup consulting business to process design at a large engineering/construction firm. Although broadly interested in engineering design and analysis, his focus has been the use of computational methods to solve practical problems, particularly involving fluid dynamics and heat transfer. Mark has recently been engaged in the application of the lattice-Boltzmann method to fluid flow through complex geometries.

Mr. Beric E. Wells joined PNNL in 1998 and has participated in and led many Hanford waste storage, mobilization, retrieval and treatment investigations including topics of gas retention and release, waste dilution and jet mixing of chemically reacting Newtonian and Non-Newtonian fluids, and liquid and solid pipeline transport phenomena. He has also investigated Loss of Coolant Accident scenarios for the Nuclear Regulatory Commission. Mr. Wells received both a B.S. and M.S. in Mechanical Engineering from Washington State University.

Dr. Yokuda is a Senior Research Engineer in the Fluid and Computational group at the Pacific Northwest National Laboratory (PNNL). His primary role at PNNL is analysis of both experimental and computational fluid dynamics including multi component and multi phase flow. His experience also includes application of a Monte Carlo N-Particle transport code for radiation detector analysis.

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