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Oil Release from Macondo Well MC252 Following the Deepwater Horizon Accident

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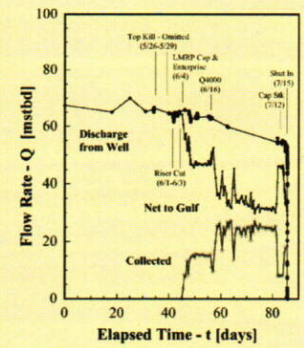
Ⓢ *Supporting Information*

ABSTRACT: Oil flow rates and cumulative discharge from the BP Macondo Prospect well in the Gulf of Mexico are calculated using a physically based model along with wellhead pressures measured at the blowout preventer (BOP) over the 86-day period following the Deepwater Horizon accident. Parameters appearing in the model are determined empirically from pressures measured during well shut-in and from pressures and flow rates measured the preceding day. This methodology rigorously accounts for ill-characterized evolution of the marine riser, installation and removal of collection caps, and any erosion at the wellhead. The calculated initial flow rate is 67 100 stock-tank barrels per day (stbd), which decays to 54 400 stbd just prior to installation of the capping stack and subsequent shut-in. The calculated cumulative discharge is 5.4 million stock-tank barrels, of which 4.6 million barrels entered the Gulf. Quantifiable uncertainties in these values are −9.3% and +7.5%, yielding a likely total discharge in the range from 4.9 to 5.8 million barrels. Minimum and maximum credible values of this discharge are 4.6 and 6.2 million barrels. Alternative calculations using the reservoir and sea-floor pressures indicate that any erosion within the BOP had little affect on cumulative discharge.



■ INTRODUCTION

On April 20, 2010, the BP Macondo Prospect well MC252 in the Gulf of Mexico suffered a blowout following routine cementing operations, leading to an explosion and fire on the Deepwater Horizon drilling platform.[1] The platform sank two days later, leaving the ruptured marine riser open to the sea. For reasons still not clear, the blowout preventer (BOP) did not seal the wellhead as intended, and the well discharged to the Gulf for almost 86 days prior to being capped and finally shut-in on July 15. In total several million barrels were discharged from the well roughly 40 miles off the Louisiana coast, making this one of the largest offshore releases to date. The environmental, economic, and social impacts of this massive release will be studied and discussed for many years and, as such, accurate estimates of the history of oil flow and cumulative discharge are needed.

Historical flow rates can be computed using a first-principles approach given that the nominal well geometry and reservoir and exit conditions are more-or-less known. A schematic this geometry is shown in Figure 1. In general, however, such calculations involve complex heat transfer, two-phase flows, possible flow through the production casing or annulus or both, flow through a BOP of unknown state, flow through external piping that was altered in the course of the response, and a multispecies equation-of-state for the gas-oil mixture that may or may not be in equilibrium. This first-principles approach can thus provide estimates of the release only for various scenarios.

In contrast, flow rates in the present study are calculated via a physically based model containing several unknown parameters that are determined from pressures and flow rates measured just prior to and during shut-in on July 15, 2010. Historical flow rates over the 86-day period are then calculated using measured BOP pressures, and these flow rates are integrated over time to yield the cumulative discharge. The main advantage of this approach is that calculated flow rates using the reservoir and BOP pressures directly account for the many alterations of the wellhead geometry downstream of the BOP gauge through their influence on BOP pressures. Removal of the marine riser, installation of the top-hat, installation of the final capping stack, and even erosion of the BOP rams are therefore dealt with in a rigorous manner without need for detailed knowledge of the changing wellhead geometry. This approach also does not require a priori knowledge of the flow path up the well and through the BOP.

■ METHODOLOGY AND MODEL

Calculation of historical flow rates using reservoir and BOP pressures requires only a simple model involving just two parameters. These parameters are the reservoir productivity index (κ) and wellbore discharge coefficient (k_{well}). The first of these is an industry-standard constant relating the frictional pressure drop between the far-field reservoir and bottom of the well, δP_{res}, to the laminar flow rate of oil in stock-tank barrels per day, Q_{st}.[2] That is, $\delta P_{\text{res}}=Q_{\text{st}}/\kappa$. The second parameter, k_{well}, relates the pressure drop δP_{well} between the bottom of the well and the bottom of the BOP to the flow rate up the well casing. This flow is turbulent, so given a constant friction factor the

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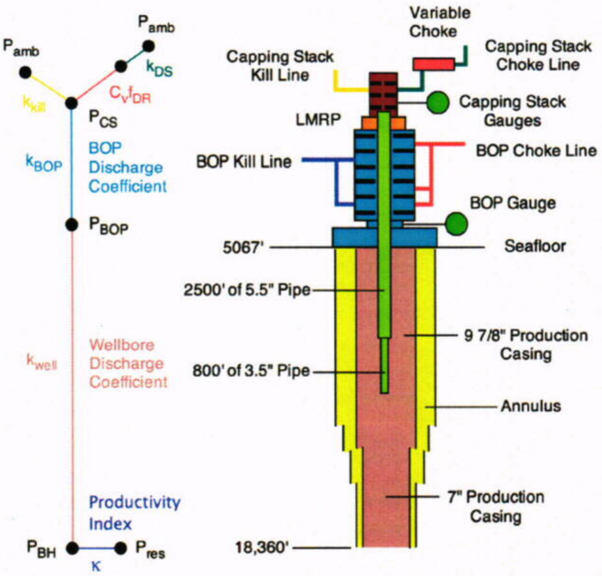

Figure 1. Schematic of MC252 well, blowout preventer, and capping stack. Depth of well from the seafloor is roughly 13 300 feet. The diagram at left shows relative positions of pressures and flow coefficients used in calculating flow rates. Each coefficient relates local flow rates to the pressure difference over the line segment of corresponding color.

frictional pressure drop here is proportional to the square of the flow rate,[3] $\delta P_{\text{well}} = Q_{\text{st}}^2/k_{\text{well}}^2$ or equivalently $Q_{\text{st}} = k_{\text{well}}(\delta P_{\text{well}})^{1/2}$. The discharge coefficient k_{well} is thus just a constant of proportionality between the flow rate and square-root of the pressure difference.

Because the flow rate of oil through the reservoir must equal that up the well casing, the total frictional pressure drop δP between the reservoir and bottom of the BOP is the simple sum $\delta P = \delta P_{\text{res}} + \delta P_{\text{well}} = Q_{\text{st}}/\kappa + Q_{\text{st}}^2/k_{\text{well}}^2$. Given the two parameters κ and k_{well}, this quadratic expression can be solved analytically to yield the instantaneous historical flow rate as a function of the total frictional pressure drop. The result is

$$Q_{\text{st}} = \frac{\theta}{2}\left(\sqrt{1 + \frac{4\kappa\delta P}{\theta}} - 1\right) \quad \text{where} \quad \theta = \frac{k_{\text{well}}^2}{\kappa}$$
$$\text{and} \quad \delta P = P_{\text{res}} - P_{\text{BOP}} \tag{1}$$

where again Q_{st} is the flow rate in stock-tank barrels per day (stbd), and δP is the frictional pressure drop between the reservoir and BOP. This frictional pressure drop excludes differences in elevation head. The elevation head, which does not contribute to flow, is simply that pressure due to the weight of the fluid column in either a static or flowing state, so the difference in total pressure between any two points along the flow path is always equal to the sum of the elevation head and frictional pressure drop.

To obtain the cumulative discharge, these historical flow rates can be integrated in time on intervals of the measured BOP pressures. The assumptions used in developing this model are discussed in Appendix A of Supporting Information; a more detailed description of the model is presented in Appendix B.

While only these two parameters are needed to compute historical flow rates, their values are not known beforehand and cannot be determined accurately from first principles. Instead, a more complete model of the well is needed, and this model must describe flow at all points between the reservoir and exit, including flow through the capping-stack choke and kill lines. This model consists of a simple one-dimensional network of five flow coefficients arranged in series that describe pressure-driven transport through the reservoir to the bottom of the well (κ), along the wellbore to the wellhead (k_{well}), through the BOP (k_{BOP}), and if present through the capping-stack variable choke ($C_V f_{DR}$) and downstream tubing (k_{DS}). A schematic of this configuration is shown at the left of Figure 1. Here the choke discharge coefficient C_V is known from calibration measurements, as discussed in Appendix B, while the choke derating factor (f_{DR}) represents an additional unknown parameter accounting for local fluid densities, the live-oil liquid mass fraction, and possible two-phase flow. This derating factor represents the ratio of the actual flow rate of stock-tank oil through the choke to the flow rate of water given the same pressure differential. It is defined in this manner because the choke is calibrated using water. One additional coefficient, in a parallel arrangement with the capping-stack choke, describes flow through the capping-stack kill line (k_{kill}).

Except for the productivity index, these discharge coefficients are all constants of proportionality between local turbulent flow rates and the square-root of the local pressure differential. As such, the flow between any two points along a flow path that lies outside the reservoir can be written as

$$Q_{\text{st}} = k_{\text{eff}}\sqrt{\delta P}_{i,j} \quad \text{where} \quad k_{\text{eff}} = \left(\sum_{m=i}^{j} \frac{1}{k_m^2}\right)^{-1/2} \tag{2}$$

where $\delta P_{i,j}$ denotes the pressure difference between the two points, and the sum over local discharge coefficients yielding the effective coefficient k_{eff} includes all values along the flow path. If this path additionally includes the reservoir, then the flow rate is given by

$$Q_{\text{st}} = \frac{\theta}{2}\left(\sqrt{1 + \frac{4\kappa\delta\hat{P}_{i,j}}{\theta}} - 1\right) \quad \text{where} \quad \theta = \frac{k_{\text{eff}}^2}{\kappa} \tag{3}$$

Here a circumflex on the pressure difference indicates that this difference must include that from the reservoir to the bottom of the well, while the sum yielding k_{eff} in eq 2 is just over those path elements involving turbulent flow. Again, derivation of these equations is discussed in Appendices A and B.

An important feature of this model is that it conserves mass along the flow path. As a result, any pair of measured pressures along segments of this path should yield identical flow rates under all conditions, before or during shut-in, provided the measured pressures are accurate and assumptions in the model remain valid. If the capping stack is present, then the setting on the choke and state of the kill-line valve must also be known. This feature of the model provides an invaluable means for evaluating assumptions made in the model and for validating the measured pressures.

■ PARAMETER ESTIMATION

The six unknown parameters appearing in this model are estimated in part from pressures measured during shut-in and in part from flow rates measured through collected oil in tests conducted the previous day. Details of the process are discussed in Appendix B. During the shut-in process, the capping-stack kill line was closed, the choke line was closed in a series of 15 steps characterized by turns of the choke stem, and pressures were measured at both the BOP and capping stack as shown in Figure 1. A plot of the measured choke valve coefficient, C_V, as a function of the number of turns is also shown in Appendix B. During the collection tests preceding shut-in, both the BOP and capping stack pressures were measured while oil was collected from the choke and kill lines on the BOP. During this collection, the capping-stack kill line was left open and the choke was closed.

The first step in determining these parameters is to eliminate gauge offsets and any differences in elevation head as these do not contribute to flow. Without loss of generality, the stacking-cap gauge is taken as the reference state. From capping-stack pressures measured before start of the shut-in process, the ambient seawater pressure is 2198 psi. This is consistent with a seawater density of 1025 kg/m^3 and a depth of roughly 5000 feet. Just after shut-in, the calibrated capping-stack gauge at zero flow read 6605 psi, while the BOP gauge read 7219 psi, implying a BOP gauge offset of +614 psi. That is, the BOP gauge read erroneously high by 614 psi. This offset is believed to have resulted from the replacement of batteries in BOP gauge electronics on July 12 without subsequent rezeroing the gauge output. This view is supported by a sudden increase in the BOP pressure of 609 psi between July 11 and July 13 following a month or more of fairly consistent values. No additional pressures were reported between these dates so this appears to be a sudden jump of 609 psi that was coincident with changing the batteries. The capping stack was also installed in this interval, but the estimated increase in BOP pressure associated with this is at most a few 10s of psi when the capping-stack rams were open. Noting that all pressures less their elevation heads must be uniform in the well at zero flow, the reference capping-stack pressure of 6605 psi just at shut-in also yields an implied reservoir pressure of 6605 psi, again excluding the elevation head.

All six parameters are estimated simultaneously using a nonlinear least-squares algorithm, TJMAR1.[4] For this, 30 residuals and two constraints are constructed. Fifteen of the residuals are the differences between flow rates computed using pressure drops from the capping stack to ambient and from the BOP to the capping stack, at each of 15 choke positions during shut-in. Another 15 are the differences between flow rates computed using pressure drops from the reservoir to BOP and the capping stack to ambient, again during shut-in. The first constraint is that the capping-stack pressure must be equal to the measured pressure of 2625 psi when the capping-stack choke and rams are closed, the kill line is open, and there is no oil collection from the BOP. The final constraint is that oil flow diverted from the BOP via the choke and kill lines is 20 012 stock-tank barrels per day (stbd), equal to rate of measured oil collected, when the measured capping stack pressure is 2376 psi with the capping-stack kill line open and the choke closed.

The results obtained from this constrained nonlinear parameter estimation are as follows:

Productivity Index. The estimated value is $\kappa = 47.2$ stbd/psi.

Well Discharge Coefficient. The estimated value is $k_{well} = 1219$ stbd/psi$^{1/2}$. Using this value and the estimated productivity index above, the calculated open-well flow (without BOP) is 81 600 stbd at the initial reservoir pressure. In comparison, BP estimates of the initial flow from the open well were 63 000, 43 000, and 87 000 stbd for flow through the production casing alone, the annulus alone, and both.

BOP Restriction. The estimated discharge coefficient for the BOP is $k_{BOP} = 1529$ stbd/psi$^{1/2}$. This value represents a possibly complex combination of flow through two drill pipes in series passing through the BOP, as well as flow past the several BOP rams intended to seal the well.

Capping-Stack Kill and Choke Lines. The estimated kill-line coefficient is $k_{kill} = 2482$ stbd/psi$^{1/2}$; that for the tubing downstream of the choke is $k_{DS} = 2511$ stbd/psi$^{1/2}$. Not surprisingly, these are close to one another because the pipe diameters and lengths are comparable.

Variable Choke De-Rating Factor. The estimated overall choke derating factor is $f_{DR} = 0.257$, which corresponds to an effective discharge coefficient for the fully open choke of 2259 stbd/psi$^{1/2}$. The flow rate calculated at the time of shut-in using this value of the derating factor, with the choke fully open, and the kill line closed is 48 100 stbd based on the pressure difference between the reservoir and exit. The flow rate calculated in a similar manner for the same time but without the capping stack in place is 54 400 stbd.

■ ASSESSMENT OF MODEL, PARAMETERS, AND SHUT-IN DATA

Accuracy of the model, validity of assumptions, and the quality of the parameter estimation can be determined in part through internal self-consistency and agreement with measured pressures. This is demonstrated in Figure 2 showing the

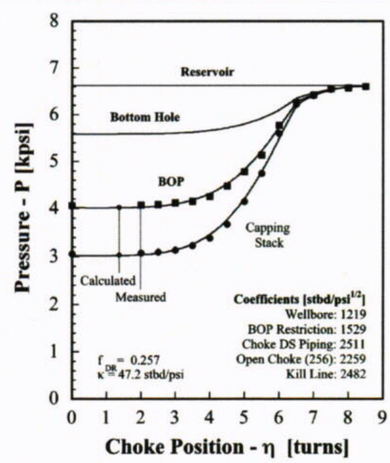

Figure 2. Measured BOP and capping-stack pressures during shut-in with computed pressures at BOP, capping stack, and well bottom. All pressures are less elevation head relative to the capping stack.

computed capping-stack, BOP, bottom-hole, and reservoir pressures, along with the BOP and capping-stack pressures measured during shut-in. Over the entire range of conditions the calculated and measured capping-stack pressures agree to within ±2.6% (±110 psi maximum); those for the BOP pressure agree within ±1.7% (±90 psi maximum). These deviations are considerably smaller than the estimated absolute accuracy of the BOP gauge, ±200 psi.

Such good agreement is significant for several reasons. First, these pressures were not fit directly in estimating the model parameters; instead, the parameters were selected to conserve mass along the flow path given the measured pressure histories. While agreement of this sort might be expected for single-phase flows or over a small range of flow rates, the fact that these pressures agree very well over such a broad range of conditions provides substantial validation for the use of a single fixed choke derating factor. Second, this good agreement over the range of pressures clearly indicates that both the BOP and stacking-cap gauges are accurately measuring local pressures, subject to the BOP gauge offset already discussed. Finally, agreement between the calculated and measured pressures over the wide range of flow rates indicates that the model correctly describes relevant physical phenomena and that the assumptions remain acceptably valid over this range of conditions. If, for example, gas-oil mixture densities varied significantly as the pressures increase, then some portion of the calculated and measured pressures would need also to differ because the physical description of this is not accounted for in the model. As already suggested, any significant change in the choke two-phase factor would also be clearly evident.

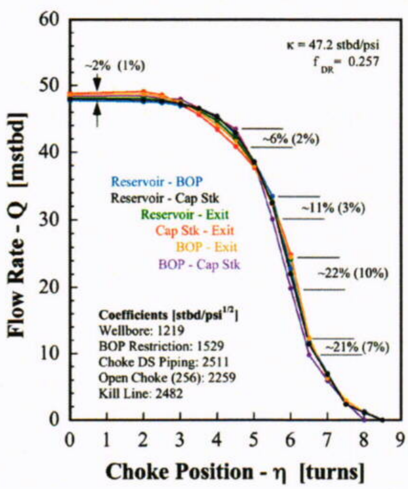

Figure 3. Comparison of calculated flow rates during shut-in using various combinations of pressures. Values are computed using measured BOP and capping-stack pressures.

Validity of the model and data is further illustrated in Figure 3. Here the baseline parameters are used with various combinations of the measured pressures to calculate flow rates over the course of the shut-in process. These are, for example, the reservoir-to-BOP pressure difference or that between the BOP and capping stack. In total there are four known pressures, yielding six possible unique combinations. All of these combinations are shown. Surprisingly, all such combinations yield calculated flow rates that agree well with one another, especially when the choke is nearly wide open. This is important because that condition most closely replicates conditions over the 86-day history. As the choke is closed, the various flow rates drift apart slightly along the steepest portion of the curves. This is due in part to increased sensitivity when the curves are steep and in part due to the fact that some of the pressure differences get very small as the flow is reduced. For example, flow rates calculated using the pressure difference between the BOP and capping-stack gauges (purple curve) are noticeably lower than all others past a choke position of about 5 turns. In this regime, the difference between the BOP and capping-stack pressures is small, just 170 psi at a choke position of 6 turns, so even very small relative errors in measured pressures can lead to a discernible affect on the calculated flow rate. In contrast, flow rates calculated using those combinations exhibiting the largest pressure differences (reservoir to BOP, reservoir to capping, and reservoir to exit) show consistently good agreement over the full range of choke positions. This distinction is illustrated by the spreads noted along the curves. The first number in each case represents the total fractional spread; the value in parentheses is the fractional spread among those curves using the reservoir pressure. The latter is typically half or less of the former. This variability in the calculated flow rates is perhaps also due in part to minor breakdown of the assumption that the overall choke derating factor is constant since both fluid densities and the two-phase factor must increase at least slightly as the choke is closed. Still, the impact of such breakdown on flow rates through the choke cannot exceed the maximum observed spread of 22%. Moreover, significant variation in the two-phase factor gives rise to anomalous behavior in which calculated flow rates rise as the choke is closed. This is discussed further in Appendix C and illustrated in Figure 2C.

Finally, the results in Figure 3 clearly demonstrate that changes in the conditions downstream of the BOP are properly accounted for through their influence on BOP pressures, even under dramatically varying conditions as the choke is closed. It is also clear that the measured BOP pressures provide estimates of flow rates that are consistent with values calculated using any other measured pressures. These observations again confirm the validity of this methodology and its ability to yield accurate estimates of historical flow rates that rigorously account for both known and unknown variations in the wellhead and riser geometries downstream of the BOP gauge, including erosion within the BOP.

■ CALCULATED FLOW RATES AND CUMULATIVE DISCHARGE

Given the estimated baseline parameters, the instantaneous flow rate can now be calculated directly from eq 1 and the reservoir and BOP pressures. Measured BOP pressures are shown in Figure 4, along with a baseline linear estimate of the reservoir pressure history having an initial measured pressure of 11 850 psi less an elevation head of 3445 psi and final pressure, less head, of 6605 psi measured at initial shut-in. Calculation of

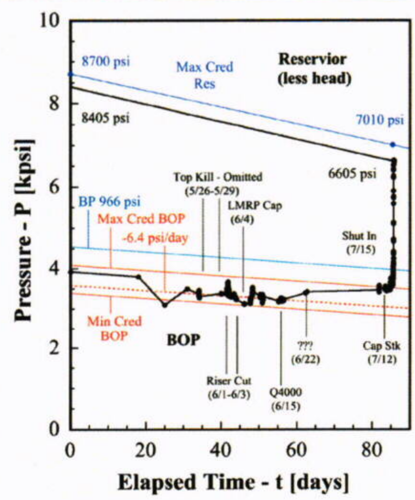

Figure 4. Measured BOP pressures and estimated reservoir pressure history. Per earlier discussion, pressures measured after July 12 are offset by −614 psi.

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the elevation head is discussed in Appendix C of the Supporting Information. Note, however, that the BOP pressure at time zero was not measured, but instead was extrapolated to the origin using the first measured value on day 18 (May 8) and a correlation between reservoir and BOP decay rates based on the model. As discussed in Appendix C, this approximate treatment of the initial BOP pressure has little impact on the calculated flow rate or cumulative discharge of oil owing to the large initial difference between the reservoir and BOP pressures. Also note that BOP pressures after day 82, July 12, were corrected by −614 psi as previously discussed. Solid red curves shown in Figure 4 are estimated minimum and maximum credible bounds on the mean BOP histories; the solid blue line represents the mean BOP pressure history resulting from a correction of +966 psi proposed earlier by BP. These bounds are discussed in a later section and in Appendix C on uncertainties.

All available data are included in Figure 4, with exception of pressures measured during the top-kill effort, indicating their somewhat sparse and episodic nature. Still, the measured pressures seem generally well behaved and exhibit a slight downward trend over much of the 86-day period with a mean early decay history indicated by the dashed red curve. This dashed curve is a linear least-squares fit to the measured pressures between May 8 (first measured value) and June 16, 2010. To eliminate biases associated with highly episodic data having variable numbers of points within each measurement period, the measured values were interpolated onto uniform intervals of one day for each point prior to fitting. The slope of this fit is −6.44 psi/day, with an intercept at the origin of 3580 psi. As discussed in Appendix D, the calculated mean reservoir decay rate associated with −6.44 psi/day at the BOP is −20.0 psi/day or 1720 psi over 86 days.

The baseline reservoir pressure history less elevation head depicted in Figure 4 (black curve) is a linear decay from an initial pressure of 8405 psi to a final value of 6605 psi. As previously discussed, however, this final pressure does not reflect a true reservoir pressure because the reservoir and wellbore are not yet in equilibrium. As such, the baseline reservoir pressures (less head) are arguably low and so also represent a minimum credible pressure history. This is taken as the baseline pressure history simply because it requires the fewest assumptions and calculations regarding the elevation head. In contrast, the maximum credible pressure history (violet) is based on an initial value of 8700 psi obtained from the measured reservoir pressure of 11,850 psi less a calculated flowing elevation head of 3150 psi. The final pressure of 7010 psi in this case is based on a reservoir pressure of 10 090 psi obtained from the measured longer-term wellhead shut-in pressure of 6870 psi, plus a calculated static elevation head of 3220 psi, less a flowing head of 3080 psi. These conditions correspond to a reservoir pressure decay of 1760 psi over the 86 days. The impact of this maximum credible reservoir pressure history is discussed below and in Appendix C.

Flow rates calculated using eq 1 and the baseline pressures presented in Figure 4 are shown in Figure 5. The initial flow rate from the well is slightly over 67 100 stbd, and this decays to 54 400 stbd just before installation of the capping stack. Following installation of the capping stack, the flow drops further to roughly 48 100 or 51 300 stbd when only the choke or kill line is open; when both are open, the calculated flow rate is 53 200 stbd. Figure 5 illustrates that the flow rate decays fairly smoothly with little evidence of any significant lasting effects from the various wellhead activities, except perhaps removal of the original marine riser. Linear fits to flow rates just before and after removal of the riser show an increase in flow rate of about 1800 stbd or 2.8%. Calculated flow rates just before and after the top-kill effort are continuous along the trend, indicating that the injection of mud and debris had no significant lasting effect on flow rates. Linear fits to these rates just before and after top-kill are offset by just 0.1%.

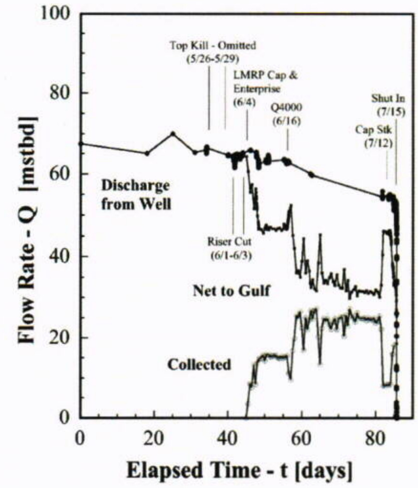

Figure 5. Calculated flow rates in thousands of stock-tank barrels per day using measured BOP pressures and baseline reservoir pressure history. Collected oil rates are as reported by BP.

Also shown in Figure 5 are total oil recovery rates as reported by BP and the net difference between these and the calculated total flow rates. Prior to installation of the LMRP cap, essentially all flow from the well entered the Gulf. Subsequently, increasing fractions of the total release were captured and either processed or burned.

Cumulative discharge of oil from the well can be calculated readily from the results of Figure 5. This was done using a trapezoid algorithm to integrate the instantaneous flow rate from one measured BOP pressure to the next. The cumulative oil collected was likewise calculated by integrating the instantaneous rate, in this case over the half-day intervals reported by BP. The cumulative total was then interpolated onto half-day intervals to compute the net release. These results are presented in Figure 6. The calculated nominal cumulative total oil discharged from the well is 5.4 million stb (mmstb), the cumulative oil collected is 0.8 mmstb, and the net release to the Gulf is 4.6 mmstb. The average flow rate from the well over the 86-day period was thus 62 800 stbd.

■ DISCUSSION OF UNCERTAINTIES

A detailed discussion of uncertainties is provided in Appendix C of Supporting Information. The following is a brief synopsis of conclusions.

Quantifiable uncertainties in historical flow rates and the cumulative discharge are −9.3% and +7.5%, yielding a likely total discharge in the range from 4.9 to 5.8 mmstb. As shown in Table 1, these uncertainties arise either from sources associated with parameter estimation (yellow) or from uncertainties or variations over the 86-day period (blue). The uncertainties associated with parameter estimation in turn arise largely from variations in density, viscosity, and/or quality of the gas-oil mixture that are not accounted for in the model. In Table 1, for

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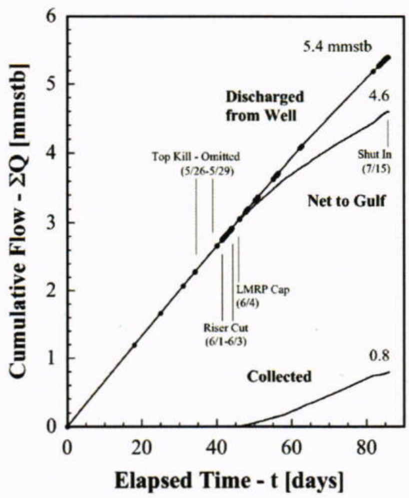

Figure 6. Calculated cumulative and net oil discharged from MC252. Cumulative discharge over the 86 days is 5.4 mmstb. Net release to the Gulf of Mexico is 4.6 mmstb.

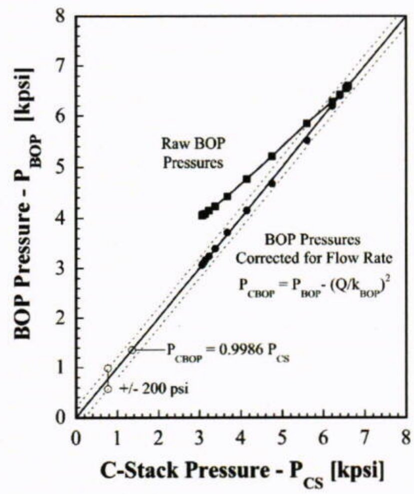

Figure 7. Correlation between BOP and capping-stack pressures. BOP pressures measured during shut-in are plotted against capping-stack pressures measured at the same times. Dashed curves are the linear correlation (solid line) plus and minus 200 psi, roughly the expected accuracy of the BOP gauge at these pressures.

Table 1. Summary of Uncertainties in Calculated Historical Flow Rates Due to Various Sources[a]

Source of Uncertainty	Negative (%)	Positive (%)
BOP ±3.4%	-1.6	+1.8
Choke Dwn-Strm Tubing ±4.5%	-0.3	+0.3
Kill Line ±1.9%	-0.3	+1.0
Choke 2-ϕ Factor +250/-0%	-1.7	
Measured Flow Rates	-1.6	+1.8
Res Press (7010 vs 6605 psi)		+0.5
Head Variation During Shut-In	-0.7	
Wellbore Density +3.4/-4.0%	-1.3	+1.1
Res Density & Viscosity +0/-12%	-1.0	
Reservoir Pres Decay ±10%	-0.8	+0.8
Initial BOP Pressure		+0.2
Total	-9.3	+7.5

[a]Numbers immediately following each source generally represent the uncertainty in flow rate associated with that source. Values listed in the last two columns represent resulting uncertainties in the calculated historical flow rates and cumulative discharge of oil from the well.

example, the estimated variation in flow rates through the BOP due to density variations is ±3.4%, and this leads to uncertainties in the calculated cumulative discharge of −1.6% and +1.8%. These uncertainties, are calculated by perturbing the BOP discharge coefficient from its baseline value by ±3.4%, estimating all other parameters holding this perturbed value constant, and calculating the cumulative discharge that results. Uncertainties arising from density-induced variations in flow rates through the capping-stack choke and kill lines are computed in a similar manner. Methodologies for the remaining uncertainties are discussed in Appendix C. These include uncertainties in measured flow rates, the reservoir pressure used in parameter estimation, variation in elevation head during shut-in, and uncertainties over the 86-day period.

Additional uncertainties that are more difficult to quantify arise from potential unknown nonlinearity and offsets in the BOP pressure gauge. Pressures measured at the BOP were erratic at times and, as a result, the measured BOP pressures have been dismissed or treated with great suspicion. This appears to be largely unjustified. BOP pressures measured during shut-in in fact correlate very well with those measured concurrently via the calibrated capping-stack gauge, provided the frictional pressure drop through the BOP is accounted for. And, this pressure drop is readily calculated using the baseline BOP discharge coefficient of 1529 stbd/psi$^{1/2}$ and flow rates calculated using the reservoir and exit pressures. The raw and corrected BOP pressures are shown in Figure 7 as a function of measured capping-stack pressures. As expected, the raw pressures (from Figure 2) do not show a linear correlation due to variation in flow rates as the choke is closed. When the BOP pressures are corrected to remove the frictional pressure drop, however, the result is a linear correlation between BOP and capping-stack pressures having a least-squares slope of 0.9986 and rms deviation of just 33 psi. The BOP gauge thus appears to exhibit good linearity at the time of shut-in. As discussed in Appendices C and D, analysis of the decay rate in BOP pressures indicates that this linearity was also present between May 8 and June 15. It is therefore unlikely that errors in BOP gauge linearity contribute discernible uncertainty to the calculated historical flow rates.

This leaves only concern about BOP gauge offsets and uncertainties in the reservoir pressure history. Taking into account all extremes of the credible reservoir and BOP pressures, the minimum and maximum nominal discharge from the well are 5.1 and 5.8 mmstb. The minimum discharge occurs for the minimum reservoir pressure history and maximum BOP pressures; the maximum occurs for the opposite pairing. Applying the quantifiable uncertainties of −9.3% and +7.5% to these values then yields bounds on the minimum and maximum credible cumulative discharge of 4.6 and 6.2 mmstb.

■ ALTERNATIVE CALCULATION OF FLOW RATES USING RESERVOIR AND AMBIENT PRESSURES

The primary objective of this study was to calculate flow rates using measured BOP pressures. However, these flow rates and

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the cumulative discharge can also be calculated using the reservoir and ambient exit pressures given that the model and parameters fully characterize the wellbore and BOP. Moreover, calculations of this sort can also account for nonlinear decay of the reservoir pressure in response to flow from the well and, in addition, yield calculated BOP pressures that can be compared with measured values. While such calculations do not account for the evolving state of the wellhead and riser, they can still serve as independent confirmation of the methodology, model, and parameters. Details of this alternative method are discussed in Appendix E.

Using baseline conditions, this alternative approach yields a cumulative discharge of 5.2 mmstb and initial and final BOP pressures of 4070 and 3460 psi. Remarkably, this cumulative discharge differs by less than 4% from the baseline value of 5.4 mmstb calculated using measured BOP pressures. This again indicates that the various wellhead alterations did not significantly affect flow rates. Such agreement also indicates that flow rates over the 86-day period were not significantly affected by erosion within the BOP since use of the BOP pressures accounts for this possibility while use of the ambient pressure does not.

■ ASSOCIATED CONTENT

Ⓢ Supporting Information

Appendices A through E as cited in the text. This information is available free of charge via the Internet at http://pubs.acs.org/.

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Notes

All pressures, temperatures, flow rates, and well characteristics reported in this paper were provided by BP to Secretary of Energy Dr. Steven Chu and his Science Team in the course of the government response to the Deepwater Horizon accident. These are presented verbatim in the unusual mix of units commonly employed in the petroleum industry.

The authors declare no competing financial interest.

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