

EXPERT REBUTTAL REPORT
U.S. v. BP Exploration & Production, Inc., et al.

Prepared on Behalf of the United States

Prepared by:
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A handwritten signature in blue ink that reads "Aaron A. Zick".

Aaron A. Zick

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1. EXECUTIVE SUMMARY

On March 22, 2013, I issued an expert report on behalf of the United States. In that report, I presented an *equation-of-state fluid characterization* (a model of fluid phase behavior) for the Macondo reservoir fluids and some predictions of the Macondo fluid behavior based on my EOS model. The purpose of the EOS model was to provide key fluid behavior information that other US experts could use in their calculations to estimate the amount of oil that flowed from the Macondo well and spilled into the Gulf of Mexico. I also offered my professional opinion on the most appropriate calculation methods to convert any such estimates of the total mass of spilled hydrocarbons into volumetric units of stock tank barrels.

In response, on May 1, 2013, Curtis Hays Whitson, Ph.D., issued an expert report on behalf of BP. In his report, Dr. Whitson presented an alternative EOS fluid characterization and its predictions of the Macondo fluid behavior. While there are differences between our characterizations, and although Dr. Whitson and I both level a number of criticisms against each other's model, the EOS differences should not result in significant differences in calculating the oil discharge. Whether one uses my EOS model or Dr. Whitson's, I would not expect any resulting flow calculations to differ by more than perhaps 3 or 4 percent. I discuss the differences between the two EOS models, and the strengths and weaknesses of each, in Section 3.

The most significant difference between Dr. Whitson's work and mine is in how we would define *stock tank oil* in the most appropriate way for the Macondo disaster. If we had perfect knowledge of the physics of the reservoir and the well, we could uniquely determine the mass of hydrocarbons that spilled into the Gulf of Mexico. The simulations and models used by the various experts provide estimates of that mass, but the amount of stock tank oil that could be obtained from that mass would depend on the surface process that was used to remove some of the lighter hydrocarbons as *surface gas*, allowing the resulting stock tank oil to remain a stable liquid at atmospheric conditions. Different processes (typically using different numbers of separation stages, at different temperatures and pressures) have different efficiencies, yielding different amounts of stock tank oil (with different properties) from the same mass of reservoir fluid. Because oil is more valuable than gas, oil companies devote considerable attention to maximizing the amount of stock tank oil derived from the hydrocarbon mass. There is no unique definition of stock tank oil, however, unless some oil is actually collected in a tank of sorts, where its volume and properties can actually be measured. Since that didn't happen for the oil spilled into the ocean, we are left with the question, what is the best way to characterize the amount of stock tank oil associated with the spill?

In my original report, I argued that the most appropriate conversion from reservoir fluid mass to stock tank oil volume would be through the most efficient separation process that might have been available to BP (i.e., the type of separation process BP, or any oil company for that matter, would normally use to maximize the amount of liquid oil produced in order to maximize profit). That would seem to be a 4-stage separation process that BP had commissioned three different laboratories to test on the four fluid samples that had been collected prior to the disaster. That multistage process would yield

about 11% more stock tank oil than the simplest possible, single-stage separation process would yield, so I recommended that the multistage process be used to calculate the amount of spilled stock tank oil. My reasoning was that BP would never have used a less efficient process to define their stock tank oil during production, so why should a less efficient process define their stock tank oil during disaster?

Dr. Whitson (like several other BP experts)¹ felt that the multistage separation process that BP had planned to use was irrelevant, because the spilled oil never went through such a process. Of course, the same could be said of the simple single-stage process. Dr. Whitson, however, proposed a model of an *oceanic separation process*, in which the spilled oil, as it floated to the surface of the ocean, would pass through a large number of theoretical separation stages with continually increasing temperatures and decreasing pressures. The idea was to define the oil that stayed in the liquid phase, all the way to the ocean surface, as the Macondo stock tank oil. I agree that this could be another reasonable way of defining the stock tank oil, with the right assumptions.

Dr. Whitson calculated the yield of stock tank oil from his oceanic separation model to be higher than from a single-stage separation, but slightly less (by about 0–2.5%, depending on the well's exit temperature) than from the 4-stage separation that BP had explored experimentally. Dr. Whitson made a serious omission, however. Exiting the well, at the bottom of the ocean, there was both an oil plume and a gas plume. As the oil rose toward the surface, it would give off additional gas, causing the oil to shrink and the gas plume to grow. Dr. Whitson accounted for these effects. What he didn't account for, however, was the amount of condensable hydrocarbons contained in the rising and growing gas plume. Those heavier hydrocarbons would continue to condense from the gas for roughly the first two-thirds of its journey to the surface. The additional condensed liquids would actually make the oceanic stock tank volume about 2.1–2.3% greater than that of the 4-stage separation (with very little sensitivity to the well's exit temperature, incidentally). Details of the oceanic separation process and its predictions (using both Dr. Whitson's variation and mine) are presented in Section 2.

Dr. Whitson also suggested that, by the time the spilled oil reached the ocean surface, all of its light hydrocarbons (up to C5) and light aromatics (up to C12) would have dissolved in the seawater, reducing the ultimate volume of the hydrocarbon liquids (i.e., the stock tank oil volume) by up to 13%. In essence, Dr. Whitson is saying that oil that dissolves quickly doesn't count in an oil spill. In my opinion, this idea is irrelevant. There's no denying that some of the spilled hydrocarbons would have dissolved in the water. For that matter, additional hydrocarbons would have evaporated into the atmosphere and/or biodegraded. In fact, given enough time, all of the liquid hydrocarbons could have been dispersed by a combination of those mechanisms. That should have no bearing on the estimated amount of stock tank oil spilled, however. Otherwise, if an oil company spilled a million barrels of (clearly defined and measured) stock tank oil from an oil tanker, for example, that company could similarly argue that it should only be held accountable for the 870,000 barrels (or less) that didn't dissolve, evaporate, or biodegrade right away. In

¹ To the extent other BP experts assume multistage or oceanic separation is irrelevant to what occurred during the Macondo spill, my analysis regarding multistage separation and criticism of the use of single stage separation to determine shrinkage, FVF, GOR, or other fluid properties applies to them as well.

my opinion, an oil spill should be measured by what goes into the water, not by what remains there after nature has taken its course for some period of time.² There is no dispute that the stock tank oil that Dr. Whitson omits did in fact enter the water. Ultimately, however, whether such oil counts for purposes of this case is a legal question.

Finally, Dr. Whitson produced a large number of simplified phase behavior models, called black-oil tables, for use in simulations that could not take advantage of his EOS model. The black-oil tables varied according to the fluid samples they represented, the surface separation processes they assumed, and the software for which they were formatted. Most of them were fine (although quite redundant). However, the black-oil tables that he formatted for PROSPER³ were completely erroneous for that software (as shown in Section 4). Any simulations performed by BP experts with PROSPER, using the black-oil tables provided by Dr. Whitson, would not have given correct results for the flow of the Macondo reservoir fluids.

² To the extent other BP experts also discount some oil from the total discharged because it dissolves quickly, my analysis applies to them as well.

³ Industry standard software for pipe-flow simulation, from Petroleum Experts Ltd.

2. ON THE DEFINITION OF STOCK TANK OIL

By definition, a stock tank oil can be any mixture of hydrocarbons that would remain stable in a liquid phase at ambient, stock tank conditions (usually, 60 F and 1 atm). It is not uniquely defined, however. Its composition, properties, mass, and volume are determined not only by the reservoir fluid from which it originated, but also by the processes that it underwent in going from the reservoir to the stock tank.

During the production of most oil or gas reservoirs, the nature of the stock tank oil can be affected by the depletion of the reservoir itself, as the depletion can change the composition of the fluids flowing into the wells. In the case of the Macondo well, however, that was not an issue, as the flowing composition remained essentially constant, from the reservoir to the exit of the well, for the entire duration of the spill.

During normal oil or gas production, the nature of the stock tank oil is also affected by the processing of the hydrocarbons at the surface, where the lighter hydrocarbons must be removed (as a surface gas) so that the remaining stock tank oil will remain stable as a liquid. There are many different ways of performing that surface processing, however, each of which results in a different amount of stock tank oil with different properties.

Separating a reservoir fluid into stock tank oil and surface gas is a little like opening a bottle of champagne. If you pop the cork and release the pressure suddenly, much of the dissolved carbon dioxide will rush out of solution and out of the bottle, taking a fair amount of the valuable champagne with it. If you remove the cork gently, however, to release the pressure gradually, you minimize the loss of the carbon dioxide and keep the champagne in the bottle.

The simplest of all possible surface processes is to flash the hydrocarbons directly to stock tank conditions in a single-stage separation (like popping the champagne cork). This is often used for well testing purposes, because it is so simple, but it would rarely be used for production purposes because of its inefficiency. Too many of the valuable intermediate components (butane to decane or so) would be lost to the surface gas instead of being stabilized in the stock tank oil, resulting in less stock tank oil than would be optimal.

During normal production, surface processing is usually performed with a multistage separation, where the fluid coming from the well is passed through a sequence of separators, with temperatures and pressures decreasing at each stage from wellhead conditions toward ambient conditions (like removing the champagne cork gently). The separated liquid from the first stage is passed to the second-stage separator, the separated liquid from that stage is passed to the third-stage separator, and so forth, until the final liquid is at stock tank conditions. The separated gases from each stage are gathered together as the surface gas (which might be transported and sold separately, processed further at a gas plant to extract additional natural gas liquids, burned as fuel, or simply disposed of by flaring).

A multistage process is more efficient at recovering stock tank oil because of the way the surface gas is removed incrementally, which removes fewer of the intermediate

hydrocarbons from the liquid. Generally, the more separation stages used, the more stock tank oil is recovered.

When BP commissioned three laboratories to perform analyses and testing on four samples collected from the Macondo well before the disaster, each lab was asked to perform a specific 4-stage separator test⁴ on each sample.⁵ One can only presume that BP had intended to use that separation scheme during production, had normal production ever occurred, so it was one of the separation processes that both Dr. Whitson and I used to calculate *shrinkage factors* for the Macondo reservoir fluids.

A reservoir fluid's *shrinkage factor* is defined as the volume of oil at one stage of processing (usually at the stock tank conditions, but not necessarily) divided by the volume of the original reservoir fluid at some other conditions before processing. For it to have any meaning, the initial and final conditions must both be specified, as well as the process that was taken in between. Because those conditions and the process can be arbitrary, a fluid's shrinkage factor has no single unique value. It is also somewhat of a misnomer, because the more the fluid shrinks from its initial to its final conditions (as gas is removed), the smaller the shrinkage factor. Three things to remember are that

- Two shrinkage factors (e.g., for different processes or different fluid models) can be compared only if the specified conditions (initial and final) and are the same for both.
- The greater the shrinkage factor (for given initial conditions), the greater the volume of oil at the final (usually stock tank) conditions.
- If you know the shrinkage factor of a reservoir fluid as it is processed from condition A to condition B, and the shrinkage factor as it is processed from condition B to condition C, then the product of the two gives the shrinkage factor as the fluid is processed from A to B to C (this can provide a method of converting the shrinkage factor specified for one set of conditions to a shrinkage factor for a different set of conditions).

A reservoir fluid's *formation volume factor* is the inverse of its shrinkage factor (for a given process that would take the fluid to stock tank conditions). A formation volume factor (as a function of pressure and/or temperature) is a required input for many types of petroleum engineering software (reservoir simulators, pipe-flow simulators, material balance software, etc.), but again, its value at any given set of conditions depends on the assumed process.

In my initial report, I provided the shrinkage factors (and corresponding formation volume factors) for taking what I considered to be the average Macondo reservoir fluid from its saturation pressure of 6679.85 psia at 243 F (as calculated by my EOS) to the standard stock tank conditions of 1 atm at 60 F through two different surface processes: a

⁴ Stage 1: 1250 psia at 130 F, Stage 2: 450 psia at 120 F, Stage 3: 150 psia at 120 F, Stage 4: 1 atm at 60 F.

⁵ Pencor Volatile Oil Reservoir Fluid, Report No. 36126-19-5010068508, June 30, 2010 (BP-HZN-2179MDL00063084), Pencor Volatile Oil Reservoir Fluid, Report No. 36126-53-5010068379, June 10, 2010 (BP-HZN-2179MDL01872218), Schlumberger Fluid Analysis on Macondo Samples, June 9, 2010 (BP-HZN-MDL217900062844-62893), Intertek Multistage Separator Test Final Report WTC-10-001812, June 10, 2010 (BP-HZN-MDL217904440978-998).

single-stage separation and the 4-stage separation that BP had specified for the laboratory experiments.

Dr. Whitson reported so many different shrinkage factors and formation volume factors (for each of the four laboratory samples, different initial conditions, and many different processes and variations thereof) that it is impossible to enumerate them all. The best way to summarize his findings, however, is to repeat the shrinkage factors he calculated for an average reservoir fluid (he used the molar average of the four samples), going from initial reservoir conditions (243 F and 11,850 psia) to stock tank conditions (60 F and 1 atm). I was easily able to recalculate the corresponding shrinkage factors for my average reservoir fluid (which I took to be the molar average of the Pencor 19 sample, from highest in the formation, and the Schlumberger 1.18 sample, from lowest in the formation).

Table 1 summarizes the predictions of the two fluid models for a single-stage separation and for BP's specified four-stage separation. Regardless of the process, my EOS predicts a shrinkage factor about 3% greater than Dr. Whitson's, and regardless of the EOS, the four-stage separation would produce about 11% more stock tank oil than would the single-stage separation.

Surface Process	Calculated Shrinkage Factor		% Difference
	Whitson EOS	Zick EOS	
Single-Stage	0.433	0.445	2.8
Four-Stage	0.479	0.494	3.1
Difference, %	10.6	11.0	

Table 1. Shrinkage factors for an average Macondo reservoir fluid going from 243 F and 11,850 psia to 60 F and 1 atm, as calculated by both the Whitson and Zick equations of state for a single-stage separation and BP's specified 4-stage separation.

Since normal production, and normal surface processing did not occur for the Macondo reservoir fluids, Dr. Whitson proposed an alternative separation process for defining the Macondo stock tank oil, namely an *oceanic* separation process, a schematic of which is shown in Figure 1.⁶ In this process, the usual three or four surface separators are replaced by a continuum of theoretical separation stages, each one represented by the temperature and pressure from a different depth within the ocean, from the seabed to the surface. The first separation stage represents the conditions at the very exit of the well, before the reservoir fluid hits the water. These conditions determine the split of the reservoir fluid into an oil stream and a gas stream. From there, Dr. Whitson's model passes the oil stream through the sequence of assumed oceanic conditions from the seabed to the surface, removing the gas and adding it to the gas stream at each stage. The oil that reaches the surface is defined as stock tank oil. In Dr. Whitson's theoretical process, the gas stream does not undergo any other separation until it reaches the surface, where just the original exit gas is flashed in a single-stage separation at standard conditions, which

⁶ Despite repeated requests to BP, the modeling files for Dr. Whitson's oceanic process were not provided to the US, so I had to deduce the details of his process from the somewhat vague description in his report, some files containing a simplified version of his process, and some trial-and-error modeling of my own until I was able to duplicate his reported results.

condenses a small amount of additional liquid (condensate) that adds to the stock tank oil volume. Dr. Whitson experimented with the number of theoretical stages and found that it took 130 stages before his results became insensitive to the number.

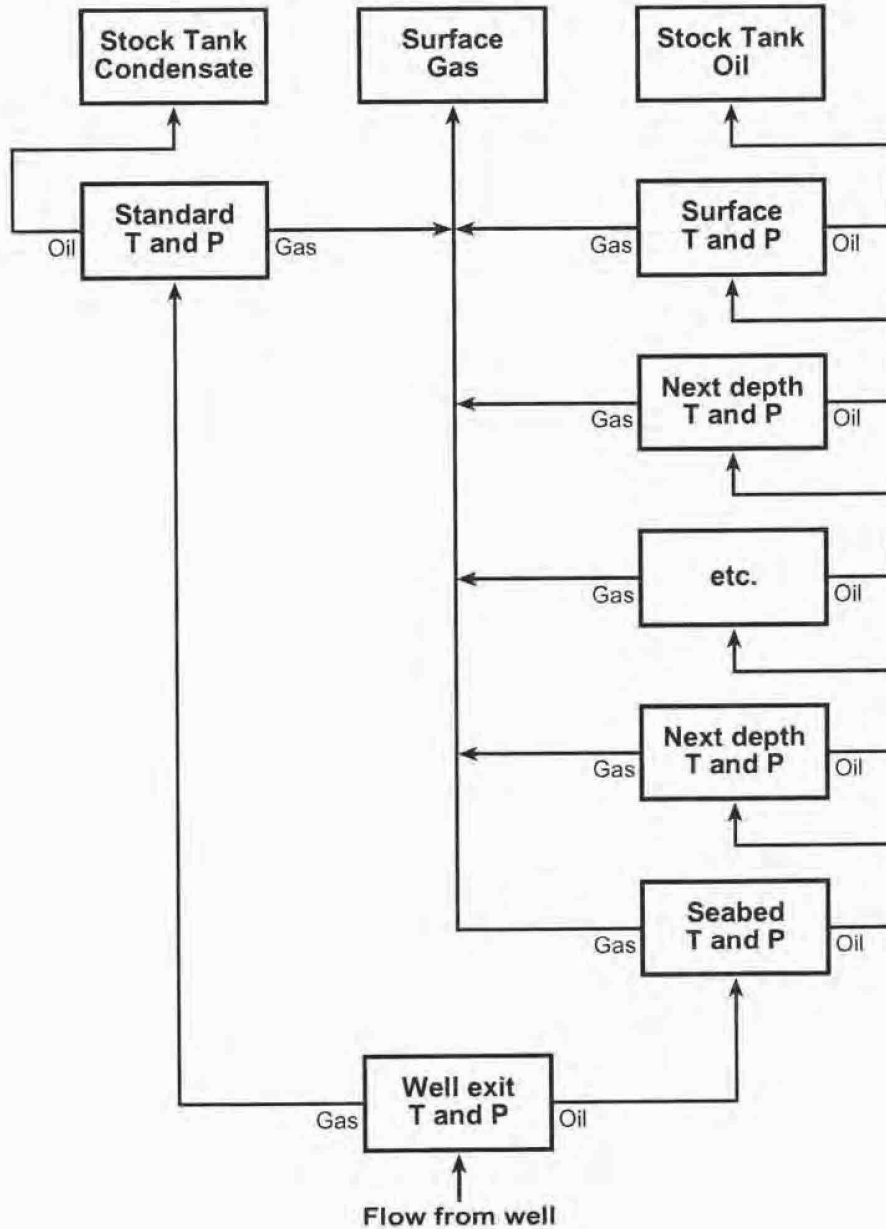


Figure 1. Dr. Whitson's proposed oceanic separation process, which does not account for potential condensation from the rising gas stream until it reaches the ocean surface. The separator conditions are determined from estimated profiles of temperature (T) and pressure (P) with depth.

Because most petroleum engineering software would not allow a separation process to be designed with so many stages, Dr. Whitson came up with a 5-stage approximation to his 130-stage oceanic separation, with the temperatures and pressures determined by regression (a mathematical form of trial-and-error), instead of being tied to oceanic temperature and pressure profiles. The schematic of the separation process remained the same; it just had far fewer separators. He called this his *oceanic proxy* separation process. I confirmed the agreement between his proxy process and his full oceanic process for a few cases, but there is no way to guarantee that it will always predict similar results. There is also no guarantee that all petroleum engineering software would simulate the separation process correctly, given the 5 sets of separator conditions. I suspect that many software packages would fail to perform the final separation on the gas stream, because that stage is not part of a typical separation train. If that were the case, the simulation would predict less stock tank oil than intended.

I have also developed an oceanic process model to simulate how the Macondo reservoir fluid might have separated into stock tank oil and surface gas on its way to the ocean surface. My oceanic process differs from Dr. Whitson's with one significantly different assumption, however. Dr. Whitson made a serious omission by assuming that the gas stream would rise all the way to the ocean surface before any additional liquids would condense from it. My calculations show that liquids should actually continue to condense (at each stage) from the total accumulating gas stream until the pressure falls below approximately 750 psia (which would occur about two-thirds of the way from the seabed to the ocean surface), and the amount of condensation is considerable. A schematic of my oceanic separation process is shown in Figure 2.

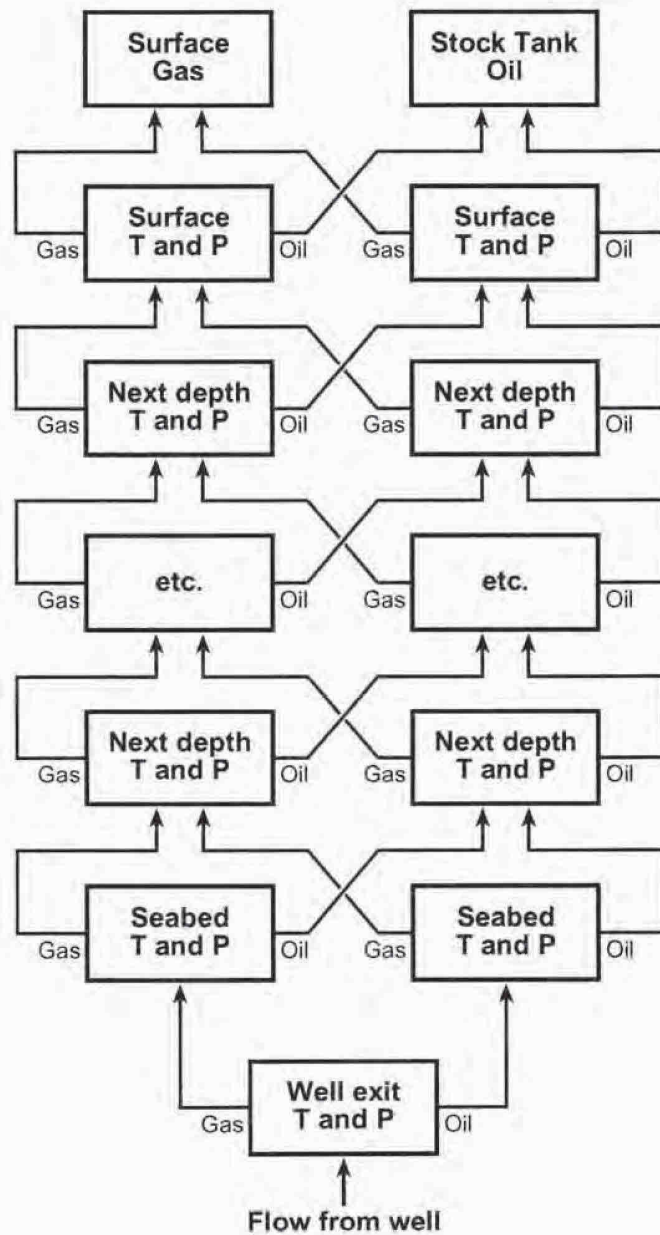


Figure 2. Zick oceanic separation process that accounts for potential condensation from the rising gas stream. The separator conditions are determined from estimated profiles of temperature (T) and pressure (P) with depth.

My oceanic separation process assumes that, at each depth, there is both an oil stream and a gas stream that remain isolated from each other. However, any gases that separate from the oil stream will commingle with the gas stream at the next depth, while any liquids that condense from the gas stream will commingle with the oil stream at the next depth.

This will continue all the way from the seabed to the ocean surface, where the final streams represent the stock tank oil and the surface gas. These assumptions are simple enough to allow the separation calculations (without requiring the tracking of each oil droplet and each gas bubble in a rigorous plume simulation), but they account for the separation of both streams in a logical way. It should not matter that the gas stream, being more buoyant, might travel at a higher velocity than the oil stream, as long as one also assumes that both streams settle into a pseudo-steady state, which I believe to be a very reasonable assumption.

In order to compare my oceanic separation model with Dr. Whitson's, I adopted his 129 sets of separator conditions, giving my model 257 separator stages (one for the well's exit and 128 for each stream), as opposed to his 130 (one for the well exit, 128 for the oil stream, and one for the exit gas stream). As in Dr. Whitson's model, the well's exit pressure is assumed to be 2250 psia. Dr. Whitson made his calculations for several different exit temperatures, but seemed to suggest 210 and 130 F as the most likely extremes, so the results for those two exit temperatures are presented here as well, in Table 2 and Table 3, respectively.

Oceanic Process	Calculated Shrinkage Factor		% Difference
	Whitson EOS	Zick EOS	
Whitson Model	0.467	0.482	3.2
Zick Model	0.489	0.506	3.5
Difference, %	4.7	5.0	

Table 2. Shrinkage factors for an average Macondo reservoir fluid going from 243 F and 11850 psia to 60 F and 1 atm, as calculated by both the Whitson and Zick equations of state for the oceanic separation models of both Whitson and Zick with an exit temperature of 210 F.

Oceanic Process	Calculated Shrinkage Factor		% Difference
	Whitson EOS	Zick EOS	
Whitson Model	0.480	0.495	3.1
Zick Model	0.490	0.507	3.5
Difference, %	2.1	2.4	

Table 3. Shrinkage factors for an average Macondo reservoir fluid going from 243 F and 11850 psia to 60 F and 1 atm, as calculated by both the Whitson and Zick equations of state for the oceanic separation models of both Whitson and Zick with an exit temperature of 130 F.

The first thing to note is that my oceanic separation model is more efficient than Dr. Whitson's, because of the additional condensation from the gas stream. It predicts 2–5% more stock tank oil than Dr. Whitson's model does, depending slightly on the EOS but much more so on the well's exit temperature. Regardless of the EOS, my oceanic model is very insensitive to the exit temperature, but that is not the case for Dr. Whitson's oceanic model. That is understandable, because the exit temperature determines how the flowing reservoir fluid splits into the initial oil and gas streams, which are both processed in a similar manner with my oceanic model, but which are processed very differently with Dr. Whitson's model.

The other thing to note is that my EOS predicts a 3.1–3.5% greater shrinkage factor than Dr. Whitson's EOS does, depending slightly on the oceanic separation model. This is similar to the differences in the predictions for the 4-stage separation.

All of the previous shrinkage factor calculations can be summarized by Table 4, which lists the calculated shrinkage factor for a given process, relative to the shrinkage factor calculated for a single-stage process (by either Dr. Whitson's EOS or mine). The processes are listed in the order of increasing shrinkage factor. The higher the shrinkage factor, the more stock tank barrels produced per barrel of reservoir fluid.

Separation Process	Relative Shrinkage Factor	
	Whitson EOS	Zick EOS
Single-Stage	1.000	1.000
Whitson Oceanic @ 210 F	1.079	1.083
Four-Stage	1.106	1.110
Whitson Oceanic @ 130 F	1.109	1.112
Zick Oceanic @ 210 F	1.129	1.137
Zick Oceanic @ 130 F	1.132	1.139

Table 4. Shrinkage factor (to stock tank conditions) for a variety of processes, relative to the shrinkage factor predicted by either the Whitson or the Zick EOS for a single-stage separation.

The way to use Table 4 is as follows. If you are given a simulated prediction of the volume of stock tank oil that flowed from the Macondo well, and you know that the simulation assumed a certain surface process (process A), then you can determine the amount of stock tank oil for any other assumed surface process (process B) simply by dividing the given results by the table's relative shrinkage factor for process A and then multiplying them by the table's relative shrinkage factor for process B.

For example, if a simulation using my EOS has predicted 5 million barrels of stock tank oil under the assumption of BP's four-stage separation, then 5.122 million barrels would be predicted by a switch to my oceanic process with an exit temperature of 210 F (5 divided by 1.110 times 1.137 equals 5.122). There would be no reason to rerun the simulation (even if the software could handle the complicated oceanic process).

The reason the Macondo stock tank volumes can be scaled so easily (without rerunning any simulation) is that the physics of the fluid flow, from the reservoir to the well's exit, can in no way be influenced by any of the processing that takes place subsequently. Furthermore, since the flowing composition was essentially constant during the entire Macondo disaster, the conversion of the flowing reservoir fluid from mass units to stock tank volumes will always be by a constant factor that is simply proportional to the relative shrinkage factor shown in Table 4 for the assumed process.

No matter which surface process is chosen to convert the amount of spilled Macondo oil into stock tank barrels, the mass of the resulting stock tank oil will still always be less than the mass of the hydrocarbons that were actually spilled (because the stock tank oil will not include the mass of the separated surface gas). My recommendation has always been to perform the conversion with the most efficient process available, to account for

as much of the hydrocarbon mass spilled into the Gulf of Mexico as possible. Some sort of multistage separation process will always be the most efficient. In light of the calculations presented in this section, my current recommendation is to use my oceanic separation process to make the conversions. Despite Dr. Whitson's claims to the contrary, there is no need for special software to simulate such a complex process. The necessary flow calculations can be performed with any software that can handle a single-stage separation to define the stock tank oil; the predicted number of stock tank barrels should then just be increased by 13 or 14% to account for the oceanic separation (see Table 4).

3. COMPARISONS BETWEEN MY EOS MODEL AND WHITSON'S

In an apparent attempt to discredit any flow calculations that incorporated my EOS fluid model, Dr. Whitson leveled a number of criticisms toward it. Most of his criticisms, however, were baseless, overstated, or relatively unimportant. In this section, I will address those criticisms, point out a few flaws in Dr. Whitson's EOS model, discuss some of the differences between our models, and show why neither model is clearly superior to the other in all aspects. Overall, both models predict the most important fluid behavior with the accuracy expected of a good EOS model and I consider their differences to be relatively minor. I would not expect to see significant differences between any flow or material balance calculations performed with either model.

Dr. Whitson's main criticisms of my EOS fluid characterization were:⁷

- A. Erroneous type of phase boundary (bubble-point instead of dew-point) for the two Pencor samples.
- B. Erroneous near-critical liquid volumes for the two Pencor samples during the constant composition expansion experiments.
- C. 1-2% overestimation of single-phase densities for all samples.
- D. 3-5% overestimation of the shrinkage factor (i.e., too much stock-tank oil) for all samples using the laboratory 4-stage separation process.
- E. My selection of pseudocomponents and my procedures for characterizing them differed from his.
- F. My intermediate, 35-component EOS was inaccurate and produced some physically unrealistic predictions.

Criticisms A and B are technically valid, although relatively unimportant. The compositions of the four fluid samples (referred to as: Pencor 19 or CL68508; Pencor 53 or CL68379, Schlumberger 1.18 or SLB 1.18; and the Intertek sample) were so close to each other that I found it impossible to produce an EOS characterization that would correctly predict dew points (and the resulting behavior for the near-critical liquid volumes) for the two Pencor samples while predicting bubble points for the SLB and Intertek samples. The Pencor supervisor was not even convinced that the Pencor data were conclusive.⁸ The fact that my EOS predicts dew points instead of bubble points for the two Pencor samples is also relatively unimportant. Those fluid systems are so near-critical, with the properties of the gas and liquid phases so near each other, that it really does not matter very much whether the system heads toward a dew point (100% gas) or a bubble point (100% liquid) as the pressure is increased. Away from the near-critical region, the liquid volumes predicted by my EOS are very comparable to those predicted by Dr. Whitson's.

Nevertheless, Dr. Whitson managed to overcome the seemingly conflicting phase boundary types by modifying the compositions of *all four* samples. It is common practice to adjust a sample composition if there is some evidence that it contains some

⁷ To the extent other BP experts make similar criticisms, my responses answer them as well.

⁸ "It's possible that it's a dew-point system, and it's possible that it's a bubble point system." Jason LeBlanc of Pencor in his deposition, Exhibit 8592.

experimental errors (if it seems completely inconsistent with other, similar samples, for example). In my case, I had to do that with the SLB 1.18 sample in order to match its experimental molecular weight and so the predictions of its saturation pressures would be consistent with the predictions for the other three samples. I found no such justification for adjusting the compositions of the other samples, however. Conversely, Dr. Whitson did not honor *any* of the measured compositions. His adjustments were seemingly minor, yet they completely changed the behavior of the two Pencor samples. I would not object to his modifications if they were necessary to match molecular weights or gas-oil ratios (which are strongly correlated with composition), but that was not the case, as shown by the significant errors his model exhibited in predicting those quantities (see Table 5). I find it disconcerting that his adjustments were designed solely to change the near-critical behavior of the four samples without maintaining consistency with the measured molecular weights (predicted 6–13% too low) or the Pencor gas-oil ratios (predicted 13–14% too high).

Sample	Liquid Molecular Weight			Gas-Oil Ratio (scf/bbl)		
	Measured	Zick EOS	Whitson EOS	Measured	Zick EOS	Whitson EOS
Pencor 19	212	211	195	2906	3010	3314
Pencor 53	208	210	196	2819	2948	3174
SLB 1.18	212	210	196	2945	2855	2917
Intertek	212	200	184	2831	2732	2942

Table 5. Comparisons of the liquid molecular weights and gas-oil ratios predicted by the Zick and Whitson equations of state with the measured data from the single-stage separations of the four fluid samples.

The ways in which Dr. Whitson manipulated the fluid compositions and the EOS parameters of his model (in order to predict dew points for the two Pencor samples) also had the unfortunate side effect of causing his EOS to predict very poorly the results of the two Pencor differential liberation experiments, as shown in Figure 3 through Figure 8.

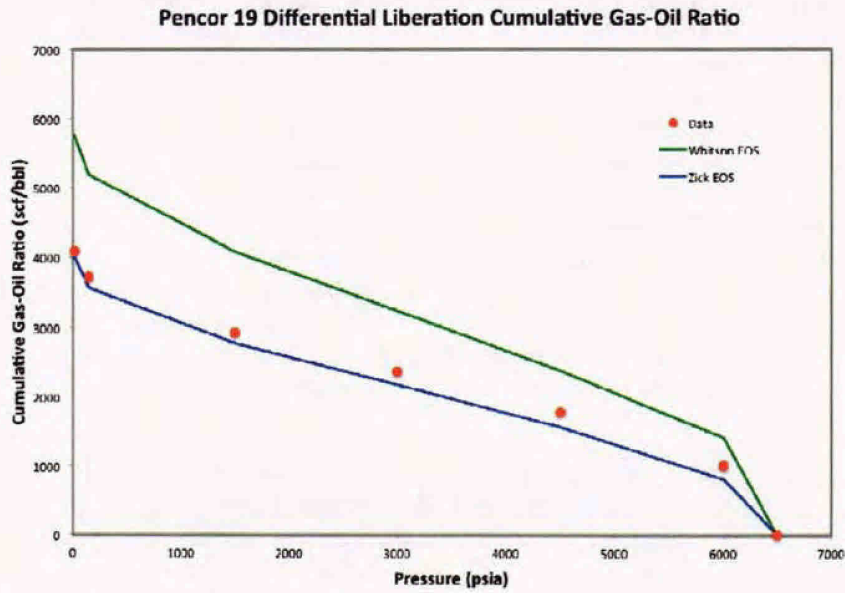


Figure 3. Cumulative gas-oil ratio (total gas removed per volume of remaining liquid) during the differential liberation of the Pencor 19 sample, comparing the predictions of the Zick and Whitson equations of state with the experimental data.

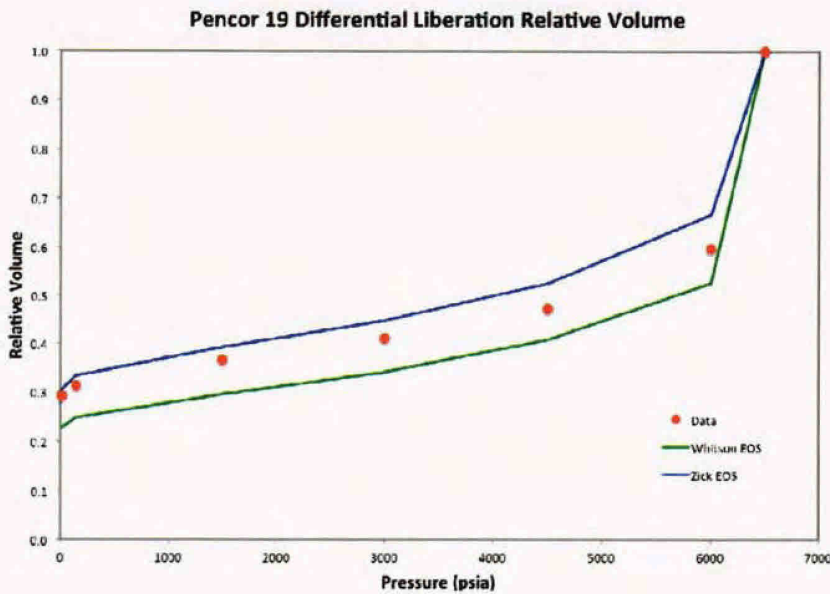


Figure 4. Relative volume (volume remaining per initial volume) during the differential liberation of the Pencor 19 sample, comparing the predictions of the Zick and Whitson equations of state with the experimental data.

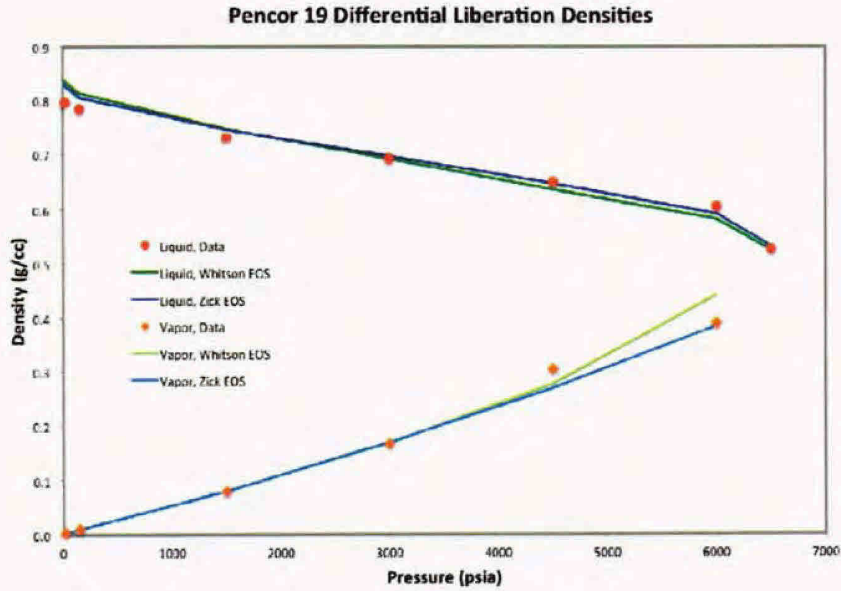


Figure 5. Liquid and vapor densities during the differential liberation of the Pencor 19 sample, comparing the predictions of the Zick and Whitson equations of state with the experimental data.

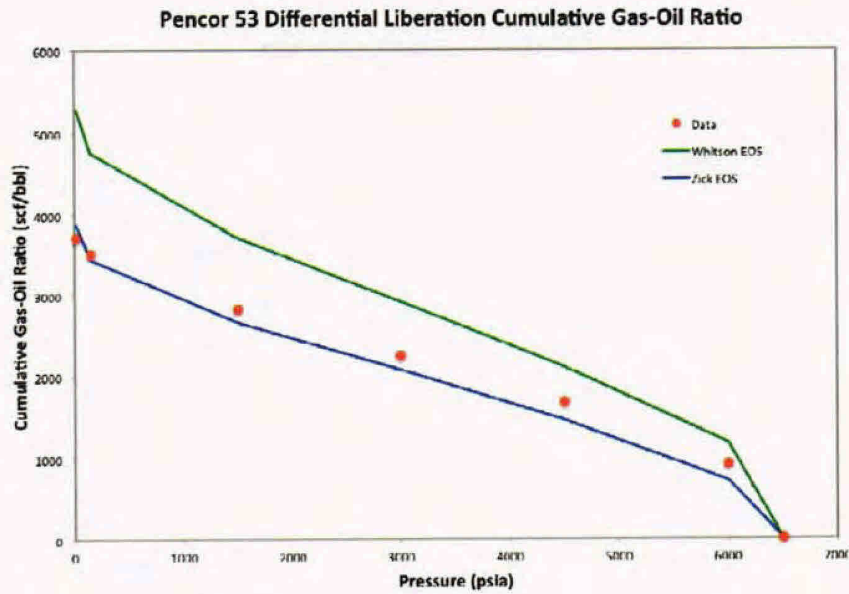


Figure 6. Cumulative gas-oil ratio (total gas removed per volume of remaining liquid) during the differential liberation of the Pencor 53 sample, comparing the predictions of the Zick and Whitson equations of state with the experimental data.

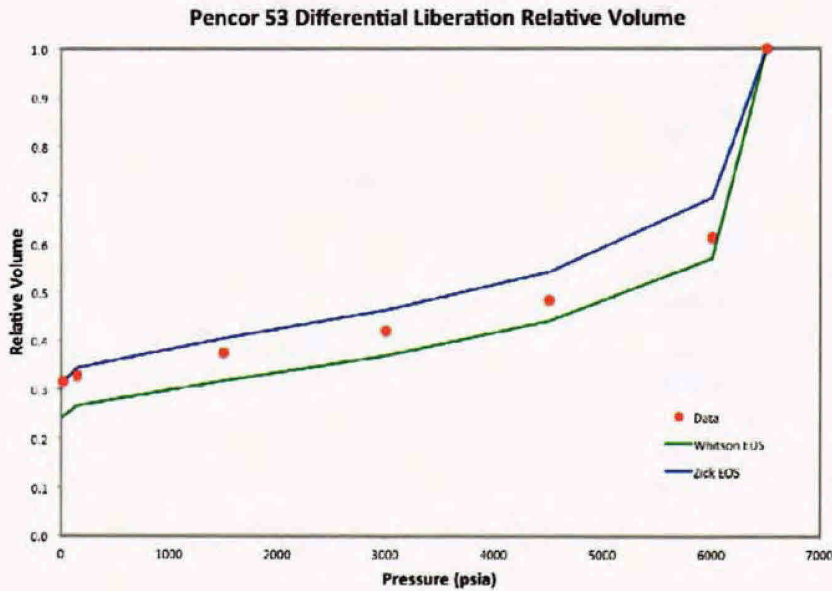


Figure 7. Relative volume (volume remaining per initial volume) during the differential liberation of the Pencor 53 sample, comparing the predictions of the Zick and Whitson equations of state with the experimental data.

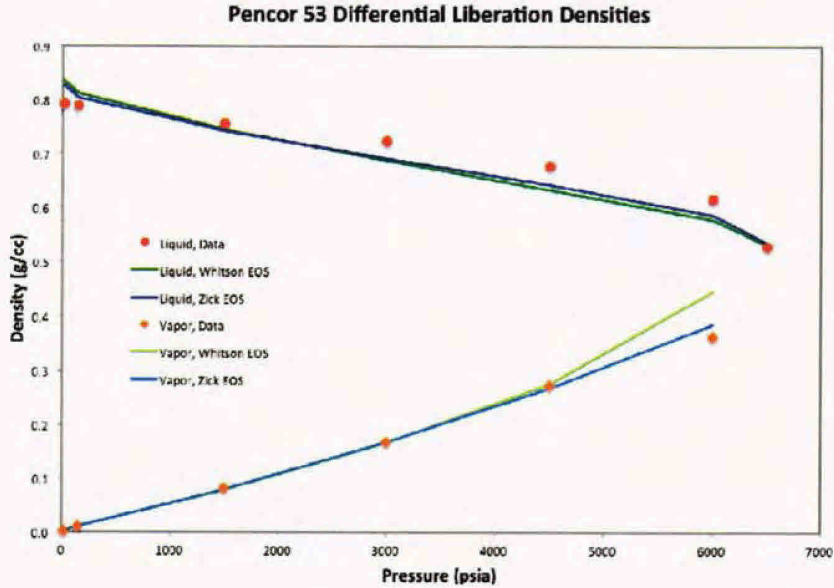


Figure 8. Liquid and vapor densities during the differential liberation of the Pencor 53 sample, comparing the predictions of the Zick and Whitson equations of state with the experimental data.

In a differential liberation experiment, the pressure is decreased in stages from the initial saturation pressure. At each stage, the gas that comes out of solution is completely removed from the presence of the remaining oil. This type of experiment is designed to mimic a reservoir process in which evolving gas will separate from, and leave behind, the remaining liquid. This type of process did not occur in the Macondo reservoir or wellbore (where the flowing compositions were essentially constant), but it may have occurred within the ocean, after the oil exited the well.

Figure 3 and Figure 6 show the cumulative gas-oil ratios (the total gas removed per remaining liquid volume) from the Pencor 19 and Pencor 53 differential liberation experiments, respectively. Figure 4 and Figure 7 show the relative volumes (the liquid volume remaining after each depletion, per initial volume). Figure 5 and Figure 8 show the liquid and vapor densities. Dr. Whitson's EOS greatly over-predicts the gas-oil ratios, under-predicts the relative volumes, and over-predicts the gas density at the first depletion pressure (6000 psia). Collectively, these facts indicate that Dr. Whitson's EOS is predicting the two Pencor samples to be too volatile, or too gas-like (which is apparently how his model can predict dew points instead of bubble points for these samples). Overall, my EOS does a much better job of predicting the differential liberation data, despite predicting bubble points instead of dew points (additional evidence that the phase boundary type is not necessarily very important for a near-critical fluid such as these).

All this said, the accuracy of the two EOS models in predicting the differential liberation data will not directly affect their predictions of flow through the reservoir and the wellbore, because there wouldn't have been any differential liberation of gas during those flows (the flowing composition would have remained constant, instead). Predictions of an oceanic separation process might be influenced, however, because such a separation would essentially be a differential liberation, operating at pressures below approximately 2250 psia.

Dr. Whitson managed to get his EOS to predict the near-critical, constant-composition behavior of the four samples slightly better than my EOS does, but he could not honor the compositions, molecular weights, gas-oil ratios, or differential liberation data in doing so. It has to make one wonder how well his EOS might extrapolate to conditions beyond those it was tuned to match.

Criticism C is overstated. For the Pencor 19 sample at reservoir temperature, my EOS predicts high-pressure densities that are about 1.2% higher than those predicted by Dr. Whitson's EOS. For the Pencor 53 and Intertek samples, however, my predictions are only about 0.6% higher than Dr. Whitson's, and for the SLB 1.18 sample, my predictions are actually slightly lower than Dr. Whitson's, by an insignificant difference of roughly 0.1%. Our predictions are even closer at lower temperatures, and in any case, they are all within the experimental uncertainty, which Dr. Whitson estimated to be about 2%.

Criticism D is also overstated. The laboratories measured shrinkage factors in taking the four samples from their saturation pressures at reservoir temperature to stock tank conditions (60 F and 1 atm), using both a single-stage and a 4-stage separation. I simulated those experiments exactly as performed with both my EOS and with Dr.

Whitson's.⁹ I have already shown (in Table 5) that the single-stage gas-oil ratios predicted by Dr. Whitson's EOS were biased between 2 and 14% too high, while my predictions ranged from 3.5% too low to 4.6% too high. Table 6 compares our predictions of the shrinkage factors from those experiments. My average bias of +0.7% is smaller in magnitude than his average bias of -2.0%, although either accuracy would normally be considered as excellent.

Sample	Single-Stage Shrinkage Factors			Prediction Errors (%)	
	Measured	Zick EOS	Whitson EOS	Zick EOS	Whitson EOS
Pencor 19	0.3820	0.3837	0.3640	0.4	-4.7
Pencor 53	0.3900	0.3892	0.3746	-0.2	-3.9
SLB 1.18	0.3939	0.3954	0.3950	0.4	0.3
Intertek	0.4421	0.4491	0.4432	1.6	0.2

Table 6. Comparisons of the shrinkage factors predicted by the Zick and Whitson equations of state with the experimental data from laboratory single-stage separations of the four fluid samples from their saturation pressures at reservoir temperature to stock tank conditions.

Table 7 and Table 8 show the measured and predicted shrinkage factors and gas-oil ratios, respectively, from the laboratory four-stage separations. Dr. Whitson and I both agree that there was something wrong with the Intertek data. The Intertek sample was collected from the same location, and at the same time, as the SLB sample. The compositions and behaviors of those two samples should have been very similar, and they were, except during the four-stage separations. The Intertek measurements were inconsistent with those of all the other samples (particularly with those of the SLB sample), showing a shrinkage factor that was much too low and a gas-oil ratio that was much too high. If we assume that the Intertek four-stage separation was performed incorrectly somehow, and ignore its data, then my EOS overestimates the four-stage shrinkage factors by 1.6–5.5% and underestimates the four-stage GORs by 0.8–5.4%, while Dr. Whitson's EOS predicts shrinkage factors that range from 0.2% too high to 2.3% too low, and GORs that are 0.8–9.7% too high.

Sample	Four-Stage Shrinkage Factors			Prediction Errors (%)	
	Measured	Zick EOS	Whitson EOS	Zick EOS	Whitson EOS
Pencor 19	0.4275	0.4402	0.4177	3.0	-2.3
Pencor 53	0.4225	0.4457	0.4281	5.5	1.3
SLB 1.18	0.4421	0.4491	0.4432	1.6	0.2
Intertek	0.4188	0.4534	0.4364	8.3	4.2

Table 7. Comparisons of the shrinkage factors predicted by the Zick and Whitson equations of state with the experimental data from laboratory four-stage separations of the four fluid samples from their saturation pressures at reservoir temperature to stock tank conditions.

⁹ When applying Dr. Whitson's EOS, I used his temperature-dependent binary interaction parameters exactly as specified, instead of fixing them at the values for one particular temperature, which was an approximation that Dr. Whitson used for most of his separator calculations.

Sample	Four-Stage Gas-Oil Ratios (scf/bbl)			Prediction Errors (%)	
	Measured	Zick EOS	Whitson EOS	Zick EOS	Whitson EOS
Pencor 19	2485	2466	2726	-0.8	9.7
Pencor 53	2554	2417	2621	-5.4	2.6
SLB 1.18	2441	2364	2461	-3.2	0.8
Intertek	2747	2342	2527	-14.7	-8.0

Table 8. Comparisons of the gas-oil ratios predicted by the Zick and Whitson equations of state with the experimental data from laboratory four-stage separations of the four fluid samples from their saturation pressures at reservoir temperature to stock tank conditions.

Dr. Whitson can rightly claim that his shrinkage factor predictions are slightly more accurate than mine for the four-stage separations, but the exact opposite is true for the four-stage GORs, the single-stage shrinkage factors, and the single-stage GORs (as shown in Table 8, Table 6, and Table 5, respectively).

The final (fourth-stage) shrinkage factors and GORs do not tell the complete story, either, because shrinkage factors and GORs were measured for the first three separation stages as well. In all cases (not counting the erroneous Intertek experiment), my EOS predicted the shrinkage factors, liquid densities, and cumulative GORs for those first three stages more accurately than Dr. Whitson's EOS did. This is shown in Figure 9 through Figure 14, which compare our predictions of those three quantities for the SLB 1.18 and Pencor 19 samples (the most oil-like and the most gas-like of the samples, respectively). All of the predictions in these six figures would normally be considered as excellent matches to the data, with the exception of Dr. Whitson's predictions of the Pencor 19 gas-oil ratios, which are quite a bit too high. This is another indication that the adjustments he made to that sample's composition may have made it excessively gas-like.

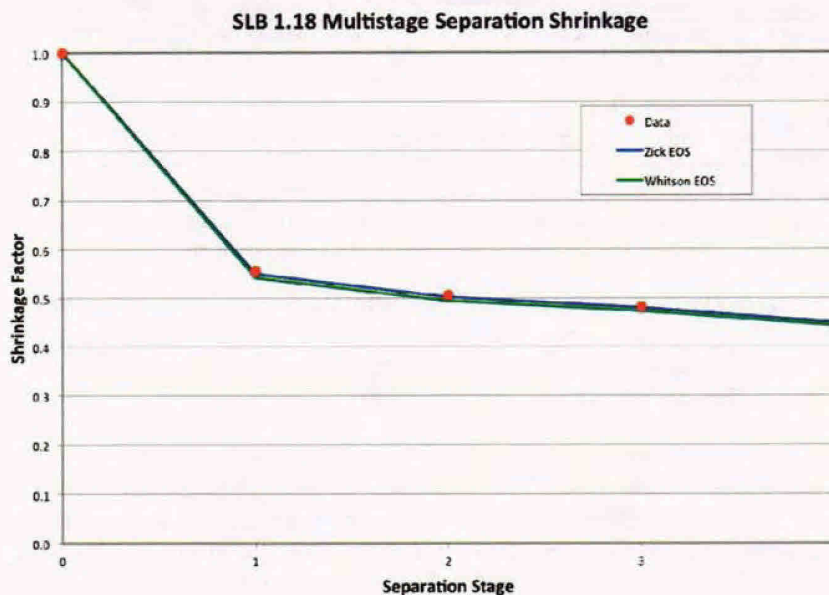


Figure 9. Comparisons of the shrinkage factors predicted by the Zick and Whitson equations of state with the experimental data from the multistage separation of the SLB 1.18 sample.

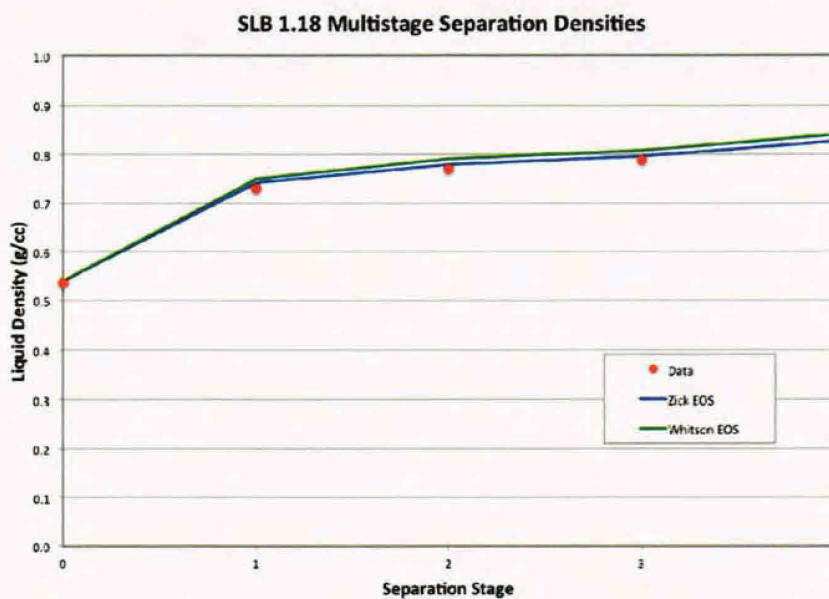


Figure 10. Comparisons of the liquid densities predicted by the Zick and Whitson equations of state with the experimental data from the multistage separation of the SLB 1.18 sample.

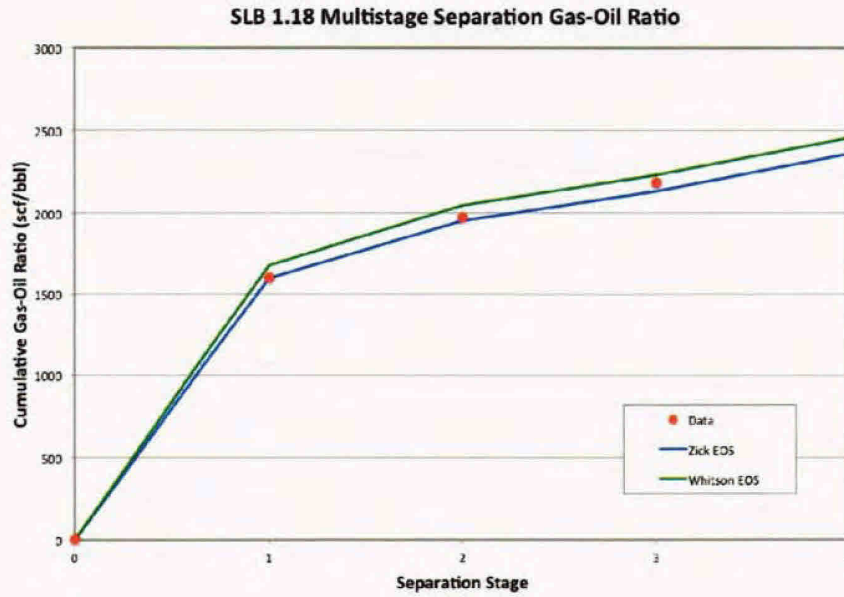


Figure 11. Comparisons of the cumulative gas-oil ratios predicted by the Zick and Whitson equations of state with the experimental data from the multistage separation of the SLB 1.18 sample.

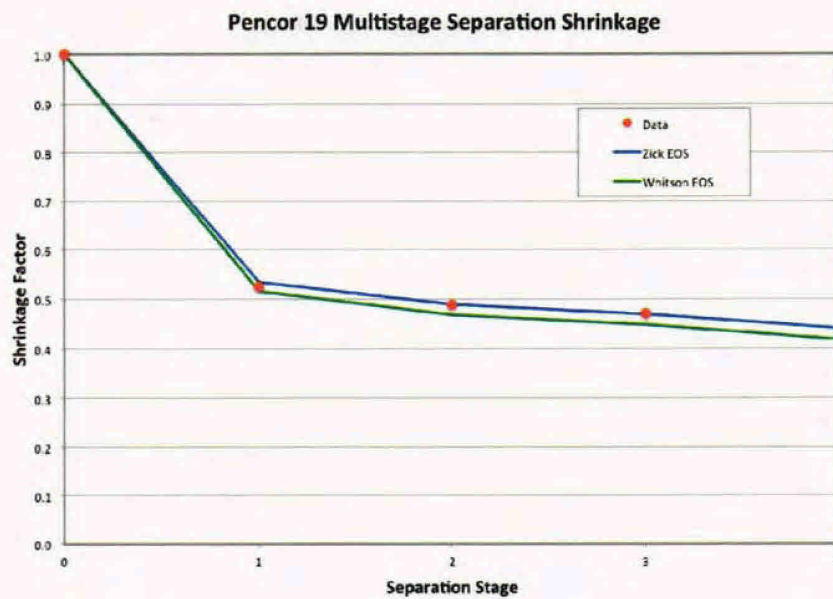


Figure 12. Comparisons of the shrinkage factors predicted by the Zick and Whitson equations of state with the experimental data from the multistage separation of the Pencor 19 sample.

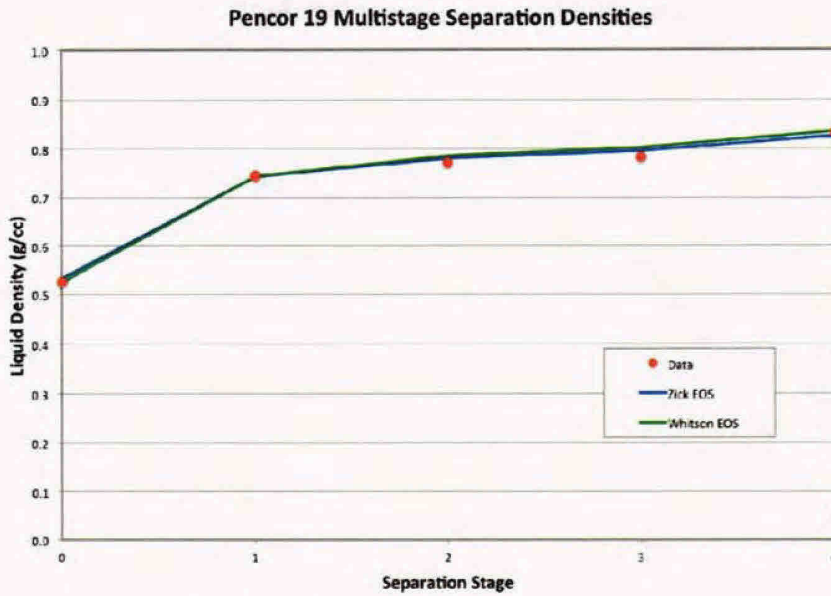


Figure 13. Comparisons of the liquid densities predicted by the Zick and Whitson equations of state with the experimental data from the multistage separation of the Pencor 19 sample.

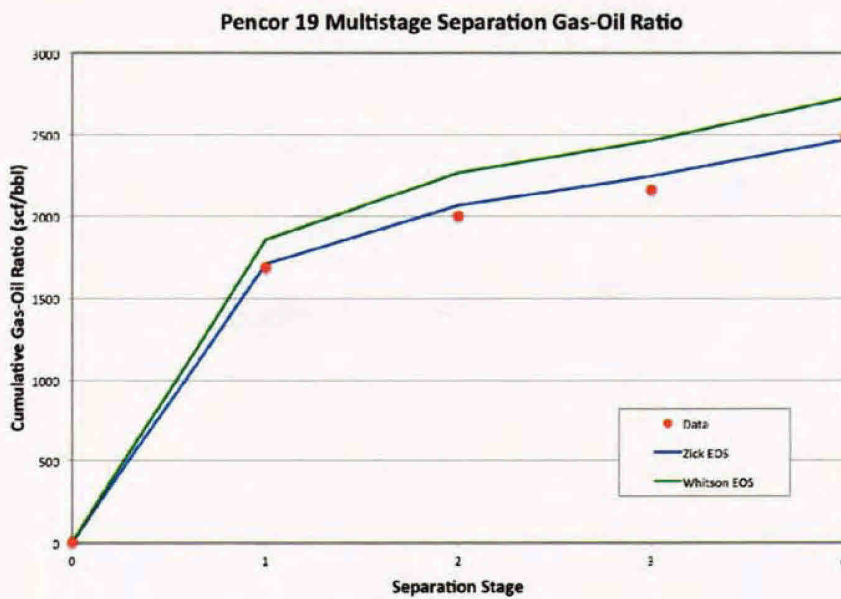


Figure 14. Comparisons of the cumulative gas-oil ratios predicted by the Zick and Whitson equations of state with the experimental data from the multistage separation of the Pencor 19 sample.

All separation data considered (both four-stage and single-stage), I do not believe that Dr. Whitson can claim that his EOS is more accurate than mine at predicting separation

processes. His fourth-stage shrinkage factors may have been slightly more accurate, but almost all other separation data were predicted more accurately by my EOS. If we are to speculate as to whose EOS would more accurately predict a complicated oceanic separation process with over 100 stages (for which we have no experimental measurements), I would not concede any advantage to Dr. Whitson's EOS.

Finally, criticisms E and F are baseless and irrelevant. Just because Dr. Whitson is unfamiliar with my EOS characterization procedures does not make them any less valid.

Dr. Whitson wondered about my choice of only 11 components for my final EOS characterization, with the heaviest component representing C20+ instead of C30+ or C36+. I experimented with more components and heavier final components, but found no advantages. With less than 3.5 mole percent of C20+ in any fluid, no more than about 5% of any other pseudocomponent, and no gas injection processes to worry about (as in the paper of mine that he cited), there was no reason for any additional refinement in the number of components. No equation of state can ever be exact, so a 40-component, single-carbon-number characterization (like Dr. Whitson's) might not be as accurate as a 10- or 12-component characterization with well-chosen pseudocomponents, pseudocomponent properties, and binary interaction parameters.

I did use a 35-component intermediate characterization to help me derive the properties of my 11-component model. Dr. Whitson criticized that 35-component model for being inaccurate and producing non-physical (three-phase) predictions, but he missed the point of that characterization completely. It was never intended for any phase behavior predictions at all. I used it for developing my molecular weight and specific gravity correlations, and to correlate the properties of my pseudocomponents, but it was never tuned to any phase behavior data and no predictions were ever made with it that had any influence over the tuning of the 11-component model.

Speaking of non-physical predictions, however, Dr. Whitson made the common mistake of tuning the viscosity parameters of his fluid characterization to match the experimental viscosities of the Macondo fluid samples without making sure that the viscosity predictions for the individual components of his characterization would increase monotonically with molecular weight (see Figure 15). The viscosities of the individual components should follow a monotonically increasing trend with molecular weight, along the lines of the Orrick-Erbar viscosity correlation¹⁰ or the component viscosities of my fluid characterization. Instead, the viscosities of Dr. Whitson's components are non-monotonic, with his intermediate components predicting viscosities that are perhaps an order of magnitude too large and his heaviest components predicting viscosities that are perhaps two orders of magnitude too small. The errors manage to cancel themselves out to produce reasonable viscosity predictions for the Macondo fluid mixtures, and luckily those mixture compositions remained constant from the reservoir to the exit of the well (i.e., along the flow path where the viscosity predictions are needed), but Dr. Whitson's viscosity model is not theoretically sound.

¹⁰ Poling, B. E., Prausnitz, J. M., and O'Connell, J. P., *The Properties of Gases and Liquids*, Fifth Edition, McGraw-Hill, New York (2001), 9.59.

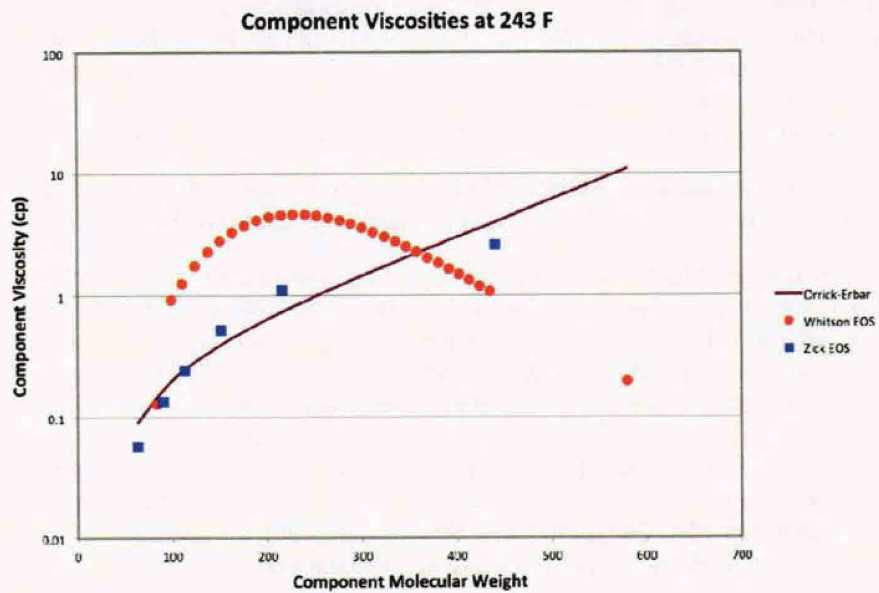


Figure 15. Component viscosities predicted by the Orrick-Erbar correlation and the Whitson and Zick equations of state.

4. BLACK-OIL TABLES

A petroleum engineering black-oil model describes a reservoir fluid as a mixture of two components: stock tank oil and surface gas. Given the temperature, pressure, and overall amounts of stock tank oil and surface gas in a reservoir fluid mixture, a black-oil model is supposed to predict the number of equilibrium phases, the volume of each phase, the amounts of stock tank oil and surface gas in each phase, the density of each phase, and the viscosity of each phase. The accuracy of a black-oil model depends on how well the reservoir fluid can be described by mixtures of just the two black-oil components (compared with perhaps 10 to 50 equation-of-state components). If the properties of the reservoir fluid's equilibrium phases can be predicted reliably as functions of pressure and temperature only (as is the case with the Macondo fluids during the time frame of the disaster), then a properly constructed black-oil model will have the same reliability. Black-oil models can be constructed directly from laboratory data (the historical approach), but the modern approach is to build them from a tuned EOS fluid characterization.

There are two types of petroleum engineering black-oil models: the *traditional* type and the *modified* type.¹¹ Dr. Whitson's report describes the modified type, which consists of the following quantities tabulated by pressure (and perhaps temperature):

- Oil formation volume factor, B_o .
- Dry gas formation volume factor, B_g .
- Solution gas/oil ratio, R_s .
- Solution oil/gas ratio, r_s .
- Liquid phase viscosity.
- Vapor phase viscosity.

The *traditional* type of black-oil model lacks either r_s or R_s . For reservoir oils (i.e., bubble-point fluids) the traditional model lacks r_s and thus cannot account for stock tank oil (or condensate) carried in the vapor phase. For reservoir gases (i.e., dew-point fluids), the traditional model lacks R_s and thus cannot account for surface gas carried in the liquid phase.

A set of black-oil tables designed for a *traditional* black-oil model (in other words, for software that implements the *traditional* model) can be used as input for a *modified* black-oil model (in other words, for software that implements the *modified* model). The missing values of r_s or R_s can just be set to zero in the *modified* model. The converse is not true, however. A set of black-oil tables designed for a *modified* black-oil model cannot be used in a *traditional* model (i.e., in software that implements the *traditional* model rather than the *modified* model). If you ignore non-zero values of r_s or R_s just because your software implements only a *traditional* model and wouldn't recognize them, then you will make serious errors in predicting the phase volumes and properties that the *modified* black-oil tables were designed to predict. The only solution is to rebuild

¹¹ Whitson, C.H., and Brulé, M.R., *Phase Behavior*, Society of Petroleum Engineers, Richardson, TX, Monograph 20 (2000), pp. 109–120.

the tables, in a completely different way, to make them compatible with a *traditional* model.

Because a black-oil model is defined in terms of stock tank oil (and its corresponding surface gas), and because the definition of stock tank oil depends on the process that the reservoir fluid is expected to take on its path from the reservoir to the stock tank (as described in Section 2), a black-oil model depends on the specification of that process (which includes both the expected depletion process within the reservoir and the expected surface separation process). The ramification is that if you build a black-oil model assuming a particular process, and then you apply that black-oil model to an engineering project that actually undergoes a different process, you will not be able to model the project correctly. If you need to model a different process, then you will need to build a different black-oil model (one that corresponds to the chosen process). If you intend to explore many different potential processes, then you will need to build many different black-oil models. That is what Dr. Whitson did.

Dr. Whitson generated at least 222 sets of petroleum engineering black-oil tables to describe the phase behavior and fluid properties of the Macondo reservoir fluids. They differed in:

- The represented fluid sample:
 - CL68379 (Pencor 53).
 - CL68508 (Pencor 19).
 - SLB-1.18 (Schlumberger 1.18).
 - Intertek (Intertek 1812).
- The represented surface process:
 - Single-stage separation.
 - Dr. Whitson's oceanic proxy separation.
 - Well exit temperatures ranging from 35 F to 210 F.
- Temperatures ranging from 35 F to 243 F.
- The software for which they were formatted:
 - ECLIPSE (a reservoir simulator from Schlumberger).
 - PROSPER (a pipe-flow simulator from Petroleum Experts, Ltd.).

Notable by their omission are any black-oil tables representing an average Macondo reservoir fluid or any multistage separation process other than Dr. Whitson's oceanic proxy process.

Dr. Whitson used PVTsim¹² to generate his black-oil tables from the EOS fluid characterization he developed (assuming a wide variety of surface processes but always the appropriate constant composition reservoir process). PVTsim assumes a *modified* black-oil model and uses the Whitson-Torp method¹³ to generate the appropriate tables. ECLIPSE implements the resulting *modified* black-oil model without any difficulties. PROSPER, however, does not implement a *modified* black-oil model. It only accepts

¹² PVTsim is an industry standard EOS software package from Calsep International Consultants.

¹³ Whitson, C.H., and Brulé, M.R., *Phase Behavior*, Society of Petroleum Engineers, Richardson, TX, Monograph 20 (2000), p. 111.

traditional black-oil tables. To reproduce the phase behavior of his original EOS fluid model, Dr. Whitson should have built PROSPER's *traditional* black-oil tables with a completely different algorithm, but he didn't. By relying on PVTsim, he ended up using the Whitson-Torp method, generating a set of *modified* black-oil tables, and then discarding the non-zero values of r_s (for bubble-point oil samples) or R_s (for dew-point gas samples) that PROSPER would not have recognized. The consequence was that significant amounts of stock tank oil or surface gas, respectively, were not accounted for, and the model had no chance of reproducing the correct phase fractions and densities (as predicted by the EOS upon which the tables were based). Examples are shown in Figure 16 and Figure 17.

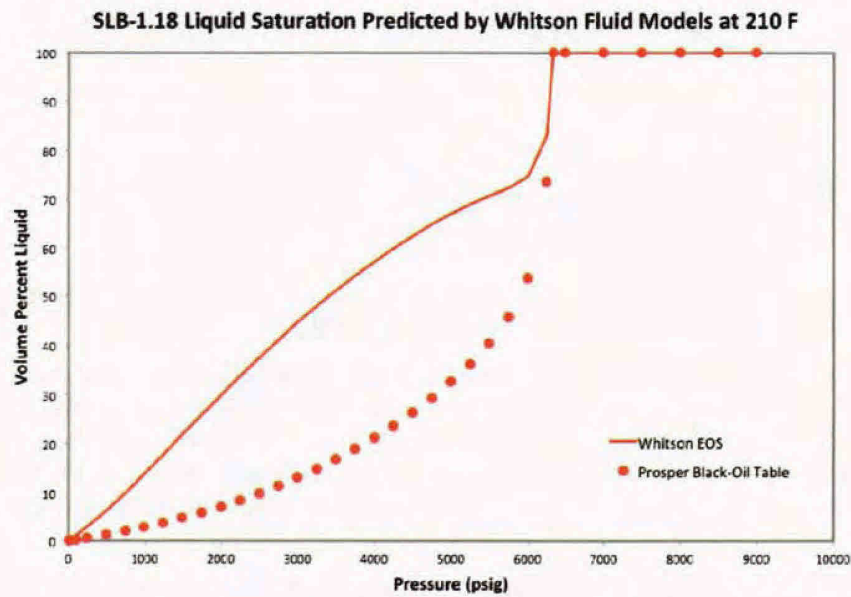


Figure 16. Comparison of the liquid saturations predicted by the Prosper black-oil tables (generated by the Whitson EOS) and those predicted by the Whitson EOS for the SLB 1.18 sample at 210 F.

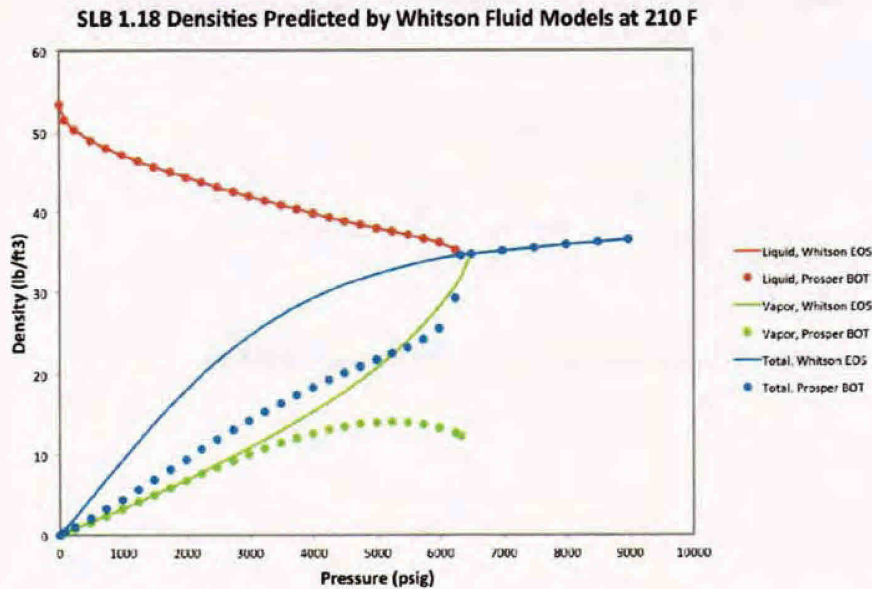


Figure 17. Comparison of the densities predicted by the Prosper black-oil tables (generated by the Whitson EOS) and those predicted by the Whitson EOS for the SLB 1.18 sample at 210 F.

Dr. Whitson realized that the PROSPER black-oil tables were incomplete, and he warned that any PROSPER simulations using them should be compared with EOS simulations, but he should have realized that the PROSPER tables had no chance of giving the correct results and he should not have made them available. Any BP expert relying on PROSPER simulations, using Dr. Whitson’s black-oil tables, is certain to have generated erroneous results.

[REDACTED]

Petroleum engineering black-oil models are designed for engineering projects in which the 2-component (stock tank oil and surface gas) reservoir fluid composition can vary with time and spatial position.

In the case of the Macondo oil spill, however, the flowing fluid composition remained constant from the reservoir to the exit of the well (and perhaps even into the plume), so a simulation would not have to track the composition or assume that it could change. A valid black-oil model for the Macondo fluid system would not have to account for the possibility of varying compositions. It would only need to be capable of reproducing the same phase volumes and densities as the EOS that generated it. For a constant-composition fluid system like the Macondo’s, those phase properties are independent of any surface process chosen for the black-oil model, so a valid black-oil model must be able to reproduce those phase properties regardless of the assumed surface process.

The ultimate prediction of produced surface volumes (or surface volume rates) will depend only on the phase properties (which determine the physics of the flow but are independent of the surface process) and the final surface separation (which is the only place the chosen separation process matters).

As a result of the Macondo's flowing composition remaining constant, if you perform a simulation for the Macondo flow with a given set of black-oil tables (representing one particular surface process), then you can immediately determine the results from any other valid set of black-oil tables for the same fluid. You would simply scale your previous results by the ratio of the shrinkage factors from the two sets of tables.

Because of this special characteristic of constant-composition fluid systems, Dr. Whitson did not need to provide 198 ECLIPSE files (covering 4 fluids, seven temperatures, and seven surface processes). He could have (and should have) chosen just one average fluid, one surface process, and a handful of temperatures (to cover those of interest). Simulation results assuming any other surface process could have been determined by simply scaling the results by the appropriate ratio of shrinkage factors (as discussed also in Section 2).

The black-oil tables that Dr. Whitson included in his report are actually subsets of his 198 ECLIPSE files. They're incomplete, however, because they lack the specification of the surface oil and gas densities (which are needed for the calculation of reservoir densities) and of the initial fluid composition (in terms of his R_{mix} or r_{mix} value). The ECLIPSE files included the surface densities, but they did not specify the initial composition. In the case of the SLB or Intertek samples (the two bubble-point fluids) that would have been given by the R_s value at the sample's bubble point. For the Pencor samples, however, the correct composition would be given by the r_s value at the sample's dew point. If anyone mistakenly initialized a Pencor sample with the bubble-point R_s , or one of the other samples with the dew-point r_s , they would have ended up simulating a fluid totally unrelated to the Macondo samples. This would be an easy mistake and one that Dr. Whitson should have prevented by explicitly specifying the initial composition for each sample.

5. INFORMATION REQUIRED BY THE FEDERAL RULES OF CIVIL PROCEDURE

Together with my original report, this report contains my opinions, conclusions, and reasons therefore. The information required by the Federal Rules of Civil Procedure was set forth in my original report.

The opinions expressed in this report are my own and are based on the data and facts available to me at the time of writing. Should additional relevant or pertinent information become available, I reserve the right to supplement the discussion and findings in this report.

Appendix A. SUPPLEMENTAL FACTS AND DATA CONSIDERED IN FORMING MY OPINION

The following list supplements the consideration list produced with my first report.

Whitson Consideration Materials
Whitson Reliance Materials
Relied-Upon Modeling Runs
Expert Report of Nathan Bushnell (March 3, 2013)
Expert Report of Ronald Dykhuizen (March 3, 2013)
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Deposition Exhibit 10443
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