Appendix C.1 Kelkar Report

Preliminary Report

Modeling of Gulf of Mexico (MC252 # 1 B01) Well

By

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Executive Summary

The project involves modeling of a well (MC252 # 1 B01) in Gulf of Mexico. The well was drilled and was completed on April 22nd. Due to unforeseen circumstances, the well was not sealed properly and resulted in catastrophic explosion. In three days, after sustained fire, the drilling rig sank. To date, the well continues to pour oil and gas in Gulf of Mexico. The sub-sea well head is approximately at water depth of 5,000 ft. The purpose of the project is to predict the daily rate of the well (both oil and gas) from the first day till the well stops flowing.

Data Available

We received the following data from Mineral Management Services (MMS) on June 16th, 2010:

- Core Grain Size Summary MC 252 Well No.1 BP01
- MC 252 Well No.1 BP01 Ko at Swi Core Data
- Rotary Core Report from MC 252 Well No.1 BP01
- Rock Mechanics from Core Report MC 252 Well No.1 BP01
- MC 252 Well No.1 BP01 GEOTAP Pressure Transient Spreadsheet
- MC 252 Well No.1 BP01 GEOTAP Pressure Transient Report
- G32306 MC252 Well No.1 BP01 LAS files
- MC 252 Well No.1 BP01 5md_MudLog Combo
- MC 252 Well No.1 BP01 Mud Log Document
- MC 252 Well No.1 BP01 Directional Survey
- MMS Log Analysis 5 inch md MC 252 Well No.1 BP01
- MMS Log Analysis Report MC 252 Well No.1 BP01
- MC 252 Well No.1 BP01Pencor Field MDT Sampling Report
- Preliminary Pencor PVT Data MC 252 Well No.1 BP01
- Preliminary 05-19-10 Schlumberger PVT Report MC 252 Well No.1 BP01
- Offset Pencor Summary PVT Report 7-30-07 MC 562 Well No.1 BP01
- MC 252 Well No.1 BP01 Schematic Rev 15 2_04-22-2010 with BOP
- M56 Upper Sand Structure map
- M56 Upper Sand Structure with Amplitude map
- M56 Upper Sand Net Sand Isochore map
- M56 Upper Sand Net Oil map – Most Likely Case
- M56 Upper Sand Net Oil map – Maximum Case
- M56 Lower Sand Structure map
- M56 Lower Sand Structure with Amplitude map
- M56 Lower Sand Net Sand Isochore map

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Exhibit No.
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- M56 Lower Sand Net Oil map – Most Likely Case
- M56 Lower Sand Net Oil map – Maximum Case
- M56 A Sand Structure map
- M56 A Sand Structure with Amplitude map
- M56 A Sand Net Sand Isochore map
- M56 A Sand Net Oil map – Most Likely Case
- M56 A Sand Net Oil map – Maximum Case

Sufficient data from well MC 252 were available to model the well. In addition, the analog well is at a significant distance from the well under investigation. Therefore, we used only the data from MC252 for modeling purposes.

Digitizing the Contours

We had several maps available which were sent to us. We needed to digitize those maps so that they can be incorporated into PETREL software. In addition, Water Oil Contact was also provided. Using the maps, we developed two scenarios: most likely case and pessimistic case. In this report, pessimistic case represents more hydrocarbons in the reservoir.

Fluid Properties Model

We received two fluid properties reports from MMS. One report was from Schlumberger and another was from Pencor Labs. On June 17th, we received an updated report from both the labs. Instead of using the original lab reports, we used the updated reports for generating our fluid properties. The updated report from Pencor Lab contained both constant composition expansion tests (CCE) as well as differential laboratory test (DL). Since Schlumberger report did not contain the DL test, we concentrated on using Pencor lab. It should be stated that both Schlumberger and Pencor reports contain CCE tests and the results appear to be very similar.

Pencor report indicates that the well may be producing from volatile oil reservoir. The gas produced during DL test produced significant gas condensate and the gas gravity of the gas produced often exceeded a value of 1.0. It is possible to model this type of reservoir using compositional process rather than black oil model; however, we chose to use black oil model to simulate the reservoir. The main reason for using black oil model is the fact that the bubble point of this oil is more than 6,000 psia [6,504 psia according to Pencor report] and the initial reservoir pressure is 11,856 psia. Based on the hydrostatic pressure and possible pressure drop in the well bore, it is extremely unlikely that the pressure at the bottom hole (or the sandface) will drop below the bubble point pressure. This means that the well will produce above bubble point for the time period we are interested in simulating the reservoir. For the reservoir producing above bubble point, when there is no free gas coming out of the oil in the reservoir, black oil model is as good as compositional model.

We also used the black oil model in the well bore. We have flash samples available in the report and we can reasonably predict the evolution of gas from the oil as the pressure is declined in the well bore.

The differential liberation (DL) data are available from the report. The most important consideration is the values above bubble point since it is expected that the reservoir pressure would remain above bubble point during the time period we are interested in. We can use the actual observed data with initial gas oil ratio of 2,554 SCF/STB as stated in the original report. However, we compared our results with available correlations to see how close we can match the observed data with the calculated values based on the correlations. The reasons for this will become clear in next few paragraphs. We fixed the initial gas oil ratio of 2,554 SCF/STB which was reported in the lab report and we estimated the formation volume factor, solution gas oil ratio and the viscosity. The three figures below show the comparison between the observed and calculated values.

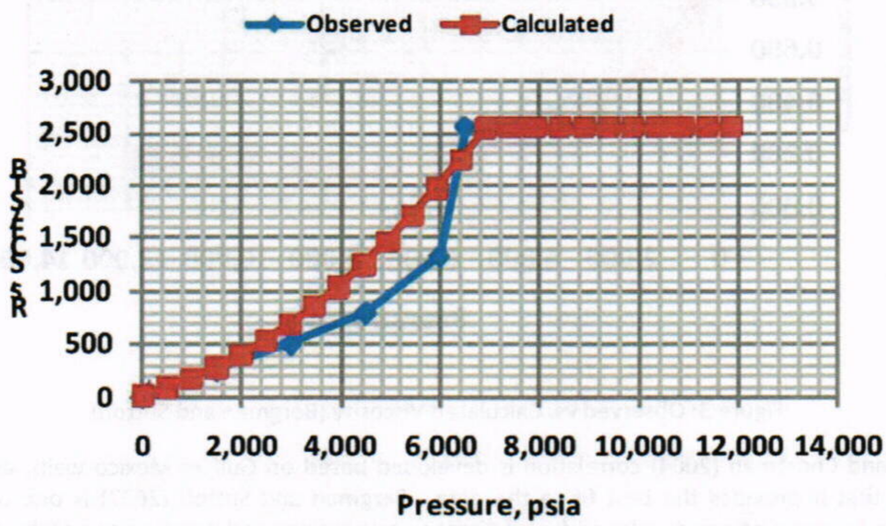

Figure 1: Observed vs. Calculated Solution Gas Oil ratio (Dindoruk and Christman)

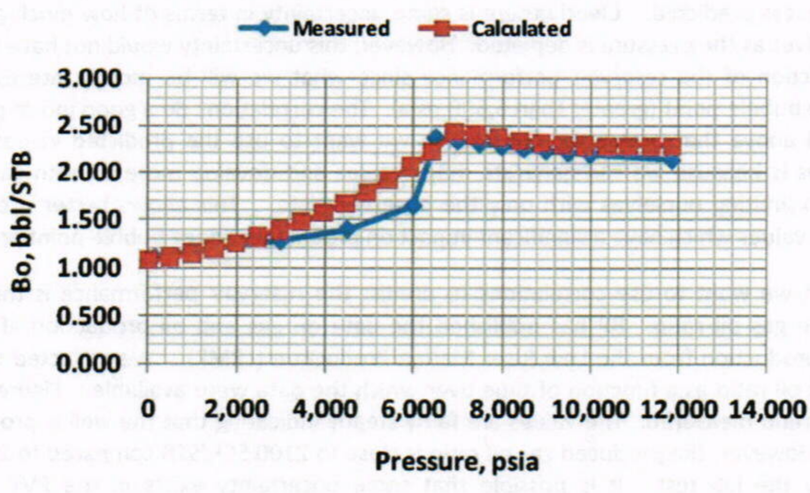

Figure 2: Observed vs. Calculated Formation Volume Factor (Dindoruk and Christman)

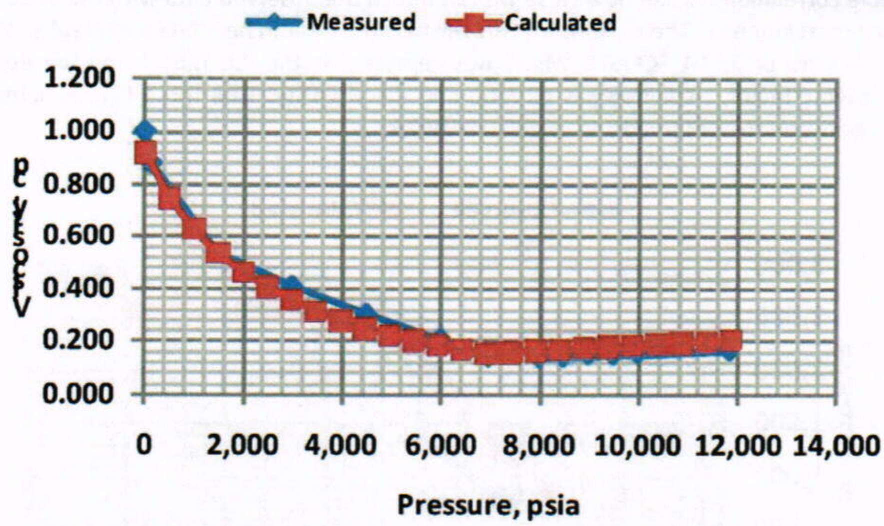

Figure 3: Observed vs. Calculated Viscosity (Bergman and Sutton)

Dindoruk and Christman (2004) correlation is developed based on Gulf of Mexico wells, and it is not surprising that it provides the best fit to the data. Bergman and Sutton (2007) is one of the most comprehensive correlations developed for oil viscosity calculations and it does a good job of predicting the viscosity of oil. Notice that between 4000 to 6000 psia, there is an inflection point in all the three parameters. This indicates that amount of gas evolving from the reservoir is more than what the correlation can predict. As a result, the measured formation volume factor is lower and the viscosity is higher than what is predicted. Clearly there is some uncertainty in terms of how much gas is evolved and how it evolves as the pressure is depleted. However, this uncertainty would not have any impact in terms of prediction of the reservoir performance since what we will be mostly interested in is the pressure above bubble point (greater than 6,500 psia). The correlations do a good job of predicting the properties well above that pressure. The reason we want to use the predicted values rather than observed values is because we can generate many values and develop more smooth variation in the properties than limiting ourselves with only the observed data. This allows better prediction of oil compressibility values which have a significant impact on production above bubble point pressure.

Another reason we want to use correlations to predict the reservoir performance is the uncertainty observed in the gas oil ratio. BP has published the data on gas and oil production after it started capturing the production from the Low Riser Marine Production (LRMP). We collected that data and plotted the gas oil ratio as a function of time over which the data were available. Figure 4 shows the data of gas oil ratio measured. The values are fairly steady indicating that the well is producing above bubble point. However, the produced gas oil ratio is close to 2100 SCF/STB compared to 2,554 SCF/STB as reported by the lab test. It is possible that some uncertainty exists in the PVT samples and measurements and the gas oil ratio is little off. It is also possible that some of the gas evolving contains condensate resulting in smaller gas production than indicated by original gas oil ratio measured in the lab. To include this uncertainty in our analysis, we also generated the black oil properties by assuming initial gas oil ratio of 2100 SCF/STB. We used the same correlations which worked well for the lab data except that we changed the gas oil ratio to a new value.

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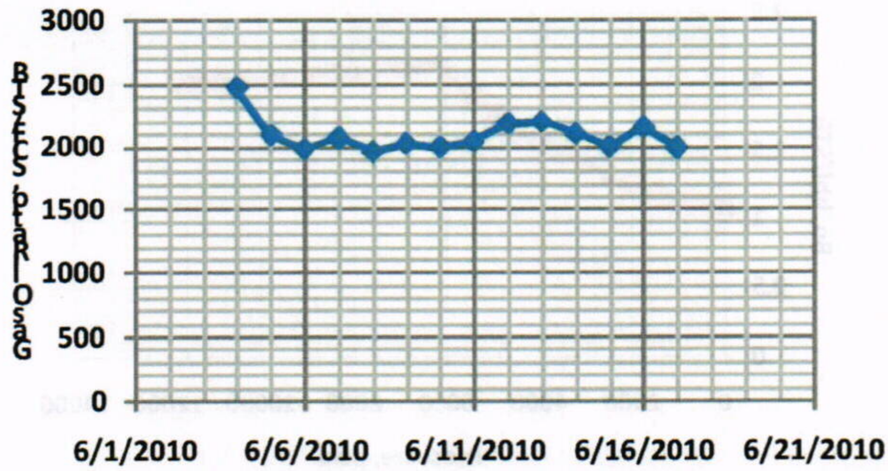

Figure 4: Observed Gas Oil Ratio from BP Well

Figures 5, 6 and 7 the data we generated for initial gas oil ratio of 2,100 SCF/STB using the same correlations. These values were also used for reservoir characterization as part of the uncertainty quantification.

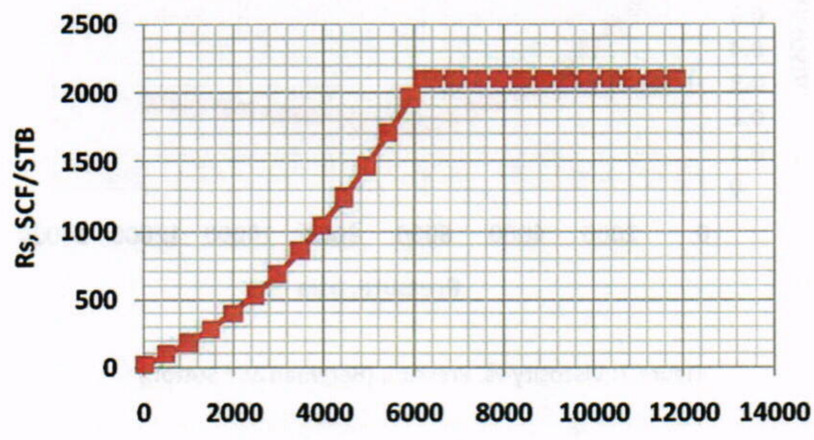

Figure 5: Gas Oil Ratio vs. Pressure (Dindoruk and Christman)

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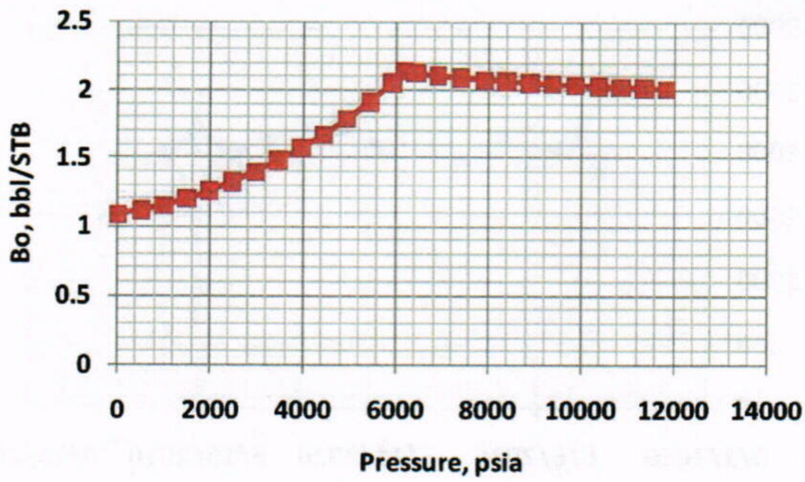

Figure 6: Formation volume factor vs. pressure (Dindoruk and Christman)

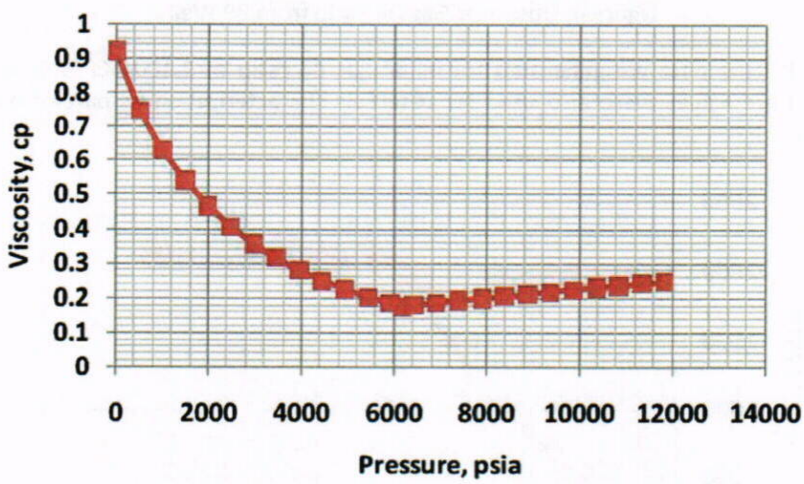

Figure 7: Viscosity vs. Pressure (Bergman and Sutton)

Tubing Model

To predict the pressure drop through the well bore, we need to understand the place where the fluid is flowing. The well bore diagram is provided by BP (in pdf presentation available as BPSpillInvestigation.pdf which is available from multiple websites). Figure 8 shows the well bore diagram.

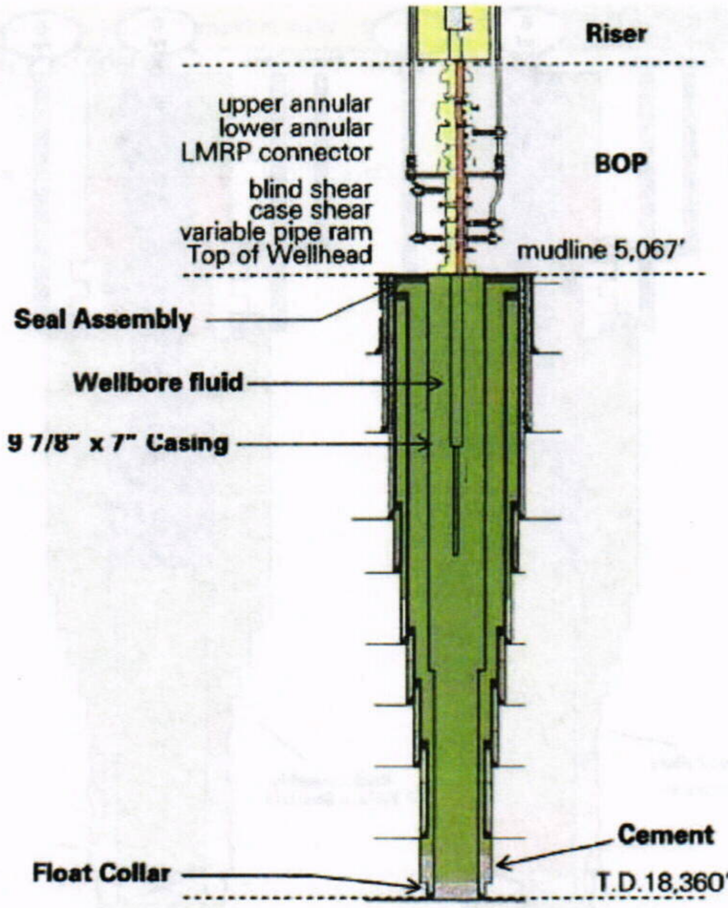

Figure 8: Well Bore Diagram

The details are provided in the presentation. There are two possibilities how the well could have leaked. If the bottom hole seal failed (left of Figure 9), the fluid would have flowed through production casing. If the seal assembly had failed at the mud line (right of Figure 9), fluid would have flowed through the annular space between the liner and the production casing. We considered both possibilities and modeled the well bore flow (either through annulus or through production tubing). Based on the pressure test done on the bottom hole seal assembly prior to the blow out, we consider that it is more likely that flow will occur through annulus rather than through production casing.

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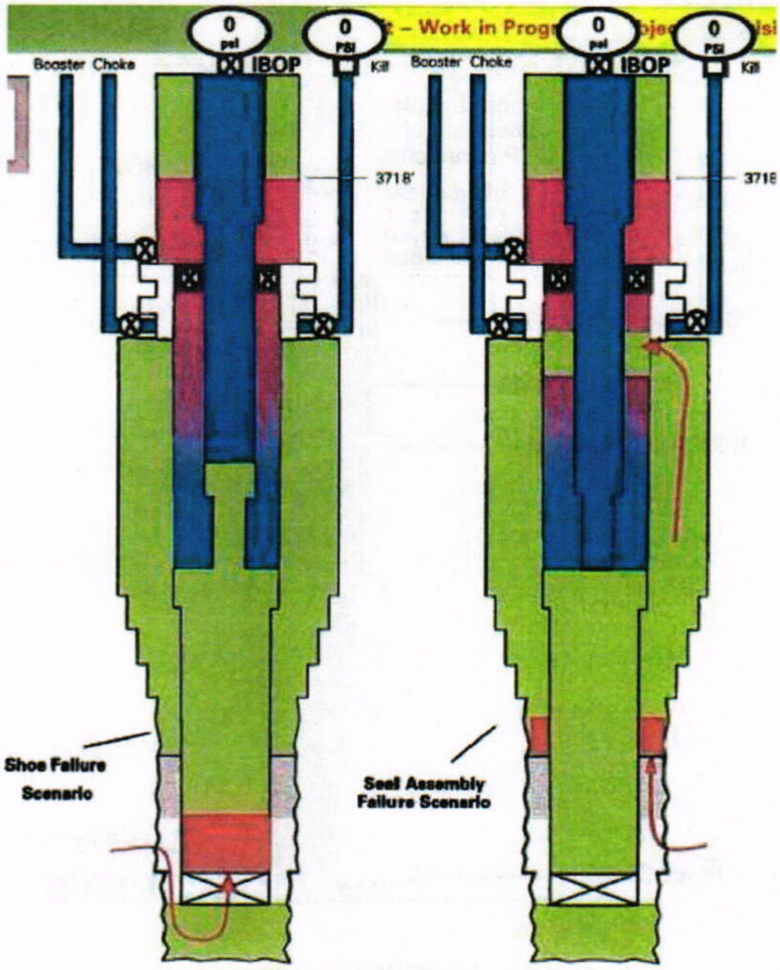

Figure 9: Two Possibilities of Leak

If the flow came through annular space, then it has to go through a series of restrictions. As shown in Figure 10, in the absence of lock-down sleeve, the most likely scenario is the possibility that hydrocarbons behind the production casing built sufficient pressure to lift the casing (9 7/8") into the well head housing (overcoming the seal assembly) and creating the space between the casing and well head housing. Then the fluid escaped through that space. If indeed we assume that the BOP tried to close but because of up-lifted casing, could not close properly, then most likely in the well head housing, we have mangled steel creating additional restriction to the flow. We do not know what type of restriction exists in that space. However, knowing that we have 18 ¾" bore housing, we can assume that the flow is restricted by choke like flow. To account for uncertainty, we considered choke sizes of 2" and 4" and modeled the flow.

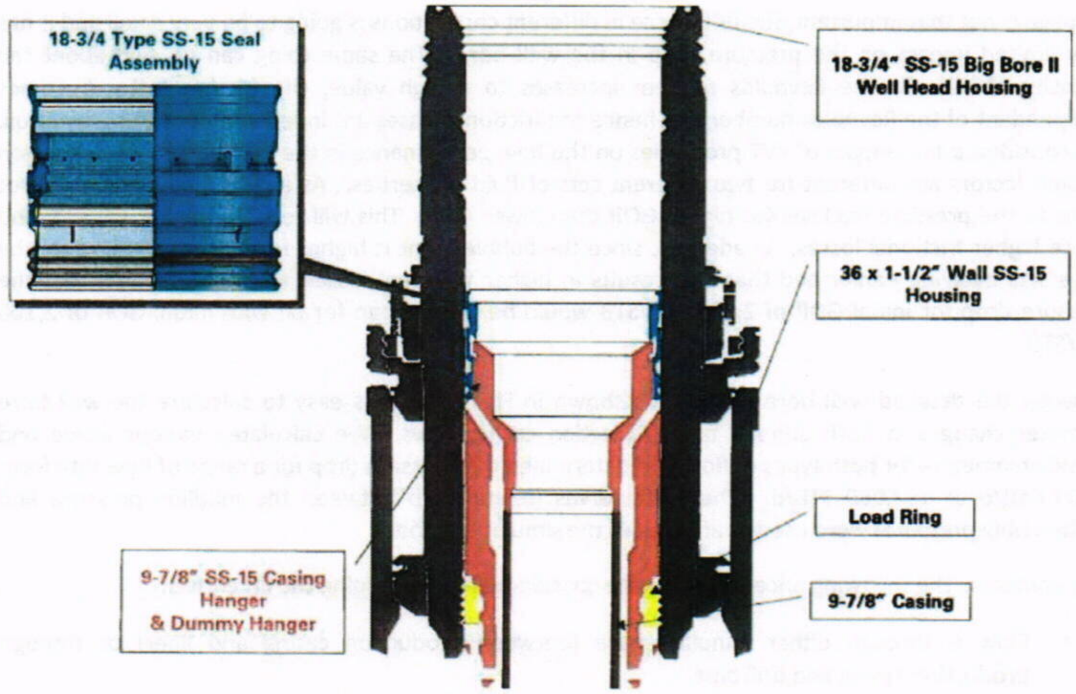

Figure 10: Casing and Well head assembly at the mud line

The flow coming through the well head housing will pass through a riser. During the sinking of the drill ship, the riser bent at the top of the well head housing and eventually broke open, spewing the oil into the ocean. The bent riser can cause some restriction to the flow. Without knowing the diameter of the bent riser, it is difficult to predict the restriction on the flow. The diameter of the riser is 19.5". Even after bending it, the diameter cannot be substantially smaller than the original diameter. By assuming an equivalent diameter of 3 to 6", for a flow rate of 10,000 STB/D to about 100,000 STB/D, the pressure drop across the restriction rarely exceeds 300 psi. This results in change in the rate of about 2 to 4 %. Considering such a small change, we assumed that before the riser was cut-off, the bent in the riser created an additional pressure drop of about 300 psi. The depth of ocean is about 5,000 feet. This results in a bottom hole pressure of 2180 psia pressure (assuming 0.433 psi/ft hydrostatic gradient). We used the well head pressure of 2,180 psia after the riser was cut-off to calculate the bottom hole pressure and a well head pressure of 2,480 psia (additional 300 psi pressure drop through the riser bent) to calculate the bottom hole pressure. In reality, since BP started producing through LRMP, it probably has the back pressure data exerted by the column of oil and gas. However, in the absence of that information, we assumed that hydrostatic pressure exerted by sea water represents the well head pressure at the mud line.

Another uncertainty we included in the pressure drop calculations is the roughness of the pipe. We have reasonable information about the roughness of pipe inside the production casing. For a new casing, we can assume it close to 0.00005 feet. However, very little information is available about the roughness outside the casing. We considered two possibilities – the roughness is the same as inside the production casing, and the roughness is order of magnitude greater than outside the casing.

Although many correlations are available to calculate the pressure drop in the well bore, we used Hagedorn and Brown (1976) correlation to calculate the pressure drop. For high rate wells where slippage is not that important, the difference in different correlations is going to be very small and it has very limited impact on the pressure drop in the well bore. The same thing can be said about the viscosity of oil. As the Reynolds number increases to a high value, the friction factor becomes independent of the Reynolds number and hence the frictional losses are independent of viscosity of oil. We considered the impact of PVT properties on the flow performance in the well bore. The formation volume factors are different for two different sets of fluid properties. As a result, oil will expand lot more as the pressure declines for higher GOR than lower GOR. This will result in higher velocity and hence higher frictional losses. In addition, since the bubble point is higher for higher gas oil ratio, the gas starts evolving earlier and that also results in higher frictional losses. Hence we expect that the pressure drop for initial GOR of 2,554 SCF/STB would be higher than for oil with initial GOR of 2,100 SCF/STB.

Knowing the detailed well bore diagram as shown in Figure 11, it is easy to calculate the well bore diameter changes in both annular and production casing flows. We calculated various inside and outside diameters for both types of flow and determined the pressure drop for a range of flow rate from 1,000 STB/d to 100,000 STB/d. These lift curves (relationship between the mudline pressure and bottom hole pressure) were used as an input in the simulation model.

To summarize, the following uncertainties were considered in determining the lift curves:

- Flow is through either annular space (between production casing and liner) or through production casing and drill pipe
- The well head is restricted by BOP. This was represented by flow through choke of 2" and 4" diameters. We also considered the possibility of no restriction as maximum rate situation.
- Friction factor outside the production casing.
- One set for different PVT properties
- We assumed the pressure drop through bent riser results in additional pressure drop of 300 psi

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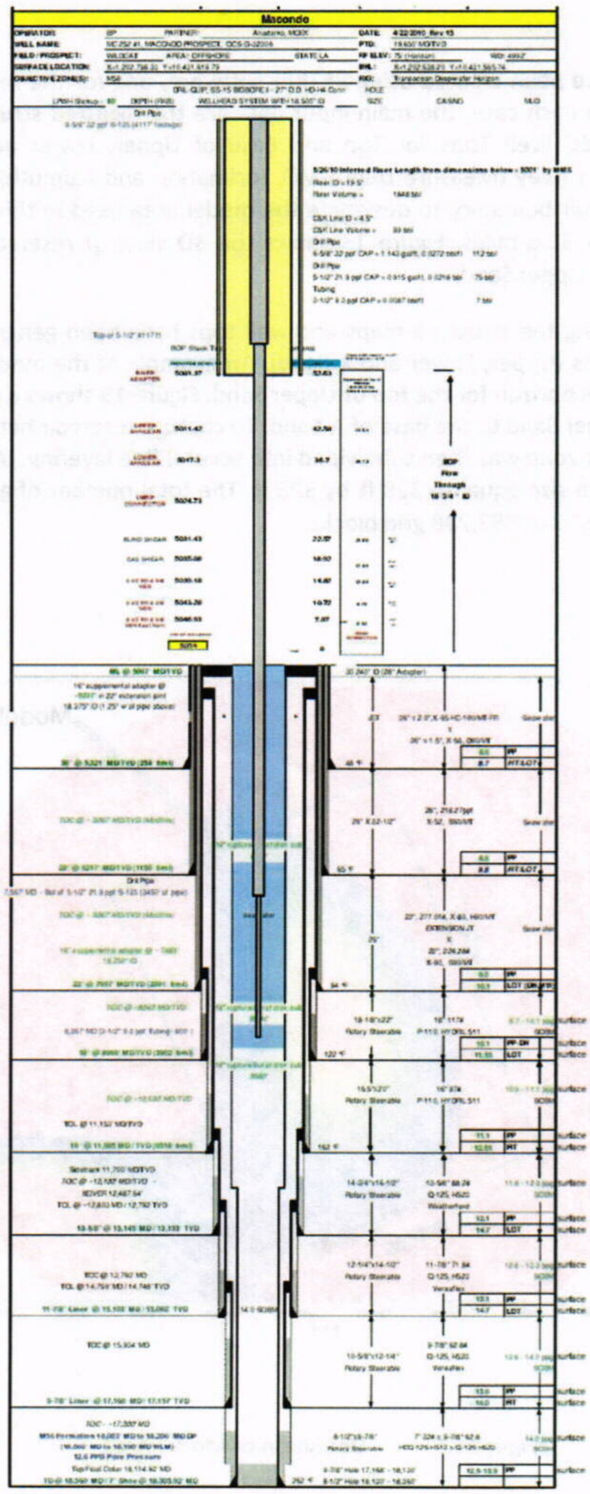

Figure 11: Well Bore Configuration

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Structural Model

Two structural models have been created using PETREL software; one for the most likely case and the other for the high case. In each case, the main input data are the digitized structure maps for Top of Upper, Lower and A-Sands, Well Tops for Top and Base of Upper, Lower and A-Sands, and Well Trajectory from deviation survey (Measure Depth-MD, Inclination and Azimuth). Figure 12 shows the structure map with reservoir boundary to designate the model area used in this study. This covers an area of approximately 4 x 3 sq-miles. Figure 13 shows the 3D view of reservoir structure above oil contact (-18,168 ft) for the Upper Sand.

Six model horizons honoring the structure maps and well tops have been generated to represent the Top and Base of each sands (Upper, Lower and A-Sand). An example of the model horizon is shown in Figure 14. This is the model horizon for the top of Upper Sand. Figure 15 shows a cross-sectional view of the model from top of Upper Sand to the base of A-Sand. To capture reservoir heterogeneity as given by the well log, each reservoir zone was then subdivided into several fine layering. Areally, the reservoir is gridded into grid block with size equal to 328 ft by 328 ft. The total number of grid blocks in the static reservoir model is 68 x 77 x 73 or 382,228 grid blocks.

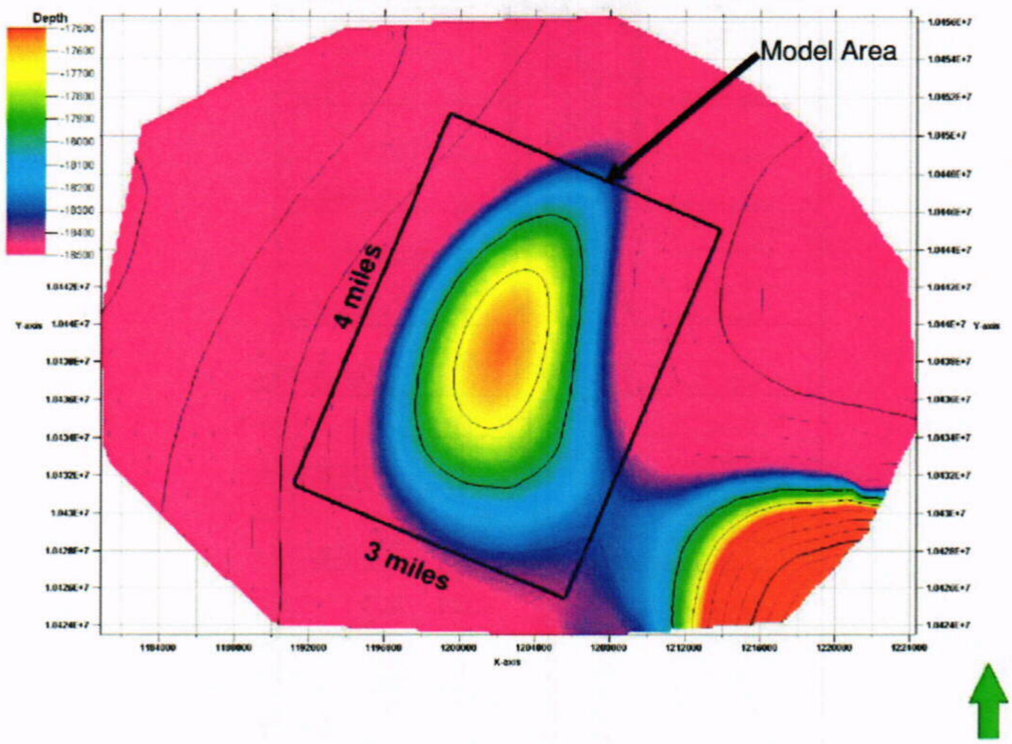

Figure 12 Definition of Model Area

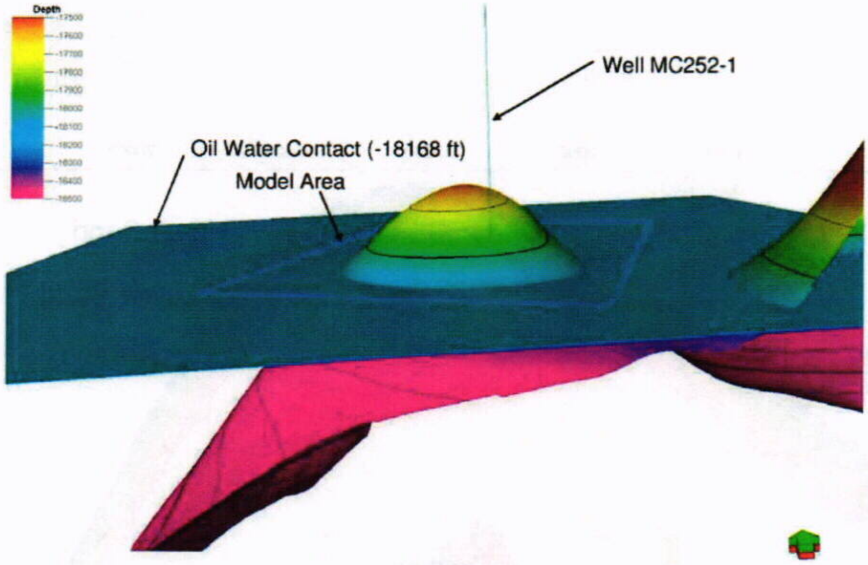

Figure 13 3D View of Reservoir Structure above Oil Water Contact for Upper Sand

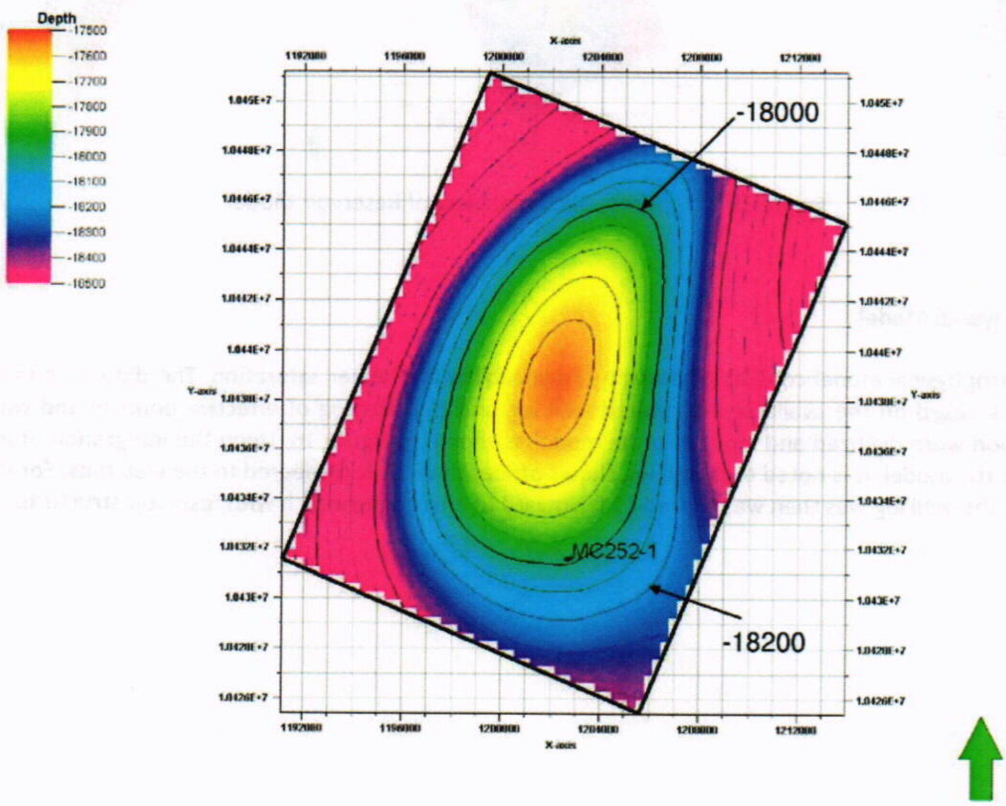

Figure 14 Model Horizon for Upper Sand

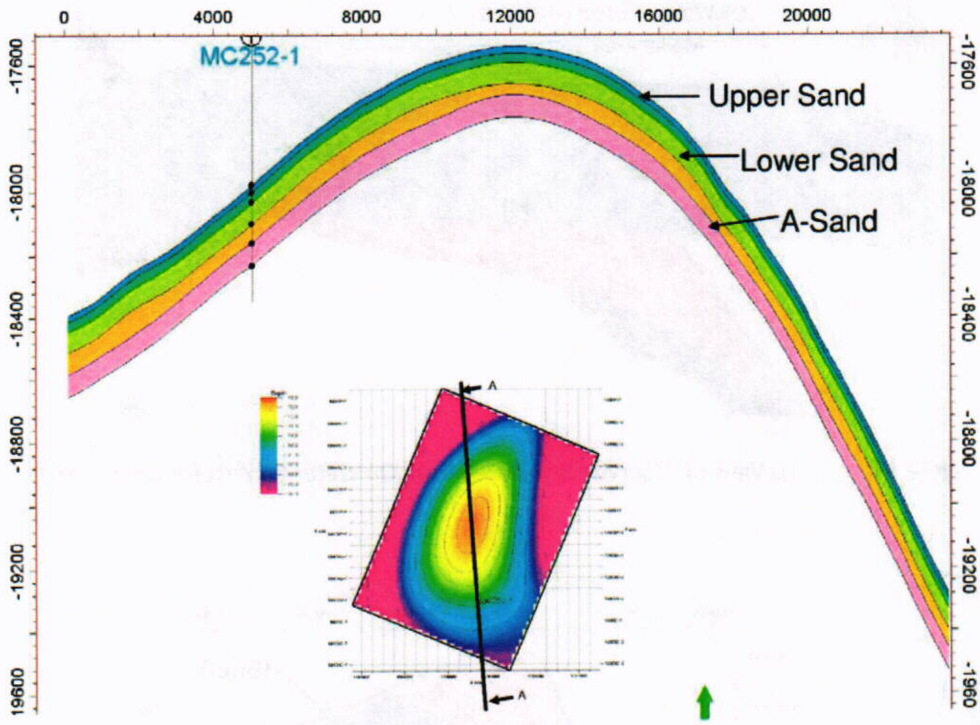

Figure 15 Cross-Sectional View of Reservoir Model

Petrophysical Model

The petrophysical model consists of porosity, permeability and water saturation. The data used in the model is based on the available interpreted well log analysis. The log of effective porosity and water saturation were digitized and input into the model as shown in Figure 16. Upon the integration of well log into the model, it is noted that well log shows off depth of 11 ft compared to the well tops. For that reason, the well log was then was shifted 11 ft upward to ensure the match with reservoir structure.

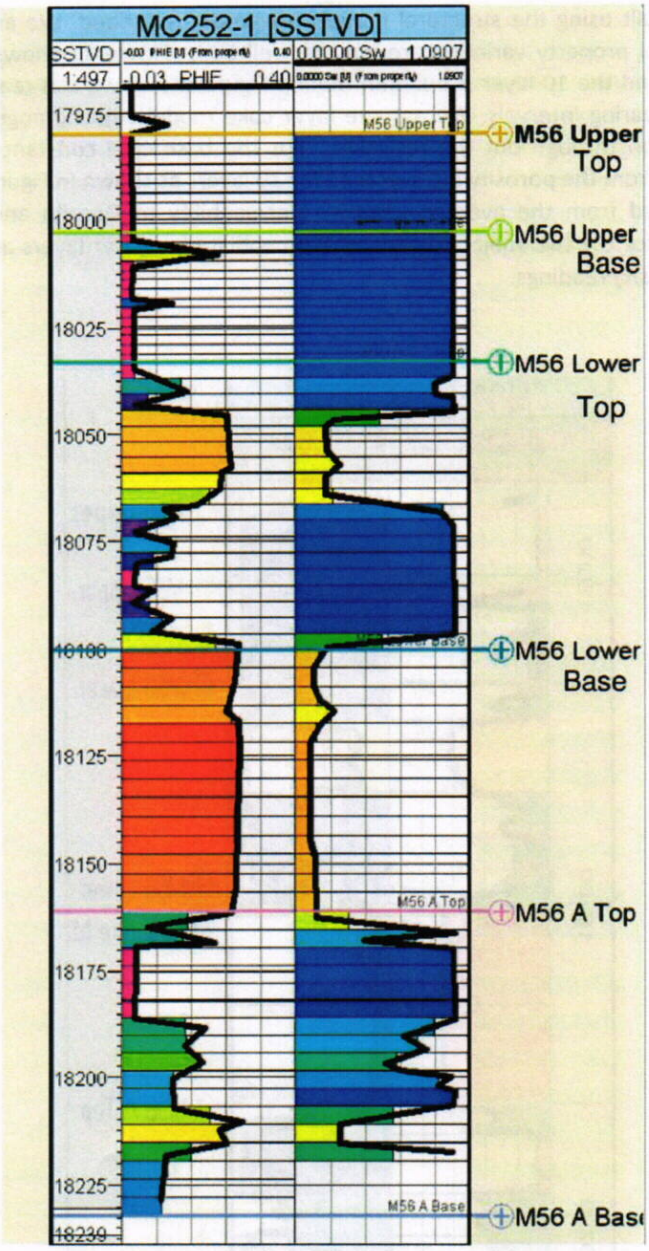

Figure 16 Well Log Porosity and Water Saturation

Simulation Model

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Simulation model is built using the structural models previously described. We assumed 10 layers to represent petrophysical property variation around the well bore. Figure 17 shows the comparison of logs for original data and the 10 layer simulation model. Figure shows we can reasonably capture the heterogeneity of oil bearing intervals. We assume layer cake model with homogeneous porosity and permeability distribution through out the reservoir. For the base case constant porosity values are assigned to each layer from the porosity log averaged for 10 layers as shown in Figure 17. The model for permeability is assigned from the average effective permeability to Decalin and Xylene from core experiments (Table-1) for the two major pay zones. Permeability for other layers are then interpolated based on their log porosity readings.

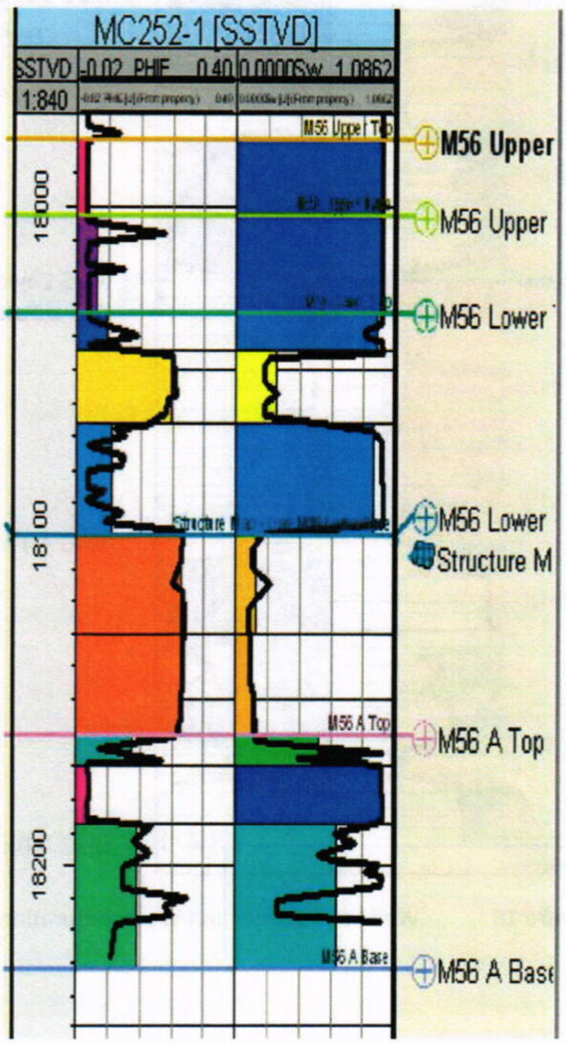

Figure 17 Well Log Porosity and Water Saturation for 11 Layer Model.

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PayZone	Depth, ft	Permeability, md	
		Decalin	Xylene
1	18070	36	32
1	18072	8	7
1	18080	37	31
1	18082	13	12
1	18083	78	65
1	18085	112	98
1	18087	126	125
Average		59	53
2	18125	76	72
2	18132	30	23
2	18142	104	103
2	18148	181	160
2	18154	109	100
2	18158	118	112
2	18161	100	100
2	18163	75	70
2	18166	74	71
2	18174	61	53
2	18178	83	81
2	18183	62	56
Average		82	77

Table 1. Permeability Data From Different Pay Zones.

Saturation log (Figure 17) shows that pay zones 1 and 2 have different residual water saturations, 20% and 10% respectively. Therefore we have generated relative permeability curves using Corey's functions with exponents equal to 2.0 for both oil and water curves (Figure 18). Capillary pressures are assumed to be zero resulting in no transition zone which will place oil at residual saturation immediately above the contact.

Average rock compressibility of 5.61 E-6 is assumed at reference pressure of 11000 psia, from available data. Uncertainty around this rock compressibility is also considered in our simulations as explained in the next section.

Initially we defined 1 equilibrium region with a single water oil contact (WOC) at 18168 ft based on the information provided to us. However, our test simulation runs resulted in high water cut values up to 20% due to proximity of the well to the WOC (Figure 19). Figure 19 shows the impact of water production to the oil production rate from the well. Considering that the well did not produce water so far, we needed to move down WOC depth to 1250 ft to avoid water production. Assuming deeper contact than what is reported is also supported by the porosity and saturation logs. Figure 16 shows presence of a thin oil interval with porosity reading of ~20.5% and Sw of 28% between 18200'-18250' interval.

Simulation runs are conducted using PVT and VFP tables previously discussed considering the following uncertainties.

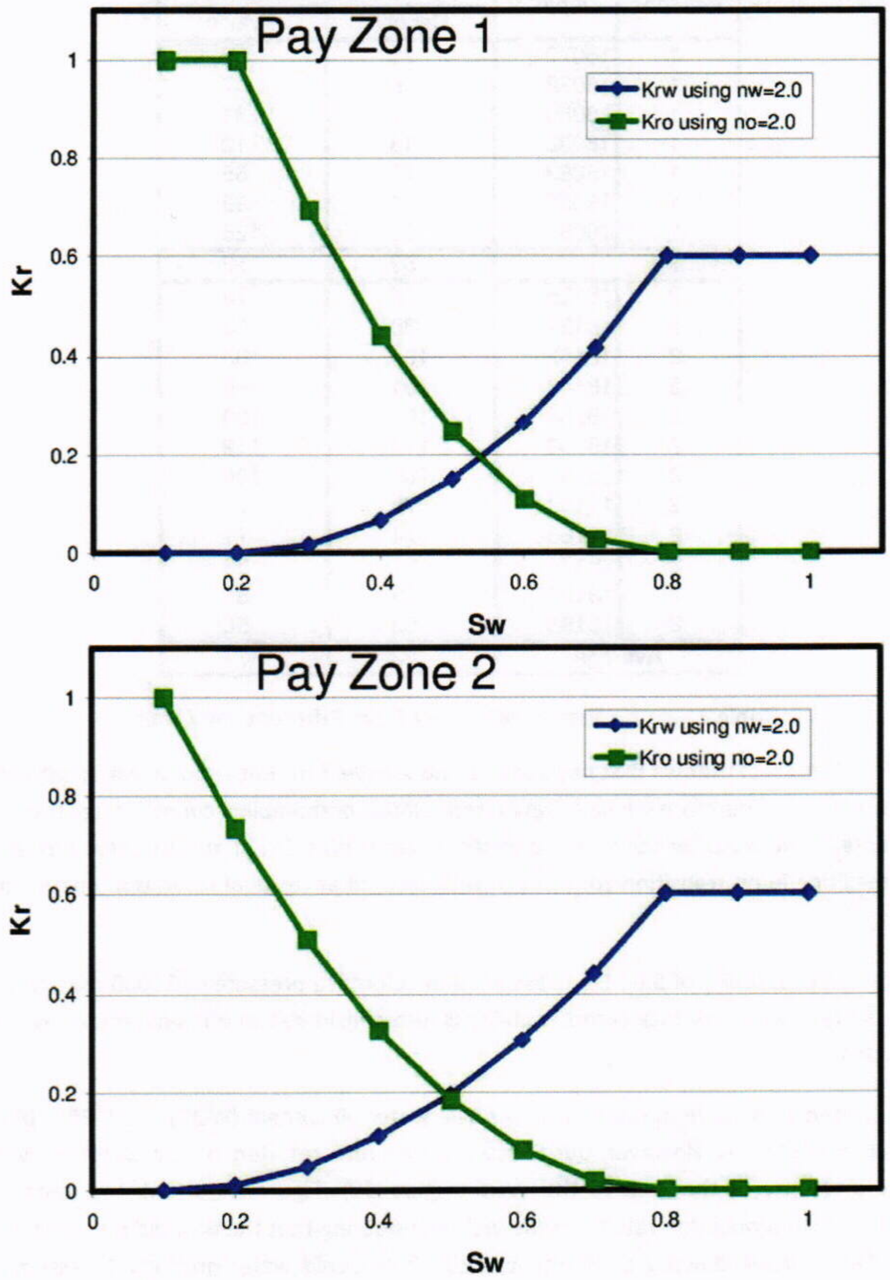

Figure 18 Relative Permeability Curves Used for Simulations.

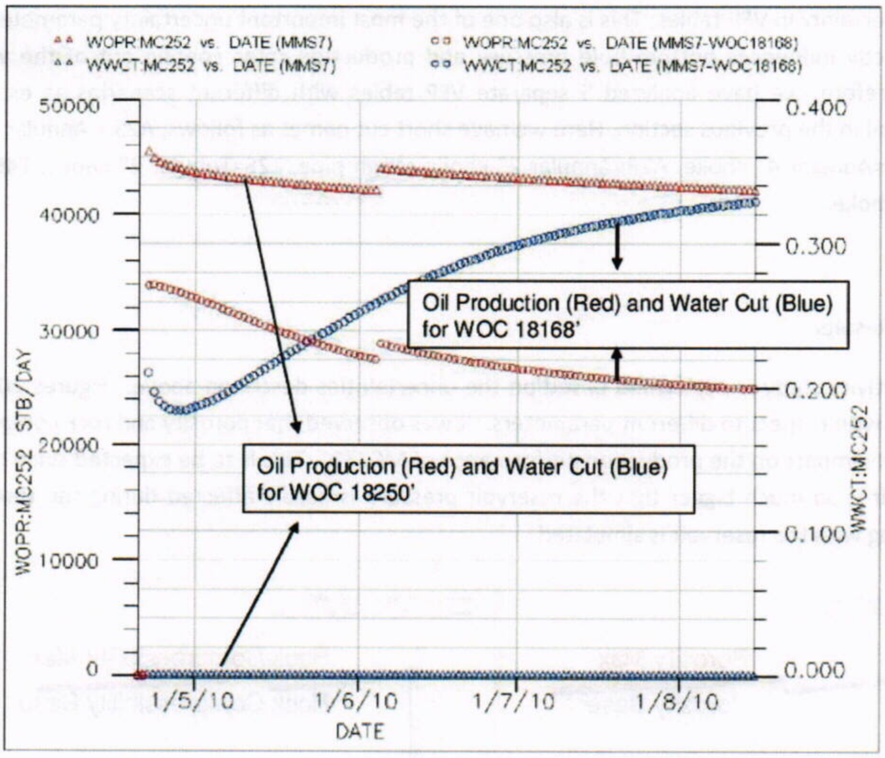

Figure 19 Simulations Results in Water Production for WOC 18168ft.

1. Uncertainty in the reservoir structure: We use the 2 structure previously described to simulate the influence of bulk volume on the wells performance.
2. Uncertainty in porosity (pore volume): We assumed that the porosity values can be 7% higher than that of log measured value. For example, pay zone 2 which has average porosity of 26% will then be 33%.
3. Uncertainty in permeability: This is one of the most important parameters for uncertainty due to its impact on wells productivity. Therefore, we assumed that permeability values can be 50% higher than that of the base case values obtained from core measurements.
4. Uncertainty in rock compressibility: We have used the average rock compressibility (5.61 E-6) from the data as base case and maximum compressibility (8.29E-6) value for the high case.
5. Uncertainty in PVT: We have assumed two different PVT tables to reflect uncertainty in the oil properties reflected in solution gas ratio (or bubble point pressure). The base case assumes an R_s (solution gas ratio) of 2544 and the maximum case uses 2100.

6. Uncertainty in VFP tables: This is also one of the most important uncertainty parameters since it directly influences bottom hole pressure and production rates coming out of the well bore. Therefore, we have analyzed 5 separate VFP tables with different scenarios as explained in detail in the previous section. Here we have short cut names as follows; A2S = Annular 2" choke, A4S=Annular 4" choke, A2R=Annular 2" choke rough pipe, T2S=Tubular 2" choke, T4S=Tubular 4" choke.

Simulation Results

First a sensitivity study is performed based on the uncertainties described above. Figures 20-22 show sensitivities with respect to different parameters. It was observed that porosity and rock compressibility had very little impact on the production performance of MC252. This is to be expected since the size of the reservoir is so much bigger that the reservoir pressure is hardly affected during the three month period during with the reservoir is simulated.

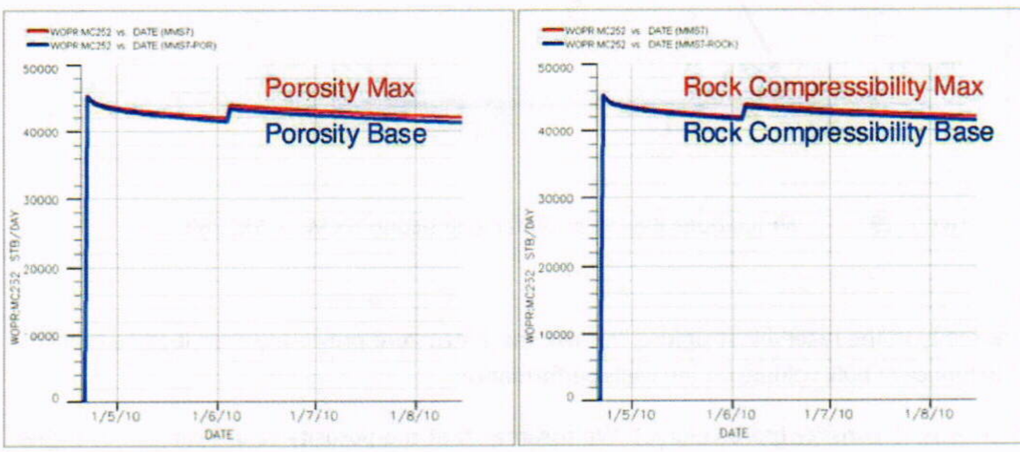

Figure 20 Sensitivity of well production rates with respect to porosity (left) and rock compressibility (right).

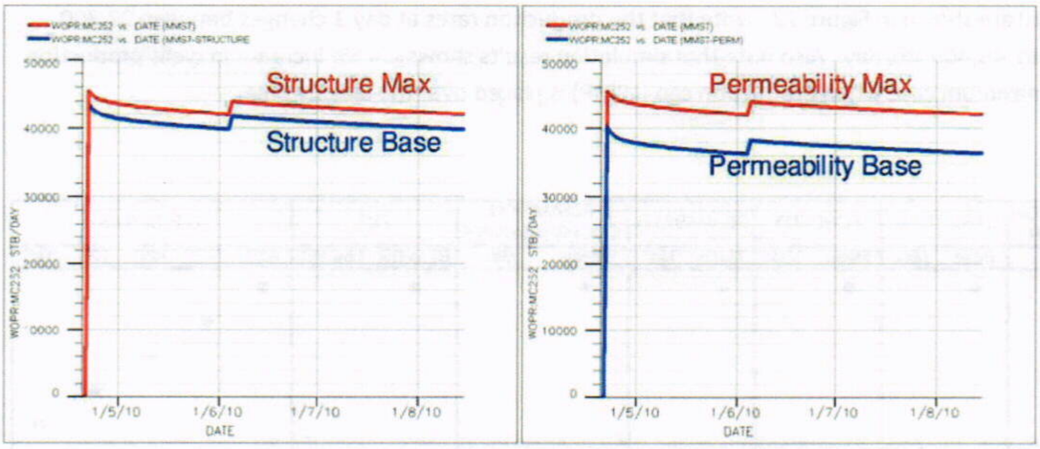

Figure 21 Sensitivity of well production rates with respect to structure (left) and permeability (right).

Figure 21 shows that the permeability is the most important static parameter to influence well's rate. A 50% increase in the permeability around the well bore can result in approximately 5000 bbl increase in production rate. Part of the reason the structure affects the behavior is because the average thickness of the formation changes slightly and hence it impacts the productivity of the well. Dynamic parameters such has PVT properties and VFP curves which are generated based on assumed tubing and annular flow scenarios are even more important than any static reservoir description parameters as illustrated in Figure 22. The maximum difference in production rates is around 6000 bbl for these cases.

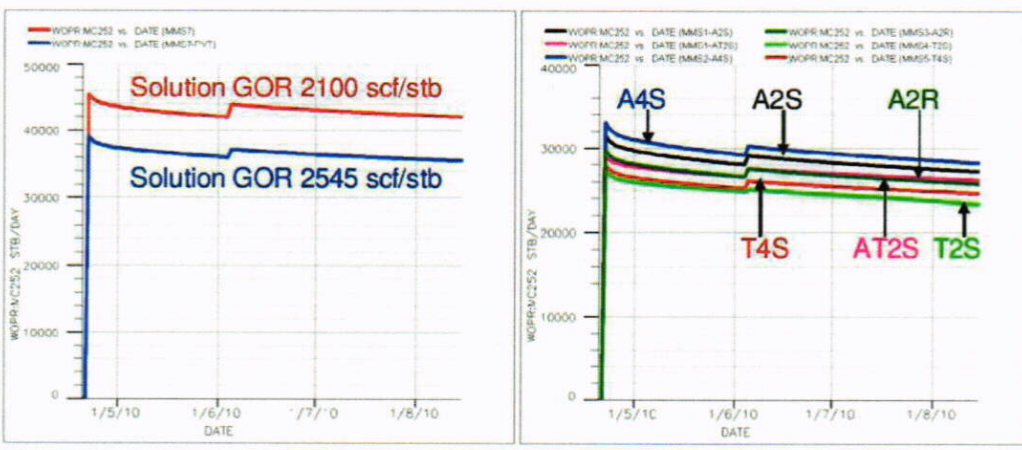

Figure 22 Sensitivity of well production rates with respect to oil PVT properties and tubing curves (right). Tubing sensitivity is shown around the base case reservoir description.

To come up with an expected (base case) and maximum production rates from well MC252, we have considered the following combinations for simulation runs (Table 2). Production rates staring on April

20th, 2010 are shown in Figure 23. Note that the production rates at day-1 changes between 27,300 stb/day to 45,400 stb/day. Also note that simulation results shows a 4.6% increase in wells production for the maximum case when production cap (LRMP) is placed over the leaking pipe.

SIMULATION NUMBER	STRUCTURE		POROSITY		PERMABILITY		FORMATION COMPRESSIBILITY		PVT		VFP TABLES				
	Base	Max	Mean	Max	Mean	Max	Mean	Max	Base RS	Low RS	A2S	A4S	A2R	T2S	T4S
1	●		●		●		●		●		●				
2												●			
3													●		
4														●	
5															●
6		●		●		●		●		●	●				
7												●			
8													●		
9														●	
10															●

Table 2. Simulation tests conducted to obtain range of production response from MC252. (A2S = Annular 2" choke, A4S=Annular 4" choke, A2R=Annular 2" choke rough pipe, T2S=Tubular 2" choke, T4S=Tubular 4" choke)

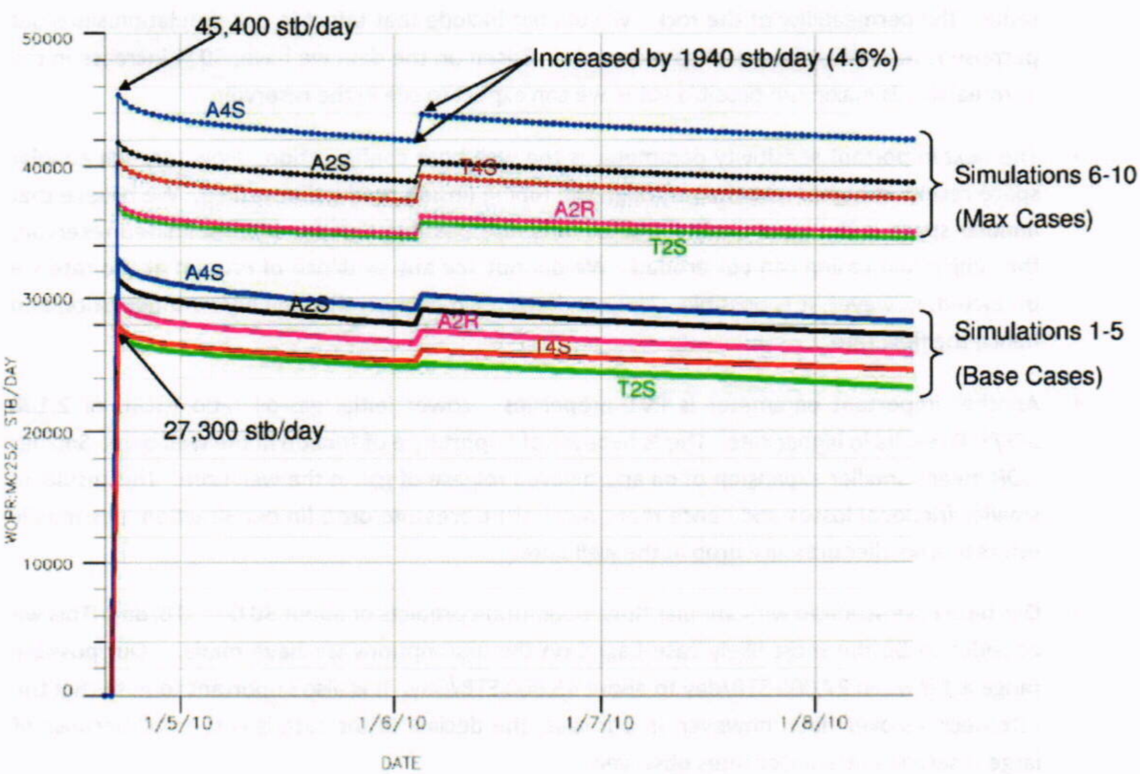

Figure 23 Simulation tests showing maximum and base case production rates from MC252.

Summary and Conclusions

In this report, we have simulated the performance of MC 252 well which blew up on April 20th, 2010 in Gulf of Mexico and since that day has been producing oil and gas. Some of the oil and gas has been collected by BP and some is being flared. Our purpose is to provide uncertainty range of possible production rate based on three month window. We have not made an effort to independently validate the data which was provided to us. Instead, we used the data which was provided to us and used engineering judgment to quantify uncertainties around the base case. It is also important to understand that we do not really know the flow configuration through which oil and gas is flowing. We have made some assumptions about the flow restrictions in the well bore and predicted the lift curves based on those assumptions. If better modeling can be done and the lift curves based on the new models is provided to us, we can refine our performance prediction. Based on the results of our simulation study, we can offer the following conclusions:

- The most sensitive parameter which has an impact on the simulation performance is the permeability of the reservoir. Our base case is the permeability of oil which was reported in the core report. The values are remarkably homogeneous. In addition, rock compressibility can reduce the permeability of the rock. We did not include that effect in our simulation since our purpose is to predict the worst case scenario. Based on the data we have, 50 % increase in the permeability is maximum possible value we can expect to see in the reservoir.

- The next important sensitivity parameter is the well bore configuration. Flow through annular space results in higher rate than through the tubing (inside production casing). We believe that annular space is the most likely scenario. It is also possible that for unconsolidated reservoir, the tubing and casing can get eroded. We did not see any evidence of erosion at the rate we predicted; however, it is possible. This can have an impact on the well bore configuration and hence the flow rate.

- Another important parameter is PVT properties. Lower initial gas-oil ratio (GOR) of 2,100 SCF/STB results in higher rate. This is because of importance of friction in the well bore. Smaller GOR means smaller expansion of oil and delayed release of gas in the well bore. This results in smaller frictional losses and hence more pessimistic pressure drop (in our situation, pessimistic refers to a smaller pressure drop in the well bore).

- Our base case scenario with annular flow assumption predicts of about 30,000 STB/day. This we consider to be the most likely case based on the assumptions we have made. Our possible range is between 27,000 STB/day to about 45,000 STB/Day. It is also important to note that the rate declines over time; however, in our case, the decline in the rate is very small because of large reservoir and smaller rates observed.

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