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Impact of Flow Assurance in the Development of a Deepwater Prospect

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Abstract

In deepwater production systems, extreme pressure and temperature conditions, multipart sub-sea networks, complex reservoir characteristics, and various fluid phases flowing from the reservoir rock to the surface could promote production interruption due to the formation and deposition of hydrocarbon solids such as asphaltene, wax and hydrates anywhere in the production system. These are flow assurance key risk factors that create significant impact on field development planning, especially, when dealing with marginal deposits having varying fluid characteristics. To reduce the risk, we have adopted a systematic approach to evaluate the potential impact of asphaltene and wax precipitation and deposition.

In this field case, two distinct layers of hydrocarbon deposits are considered marginal from reserves point of view; the upper deposit is a gas condensate layer and the lower is a black oil layer. Because of marginal reserves, mono-bore commingle production was thought to be an option. Also, in-situ gas lifting is considered to be a favorable option. Commingling of live crude oil with a gas stream may lead to precipitation of asphaltenes resulting from changes in composition. Changes in pressure and temperature can also take the system across the boundaries of asphaltene and wax. Being able to predict the formation of solid deposits along the whole production system from downhole to production facilities becomes progressively more important as water depths increase.

This paper describes the impact of flow assurance considerations in a deepwater Gulf of Mexico development project. This study is based on experimental measurements of asphaltene and wax precipitation of a hydrocarbon fluid when contacted with gas condensate from another zone. The evaluation is performed using multiphase thermal-hydraulic behavior in an Integrated Production Model (IPM) that provides system deliverability predictions through the lifetime of the project coupled with asphaltene and wax thermodynamic models. The Perturbed Chain - Statistical Associating Fluid Theory (PC-SAFT) equation-of-state (EOS) model[1,2] is the thermodynamic tool used to predict asphaltene precipitation. Wax deposition is predicted using a solid solution model.

The results of experimental and theoretical flow assurance assessment indicated that the black oil has the propensity for asphaltene precipitation caused by pressure depletion during primary production. Simulation results revealed that the downhole commingling with gas condensate is expected to significantly intensify the asphaltene precipitation condition. Results also indicate that wax precipitation will not be an issue during the life of the project.

Introduction

The size of the potential reserves drives initial capital expenditure and, reservoir appraisal is limited in the case of marginal fields. Reducing the number of flowlines by commingling streams from several wells can reduce capital and operational expenditure but may cause problems if the fluids in the streams are not compatible[3]. The mixture of the two reservoir fluids could potentially precipitate asphaltene at their commingling point. This problem might occur when fluids of very different densities are mixed. For example, a problem may occur when a condensate is mixed with black oil. The density of the entire liquid phase decreases, the crude oil solubility parameter decreases and the asphaltenes aggregate. As the field matures, oil cross-flow from the higher oil pressure zone into the lower gas pressure reservoir might also lead to precipitation and plugging of the gas sand. The consequences of asphaltene precipitation and deposition generally include changes in reservoir wettability, formation damage, and wellbore and facilities plugging.

Prediction of the precipitation at any location in the wellbore or flowline/riser at different operational pressure and temperature conditions requires the integration of thermodynamic and an Integrated Production Model (IPM). Thermodynamics gives single shot images of the production system precipitation tendencies at specific points and times; the IPM predicts thermo-hydraulic changes in multiphase pipeline systems during the lifetime of the project that can be incorporated into the thermodynamic model.

Thermo-Hydraulic Multiphase Flow Modeling

Separated oil and gas condensate reservoirs are located at approximately 22,700 feet and 21,900 feet of depth and have initial reservoir pressures of 16,990 psia and 15,740 psia respectively. Downhole commingling of oil and condensates option with downhole valve is considered in the Field Development Plan. Figure 1 depicts the IPM representing the system under evaluation.

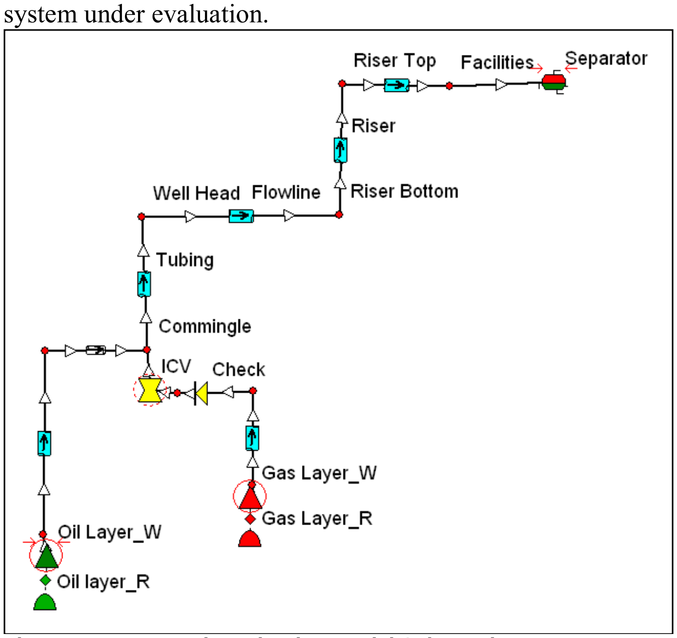

Figure 1: Integrated Production Model Schematic

The IPM design involves the mechanical design and the hydro-thermal design. The hydraulics of the system is linked to the size of the tubular and the potential need for additional pumping systems. The thermal design oversees the requirements for insulation along the pipes. These considerations apply through the life of the project and their change with composition, pressure and temperature during this long period of time depend on reservoir rock and fluid characteristics.

The Petroleum Expert toolkit Software (PETEX™) has been used for building the steady state hydrodynamic model of this field. Among the reservoir properties required by the software, rock compressibility, aquifer size, and relative permeability are critical. Rock compressibility was assumed to be constant. The aquafier size was varied from 2 to 15 times the size of the hydrocarbon accumulation to evaluate different reservoir energy scenarios (results for a value of 10 are presented in this document). In the absence of special core analysis, relative permeability curves were generated using Corey functions. A detailed description of the Integrated Production Modeling is presented in Appendix 1.

Figure 2 illustrates pressure and temperature trends at different nodes for the first five years of production obtained using the IPM. Simulations indicate that the oil reservoir will deplete 6000 psia during the first five years of production. At the commingle point, pressure can be maintained approximately constant by using a one way down-hole valve which controls the amount of produced gas. At the same time, an in-situ down-hole gas lift operation is achieved enhancing oil deliverability.

Significant temperature changes are not expected during the same production period. GOR is presented also in Figure 2 as an indicator of compositional changes. GOR at the commingle point increases as the field matures.

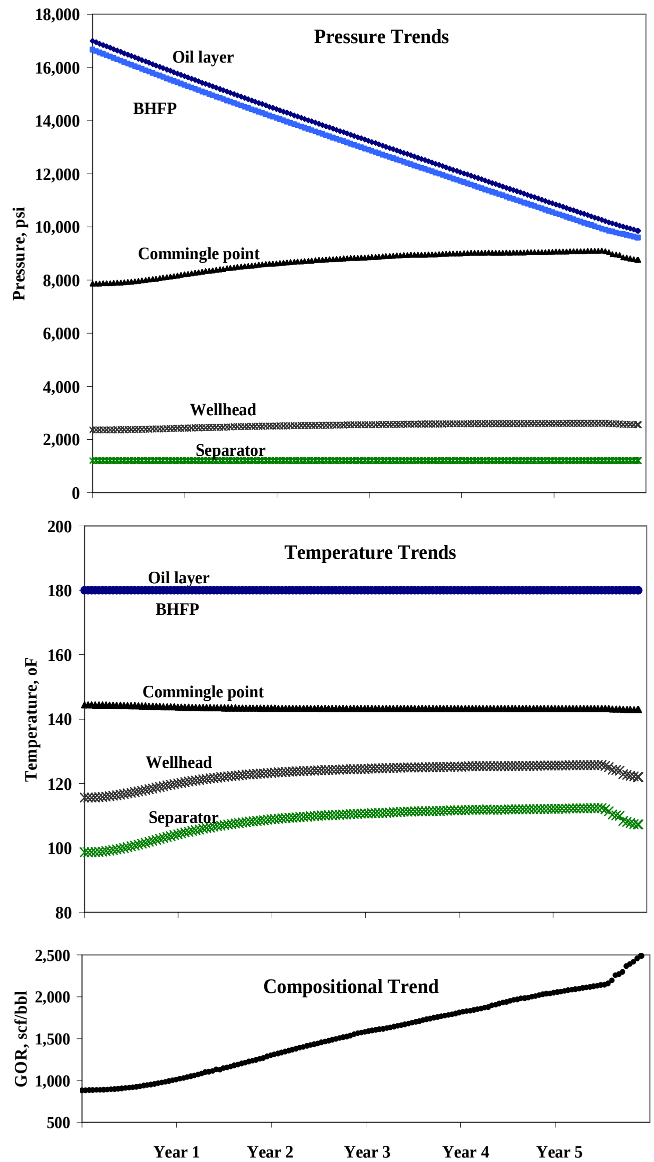

Figure 2: Predicted P, T and GOR trends at different nodes during the first five years of production

Figure 3 shows flowing conditions along 28,000 ft of production system. At early life (continuous lines), the production rate is about15,000 stb/d with a GOR of 882scf/stb. At this initial time, the total pressure and temperature losses along the whole system are 15,800 psig and 81ºF. Figure 3 also illustrates pressure and temperature profiles after 5 years of production (dash lines) when the oil rate has decreased to approximately 4,000stb/d with a GOR of 2,490scf/stb. Total pressure and temperature drop along the whole system are now 8,660psia and 73°F. The IPM predicts a minimum arrival temperature of approximately 100°F reached early in the life of the project.

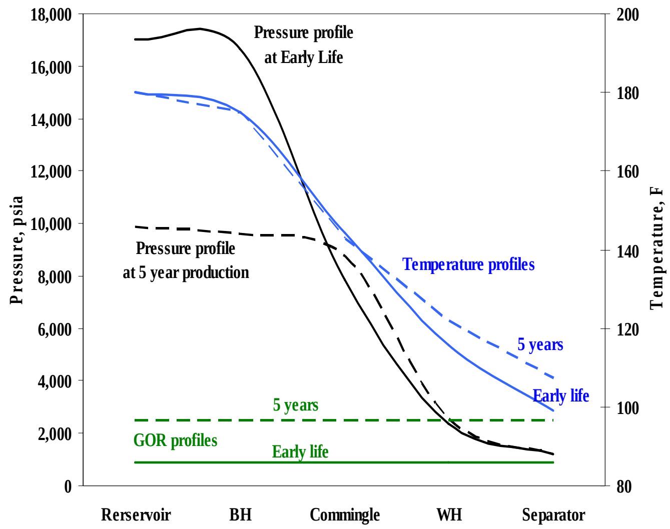

Figure 3: Predicted P, T and GOR profiles - Early life (continuos lines) and after 5 years of production (dash lines)

Another critical factor of a great importance is the down-hole internal control valve (ICV) design. As determined by the IPM, the ICV will have to operate at 0.15 inch opening to control the gas flow most of the life of the project. The pressure losses reach up to 7,000psig across this ICV early in the life of the project. The IPM predicts that the temperature drop is approximately 26°F early in the life of the project and 30°F after five years. The change in temperature of the commingled fluid as a result of the expansion of the gas across the ICV can be explained by the Joule-Thompson effect. ICV pressure and temperature performance is depicted in Figure 4.

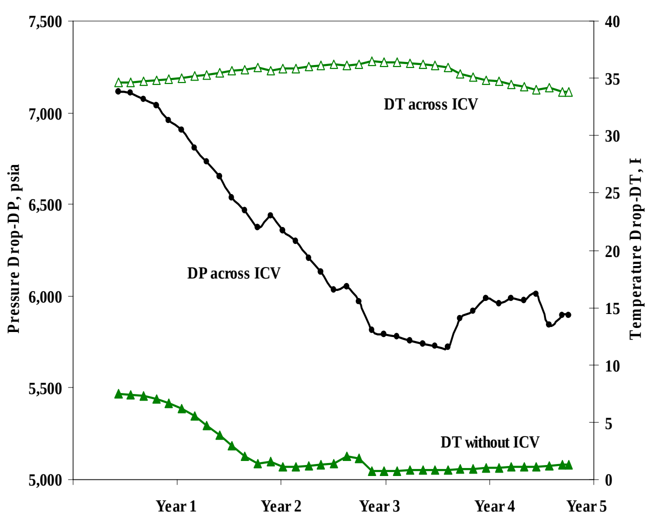

Figure 4: Pressure and temperature drop calculation across the downhole valve controlling the gas zone rates using integrated network tool.

Thermodynamic Model

Experimental Measurements

Measurements to evaluate asphaltene and wax precipitation include PVT analysis, Saturates-Aromatics-Resins-Asphaltenes (SARA) analysis, wax content, wax appearance temperature (WAT), high temperature gas chromatography (HTGC) high pressure/high temperature onset determination and gas titration using near infrared technique.

Detailed fluid properties and fluid compositions are summarized in Tables 1, 2 and 3. An OBM contaminated reservoir fluid of 36°API gravity with a characteristic GOR of 852 scf/sbl and bubble point of 3,427 psi at 184°F is mixed with a synthetic gas with a similar composition to that of the actual gas condensate located in the upper layer.

Table 1: Fluids Properties Summary

	Oil-Lower layer	Gas-Upper layer
Reservoir Conditions		
Pressure, psia	16,990	15,740
Temperature, F	184	170
Depth, ft MD	22,700	21,900
Reservoir Fluid Properties		
OBM Contamination wt% RF Basis	20.0	3.1
GOR - Single-state flash [scf/bbl], Orig / De-contaminated	852 / 1,133	13,693 / 15,253
Bubble Point Pressure at Tres, psia	3,427	
Bubble Point Pressure at 100F, psia	2,940	
Dew Point Pressure at Tres, psia		10,562
Properties at Reservoir Conditions		
Compressibility, 10^{-6}/psi	4.4	2.1
Density, g/cc	0.745	0.421
Properties at Saturation Conditions		
Compressibility, 10^{-6}/psi	12.7	1.6
Density, g/cc	0.669	0.379
FVF – Single Stage Flash, @ Pres & Tres	1.322	
Properties at 60F		
Molar mass	220.42 / 229.59	176.06 / 177.24
OBM Contamination wt% STO Basis	23.3	9.8
°API – Single Stage STO, Orig / De-contaminated	36.1 / 32.8	43.5 / 42.5
Density, g/cc, Orig / De-cont	0.8441 / 0.8613	0.8088 / 0.8131
Gas Gravity	0.76	0.592

Table 2: Oil layer fluid composition (mole %)

Component	MW	Flashed Gas	Flashed Liquid	Monophasic Fluid
Carbon Dioxide	44.01	0.07	0.00	0.05
Nitrogen	28.01	0.18	0.00	0.12
Methane	16.04	79.53	0.00	49.60
Ethane	30.07	7.40	0.00	4.61
Propane	44.10	6.49	0.56	4.26
Butane	58.12	3.93	1.35	2.95
Pentane	72.15	1.98	2.67	2.24
C6	86.20	0.26	3.79	1.59
C-Pentane	84.16	0.00	0.69	0.26
Benzene	78.11	0.00	0.12	0.05
Cyclohexane	84.16	0.07	0.46	0.22
C7	100.20	0.04	4.22	1.61
C-Hexane	98.19	0.03	1.00	0.39
Toluene	92.14	0.00	0.64	0.24
C8	107.00	0.01	4.97	1.87
E-Benzene	106.17	0.00	0.37	0.14
Xylene	106.17	0.00	1.02	0.39
C9	121.00	0.01	4.25	1.60
C10	134.00	0.00	5.33	2.01
C11	147.00	0.00	7.60	2.86
C12+	291.40	0.00	60.99	19.82
MW		22.02	221.04	96.91
Mole Ratio		0.6237	0.3763	

Table 3: Gas layer fluid composition (mole %)

Component	MW	Flashed Gas	Flashed Liquid	Monophasic Fluid
Carbon Dioxide	44.01	0.05	0.00	0.05
Nitrogen	28.01	0.00	0.00	0.00
Methane	16.04	96.73	0.00	92.62
Ethane	30.07	0.96	0.00	0.92
Propane	44.10	0.90	0.09	0.87
Butane	58.12	0.65	0.38	0.65
Pentane	72.15	0.47	1.27	0.50
N - Hexanes	86.20	0.11	2.57	0.22
M-C-Pentane	84.16	0.00	0.69	0.03
Benzene	78.11	0.00	0.05	0.00
Cyclohexane	84.16	0.04	0.40	0.05
C7	100.20	0.04	5.80	0.28
M-C-Hexane	98.19	0.02	1.25	0.07
Toluene	92.14	0.00	0.88	0.04
C8	107.00	0.01	8.65	0.37
E-Benzene	106.17	0.00	0.65	0.03
Xylene	106.17	0.00	1.26	0.06
C9	121.00	0.01	8.09	0.35
C10	134.00	0.00	9.16	0.39
C11	147.00	0.00	8.79	0.37
C12+	162.65	0.00	50.00	2.12
MW		17.15	177.24	23.95
Mole Ratio		0.9576	0.0424	

Asphaltene Measurements

The SARA content of the oil reservoir fluid gives a preliminary guideline of asphaltene precipitation.

SARA content (% w/w) – Oil layer

Saturates	61.7
Aromatics	26.0
Resins	11.4
Asphaltenes (n-C7)	0.9

The analysis indicates that the reservoir fluid has a high content of saturates (> 60%)[4] and the asphaltene content is in the range for a crude with severe asphaltene precipitation tendency (<1%)[4]. These values indicate a relatively asphaltene unstable fluid. These concentrations along with the gas compositional information need to be integrated in a single model to determine the potential for asphaltene precipitation.

The contamination of crude oil with oil-based drilling fluids affects both asphaltene stability and bubble point resulting from changes in oil composition. Previous studies[5] indicate that a contamination level of 3.6% (live basis) increases the bubble point by approximately 0.5% and increases the onset pressure by 7.5%. Therefore, during simulations, asphaltene parameters are determined using contaminated samples and predictions are calculated using the corresponding corrected de-contaminated samples. The composition for the clean fluid is corrected by subtracting the oil-base mud (OBM) composition in the appropriate percentage.

The onset of asphaltene precipitation for the reservoir black oil fluid (oil layer) was measured by pressure depletion starting from 15,000psi and at reservoir temperature of 184ºF using fixed wavelength near infrared (NIR), Particle Size Analysis (PSA) and high pressure microscopy (HPM) techniques. Description of these techniques is found in reference 6. Figure 5 shows NIR response superimposed with HPM micro-photographs obtained during the de-pressurization process of the reservoir black oil.

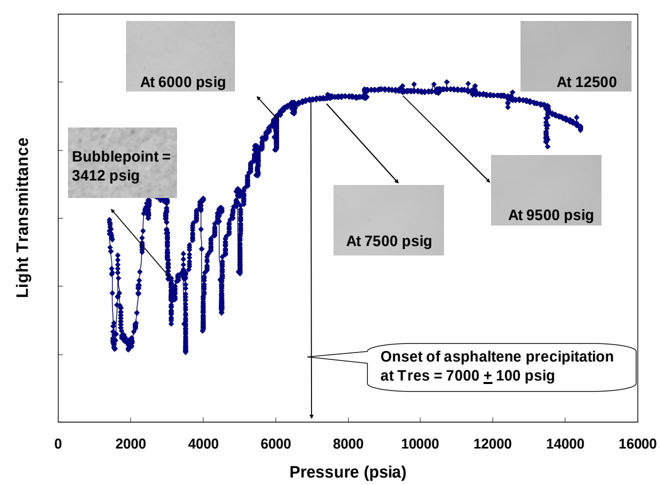

Figure 5: NIR+HPM during de-pressurization at 184ºF

Figure 6 presents the PSA results obtained by analyzing the HPM micro photographs. The asphaltene precipitation onset was estimated as 7000psia.

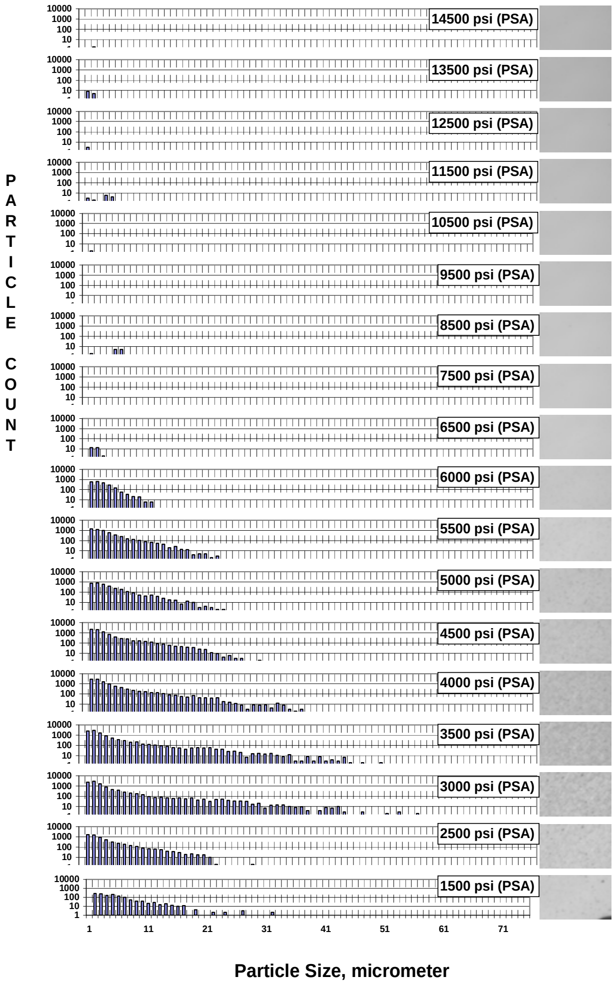

Figure 6: PSA from HPM during de-pressurization at 184ºF

The titration test measures the fluid compatibility, i.e., maximum concentration of a fluid allowed to be mixed with the reservoir fluid without asphaltene precipitation. This test is performed at reservoir conditions to investigate the compatibility between the reservoir fluid and the added gas. Figure 7 presents lab titration results using Near Infra Red (NIR) and High Pressure Microscope (HPM) techniques. The corresponding Particle Size Analysis (PSA) obtained by evaluation of the HPM micro-photographs is presented in Figure 8. These experimental measurements indicate asphaltene precipitation onset between 6 and 9 cc of added gas to the oil reservoir fluid at 15,000psia and 170F. These volumes of gas correspond to a mixture gas oil ratio between 1,700 and 2,070 scf/bbl.

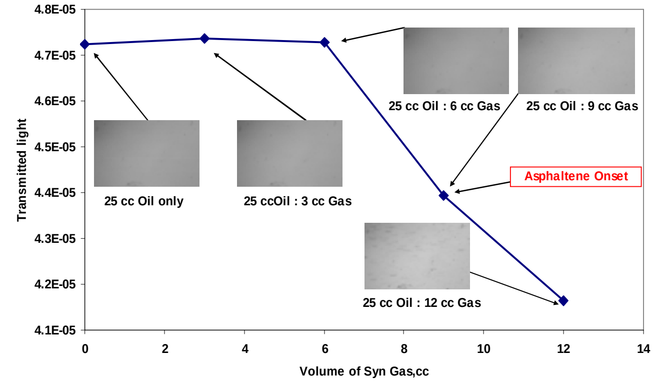

Figure 7: NIR + HPM during titration at 15,000psia and 170°F

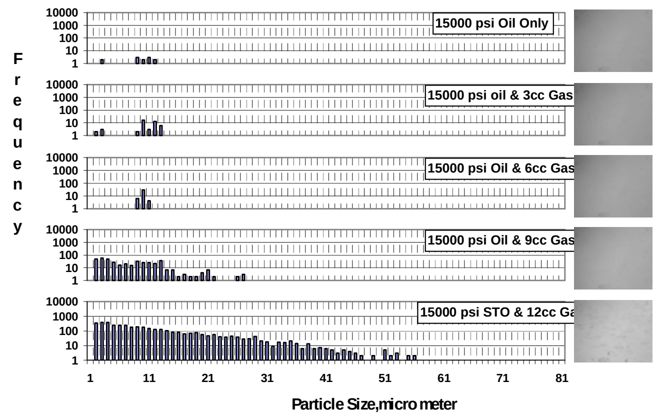

Figure 8: PSA from HPM during titration at 15,000psia and 170ºF.

Wax Measurements

The wax content for the oil reservoir fluid was measured as 1.64 wt% (STO basis). The wax appearance temperature was measured as 71ºF using Cross Polar Microscope (CPM) technique. Figure 9 presents the wax composition using high temperature gas chromatography (HTGC) technique.

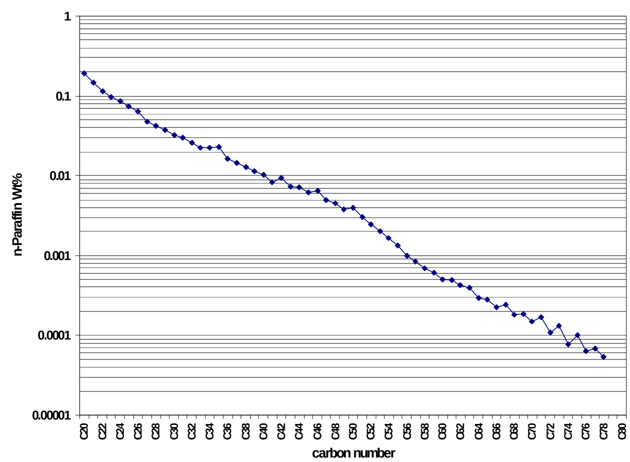

Figure 9: Wax Analysis by HTGC

Asphaltene Modeling

The PC-SAFT EOS compositional model as implemented in Multiflash™ (Infochem) was selected to predict asphaltene precipitation tendencies during production. The detailed modeling principles and assumptions of this model can be found in references 7 and 8.

A brief step-by-step calculation protocol is given below:

1. Identification of the thermodynamic asphaltene phase boundaries using PC-SAFT precipitation model for the reservoir oil-lower layer.
2. Calculation of the fluid properties and phase behavior after OBM mathematical decontamination
3. Evaluation of the asphaltene stability regions resulting from reservoir fluid contact with gas condensate (upper layer) at different concentrations.

The equation of state parameters are calculated for each of the seven components and pseudo-components of OBM contaminated sample using SARA, GOR, PVT data and compositional information. Reservoir fluid is contaminated with 20wt% (live basis) of OBM that has carbon number peaks from C10 to C21. The asphaltene parameters are tuned to meet the onset of asphaltene precipitation of 7,000±100 psig measured by de-pressurization at 184ºF (Figs. 5 and 6). Table 4 summarizes composition, molecular weight and parameter value for each component and pseudo-component. The PC-SAFT parameters are defined as:

- *m*, number of segments per molecule
- σ, diameter of each segment of a molecule in Å.
- ε/k, segment-segment interaction energy in Kelvin.

Table 4: PC-SAFT characterization of the contaminated oil fluid at 852 scf/bbl.

	Xmole	MWn	*m*	σ(A)	ε/k (K)
N2	0.00113	28.01	1.2053	3.3130	90.96
CO2/H2S	0.00044	44.01	2.0729	2.7852	169.21
Methane	0.49794	16.04	1.0000	3.7039	150.03
Light	0.12655	45.42	2.0754	3.6178	205.56
Saturates	0.24061	212.12	6.293	3.940	256.11
Aromatics + resins	0.13289	231.96	6.103	3.783	289.14
Asphaltenes	0.000437	1700	29.500	4.300	393.00

The temperature-independent binary interaction parameters (kij) are presented in Table 5

Table 5: Binary Interaction Parameters

kij	N_2	CO_2	CH_4	Light	Saturates	A + R	Asphaltene
N_2	0.00	0.00	0.03	0.06	0.12	0.11	0.11
CO_2		0.00	0.05	0.10	0.13	0.10	0.10
CH_4			0.00	0.00	0.01	0.02	0.02
Light				0.00	0.01	0.01	0.01
Saturates					0.00	0.007	0.007
A + R						0.00	0.00
Asphaltene							0.00

The PC-SAFT model calculates the contaminated fluid properties presented in Table 6.

Table 6: OBM contaminated oil sample properties at 184F and 852 scf/bbl.

	Experimental	Calculated
Ponset (psia)	7,000	6,928
Pb at 184F (psia)	3,427	3,648
Pb at 100F (psia)	2,940	3,041
Density at Reservoir (g/cc)	0.745	0.769
Density at Saturation (g/cc)	0.67	0.68
Liquid (STO) density (g/cc)	0.844	0.847

Composition of clean oil fluid is calculated mathematically by subtraction method[9]. The GOR increases from 852scf/bbl to 1133scf/bbl. The new OBM free composition is used to re-calculate the molar amount and new parameters for saturates and aromatic+resins pseudo-components (Table 7). Asphaltene parameters are maintain as calculated for the contaminated fluid because the OBM composition does not affect high molecular weight components in which asphaltene fraction is included. Binary interaction parameter values are also kept as presented in Table 5.

Table 7: PC-SAFT characterization of the OBM free oil sample (1133 scf/bbl)

	X_{mole}	MW_n	m	σ (A)	ε/k (K)
Saturates	0.203	215.22	6.371	3.942	256.59
Aromatics + resins	0.102	258.08	6.700	3.786	290.87

Fig. 10 summarizes the prediction of the complete phase envelope for reservoir fluid (contaminated and de-contaminated) at 184ºF.

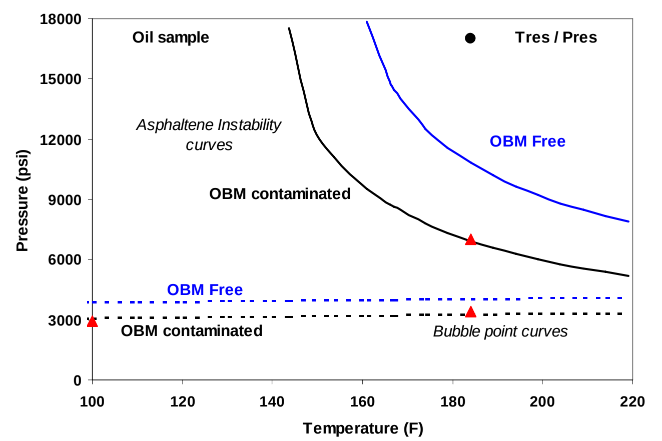

Figure 10: Asphaltene precipitation behavior for reservoir fluid at lower layer (OBM contaminated and uncontaminated)

Simulation results indicate that a contamination of 20 wt% with OBM diminishes the asphaltene precipitation onset in almost 4,000 psia. This black oil–reservoir fluid presents high tendency to precipitate asphaltene during primary depletion; the EOS predicts that the clean fluid will precipitate asphaltenes at pressures below 10,700 psia at 184ºF. Further reduction in temperature will aggravate the precipitation condition.

Oil and Gas Commingle

Asphaltene precipitation in commingled fluids is dependent on compositional changes that arise from the relative proportions of the mixing fluids. Asphaltene precipitates from the solution when a gas condensate is added to a relatively unstable crude oil. Figure 11 shows an increase in the precipitation onset as gas condensate commingles with the oil. The mixture GOR increases rapidly from 1133scf/bbl (before commingle) as the gas condensate is added to the crude oil.

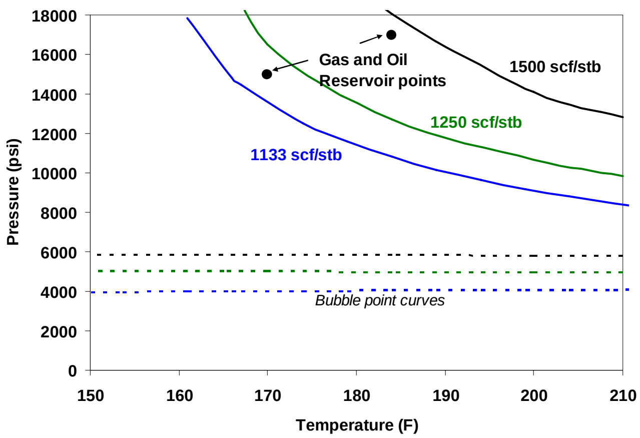

Figure 11: Asphaltene phase behavior: solid lines show the lowest pressure for asphaltene stability at the given GOR which represents a specific amount of added gas.

Asphaltene Precipitated Amount

The amount and composition of the asphaltene precipitated phase is determined as part of the equilibrium calculations. Figure 12 shows the predicted amount of asphaltene precipitated during commingled production at different conditions. Pressure, temperature and composition ranges are selected from IPM prediction (Figures 2 and 3). The amount of precipitated asphaltene is observed to increase significantly when gas condensate mixes with crude oil. For example, addition of 20% in volume of gas condensate is expected to increase the amount of asphaltene precipitation from 10% to approximately 50% at 10,000 psia and 184ºF.

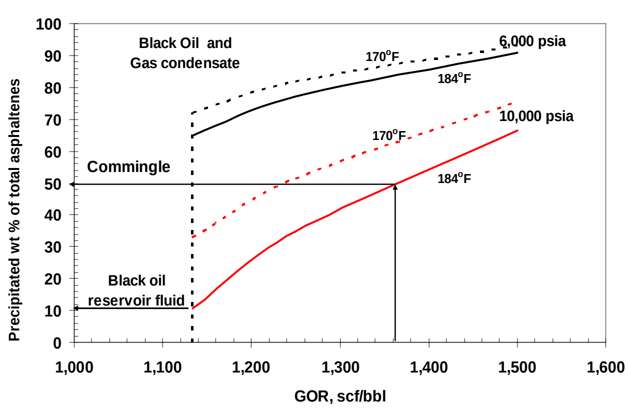

Figure 12: Predicted amount of asphaltene precipitated for different amounts of gas condensate (upper layer) added to the black oil reservoir fluid (lower layer)

Wax Modeling

Wax phase boundaries are modeled using a solid solution model as implemented in PVTPro™ (Schlumberger). The model described in reference 10 analizes the liquid and vapor phases using a cubic EOS and describes the non-ideality of the solid phase by using an activity coefficient model, which is adjusted to meet WAT at ambient pressure. Wax modeling is developed using C30+ composition and normal paraffin distribution from HTGC. The simulation results are presented in Figure 13. WAT for STO is 71ºF and decreases with increasing pressure as a result of gas solubility. Above the bubble point, WAT increases with increasing pressure caused by liquid compressibility effect.

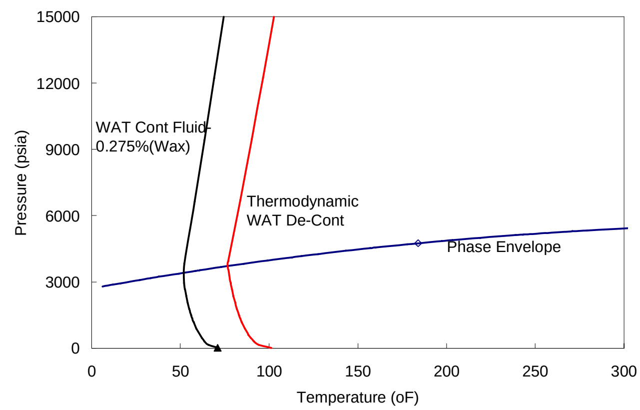

Figure 13: Wax Phase Boundaries.

The model was first used to calculate the thermodynamic phase boundary with OBM contaminated fluid (Figure13). Then WAT of the stock-tank fluid was used to tune the model and calculate the wax locus of the reservoir fluid. The tuning was achieved at a wax cut of 0.275w%. Consequently, the fluid composition was mathematically decontaminated and the wax phase boundaries were recalculated. Maximum WAT is estimated to be around 102F.

Conclusions

- The combination of an Integrated Production Model (IPM) with asphaltene and wax thermodynamic models improves flow assurance predictions because it provides means to estimate solid formation due to variations in pressure, temperature and composition during the life of the project.
- The hydro-thermal calculations revealed that the oil reservoir will deplete more than 6,000 psia during the first five years of production; significant temperature changes are not expected during the same production period and GOR at the commingle point will increase from ~1,133 to 2,800scf/bbl as the field matures

- Experimental and simulation results indicate that the lower black oil layer is unstable with respect to solid formation. Asphaltenes are expected to precipite during primary depletion of this layer; therefore, installation of asphaltene inhibitor line is recommended. There is an uncertainty associated with experimental measurements caused by the OBM contamination

- The addition of gas condensate at any ratio is expected to severely aggravate the asphaltene precipitation condition. Also, commingled production from both zones has a high potential for crossflow from high pressure oil zone into the gas condensate zone which could induce formation plugging. It is then recommended to plan the field development based on sequential/intermitent production.

- If commingled production is inevitable, the installation of an ICV is a requirement from the flow assurance and reservoir management points of view because it controls the amount of gas that mixes with the oil mitigating the asphaltene precipitation tendency and improving the oil lifting performance. Its mechanical design will have to withstand a high pressure drop early in the life of the project.

- Characteristics of the above ICV include one way flow and should allow gas deliverability in a way that the mixture gas/oil ratio (GOR) will not go beyond 2,800 scf/stb to guarantee an optimal lifting performance according to well modeling results.

- Wax precipitation is not expected to occur if temperatures along the system are maintained above 105°F. Adequate insulation is recommended to ensure arrival temperatures above WAT for all production conditions during the life time of the field.

- The integration of an IPM with asphaltene and wax thermodynamic models based on experimental measurements maked great impact on the field development plan of the Gulf of Mexico prospect studied here

Acknowledgements

We would like to thank Hydro Gulf of Mexico and Schlumberger for the permission to publish this paper. We also thank John Nighswander for valuable discussions.

Nomenclature

EOS:	Equation of State
GOR:	Gas-Oil-Ratio
HPM:	High Pressure Microscope Technique
HTGC:	High Temperature Gas Cromatography
ICV:	Internal Control Valve
IPM:	Integrated Production Model
MW:	Molecular Weight
NIR:	Near Infrared
PC-SAFT:	Perturbed Chain – Statistical Associating Fluid Theory
PSA:	Particle Size Analysis Technique
PVT:	Pressure-Volume-Temperature
SARA:	Saturates-Aromatics-Resins-Asphaltenes
WAT:	Wax Appearance Temperature

Symbols

k_{ij} Binary Interaction Parameter

The PC-SAFT EOS parameters:

m number of segments per molecule

σ diameter of each segment of a molecule in Å.

ε/k segment-segment interaction energy in Kelvin

SI Metric conversion factors

°API 141.5/(131.5+°API)	= g/cm^3
ft × 3.048E-01	= m
°F (°F-32)/1.8	= °C
mL × 1.0	= cm^3
psi × 6.894 757	= kPa

References

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Appendix 1: Integrated Production Modeling

PETEX™ is composed by different independent software packages. The ones used in this modeling work are: PROSPER™ which is the well performance analysis tool, MBAL™ which is the material balance reservoir modeling tool, and GAP™, the flow-lines and surface gathering system modeling tool. GAP™, also allows to run MBAL™ simultaneously with a representative set of curves of the well performance originated by PROSPER™ for each of the well conforming the system, involving the pipelines and the surface gathering system.

One limitation of PROSPER™ is that it does not allow the user to model oil and gas layers simultaneously due to PVT description limitation. This problem has been overcome by modeling each of the layers as independent wells, including in the tubing description of the model only the section corresponding to the top of the perforation. The tubular section from the commingle point to the sub-sea well head is modeled within GAP. Table A-1 contains the parameter used for the PROSPER models.

Table A-1: PROSPER FILES INPUT DATA

	Gas Layer	Oil Layer
FLUID DESCRIPTION		
Fluid	Dry and Wet Gas	Oil and Water
Method	Black Oil	Black Oil
WELL		
Flow Type	Annular	Tubing Flow
CALCULATION TYPE		
Predict	Pressure and Temperature (Offshore)	Pressure and Temperature (Offshore)
Model	Rough Approximation	Rough Approximation
Range	Full system	Full system
WELL COMPLETION		
Type	Cased Hole	Cased Hole
Gravel Pack	No	No
RESERVOIR		
Inflow Type	Single Branch	Single Branch
PVT		
Gas Gravity (sp. Gravity)	0.6	0.65
Separator Pressure (psig)	200	NA
Condensate to Gas Ratio (BC/MMscf)	71	NA
Condensate Gravity (API)	44	NA
Water to Gas Ratio	0	NA
Water Salinity (ppm)	20000	20000
Solution GOR (scf/stb)	NA	1100
Oil Gravity (API)	NA	28
FLUID DESCRIPTION		
Measured Depth (1) (ft)	0	0
True Vertical Depth (1) (ft)	0	0
Measured Depth (2) (ft)	500	500
True Vertical Depth (2) (ft)	500	500
DOWNHOLE EQUIPMENT		
Xmas Tree (ft)	0	0
Tubing Measured depth (ft)	500	500
Tubing Inside Diameter (in)	3.8	3.8
Tubing Inside Roughness (in)	0.0006	0.0006
Tubing Outside Diameter (in)	4.5	NA
Tubing Outside Roughness (in)	0.0006	NA
Casing Inside Diameter (in)	8.5	NA
Rate Multiplier	1	1
GEOTHERMAL GRADIENT		
Formation Measured Depth-1 (ft)	0	0
Formation Temperature- 1 (^oF)	170	180
Formation Measured Depth-2 (ft)	500	500
Formation Temperature-2 (^oF)	170	180
Overall Heat Transfer Coefficient ($BTU/hr/ft^2/^oF$)	2	8
AVERAGE HEAT CAPACITIES		
Cp Oil (BTU/lb/F)	0.53	0.53
Cp Gas (BTU/lb/F)	0.51	0.51
Cp Water (BTU/lb/F)	1.00	1.00
INFLOW PERFORMANCE		
Reservoir Model	Jones	PI Entry
Mechanical / Geometrical skin	Enter Skin by hand	NA
Reservoir Pressure (psig)	15738	16988
Reservoir Temperature (oF)	170	180
Water Gas Ratio	0	0
Condensate Gas Ratio (stb/MMscf)	66	NA
Water Cut (%)	NA	0
Total GOR	NA	1100

Each well model within PROSPER is 500 feet long. The remaining length is modeled in GAP to complete the total length of the well (tubing) which is 22,211 feet

Table A-2: OIL AND GAS BRANCHES TO COMMINGLED POINT
Segment = Line Pipe & Roughnes = 0.0006in

	Length (ft)	TVD (ft)	Inside Diameter (in)
Gas Branch		20878*	
	500	21378	4
Oil Branch	833	21711	4
	500	22211	4

*Commingle Point

GAP was used to model from commingled the point (Gas entry point from annular into tubing) to well head using the following tubular characteristics:

Table A-3: COMMINGLED POINT TO WELL HEAD
Segment = Line Pipe & Roughnes = 0.0006in

	Length (ft)	TVD (ft)	Inside Diameter (in)
Oil and Gas combined		4450*	
	16428	20878	4

The horizontal length on top of the sea floor is modeled assuming no changes in depth. Topography is not considered. However it will play an important role if the sea floor has significant undulations. The curvature from horizontal section to riser is taken into account within the riser description. These two sections are modeled as follows:

Table A-4: HORIZONTAL SECTION Segment = Line Pipe & Roughnes = 0.0006in			
Oil and Gas	**Length (ft)**	**TVD (ft)**	**Inside Diameter (in)**
		4450*	
	5280	4450	4
RISER **Segment = Line Pipe & Roughnes = 0.0006in**			
Oil and Gas	**Length (ft)**	**TVD (ft)**	**Inside Diameter (in)**
	1167	1167	6
	333.9	1500	6
	509.9	2000	6
	522	2500	6
	583.1	3000	6
	672.7	3500	6
	1029.6	4000	6
	1084.9	4273	6
	1004.1	4364	6
	250	4390	6
	750.9	4450	6
	200	4450	6

The two distinctive layers were modeled using MBAL™. The following table contains the properties for each individual horizon.

Table A-5: MBAL MODELS		
Tank Parameter – Reservoir Conditions		
Tank type	Oil	Gas
Temperature (^{o}F)	184	170
Initial Pressure (psig)	16,988	15,738
Porosity (%)	0.25	0.25
Connete Water Saturation (%)	0.22	0.22
Water compressibility (1/psig)	Correlation	Correlation
Initial Gas Cap	0	NA
Original Gas in Place (MMscf)	NA	20000
Original Oil in Place (MMSTB)	30	NA
Water Influx		
Model	Small Pot	Small Pot
Aquifer Volume (MM ft^3)	505	10000
Relative Permeabilities (from Corey Functions)		
Hysteresis	No	No
Modified	No	No

Relative Permeabilities have been approximated using generic Corey functions. The following two tables contain relative permeability parameters for both systems oil and gas.

Table A-6: Relative Permeability Oil Tank			
	Residual Saturation	**End Point**	**Exponent**
Krw	0.22	0.6	2
Kro	0.2	0.4	2
Krg	0.25	0.2	2

Table A-7: Relative Permeability Gas Tank			
	Residual Saturation	**End Point**	**Exponent**
Krw	0.22	0.2	2
Krg	0.2	0.6	2