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HYDRATE MANAGEMENT STRATEGIES IN SUBSEA OIL AND GAS FLOWLINES AT SHUT- IN CONDITION

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Abstract

Flow assurance in deep-water developments has been identified as one of the main technological problems that the oil and gas industry faces today. Extreme conditions such as high pressures and low temperatures promote the formation of gas hydrates that can potentially reduce or completely block the flow path, causing severe financial losses. This work presents an integrated framework of model-based flow assurance management strategy to handling the effect of hydrates. The model-based flow assurance framework determines the operational limits of the production system to avoid the effect of hydrate plugs in the event of unplanned shut-in. P-T curve generated with a PVT sim software using Peng Robinson equation of state predicted the temperature – pressure operating envelop of the system. A Hot Oil return Temperature of 40^{0}C at the topside of the FPSO was determined with a suitably selected insulation material type and a minimum flow rate of 20,000bpd was determined. The analyses on how long the production system can sustain the available heat in the event of unplanned shut-in before a restart was done and a 10hr flowline cool down was achieved. A maximum of 3.5hrs of blowdown was also determined for the production system, which satisfies the analyses with three different water cuts- 0%, 50% and 70%. The framework is implemented in a state-of-the-art modelling tool (OLGA). The above analyses on these different scenarios are geared towards defining the operating limit of the subsea production facilities to preventing hydrate from forming during unplanned shut-in.

Key words*:* Flow Assurance; Hydrate; Peng Robinson; Hot Oil Return; Olga; Blowdown.

1. INTRODUCTION

The concept of flow assurance is the ability to produce fluids economically from the reservoir to the production facilities over the life of the field and in all conditions and environments. It governs the success of the fluid movement from reservoir to point of sale. A clear understanding of the concept helps to ensure that any development plan from exploration through production and abandonment of any field is technically viable and designed for optima, operation throughout the field's life. Flow assurance involves: understanding the subsurface, fluid sampling and analysis, well and facilities design, production operations including surveillance, production architecture, interaction among the reservoirs, the wells, the pipelines and the process facilities and the challenges these interaction may present.

The term flow assurance can also be associated to the evaluation of the effects of fluid hydrocarbon solids (i.e asphaltene, wax and hydrate) and their potential to disrupt production due to disposition of inorganic solids arising from aqueous phase (i.e scale) also poses a serious threat to flow assurance. The recent trend to deepwater developments, future oil and gas discoveries increasingly will be produced through multiphase flow lines from remote facilities in deepwater environments. These are multiphase fluids area combination of gas, oil, condensate and water. Together with sand scales, they have the potential to cause many problems including hydrates, wax/asphaltene.

Gas hydrates are solid crystalline compounds formed by the physical combination of water molecules and certain small molecules of hydrocarbon gases (primarily methane, ethane, propane, CO_2 and H_2S), under pressure and temperature considerably above the freezing point of water. Hydrates are formed when the temperature is below a certain degree in the presence of free water. This temperature is called Hydrate formation temperature. Hydrates are like snow in appearance but not as solid as the ice. Water molecules forms the main framework of the hydrate crystal while the gas molecules occupies void spaces -cages in the water crystal lattice They continue to be the most prevalent flow assurance problem in offshore oil and gas operations: an order of magnitude worse than waxes and asphaltenes. The risk of hydrate plugging increases as the oil and gas industry move into deeper water with corresponding higher pressure from the additional liquid head and to longer tie backs in which the production fluids cool deep into the hydrate stability zone.

The energy industries worldwide incur financial expenses estimated to US$220 million annually [13] for the purchase of methanol for hydrate prevention. Moreover several financial penalties are paid for large methanol storage capacity on offshore platforms and for greater than 50p.p.m methanol contamination in refinery feedstocks. The above analysis of the cost of hydrate prevention shows that about US$600,000 are spent daily worldwide. This is considerably minimal compare to estimated US$6.4 trillion (80million barrels pd of oil production worldwide) generated from oil production on daily basis which could be lost due to total plus off of production system by hydrated if allowed to form.

This work presents an integrated framework of model-based flow assurance management strategy to handling the effect of hydrates. The model-based flow assurance framework determines the operational limits of the production system to avoid the effect of hydrate plugs in the event of unplanned shut-in.

2. CASE STUDY- A NIGERIAN OIL FIELD STUDY

A typical Nigerian Oil Field Location was studied and used for analyses on how flow assurance challenges as it affects hydrate could be managed in the case of unplanned shut-in in a subsea production flowline Stated below are the relevant information extracted from the field studies;

2.1 FIELD LOCATION

The Field development lies offshore Nigeria, located at approximately 120 Kilometres south of Nigerian shoreline adjacent to Bonny Island in water dept ranging between 720 – 860 meters. The field is currently being developed by over 15 production wells producing back to FPSO with about 2,000,000 barrels storage capacity via subsea production manifolds and production flowlines, for processing before production exports to offloading tankers via a buoy. The field is supported by 8 water injection wells and 9 gas injection wells. The field development comprises of 4 umbilicals for distribution of chemicals, hydraulic controls and power supplies through retrievable sub-sea distribution/control units. The field are being developed with 5 drilling centres, DC-01 – DC-05 distributed unequally between two flowline loops. There is one offline subsea production Manifold (SPS) at each drill centres. This provides the facility with the direct tie-in of 4 wells.

The trees in the subsea field lie along two production flow loops, two water injection flow lines and one gas injection flow line. It comprises of three X mass trees:

- Production
- Water Injection
- Gas Injection

All the subsea trees are dual bore type 5” x 2 normal size, rated at API 5,000 psi (accounting for external hydrostatic pressure). All the subsea trees will be installed with tree guide bases and 18 3/4” 10,000 psi wellheads.

2.2 The Field Layout

The overall field layout was developed from subsea to topsides to respect the constraints given by the production and injection systems

In summary the production system consists of

- Spread moored FPSO in 760 m water dept
- 2 X 10” ID production flow loops (PIP flowline or bundle).
- 4 X 10” ID production risers (flexible catenary riser).
- 4X 2.5” ID gas lift injection riser connected to production line riser base.
- 16 oil producers on 2 production loops
- 2 future subsea production wells.
- Umbilicals: 2 per production loop/ water injection line and 1 per gas injection system (methanol lines are incorporated in the umbilicals)

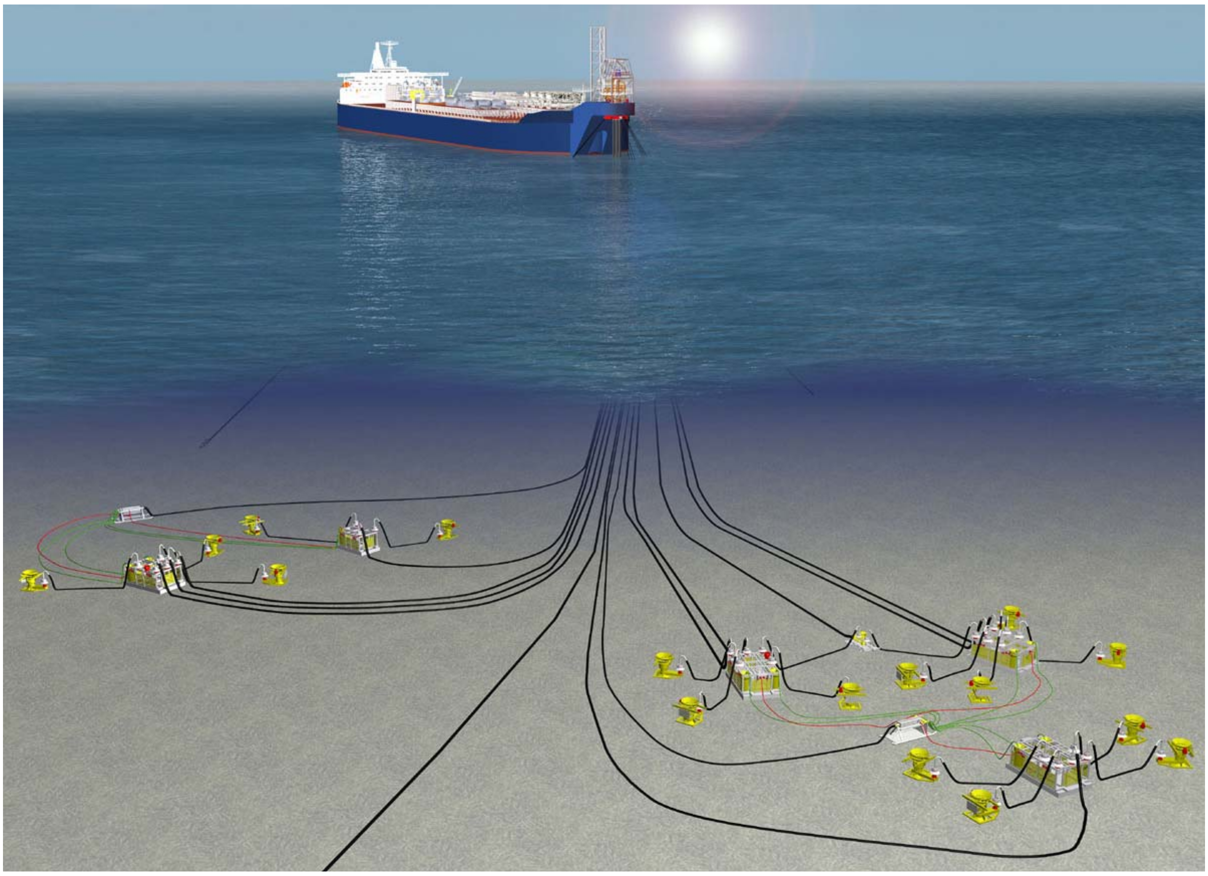

Fig 1 The overall Field Layout

2.3 Well Arrangement

Tables 1 and 2 below shows, for each production loop, the distribution of the oil producer wells within each branch of the flow loop.

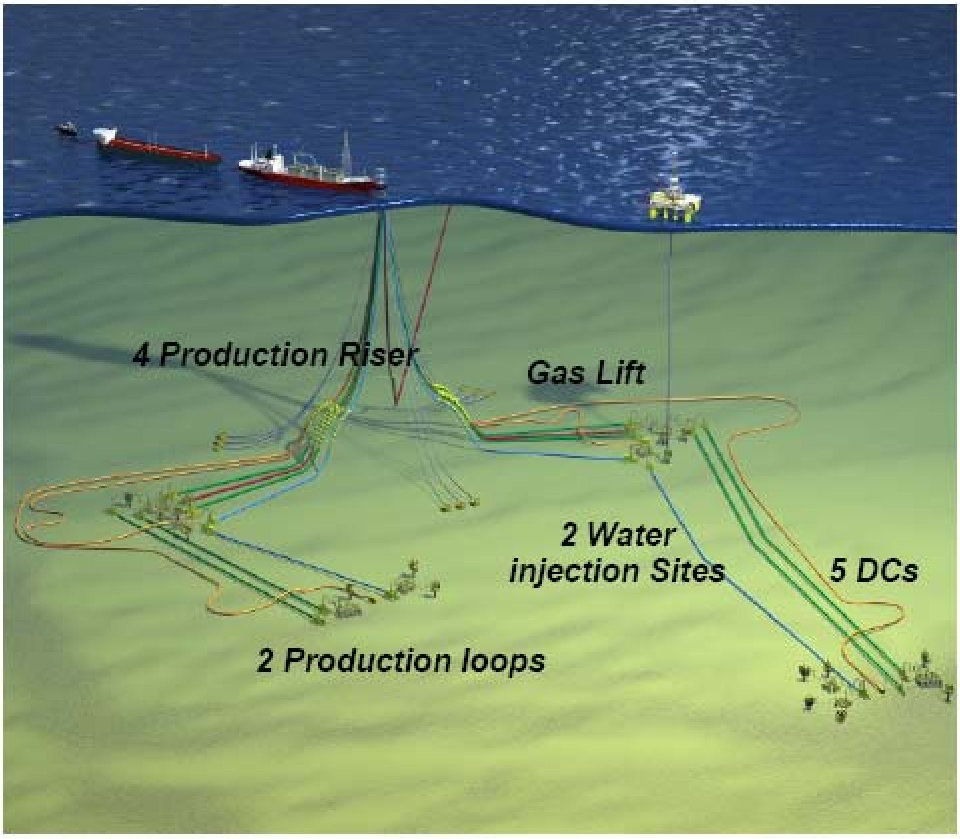

Fig 2 Well Arrangements

Table 1 North Loop Well distribution

Loop	Drilling Centre	Well	TVD (M)	Branch	Reservoir Series	Reservoir pressure,(bara)
North	DC01	P630-1	-2807	Right	R-600N	273.8
		P605-2	-2438	Left		
	DC02	P500-4	-2441	Left	R-500 NC	253.5
		P500-5	-2168	Right		
		P630-4	-2668	Left	R-600 N	273.8
	DC03	P500-1	-2344	Right	R-500 NC	253.5
		P500-2				
		P500-3	-2461	Left		
		P500-9				

Table 2 South Loop Well distribution

Loop	Drilling Centre	Well	TVD (M)	Branch	Reservoir Series	Reservoir pressure, (bara)
South	DC04		-2306	Right	R-500 NC	
		P605C-1	(HOLD)	N/A		
		P500-7	-1746	Right	R-500 S^3	
		P605-8	(HOLD)	Left		
	DC05	P605-1	-1803	Left	R-605 S	
			-2590	Right	R-605 C	(HOLD)
		P630-9	-2293	Right	R-635 S	
		P670-1	-2126	Left		

3. Product lines characteristics

3.1. Thermal Properties

Table 3 Material characteristics

Material	K value (W/mK)	Density (kg/m^3)	Specific Heat Capacity (J/kg^{o}C)
Polypropylene (inner layer)	0.240	920	1700
Carbon Steel	45.000	7850	470
Gel	0.170	850	2000
Insulation	0.165	710	1500

3.2. Wall definition

Table 4 The wall material and thickness to be used in all the hydraulic analyses

Pipeline / Section	ID Inch (mm)	W.T Inch (mm)	Insulation Type	Insulation Thickness (mm)
Flexible production Riser	10 (254.0)			
Production Flowline	10.5 (266.7)	1.25 (31.8)	Insulation	80.0
Production Jumper	7.4 (189.1)	0.59 (15.0)	Insulation	88.9
Manifold	5.2 (131.7)	7.5 (190.5)	Insulation	88.9
Well Jumper	5.2 (131.7)	0.719 (18.26)	Insulation	88.9
Well Spool	(HOLD)	(HOLD)	(HOLD)	(HOLD)
Tree	5.1 (130.3)	7.5 (190.5)	Insulation	88.9
Tubing	5.5 (139.7)	0.36 (9.17)	Gel	39.47

Table 5 Overall Heat Transfer Coefficients

SPS Location	U Value (W/m^{2}K)
Tubing	5.8
Tree	8.2
Well Jumper	3.4
Manifold	8.2
Production Jumper	2.9
Flowline	3.0
Riser	3.2

3.3. Production Flowlines

Table 6 Production Flowline Data

Production Flow Loops Total length	38.8 km
North Flow Loop length	14.3 km
South Flow Loop length	24.5 km
Internal Diameter	10.5 inch (266.7 mm)
Wall Thickness	1.25 inch (31.8 mm)
Pipe Material	Carbon Steel
Insulation Thickness	3.0 Inch (80 mm)
Insulation Material	Insulation (see Table 4-3 for properties)
Internal Roughness	46 µm

Production Riser

Table 7 Production Riser Data

Internal Diameter	10 inch (254 mm)
Wall and Insulation Thickness	97.7 mm
Internal Roughness	1.016 µm

RESERVOIR DATA

Reservoir pressure

The reservoir pressure for the four reference reservoirs used in this paper. These four main reservoirs are considered representative for this field.

Table 8 Reservoir Pressure

Reservoir	Reservoir Pressure (bara)	TVDSS (m/msl)
R-500NC	235.5	2419
R-600N	273.8	2332
R-605S	230.3	1855
R-635S	209.7	2162

Reservoir Temperatures

The reservoir temperatures, at depth, from each of the four reference reservoirs are presented below

Table 9 Reservoir Temperatures

Well	MD (m)	TVD (m)	Temperature (^{0}C)
P500_1	2638	2275.6	77.2
P500_2	2332	2256.3	76.5
P500_3	2829	1921.0	64.6
P500_4	2496	2122.4	72.0
P500_5	2136	1909.8	64.2
P605C_1	3010	2360.7	80.2
P605C_2	3102	2419.5	82.3
P605_1	1584	1576.3	51.6
P605_2	2175	2167.1	73.4
P605_3	2319	1881.0	60.4
P605_4	2319	1881.0	60.4
P630_1	2609	2609.0	90.7
P630_4	2416	2386.8	82.0
P630_5	2014	1847.7	62.0
P670_1	2205	1955.8	65.8
P670_2	2029	1739.9	58.2

Well Productivity Index

The well productivity index assumed for all simulation is oil PI of 10 bpd/ psi. The table below shows the fluid data for the four reference reservoirs to be used in all hydraulic analyses for the field development.

Table 10 Fluid Characteristics

	Reservoir Characteristics			
	R-500 NC	R-600 N	R-605 S	R-635 S
Bottom Hole Pressure (bara)	253	269	210	230
Bottom Hole Temperature (^{0}C)	81	76	56	67
Saturation Pressure (bara)	245	263	200	225
GOR (Sm^3/Sm^3)	189	186	135	80
Bo Process (Sm^3/Sm^3)	1.54	1.50	1.35	1.20
MW dead Oil (g/mole)	167	172	190	250
Reservoir Viscosity (cP)	0.28	0.34	1.0	2.3
Bottom Hole Density (kg/ m^3)	660	684	741	820

FLUID COMPOSITION

A unified compositional PVT model was built and matched on experimental data from the four main reservoir fluids that made up the field. The well fluid compositions are shown table 11

Table 11: Reservoir Compositional data

Component	Reservoir Composition (% mole)			
	R-500 NC	R-600 N	R-605 S	R-635 S
N_2	0.00	0.10	0.00	0.00
CO_2	0.18	0.58	0.61	0.18
C1	47.63	48.26	41.29	44.19
C2	5.18	7.02	2.98	1.92
C3	5.53	4.11	4.83	1.50
IC4	1.58	1.19	1.56	0.49
NC4	2.87	1.79	3.22	0.83
IC5	1.75	1.43	2.16	0.62
NC5	1.31	1.01	1.31	0.38
C6	3.43	3.06	3.86	1.25
C7	4.23	3.37	4.24	1.71
C8	3.69	3.61	4.16	2.19
C9	2.99	3.19	3.71	2.85
C10	2.49	2.42	3.15	2.50
CN1	10.50	12.20	8.00	22.50
CN2	4.85	3.50	13.80	4.80
CN3	1.80	3.19	0.93	12.09
MW Reservoir Fluid	79	81	98	138

4. Project description

No H_2S was detected in the initial reservoir fluid, but the maximum H_2S content to be used for design is currently evacuated at 100 ppmv

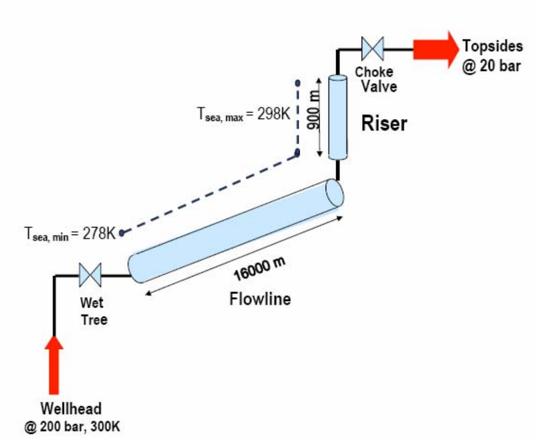

Fig 3 Schematic representation of the Sub sea flowline – Riser physical arrangement

This project intended to consider a subsea close loop flowline from the well head up to the riser above the sea water level. The flowline has multiphase fluid from the well head to the process facility. The ambient temperature of the subsea environment is at 4^0C and at a high pressure necessitated by the water head. The Bottom Hole Pressure (BHP) about 260 bara, is assumed to be the highest pressure of the designed subsea system.

The figure 6 is the actual arrangement of subsea flowline systems from the well head through to the top- side.

DESIGN CONDITIONS

Design Assumptions

1) Length of Flowlines
2) Temperature along the pipe length
3) Heat conduction coefficient

Design constraints

1) Multiphase flow liquid
2) Bottom Hole Pressure as the highest pressure (Over 250 bar)
3) Field floor temperature is 4^oC
4) The Hot Oil Return Temperature is at 40^0C
5) Flowline cooling to HDT in 10hrs
6) Riser base is the weakest point
7) U value is = 3.0 W/m^{2}K

Conditions that necessitates Hydrate Formation

1) High pressure
2) Low Temperature
3) Presence of free water and gas molecules
4) Natural gas at or below its water dew point
5) High velocity or Agitation
6) Presence of more soluble acid gasses such as H_2S and CO_2

5. DISCUSSION OF RESULTS

Pressure temperature gas hydrates curve is generated at in-situ conditions using fluid characterisation software- PVTsim. The unified PVTsim model matched the combined fluid from the reservoirs.

Peng Robinson Equation of State (EQS = PR 78 Peneloux) was used to generate the model fluid characteristics. PVTsim gives conservative hydrate formation check curve.

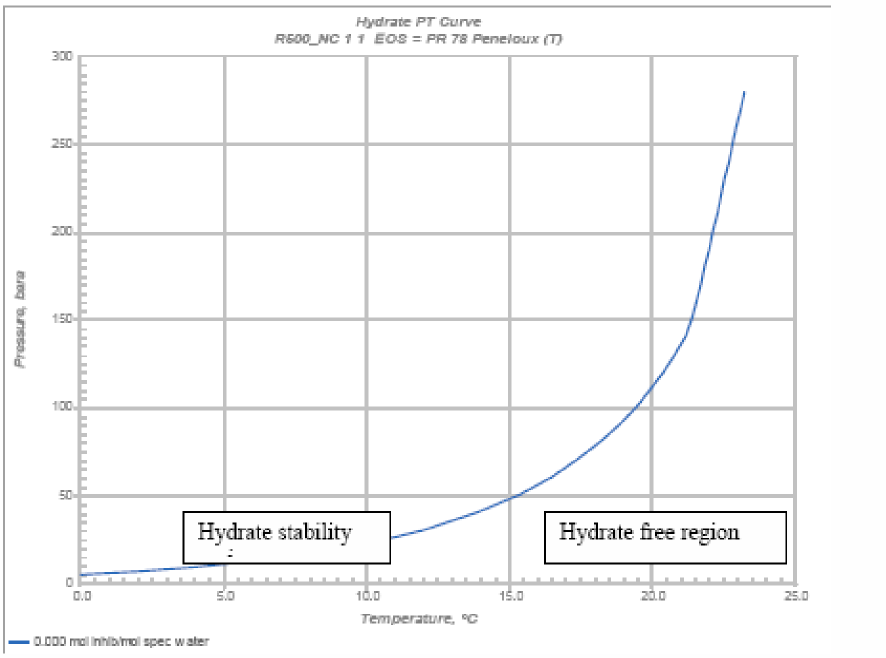

Fig. 4 Pressure- Temperature curve

The pressure – temperature curve is generated considering the reservoir pressure – about 260 bar as the highest pressure and taking the corresponding temperature which forms the HDT. It defines the temperature – pressure envelope at which the system must operate in a steady state and transient conditions in order to avoid the possibilities of hydrate formation. The region to the left of the graph is the hydrate stability region. The stability of hydrates increases with increase in pressure and decrease in temperature. While to the right of the graph is referred to as hydrate free region, at which the system shall operate to avoid hydrate formation. The project flowline was analysed for hydrate formation during steady state normal operations.The flowline temperature profile and hydrate subcooling temperature profile is shown in the figure 5.

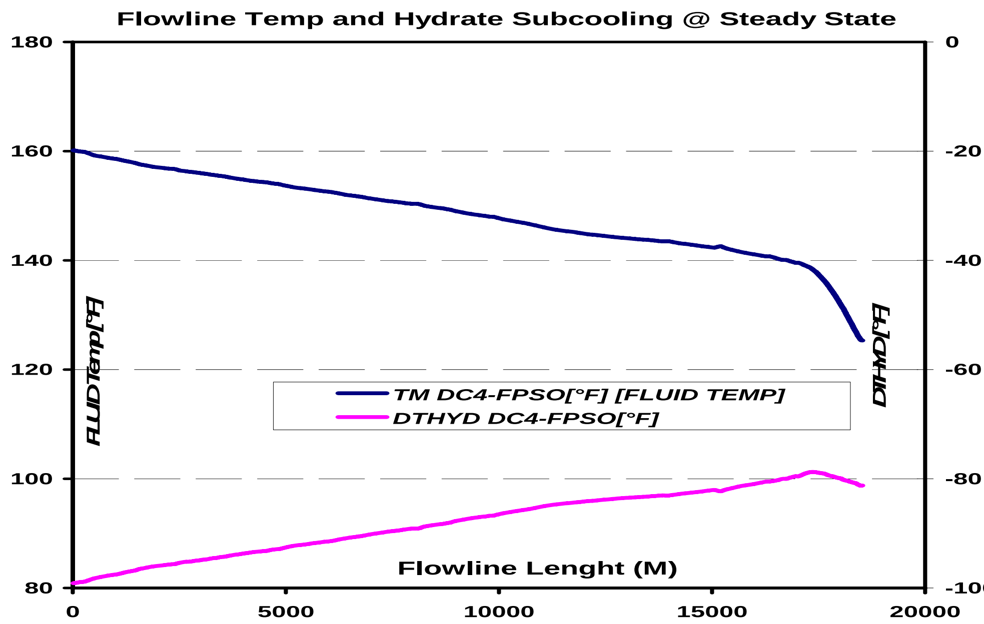

Figure 5 Flowline Temperature Profile in Normal Operations

At steady state normal operations the minimum flowline temperature anticipated is at the top of the riser is 120°F. The OLGA variable DTHYD is the hydrate subcooling temperature, which is the difference of the hydrate formation temperature and the insitu fluid temperature. A negative DTHYD indicates that hydrate formation would not be an issue of concern at steady state normal operations. This also implies that the selected insulation type is adequate at steady state normal operations.

The project flowline is analysed based on unplanned shut-in transient condition for hydrate formation during operations

PROCEDURES

- Configure flowline with three different insulation type as shown below
- Produce a single well at minimum flow rate at 20,000 bpd
- Monitor oil return temperature at the top Side of FPSO @ 40^{0}C

Table 12 Insulation Type Material for Flexibility at FPSO Arrival, insulation comparison

Materials	Thickness	OHTC (Uid) [Btu/ft2-h-F]
Type A	3.00	0.49
Type B	4.00	0.41
Type C	5.00	0.36
WT of steel pipe 1.25 inch		

A sensitivity study was done to get the type of insulation which would give the required hot oil temperature at the FPSO. The required hot oil temperature is 40 °C. A different insulation type of the flexible material at a supply flowrate of 20,000 bbl/d was studied.

The result of the simulation analysis shows that from the three insulation type looked at, it takes approximately 20 hours to heat up the flow line to achieve the required return temperature at FPSO topside. The difference in time required for the three insulation types to attain the return temperature is negligible. But, type A insulation material is selected since it has lower U-value and lower cost.

Hot oiling is a process of pre-heating the process facility (oil flowlines) with hot oil before actual production processes commenced to avoid hydrate formation. In the process heat is transferred from the hot oil to the flowline thereby keeping the flowline at a certain temperature before the actual production process begins. Otherwise there will be temperature drop which will lead to hydrate formation in the production flowline.

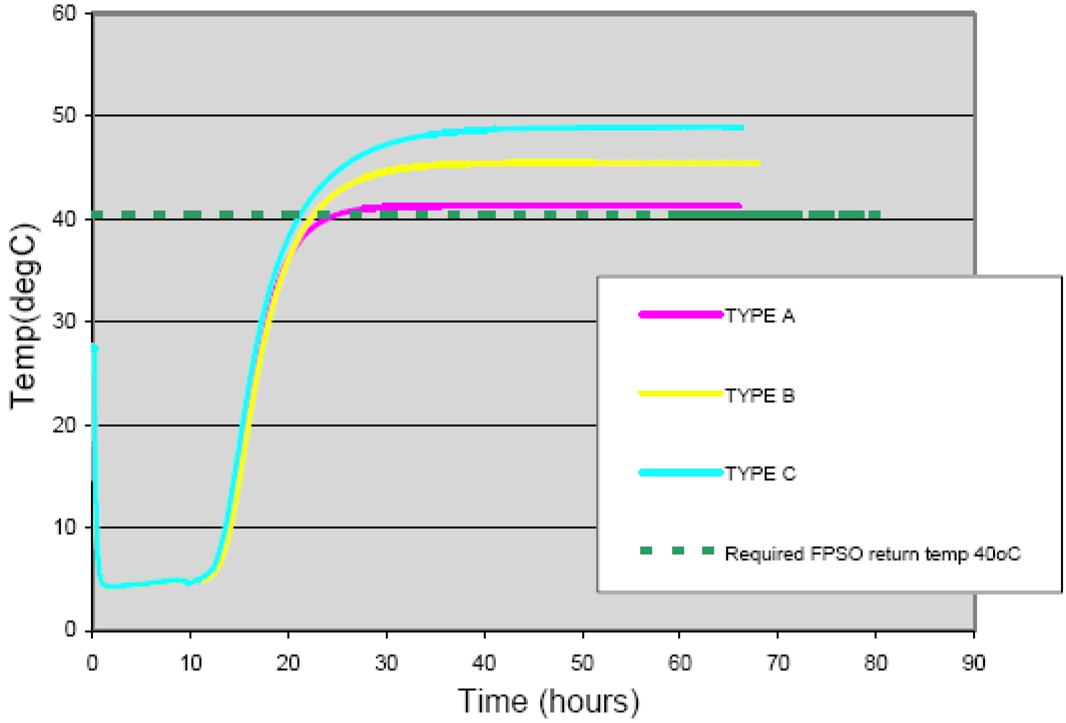

Fig. .6 Hot Oil Return Temperature for Different Insulation Type Material.

The three insulation type materials satisfy the FPSO required return temperature at 40°C. Type C material gives the highest return temperature.

Flowline Cool Down Profile

- Achieve steady state production process
- Unplanned shut-in well and flowline
- Monitor the flowline temperature profile over time

The flowline was analysed for hydrate formation during shut down cool down at long intervals of time. As highlighted a flowline cool down to 10 hrs is required to be satisfied in the flow design. This condition is achieved with the insulation material selected which has a U-value of 3.0W/m^{2}k. The flowline, production system should be able to retain and sustain heat up to 10 hours. The figure 7 show flowline profile temperatures at different cool down times.

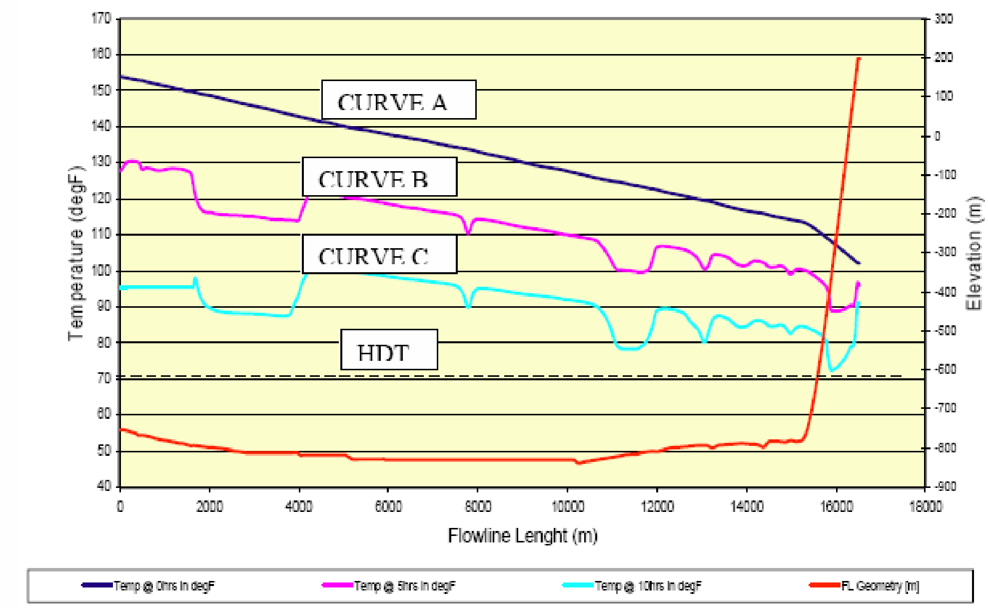

Fig. 7 Flowline Cooldown profile

At cool down time 0hr corresponding to flowline shut-in, the temperature ranges profile ranges from 150^0F to 110^0F as shown in curve A in the graph above.

Also, at cool down time 5hrs corresponding to flowline shut-in, the temperature ranges profile ranges from 130^0F to 90^0F as shown in curve B in the graph above.

Furthermore, at cool down time 10hrs corresponding to flowline shut-in, the temperature ranges profile ranges from 95^0F to 75^0F as shown in curve C in the graph above.

The pockets along the slope of the graphs signify more Gas accumulation within those areas compare to other parts along the production flowlines. Gas expands more rapidly than liquids.

From the graphs, it is established that the system gives 10hrs for cooldown without the system temperature falling below HDT. This also infers that the system offers a maximum of 10hr within which to manage the risk of hydrate formation in the event of unplanned production system shut-in.

Flowline Blow Down Operation

- Production at steady state is achieved
- Unplanned shut-in due to sudden disturbance in the production system
- Simulate production shut-in condition
- Allow No Touch- Time of 3 – 4 hrs. This is a suitable time necessary to understand the nature of the shut- in condition
- If production system cannot be restarted after No Touch- Time, blow down flow line to HDP

The system simulation shows that it will take approximately 3.5hrs to blowdown the system to a safe pressure well above Hydrate formation pressure (HDP) in the event of unplanned shut-in.. This simulation is carried out from different water cuts of 0%, 50% and 70% as shown in the graph below.

A hydrate dissociation pressure of 150 psia (10.4 bara) is anticipated. From the PT-hydrate curve this would have to correspond to a temperature of less than 5°C to form hydrates, (<5°C, 150 psia) Analysis from the P-T curve inferred that the operating temperature of the flowline at any given time must not fall below the HDT- 74^0F. This is with only an exception of the use of hydrate inhibitors such as MeOH.

Type A insulation is recommended since it satisfies all flow assurance requirement of Oil Return Temperature of 40^0C with minimal cost in the production system.

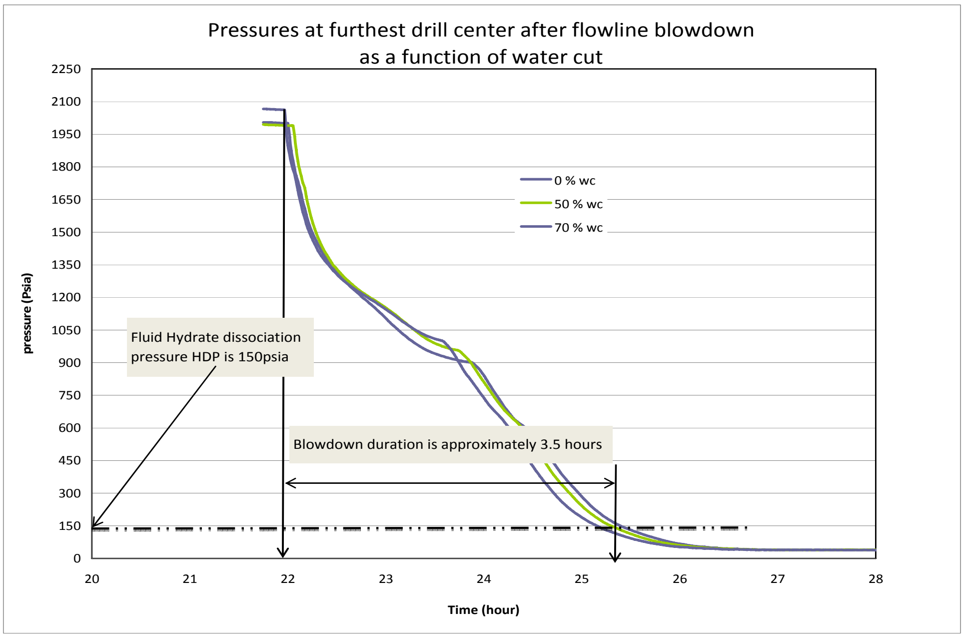

Fig. 8 The blowdown pressure against time

The system can sustain life fluid for a period of 10hrs on an event of unplanned shut-in. On the other hand, the life fluid should not be allowed to remain in the flowline for more than 10 hrs uninhibited otherwise hydrate will form. A blowdown of 3.5hrs is required on this project to keep the production system free from hydrate plug. But, if blowdown is not feasible may be due to water hold up or steep flowline situations, then dead oiling is recommended.

6. Conclusion

The flow assurance challenges in this projects production system in terms of hydrates are well addressed and taken care of if these findings are adequately and strictly adhered to:

- Operating temperature of the production system must always be above 74^{0}F- HDT
- Operating pressure of the production system must always be above 150 bara- HDP
- FPSO Hot Oil Return Temperature at 40^{0}C at the top side
- The life fluid should not be allowed to remain more than 10hrs uninhibited in the flowline in the case of unplanned shut-in
- A blowdown time of 3.5hr maximum in the case of sudden shut-in

Glossary

The following terms are referred to in this Technical work:

CHC	Cameron Horizontal Connector
Cv	Valve Characteristics
DC	Drilling Centre
FPSO	Floating Production Storage and Offloading Unit
ILT	In line Tee
FWHP	Flowing Well Head Pressure
FWHT	Flowing Well Head Temperature
GOR	Gas to Oil Ratio
MD	Measured Depth
MSL	Mean Sea Level
PI	Productivity Index
PIP	Pipe in Pipe
ROV	Remotely Operated Vehicle
SPS	Subsea Production System
SRB	Sulphate Reducing Bacteria
TOP	Touch Down Point
SOU	Subsea Distribution Unit
SPS	Subsea Production System
SUT	Subsea Umbilical Termination
TVD	True Vertical Depth
WTHP	Well Tubing Head Pressure
WTHT	Well Tubing Head Temperature
XMT	Christmas tree
BIT	Bundle Insulation Test
b/d	Barrels per day
FPSO	Floating Production Storage and Offloading
FSM	Field Signature Method
GOR	Gas-Oil-Ratio (Sm3/m3)
MDT	Modular Dynamic Tester
mScm/d	Million standard cubic meter a day
OCWR	Overall Control of Wells and Risers
OHTC	Overall Heat Transfer Coefficient
OPEX	Operation Expenditures
ppm	Parts per Million
QC	Quality Control
QRA	Quantitative Risk Analysis
RAM	Reliability, Availability and Maintenance
SPS	Subsea Production System
TIT	Tower Insulation Test
UFL	Umbilical and Flowlines
CDT	Cool Down Time
HDT	Hydrate Dissociation Temperature
HDP	Hydrate Dissociation Pressure
HFT	Hydrate Formation Temperature
LDHI	Low Dosage Hydrate Inhibitors

MEOH	Methanol
SCSSV	Surface Controlled Subsea Safety Valve
SSAT	Steady State Arrival Temperature
UFR	Umbilical Flowline Riser
VIT	Vacuum Insulation Tubing

DEFINITION OF TERMS

Hydrate Dissociation Pressure (HDP) is the minimum pressure at which the system will operate without hydrate plug formation in the production system
Hydrate dissociation Temperature (HDT) is the minimum temperature at which the system will operate without hydrate plug formation in the production system
Flowline cooling to HDT in 10hrs - This in effect means that my production system should be able to retain and sustain heat between 10- hours to keep the system out of hydrate formation
U value (W/m^2K) - This is selected putting design intension, cost etc into consideration. The lower the U-value the better the insulation and the higher is terms of cost

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