OTC-17376-PP

Real-time Flow Assurance Monitoring with Non-Intrusive Fiber Optic Technology

David V. Brower / Astro Technology Inc., C. Neal Prescott / Fluor Corporation, Jeff Zhang / Fluor Corporation, Chris Howerter / Astro Technology Inc., David Rafferty / Astro Technology Inc.

Abstract

Flow assurance is a key aspect of offshore, particularly deepwater developments. Tremendous progress during the past two decades in the understanding of the issues and the required technology has enabled the developments be designed and operated with low risk of flow assurance problems. However, the problems have not been eliminated due to system component failures or un-designed for operating conditions. Real time monitoring of the production and transportation system can help significantly reduce the occurrence and impact. The present paper discusses the use of non-intrusive fiber optic technology for this purpose.

A series of fiber optic sensors for temperature, pressure, heat flux, strain, and acoustic measurements have been developed, which form the basis of the methods proposed in this paper for detecting the formation of hydrate plugs in pipelines, for determining the amount and location of paraffin deposition, for pig detection, and slug detection.

Introduction

As one of the critical issues for deepwater oil and gas developments, flow assurance has progressed over the past two decades from mostly pipe sizing and flow pressure management to an integral part of the development and production process. Tremendous progresses have been made in the understanding of flow assurance issues and in the development of related technology. Operational procedures are commonly developed with flow assurance in mind. These progresses have enabled the deepwater development be designed and operated with low risk of flow assurance problems. Some subsea developments have been operated at almost no unplanned production shutdown. However, the problems have not been eliminated due to system component failures or un-designed for operating conditions. Real time monitoring of the production and transportation system can help significantly reduce the occurrence and impact. The present paper discusses the use of non-intrusive fiber optic technology for this purpose.

Flow assurance is a cross-functional discipline with technical areas including multiphase flow and pressure management, thermal insulation, slugging issues, gas hydrates, paraffin deposition, asphaltene deposition, scales, erosion and internal corrosion, emulsion, etc. In this paper, we focus on gas hydrates, paraffin deposition, and slugging/liquid management.

Common Flow Assurance Issues

Gas hydrates. As is well known, gas hydrates form under high pressure and low temperature conditions and can plug flow path during normal flow or during start-up. Gas hydrate plugging is a fast paced phenomenon, occurring as quickly as a few hours.

With the exception of a few special cases, for example high pressure or black oil systems, gas hydrate equilibrium can be accurately predicted (with an accuracy of about 2^oF). The required amount of thermal dynamic inhibitors can also be reliably predicted with good quality hydrocarbon and formation water samples. These have enabled the determination of the time and location of potential hydrate occurrence in the system, thus making the hydrate prevention designs reliable.

New technologies such as low dosage hydrate inhibitors and active heating systems with heating medium or electricity have been developed and applied to offshore/deepwater developments. These technologies can reduce the hydrate prevention cost, simplify operations, and reduce remediation cost. Hydrate kinetics research currently underway will further enhance the management of hydrate risk.

Paraffin deposition. These depositions and flow restraints typically develop at one or more orders of magnitude slower than gas hydrate plugging. However, deposition can be over a very long section of flow path, for example several miles of pipeline, therefore even a thin layer of deposits can sum up to a large volume. This may cause a stuck pig and plugged pipeline, which is the most common cause of total plugging by wax. Total pipeline blockage by wax build-up during normal flow is a rare occurrence, however it can occur when hydrates or other large pieces of solids in the flow stream acts as a pig.

Through the collaboration work pioneered by DeepStar, the industry has standardized the measurement of an important parameter for paraffin deposition prevention or management, the wax appearance temperature. Thermodynamic models can be tuned to the measurement and are further used in design. Paraffin deposition rate predictions can at present predict the order of magnitude. Paraffin deposition is managed by a number of methods, including heat preservation (insulation), pigging, and chemical inhibition. New technologies such as upstream crawlers and extended reach coiled tubing add to the industry's ability to prevent and remedy paraffin deposition. Innovative method has also been developed to quantify the deposit amount, to optimize pigging frequency[1].

Slugging and liquid management. In deepwater subsea tiebacks to a hub, frequently some of the flowlines originate from higher seafloor elevations than at the hub, severe riser slugging can occur which causes liquid handling and gas handling problems. Multiphase pipelines may also have terrain slugging which causes similar problems. In long gas condensate pipelines of large size, huge amount of liquid can accumulate during flow, particularly with turndown flow. It is frequently necessary to manage the liquid to optimize flow efficiency and reduce the slug size associated with the liquid. Slugs can form when the pipeline is pigged, or as terrain slugging.

A key component in designing for slugging and liquid management is the transient multiphase flow prediction. With tremendous progresses in multiphase flow research, as well as field validation and improvement of simulation software, transient multiphase flow simulations have become a valuable design tool and have been performed on most if not all deepwater developments. Some developments (e.g., Burullus Gas Scarab/Saffron and Norsk Hydro Ormen Lange[2]) also utilized or will utilize real-time online transient flow simulation to assist in liquid management. Other emerging technologies such as active feedback control system from ABB Vecto Gray[3] and S^3 Slug Suppresion System from Shell[4] attempt to use active control to reduce the size of slug catcher.

Flow Assurance Monitoring

The industry has been able to use understanding of flow assurance issues and advancement of new technologies to reduce tremendously flow assurance risks for deepwater developments. But, the problems have not been eliminated due to system component failures, un-designed for operating conditions, faulty operational procedures for some situations, or operator failures. Wilson et al.[2] discussed hydrate plugging risk for Norsk Hydro's Ormen Lange subsea to land gas development in the North Sea.

Real time monitoring of the production and transportation system can help significantly reduce the occurrence and impact of these failures. In the case of paraffin deposition, real time estimate of deposition location and amount can reduce the costly downtime caused by pigging. For slugging, the ability to determine the timing, length, and other important characteristics at selected points of the pipeline and riser can greatly assist the control of slugging.

To be effective in managing the flow assurance risks, real time monitoring must be used in connection with operating procedures that efficiently utilize these results. The present paper focuses on the monitoring technology. Operating procedures vary drastically with specifics of each development, and are outside the scope of this paper.

Non-intrusive fiber optic sensor is a promising technology to monitor flow assurance phenomena. The primary measurements are pressure, temperature, strain, heat flux, etc. Conventional sensors are often limited in capability to provide all needed flow assurance properties. The fiber optic technology overcomes three shortcomings of conventional measurement methods.

- Conventional pressure measurements are intrusive in nature, thus are limited by number of measurements without affecting the integrity of the system.
- Conventional measurements have limitations on the distance of signal transmission, whereas fiber optics are well suited for long distance signal transmision.
- Multiplexing - many sensors can be placed on a single fiber optic line in a manner that significantly reduces cabling requirements and increases the total number of measurement locations.

Brief Description of Fiber Optic Measurement Technology

There are several different configurations of fiber optic sensors. One of the most common is the fiber Bragg grating (FBG) configuration. The FBG is the type of sensor used to measure flow assurance properties described throughout this paper, although other configurations could be similarly used. FBG's can detect and measure numerous physical quantities due to its high response to temperature and strain.

A FBG contains gratings etched on an optical fiber in a manner to create periodic changes in the index of refraction. The basic configuration is shown in figure 1. The basic theory of FBG operation can be found in various publications[5]. The FBG sensor depicted in figure 1 consists of a single-mode optical fiber with gratings positioned at various locations along its length. The gratings are produced by doping the fiber with Germania and exposing it to an interference pattern of coherent light. Each grating is designed to reflect a certain frequency of light. Multiple such grating can be placed along a single fiber optic strand. The system is interrogated with a broadband light source and the multiple wavelength sensors within this source are detected.

The FBG wavelength is sensitive to dimensional and temperature changes. The instrumentation senses the reflected frequencies and in turn determines the grating location and the dimensional change. Grating can be incorporated at any position along the fiber length. Changes in strain or temperature to which the optical fiber is subjected will consequently shift this Bragg wavelength, leading to a wavelength-encoded optical measurement.

One of the most important advantages of this sensor is the direct relation between the Bragg wavelength and the fiber strain, which makes absolute measurements of the strain possible. The shift in the Bragg wavelength can be observed and related to strain by the relationship:

$$\Delta\lambda_b / \lambda_b = (1 - p_e)\,\varepsilon$$

Where $\Delta\lambda_b / \lambda_b$ is the fractional shift in the Bragg wavelength,
p_e is the effective photoelastic constant
ε is the longitudinal strain.

The wavelength shift ($\Delta\lambda_B$) for a temperature change of ΔT may be expressed as

$$\Delta\lambda_B = \lambda_B\ (\alpha_\Lambda + \alpha_n)\Delta T$$

where
α_Λ is the thermal expansion coefficient for the fiber
α_n represents the thermo-optic coefficient

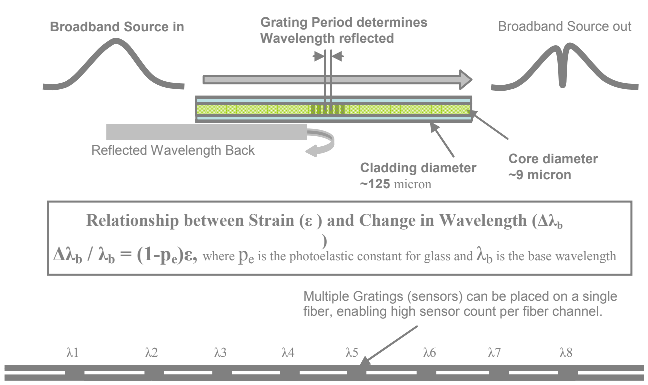

Figure 1. Illustration of a uniform fiber Bragg Grating with constant index of modulation and period.

Figure 2 shows a schematic of the typical response of a FBG when subjected to strain and resulting in a wavelength shift. By detecting this strain induced wavelength shift, a determination of absolute strain is made. Similarly, temperature induced shifts are detected resulting in absolute temperature.

Temperature compensation is provided by placing an additional FBG in the strain field area so that it is exposed to temperature but isolated from the strain field. The temperature induced shift is then subtracted from the strain measurement.

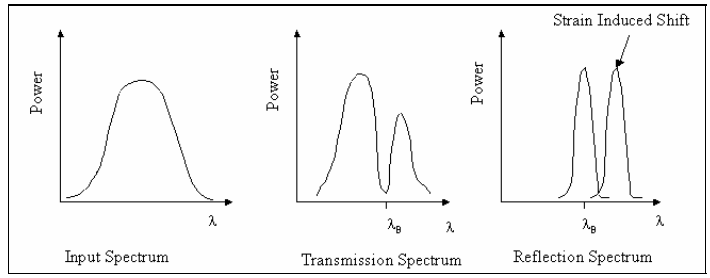

Figure 2. Functional principle of a fiber Bragg Grating.

Hydrate Monitoring

There are generally two types of conditions when hydrate plugging can occur in a pipeline or flowline: the pipeline becomes uninhibited or under-inhibited for a number of reasons, and restarting after an unplanned shutdown that stayed long enough for the pipeline to cool down to hydrate region. Monitoring of plugging development and remedial actions are more challenging in the latter.

Normal Flow. During normal flow, the pipeline can become uninhibited or under-inhibited reasons including the following, some of which have been discussed in the literature[2], [6] :

- Inhibitor injection failure due to broken umbilical
- Inhibitor injection failure due to operator failure
- Inhibitor metering error
- Inhibitor quality
- Undetected formation water breakthrough
- Export gas with off-specification

When un-inhibition or under-inhibition occurs, gas hydrate particles may form in the fluids. The particles either cling to the pipe wall or are suspended in the liquid, causing a gradual increase in pressure drop in the section containing these particles. The particles may begin sloughing and accumulating into partial flow restrictions, which sometimes break. The pressure drop in the pipeline section may exhibit spikes or stepwise increase corresponding to these physical processes. Finally, the particles may form a complete flow restriction without breaking, completing the plugging process. This process of hydrate formation and plugging is a gradual process.

Fiber optic pressure sensors can be installed at pre-defined distances along the pipeline to monitor the trend as described above. The distance between sensors can be several hundred feet to several miles depending on the severity of the hydrate potential and the accuracy desired for locating the hydrate plugs. If the monitoring system indicates hydrate occurrence in some sections, pre-defined remedial actions can be taken.

As an illustration, a simple air water flow loop (Figure 3) was setup with a valve to produce a flow restriction. Fiber optic pressure sensors were installed up and downstream of the valve. The instrumented flow loop pipe was assembled with 2 inch, schedule 40 PVC tubing and 2 inch ID x 2.25 inch OD clear, polycarbonate tubing. A PVC ball valve was assembled in the middle of the instrumented pipe. This valve was used to simulate hydrate and wax build-up. The test data recorded consists of full open, 50% open, 25% open, and a 15% opening of the valve. A 180° bend pipe connected the instrumented pipe to the return pipe in order to re-circulate water. Varying flow characteristics were created by introducing compressed air and water into the inlet of the pipe and by varying the angle of flow at the inlet. Up-flow at the water/compressed air inlet induced slug flow development and down-flow at the water/compressed air inlet will induced stratified flow development.

The flow loop pipe was supported with a sand box and sand bags and was leveled in order to create more consistent flow through the pipe. The data monitoring was accomplished with four sensor stations affixed to the OD of the pipe. Each sensor station consisted of a hoop and longitudinal FBG sensor. Sensor Station 1 is close to the water/air inlet, sensor station 2 is close to and upstream of the PVC valve, sensor station 3 is close to and downstream of the PVC valve and sensor station 4 is just before the bend in the pipe to return flow to the tank.

Figures 4 and 5 show the measured pressure at normal flow and a developing restriction (increasingly smaller valve opening). Flow reduction from valve, at 25% setting, caused slug formation immediately downstream of valve and can be seen as pressure spikes in figure 5. Slugs became larger at 15% setting. Slugging is apparent in the pressure spikes in the up and down stream sensors after 25% setting.

Fiber optic pressure sensors have been used to measure the annulus nitrogen pressure buildup of a 10” in 24” pipe-in-pipe configuration, as shown in Figure 6.

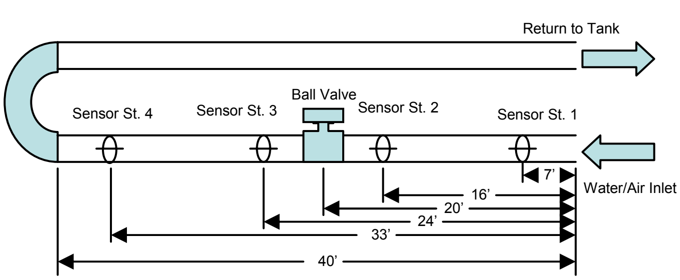

Figure 3. Loop measurement with valve closing sequence.

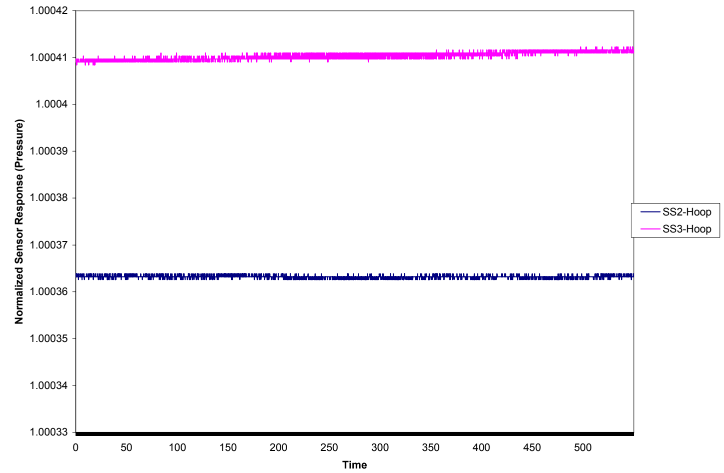

Figure 4. Pressure response up and downstream of ball valve with stratified flow. - Downward slope of the pipe at the water/air inlet

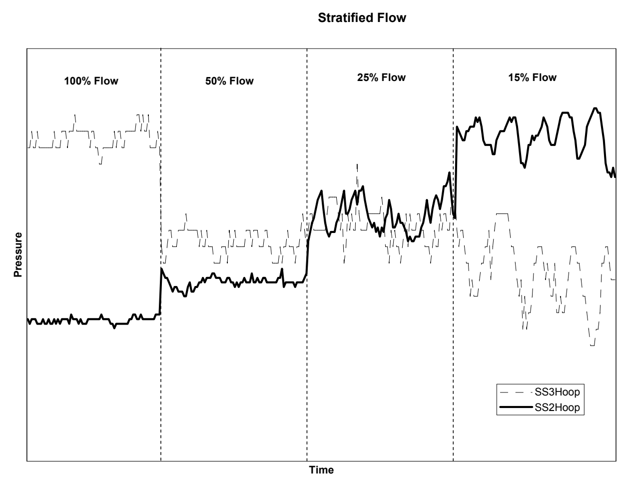

Figure 5. Pressure response up and downstream of ball valve with stratified flow – Slugging pressure differential.

Nitrogen pressurization of two 7-mile long pipeline segments (10” in 24” pipe-in-pipe configuration) was monitored with fiber optic sensors. The test operation was performed on the beach in Matagorda, Texas prior to pipeline deployment in the Gulf of Mexico. Pressurization, at the fill end, was monitored by a standard pressure gauge. Fiber optic sensors were surface mounted (no pipe penetration) at the 7-mile end. The onset of nitrogen pressurization was clearly detected and read with the fiber-optic sensors. As expected, a significant time lag in the presence of pressure over the seven mile length was detected.

Prior to field measurements, calibration testing determined 1135με correlated to a pressure level of 1900 psig.

Figure 6 shows the time history of hoop strain measured one 7-mile pipeline section during nitrogen pressurization. A maximum strain of 1300 µstrain was reached. This corresponds to a pressure of 1650 psig when the calibration curve is applied for 3/8” wall pipe. The final pressure reported from the fill end of the segment was 1610 psig after stabilization. The high frequency oscillations that begin at approximately 13 hours into the pressurization of the pipeline began during purging of water from the 10 inch flow line and subsequent wave action when the pipeline (following deployment in the water) became buoyant.

A second 7-mile long pipeline was also instrumented. A maximum strain of 1230 µstrain was reached. This corresponds to a pressure of 1600 psig. The final pressure reported from the fill end of the segment was 1606 psig.

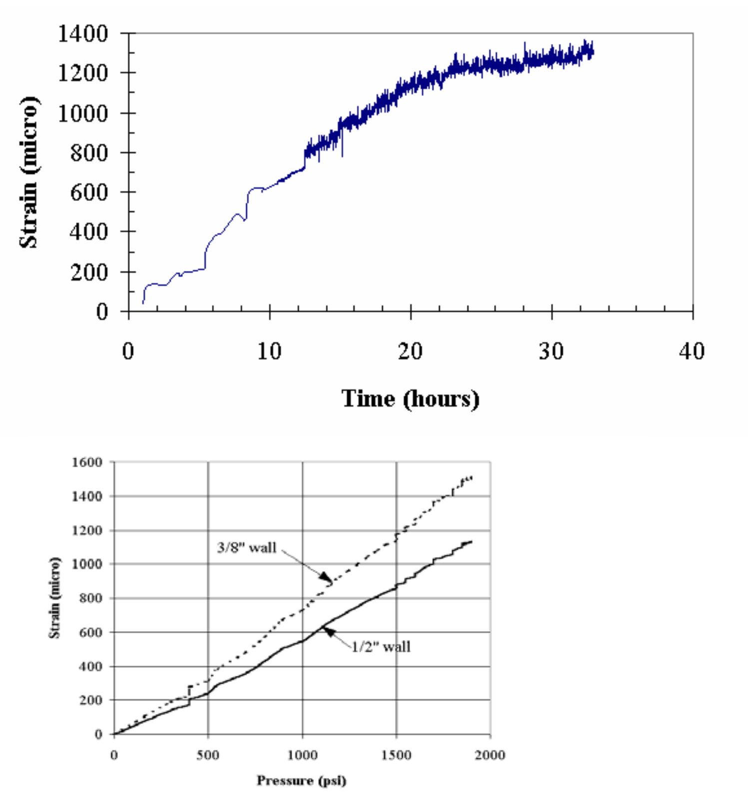

Figure 6. Fiber optic measurement of pressure during pressure-up of a 10”X24” pipe-in-pipe pipeline.

Pressure measurements from multiphase pipelines and flowlines are potentially highly transient even without hydrate formation. The transients can be from hydrodynamic slugging, terrain slugging, and inherent oscillations in other flow regimes. The trend of increasing pressure drop, particularly in the early stages of hydrate formation and sloughing, may not be readily identifiable. Obviously, effective remedial action depends on early detection of hydrates. To enhance hydrate detection, fiber optic based pressure measurements can be used in conjunction with real time online simulations, statistical analysis, pattern recognition techniques, and other monitoring results (e.g., slug detection).

Cold Restart. Hydrate formation in a cold restart operation is a much faster process. During the shutdown, hydrate crystals form at the water-hydrocarbon interfaces. When the flowline is restarted, these crystals may quickly agglomerate and form a flow stopping plug. Due to the highly transient nature of the start-up process, determining the formation of the plug from pressure monitoring is much more difficult than for normal flow. However, comparing the results with carefully tuned real time online simulation results may still give indication of whether a plug is being formed. Pre-defined, start-up procedures can use this information as a trigger to avoid plugging.

Plug Location for Length Determination. Careful deployment of hydrate formation monitoring and well defined remedial actions in response to the monitoring results will be able to greatly reduce the likelihood of plugging. However, pre-defined remediation actions may not be possible to prevent the flowline from being plugged in some situations. Under these circumstances, the fiber optic pressure measurements can be used to determine the plug location and length. These can be from the measured data before plugging completed, or from controlled depressurization for location purposes.

Paraffin Deposition Monitoring

Paraffin deposition is a much slower process than hydrate formation and plugging. It occurs in the pipeline segment that is below the wax appearance temperature and that has a heat flux from the fluid mixture to the pipe wall. There is a secondary mechanism of wax deposition when there is no heat flux, but the deposition rate from this mechanism would be very low. Typically paraffin deposits adhere to the pipe wall and form a thin layer over a long distance.

Pressure Monitoring. Although paraffin deposition reduces the flow area and increases effective wall roughness, thus increases frictional pressure drop, monitoring using pressure drop is not expected to be effective. Table 1 shows an example with a flow of 100,000 BOPD in a 16” flowline, 20 miles long, changing from a water depth of 3000 ft to 1000 ft, followed by an SCR to the platform. The oil is assumed to be 30^{o}API and to have a GOR of 1000 scf/bbl. Paraffin deposition is assumed to occur in a one-mile long section of the flowline. Table 1 shows that the overall pressure drop increases by 1 psi if the average wax thickness is 1 mm. However, the accumulated wax volume is 66 ft^3, which probably causes difficulty in pigging.

Table 1. Paraffin deposition effect on pressure drop.

Wax thickness (mm)	Total Wax Volume (ft3)	Inlet Pressure (psig)	Outlet Pressure (psig)	friction pressure gradient in the mile with wax psi/ft
0	0	2470	1000	0.00625
1	66	2471	1000	0.00657
5	363	2475	1000	0.00731

However, we see the frictional pressure gradient has a 5% difference with 1 mm thick wax layer. Fiber optic pressure sensor pairs can be installed along the pipeline, each measuring the pressure gradient, and provided indication of wax buildup. A method to maximize strain sensitivity is in development to provide highly accurate measurements.

Temperature and Heat Flux. Another approach to determine the existence and thickness of paraffin deposit is through its insulation effect. Paraffin wax has similar thermal conductivity as oil. However, heat transfer in flowing oil is primarily convective, while in the deposit layer it is primarily the much lower rate conduction heat transfer. This difference will result in two changes at the pipe location where paraffin deposit occurs, as shown in Figures 7 and 8, for a 16" pipeline with and without insulation.

- The pipe temperature decreases from the value when the pipe was clean,
- The radial heat flux decreases from the value when the pipe was clean,

Figures 7 and 8 show the changes produced from the additional insulation effect of the wax layer. The conditions are much more significant for less insulated pipes. For the pipe with 2" syntactic foam insulation (Figure 7), every 1 mm of wax layer results in 0.7 – 1^{o}F decrease in pipe temperature, and about 2% decrease in heat flux. For the bare pipe (Figure 8), the first 0.5 mm of wax layer results in 13^{o}F decrease in pipe temperature and 41% decrease in heat flux. The next 0.5 mm of wax layer results in an additional 3.5^{o}F decrease in pipe temperature and 29% decrease in heat flux.

We can conclude from these observations that the onset of wax deposition and wax thickness can be detected by the measured changes of pipe temperature and heat flux, particularly for bare pipelines or pipelines with low to medium insulation. However, the required measurement accuracy increases with pipeline insulation, and may be impractical for highly-insulated pipelines such as those with pipe-in-pipe insulation.

The temperature and heat flux changes due to wax deposition can be monitored using fiber optic sensors. These sensors have been developed for the extremely low temperature LNG applications, and are under test for applications in normal pipeline temperature ranges. Figure 9 cryogenic temperature (bench marking) and Figure 10 (flowing LNG) data are shown below.

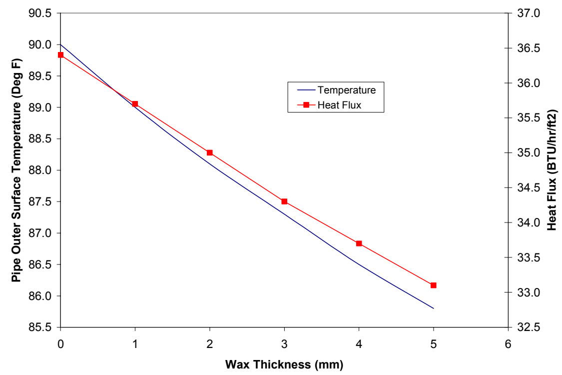

Figure 7. Effect of wax deposition on pipe temperature and radial heat flux, with 2" syntactic foam insulation on the pipe. Fluid temperature = 90oF, ambient temperature = 40oF.

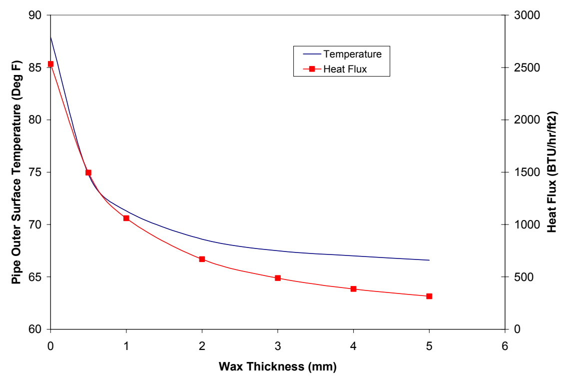

Figure 8. Effect of wax deposition on pipe temperature and radial heat flux, with 3 mm thick external polyethylene coating on the pipe and no insulation. Fluid temperature = 90oF, ambient temperature = 40oF.

Figure 9. Fiber optic sensor for measuring temperature and heat flux (bench marking)

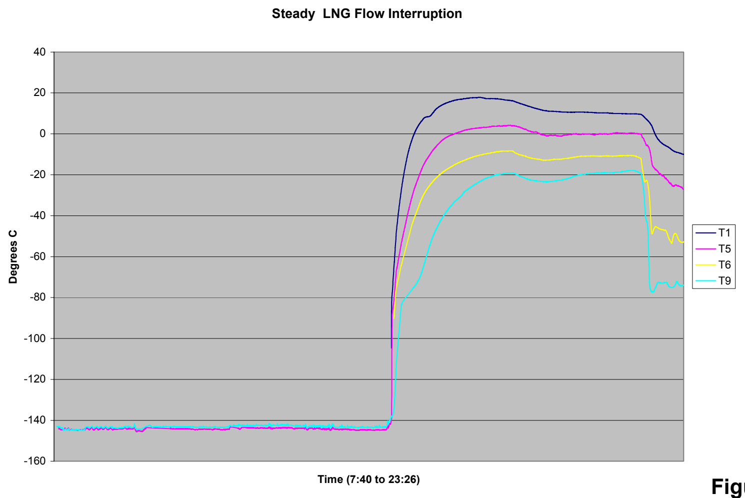

Figure 10. Fiber optic measurement of LNG pipeline test specimen.

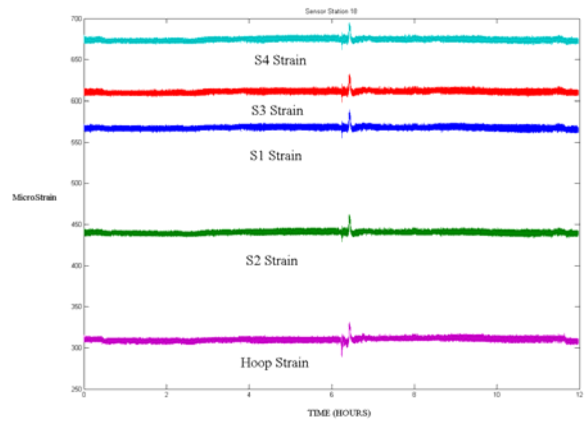

Figure 11: Fiber optic sensor station response data to pig traveling in 24-inch SCR

Pig Tracking and Stuck Pig Prevention

Pipeline pigs are periodically deployed to clean deposits and to inspect the interior conditions for corrosion or other potential defects. It is desirable to track pig passage and identify arrival time during normal pigging activities. However, in some cases pig passage is impeded or even stopped, during it travel through the pipeline, due to interior conditions involving wax or paraffin build-up. Non-intrusive fiber optic sensors have successfully been used to identify passage of a flushing pig through a 24-inch oil/gas pipeline in a deepwater field. Pig location was identified as it passed through a series of sensor stations located in the touchdown zone and in the upper section of a steel catenary riser (SCR).

The sensor stations were installed on the SCR to monitor structural properties such as strain, vibration, and fatigue. Figure 11 shows the sensor response to pig passage in the upper section of the SCR. The sensors are highly accurate and the installation configuration was designed to measure the strain response of all pipeline conditions including pig presence. The sensor station consisted of fiver fiber optic sensors located 90 degrees apart circumferentially around the SCR. Four of the sensors were oriented axially and the fifth sensor was oriented in the hoop direction. The sensors were exterior mounted prior to deployment in the deepwater environment. All four sensors clearly detected the presence of the pig as shown in figure 11. This particular figure shows data from the top section of the SCR. Similar data was obtained at additional instrumented locations as the pig passed through the touchdown zone.

Slug Monitoring

A detection and characterization method based on non-intrusive FBG's has been developed and tested to detect the presence of a hydrate/H_20 slug traveling inside a gas flow line. Slug presence, size, velocity, acceleration, growth, quantity and frequency can be determined by installing the sensors at key locations along the flow line. A major benefit of the fiber optic system is it can be used at extremely long distance from the computer and control room. Testing was conducted on a flow loop that included a 2-inch diameter pipe approximately 100 ft. in length. Sections of the pipe included transparent polymer, allowing visual observation as slugs flowed through the system. Data clearly identified the presence of slugs in real-time. Data analysis subsequently determined other slug characteristics.

An Optical Sensing System and PC software were used for slug monitoring data acquisition and storage. Standard polyacrylate single mode fiber optic cable was used as the leads to the specified fiber optic sensors (FBG's). A two part fast cure epoxy was used to attach the sensors to the polyacrylate flow loop pipe. The FBG's were placed on the pipe at each sensor station location to measure hoop stress and axial strain from which the slug presence and characterization is determined.

Figures 12 and 13 show the excitation response of the individual sensors. A very repeatable waveform is seen in the data as each slug passes. As a slug approaches the sensors, pressure/strain starts to build up and a subsequent change in strain occurs as the slug passes by the sensor. As the rear of the slug passes, a peak rise in signal is observed again. Hence the initial peak of each signal is the point at which the full diameter slug is directly below the sensor, and the last, top peak, of the signal is the rear of the slug. In the slug data, an increase in the signal can be seen, where the pressure builds up again after the slug passes by. This is believed to be pipe filling back with water after a slug passes by and is a possible early warning indication of slug formation.

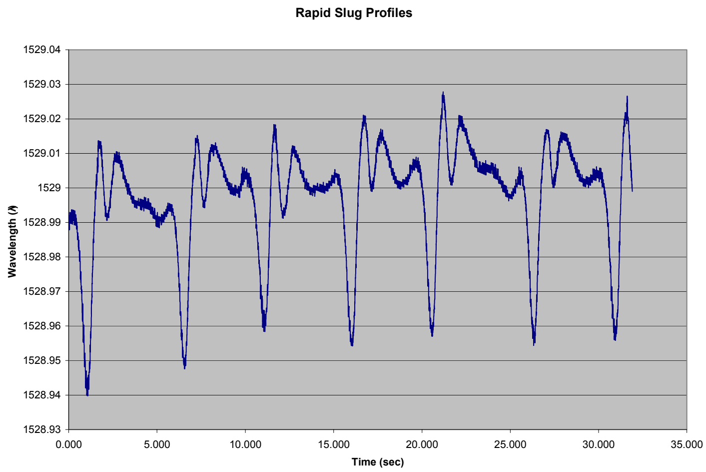

Figure 12: Slug detection in subscale pipeline (rapid flowing slugs)

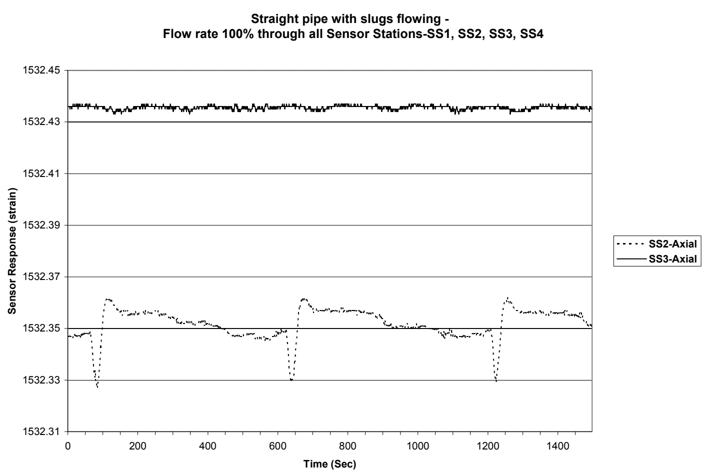

Figure 13: Slug detection in subscale pipeline

Conclusions

Non-intrusive fiber-optic sensor based monitoring technology is being developed to advance the management of flow assurance risks. These sensors have the advantages of non-intrusiveness and low signal attenuation over long distance, compared with conventional sensors, which make the technology very promising for deepwater applications. The sensors can measure temperature, pressure, heat flux, strain, and acoustic measurements. The measurements can be used to detect gas hydrates blockage development, to estimate paraffin deposition, to locate pigs, and to detect passage of liquid slugs.

Further development in sensor technology, as well as in data processing and flow simulation capabilities, is necessary to correlate the measurements reliably with the flow assurance phenomena to be monitored.

References

[1] K.S. Cooper, W.J.Nisbet, "Flowline Deposition Assessment Using Chemical Tracers," OTC 16690, Offshore Technology Conference, Houston, Texas, May 2004

[2] A. Wilson, H.T. Holm, S. Overa, "A. Wilson, S.J. Overaa, H. Holm, "Ormen Lange – Flow assurance challenges," OTC 16555, Offshore Technology Conference, May 2004, Houston, Texas.

[3] K. Havre1, M. Dalsmo, "Active Feedback Control as the Solution to Severe Slugging," SPE 71540, SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, October 2001.

[4] K. Kovalev, A. Cruickshank, J. Purvis, "The Slug Suppression System in Operation,"
SPE 84947, Offshore Europe, Aberdeen, UK, September 2003.

[5] A.D. Kersey, et al.,, "High Resolution Fiber Based Strain Sensor with Interferometric Wavelength Shift Detection," Electron. Lett. 28, 809, 1992

[6] S.F. Kashu, P.N. Matthews, S. Subramanian, "Gulf of Mexico Export Gas Pipeline – Hydrate Plug Detection and Removal," OTC 16691, Offshore Technology Conference, May 2004, Houston, Texas.