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Experimental Studies of Water Wetting in Large Diameter Horizontal Oil-Water Pipe Flows

Jiyong Cai, Srdjan Nesic,Chong Li, Xuanping Tang and Francois Ayello/Institute for Corrosion and Multiphase Technology, Ohio University

C. Ivan T. Cruz and Jamal N. Al-Khamis/Saudi Arabian Oil Company

Abstract

Internal pipeline corrosion in oil production and transportation is always associated with the presence of water, and the likelihood of corrosion generally increases with the volume fraction of water. When the walls of the pipeline are wetted with oil no corrosion is possible. Highly turbulent flow was associated with negligible corrosion due to water entrainment by the flowing oil, whereas low flow rates or intermittent flow have been associated with corrosive conditions.

In this study, four advanced techniques (wall conductance probes, corrosion monitoring, wall sampling and flow pattern visualization) were used to determine phase wetting on the internal wall of pipe at different superficial oil and water velocities in the large diameter oil-water horizontal flow.

Four flow patterns were observed: stratified flow, stratified flow with mixed layer, semi-dispersed and dispersed flows.

Three types of phase wetting regimes (water wetting, intermittent wetting and oil wetting) were determined. A phase wetting map was obtained based on the overlapping information from these techniques. It is clear that the critical oil velocity of water entrainment increases with increasing input water cuts. The water cut has a significant effect on the critical oil velocity for water entrainment.

Based on the results of corrosion monitoring, it is also found out that no corrosion occurs under oil wetting. At same superficial oil velocity, corrosion rate under water wetting is much higher than that under intermittent wetting.

Introduction

The simultaneous flow of oil and water in crude oil production and transportation pipelines is a common occurrence, seen anywhere from the well perforations to the final stages of separation. Corrosive gases such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S) are also commonly present in these systems. Typically at low water cuts this is not an issue as all the water is entrained by the flowing oil. As the water cut increases, water "break-out" may occur, leading to segregated flow of separate layers of water and oil phases. Therefore, the possibility of corrosion is high where the water phase wets the pipe wall (typically at the bottom).

In the past, the effect of multiphase oil-water flow on CO_2 corrosion has been considered only in a qualitative sense. Highly turbulent flow at low water cuts was associated with negligible corrosion, whereas low flow rates or intermittent flow at higher water cuts has been associated with corrosion conditions. Hence, it is a challenge for corrosion engineers to determine more precisely the flow conditions leading to corrosion and conversely the conditions leading to entrainment of the free water layer by the flowing oil phase.

Little quantitative research has been performed in the past on the subject of water separation and entrainment when considering how significant a factor it is for internal corrosion of mild steel pipelines. Wicks and Fraser (1975)[1] proposed a simplified model for predicting the critical velocity of the flowing oil phase required to sweep out settled water. However, the Wicks and Fraser[1] model is suitable primarily for very low water cut situations. At high water cut, their model underestimates the critical velocity without considering the coalescence of water droplets. Wu[2](1995) modified Wicks and Fraser[1] model without a big improvement in the performance. Smith et al.[3](1987) published data that show the ability of some oils to carry water up to 20% water cut, if flowing at velocities larger than 1 m/s. In the CO_2 corrosion model of de Waard and Lotz[4] published in 1993, the presence of the hydrocarbon phase was accounted through a so-called water-wetting factor. From the original experiments of Wicks and Fraser[1] a binary prediction factor was extracted suggesting that oil-wetting will occur only for water cuts less than 30% and velocities larger than 1 m/s, when all water can be entrained in the oil phase. In another study published the same year (1993), Adams et al.[5] estimated that below 30% water cut the tubing will be oil-wet; from 30-50%, intermittent water wetting occurs, and over 50% the tubing is water wet. These

are very crude criteria that neglect or oversimplify the varying properties of the oil and water phases, the flow regime and the flow geometry. Furthermore, field experience suggests that in some cases corrosion was obtained at water cuts as low as 2%, in others no corrosion was obtained for water cuts as high as 50%. de Waard et al.[6] in 2001 and 2003 updated the original de Waard and Lotz[4] empirical model from 1993 and proposed a new empirical model using an analysis based on the emulsion breakpoint approach. A link between API gravity, emulsion stability and water wetting of steel by an oil-water mixture was considered by taking into account the changes in interfacial tensions in an oil-water-steel system. This was a major step forward from the original model, however, while agreeing reasonably well with the specific pool of field cases used for its calibration, the new model remains an empirical correlation built on limited field data with an uncertain potential for extrapolation. More importantly, this model does not consider the effect of pipe diameter, oil density, oil viscosity and system temperature on the critical velocity of the flowing oil phase required for entrainment. It can be argued though that the simplified Wicks and Fraser[1] model gave critical velocities which did not depend much on diameter and viscosity and that density and viscosity are inversely correlated.

As a part of Ohio University's newly released software package MULTICORP V3.0[11], a mechanistic model (Cai et al. [12-13]) of water wetting prediction in oil/water and gas/oil/water systems is included. The effects of pipe diameter, pipe inclination, oil density, oil viscosity and system temperature on the critical velocity of the flowing oil phase required for entrainment are considered in that model[12-13]. It should be pointed out that the model has not been verified in three-phase flow and does not consider the effect of gas, steel surface state, chemical additives and type of crude oil on water wetting because of lack of experimental and field data.

To understand the mechanism of water entrainment in the oil-water pipe flows, it is necessary to look closer into different flow regimes that occur. The main difficulties in understanding and modeling of the behavior of oil-water flows arise from the existence of the interfaces between the phases. The internal structures of two-phase flow can be best described by the flow patterns. The momentum and mass transfer mechanisms between the two phases significantly depends on the flow patterns. Also, flow patterns can indicate the phase wetting the pipe wall, position of the phases and the degree of mixing during the flow. Compared to gas-liquid flow studies, a fewer studies[7-27] are dedicated to flow of two immiscible liquids such as water and oil. Various flow patterns observed in the horizontal pipe flows are given in the Figure 1. Stratified flow with a complete separation of water and oil phases may exist at very low flow rates where the stabilizing gravity force due to a finite density difference is dominant. With increasing the flow rate, the interface displays a wavy character with possible entrainment of droplets at one side or both sides of the interface (semi-stratified flow). The entrainment processes for both phases increase with the flow rates. When the pure water and oil layers are still continuous at the bottom and top of the pipe respectively, and a layer of dispersed droplets exists at the interface, a three-layer structure is formed. At sufficiently high oil flow rate and low water cut,

the entire water phase becomes discontinuous in a continuous oil phase resulting in a water-in-oil dispersion. Vice versa, at sufficiently high water flow rate and a high water cut, the entire oil phase becomes discontinuous in a continuous water phase resulting in an oil-in-water dispersion. There are operating conditions under which an oil-in-water dispersion will change to water-in-oil dispersion. This phenomenon is referred by lots of researchers as "phase inversion" and is associated with an abrupt change in the frictional pressure drop and a switch of the phase wetting the pipe wall from water to oil phase.

In order to validate an improve the model[12-13] with more experimental data from large diameter pipelines, in this study, experiments are carried out to determine the phase wetting with 4 advanced techniques (wall conductance probes, corrosion monitoring, wall sampling and flow pattern visualization) at different superficial oil and water velocities in large diameter horizontal oil-water pipe flows.

Experimental Setup

The experiments have been conducted at the Institute for Corrosion and Multiphase Technology at Ohio University in a 200' long, 4" ID multiphase flow loop mounted on a fully inclinable rig. The multiphase flow rigs at the Institute for Corrosion and Multiphase Technology are specially designed to investigate corrosion and multiphase flow under realistic flow conditions found in the field. Figure 2 shows the schematic of the fully inclinable multiphase flow rig.

Oil is stored in a 1.2-m^3 stainless steel storage tank. The tank is equipped with two 1-kw heaters and stainless steel cooling coils to maintain a constant temperature. Water with 1% wt. NaCl is stored in a 1.2-m^3 stainless steel storage tank. Oil is pumped through the system using a Moyno pump equipped with a variable speed motor. The oil flow rate is controlled within a range of 0.5 to 3 m/s with a combination of the variable motor speed and a bypass system. Two Moyno pumps with small and high flow rate are used to pump water through the system from the water storage tank. The pump with small flow rate is used when input water cut is smaller than 20%, otherwise the pump with high flow rate will be chosen.

Oil and water mix in the static T-mixer and then the oil-water mixture flows through a 3 m-length flexible hose, which allows the inclination to be set at any angle for this fully inclinable rig, and then enters the 10 cm I.D., 14 m long stainless steel pipeline and then flows through a 2 m-long upstream test section, where all measurements are carried out. Since the test section is set at 14 m downward from the static mixer, the pipe has enough length for the development of flow structure and the effects of pump, valves on flow structure are evened out. The test section is made of carbon steel. A 2 m-long transparent pipe is connected to the carbon steel test section, which is used to visualize the flow pattern. After the oil-water mixture flows through a 180 degree bend, it enters into a 14-m long stainless steel pipe and another 6 ft long transparent pipe is connected to the stainless steel pipe section and the 6 ft-long downstream test section, which is made of carbon steel. After the oil-water mixture leaves the downstream test section, it flows through a 20 m long 4-inch

I.D PVC pipe and enters into the oil-water separator (Figure 3), where the separation process of oil and water takes place. After oil and water separate, water accumulates in the water boot and it flows through the valve at the bottom of water boot back to the water storage tank. Pure oil phase flows through the oil-outlet back to the oil storage tank for further circulation.

It should be pointed out that all the components, except the test sections in this multiphase flow rig, are made of corrosion-free materials (either stainless steel or PVC). The material for test sections is carbon steel.

Oil-Water Separator. The oil/water separator is a crucial element for the reliability of all the tests. A good separation leads to a solid baseline for the reliability and repeatability of each test point. Figure 3 shows the internal structure of the oil-water separator. In order to enhance the separation efficiency, three main internal components are installed into the separator. One liquid distributor is set at the side close to the oil-water mixture inlet, which is used to distribute the oil-water mixture uniformly on the cross-section of separator. One set of DC-Coalescer and 4 sets of enhanced plate separator are connected with liquid distributor subsequently. The DC-coalescer and enhanced plate separators are designed by Advanced Separation Technologies Ltd. The essence of DC-coalescer is to use a composite of two materials with very different surface free energy – typically stainless steel and plastic. The combination of both high and low surface energies means effective separation irrespective of which phase (either oil or water) is dispersed. The rate of coalescence is significantly increased when dispersed droplets are captured and meet at the interstices of the two dissimilar materials.

The dimension of the oil-water separator will be 30" x 14'. An 18'' x 24'' water boot is assembled with the vessel at the end side of the vessel, which will be used to collect all the dispersed water droplets. The separator is made of carbon steel and is carefully coated with corrosion resistance epoxy inside.

In order to determine the separation efficiency of the oil-water separator, two sampling ports for water and oil samples are installed. The water sampling port is located at the water boot and the oil sampling one is installed on the oil line (see Figure 2).

De-Oxygenation System. Since corrosion measurements are carried out in this study, in order to minimize the effect of oxygen on corrosion process, the whole flow system is de-oxygenated using pure carbon dioxide (CO_2) before experiments. The green line (CO_2 gas line) in Figure 2 shows the de-oxygenation system. The whole de-oxygenation process for this system takes about 2 and half hours and the oxygen concentration in the system is below 25ppb, which is allowable for corrosion measurements under this environments.

Test Section. Figure 4 shows the schematic of the 6-ft-long test section for current studies. During the experiments, the test section is corroded and leads to an increase of Fe^{2+} ion concentration if the corrosive water phase wets the pipe inner wall. 5 rows of wall conductance probes, one set of high frequency impedance probes, wall sampling port and ER probe

holder are installed and located at the downstream of test section. The test section is connected with downstream and upstream pipe sections with two clamp flanges, which allow the test section being rotated in any angle.

Instrumentation

In this study, four advanced techniques (flow pattern visualization, wall conductance probes, corrosion monitoring and wall sampling) were used to determine phase wetting on the internal wall of pipe at different superficial oil and water velocities in the large diameter oil-water horizontal flow.

A set of wall conductance probe are used to measure the water content very close to the pipe internal wall at the bottom of the pipe. Figure 5(a) shows the wall conductance probes used to determine the phase wetting on the surface of pipe inner wall. The O.D. of wall conductance probe is 0.45 mm. Five rows of 18 probes are flush-mounted on the bottom of the pipe wall. Staggered configuration of probes spaced every certain degrees is applied around the pipe circumference. Figure 5(b) shows the staggered configuration of wall conductance probes. This particular 5-row of staggered configuration of wall conductance probes is used to minimize the effect of a particular phase "snaking" around the isolated pin heads leading to erroneous readings. Also, this special configuration is very useful to determine the phase wetting at the flowing condition that small droplets randomly impinge the pipe wall surface. However, this flow condition usually occurs when water is almost entrained by the flowing oil phase and no clear water layer exists at the bottom of pipe surface.

A wall sampling method is used to measure the water/oil distribution very close to the surface of pipe inner wall by extracting the fluid. A combination of a very precisely controlled needle valve and a solenoid valve is used to extract the fluid from the sampling port (shown in Figure 4). The instrumentation is carefully calibrated and the proper extraction rates are determined at different velocities. This technique yields a reasonably accurate estimate of the local water/oil ratio very close to pipe wall surface.

At the Institute for Corrosion and Multiphase Technology equipment for high-speed video recording exists which can be useful for recording and identifying flow regimes in multiphase flow. While this technique will be considered, it is anticipated that the opaqueness of the mixture will make it difficult to obtain clear visual images, particularly at higher mixture velocities.

Since a CO_2 saturated water/oil mixture is circulated through the loop it is straightforward to conduct corrosion measurements on mild steel test section. In selected tests the corrosion rate is measured using the electrical resistance probes. The corrosion process also enables an alternative way to measure water wetting. Since the material of test section is made of carbon steel, if water wetting occurs in a given test, corrosion happens as well. This will manifest itself as a rise in dissolved ferrous ion (Fe^{2+}) concentration in the water phase, which can be easily detected by sampling the water and employing a standard colorimetric technique. In general, CO_2 dissolves in water to give carbonic acid (H_2CO_3), the overall corrosion process of carbon steel in CO_2 environment can be written as:

$$Fe + CO_2 + H_2O = Fe^{2+} + CO_3^{2-} + H_2 \qquad (1)$$
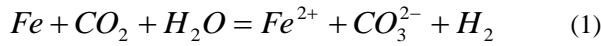
It is anticipated that by using at least 4 very different techniques for detection of water wetting (wall conductance probes, wall sampling, flow pattern visualization and corrosion measurement), overlapping information is obtained what will reinforce our confidence in the overall results and give us a stronger base for water wetting modeling.

Results and Discussions

4 series of experiments were conducted with LVT200 oil and 1%wt. NaCl water at different flowing conditions as described below in the large diameter horizontal pipe flow. The most important parameters and test matrix are shown in **Table 1** below. The viscosity μ and density ρ of LVT200 oil is 2 cP and 825 kg/m^3 at room temperature, respectively. The surface tension and interfacial tension of the oil-water mixture is 0.0284 N/m and 0.0334 N/m.

Flow Pattern Visualization. Based on the images recoded with high speed tape recorder, four types of flow patterns, stratified flow, stratified flow with mixed layer, semi-dispersed and dispersed flows, were observed during all experiments.

Stratified flow prevails at the flow conditions of superficial oil velocity of 0.5 m/s and water cuts ranged from 4% to 20%. At this superficial oil velocity, it was observed that lots of scattered water droplets move on the bottom of pipe when water cut is less than 7%. The size of water droplet is around 5mm to 1cm. some smaller water droplets float into the top portion of pipe. The interaction between water droplets is very weak since the turbulence in the pipe is low. The coalescence between water droplets is low. With increasing the water cut, the interaction between droplets is getting stronger and the coalescence process enhances. When the water cut is up to 10%, it is clear that a thin water layer gradually forms on the bottom of the pipe. There are still lots of water droplets existing on the oil-water interface. Further increasing water cut to 13% leads to a clearer and thicker water layer on the bottom of pipe. Few water droplets exist on the oil-water interface. The oil-water interface is relatively smooth. An idea oil-water stratified flow occurs. However, a mixed layer takes place on the oil-water interface when the water cut is higher than 15% and the thickness of the mixed layer increases with increasing water cut. A flow pattern called stratified flow with mixed layer occurs.

At superficial oil velocity of 1 m/s, two types of flow pattern, stratified flow and stratified flow with mixed layer, exist for water cuts ranged from 2% to 17%. A clear water layer forms at the bottom of pipe until the water cut is 14% at this oil velocity. However, no smooth oil-water interface exists at these flowing conditions. When water cut is less than 14%, lots of water droplets flow on the bottom pipe. The size of water droplets is much smaller than that at superficial oil velocity of 0.5 m/s. The interaction is much stronger than that at velocity of 0.5 m/s. More small droplets go into the oil phase. Although the interaction and the coalescence between water droplets is stronger than that at velocity of 0.5 m/s,

bigger water droplets still rarely survive when water cut is lower than 10% because of high turbulence. Thicker water layer gradually forms when water cut is higher than 10%. Stratified flow with mixed layer forms when water cut is higher than 14%. The thickness of the mixed layer is much higher than that at superficial oil velocity of 0.5 m/s.

Semi-dispersed flow occurs at the flow conditions of superficial oil velocity of 1.5 m/s with water cuts up to 13%. No clear water layer forms. Water flows as very small droplets in the oil phase. The distribution of water droplets on the cross-section of pipe is not uniform. More water droplets exist at the bottom portion of pipe. Increasing superficial oil velocity up to 2.5 m/s leads to an occurrence of dispersed flow. Oil is the continuous phase and water is dispersed. The distribution of water droplets on the cross-section of pipe is uniform. All the water phase is entrained by the flowing oil phase.

Results from Wall Conductance Probes and Wall Sampling. The results of phase wetting determined by 93-wall conductance probes at different levels on the half portion of the pipe circumference under the flowing conditions of superficial oil velocity of 0.5 m/s and water cut of 4.25% are shown in Figure 6. The results from 5 rows of wall conductance probes are obtained simultaneously. Each experiment is repeated 5 times. Each data point in Figure 6 represents the average phase wetting indicator ψ at that level during 5 times running. If oil phase wets that point, the phase wetting indicator ζ_{oil} is 0 and ζ_{water} is 1 if water wetting occurs. The average phase wetting indicator ψ at that level can be calculated by:

$$\psi = \frac{\sum N_{water} * \zeta_{water}}{N_{Test} * N_{row}} \qquad (2)$$

where N_{test} denotes the number of repeating tests and N_{row} represents the number of rows of wall conatductance probes at that level. $N_{water \; wetting}$ denotes the number of water wetting occurrence during N_{test} times of tests at that level.

Hence, the phase wetting at certain flowing conditions can be determined based on the average phase wetting indicator ψ_{bottom} of the wall conductance probes at the bottom of pipe wall:

$$\begin{cases} \psi_{bottom} = 0 & Oil \quad wetting \\ 0 < \psi_{bottom} < 1 & Intermittent \quad wetting \\ \psi_{bottom} = 1 & Water \quad wetting \end{cases} \qquad (3)$$

It should be clearly pointed out that water wetting occurs only water phase continuously wets the bottom of pipe wall and there is a water layer existing at the bottom of pipe. Similarly, oil wetting takes place when all water phase is entrained by the flowing oil phase. Oil phase always wets the pipe wall and water flows as droplets into the oil phase. If oil and water phases alternatively wet the bottom of pipe wall and there is no continuous water layer on the bottom of pipe, intermittent wetting prevails. It is the consequence of two processes (water droplet breakup and water droplet coalescence). Water droplet breakup is caused by the

turbulence. The coalescence of water droplets is caused by the interaction of droplets. These two processes occur simultaneously. At the medium level of flow turbulence, water phase is entrained into small droplets by the flowing oil phase. Gradually all the water is totally entrained into oil pahse and water entrainment occurs. In this case, since lots of small water droplets flow in the oil phase, the interaction of droplets is strong. More and more small droplets coalesce into bigger water droplets. Bigger water droplets drop out the oil phase and gradually form water layer, water separation occurs.

It is seen from Figure 6 that intermittent wetting prevails at the bottom of pipe when the superficial oil velocity is 0.5 m/s and the input water cut is 4.25%. Oil phase flows on the top portion. However, at the bottom portion of the pipe wall circumference, oil still occationally wets pipe wall. Oil and water alternatively wets the bottom of pipe wall. This result is consistent with the information from flow pattern visualization as above mentioned. At this flow condition, lots of scattered water droplets contact the bottom portion of pipe circumference and oil still partially wets the pipe wall. At the same superficial oil velocity, increasing water cut to 12.89% (Figure 7) leads to the occurrence of water separation. Water wetting occurs at the bottom of pipe. On the other side, it is seen that more and more water drops out the oil phase and wets the wall surface at the bottom of pipe. At the same time, more water flows into the oil phase. The area wetted by oil phase decreases with increasing the water cut. Further increase of water cut leads to a continuous water layer flowing at the bottom of the pipe (seen in Figure 8) since the turbulence provided by the flowing oil phase is not high enough to break up the water layer into droplets and entrain water droplets into the oil phase.

Table 2 shows the results from wall sampling. It is seen that there is about 99% water and 1% of oil in the fluid sample when the input water cut is up to 10% at superficial oil velocity of 0.5 m/s. It is obvious that some oil wets the bottom of pipe wall. When the input water cut is higher than 13%, fluid sample only includes pure water. This means that a pure water layer is formed at the bottom of pipe. This is consistent with the information from wall conductance probes (Figure 6 and Figure 8) and flow pattern visualization.

The relationship between water cut and phase wetting at superficial oil velocity of 0.5 m/s is shown in Figure 9. It is obvious that increasing the water cut leads to a transition from intermittent wetting to water wetting. The minimum water cut leading to stable water wetting at superficial oil velocity of 0.5 m/s is about 13%.

Typical intermittent and water wettings are shown in Figure 10 and Figure 11at superficial oil velocity of 1 m/s and water cuts of 13% and 17%, respectively. The relationship between water cut and phase wetting is shown in Figure 12 at superficial oil velocity of 1 m/s. It is found from Figure 12 that the minimum water cut is around 14% to form stable water wetting at superficial oil velocity of 1 m/s. Obviously, the rule, which water entrainment occurs when water cut is 30% at oil velocity of 1 m/s, is questionable. The results from wall sampling method (shown in **Table 3**) are consistent with those obtained from wall conductance probes and flow pattern visualization. Compared to the results at superficial oil velocity of 0.5 m/s, it is clear that water concentration in the

water sample decreases from 99% to 50 % with increasing superficial oil velocity from 0.5 m/s to 1.0 m/s at same superficial water velocity of 0.0185 m/s. That means that more oil flows into water phase since higher oil flow rate leads to higher turbulence and higher mixing between oil and water phases. On the other side, at the superficial oil velocity of 1 m/s, increasing water flow rate leads to higher possibility of coalescence of water droplets and eventually an occurrence of water layer existing at the bottom of pipe.

Figure 13 and Figure 14 show the typical oil wetting and intermittent wetting obtained from wall conductance probes at superficial oil velocity of 1.5 m/s and water cuts of 6.9% and 12.89%, respectively. All wall conductance probes detect that oil phase wets the pipe all when water cut is lower than 9%. In this case, all water is entrained by the flowing oil phase. Oil is the continuous phase and water turns into dispersed phase and flows as droplets in the oil. This is consistent with the information from flow pattern visualization. When water cut is higher than 9% and lower than 13%, only intermittent wetting exits and no stable water wetting occurs since high turbulence breaks up the bigger water droplets into smaller ones and prevents the coalescence of small water droplets. No water layer can form on the bottom of pipe. Only small water droplets contact the pipe wall. The relationship between water cut and phase wetting is shown in Figure 15. Increasing water cut leads to a transition from stable oil wetting to intermittent wetting at superficial oil velocity of 1.5 m/s.

Stable oil wetting (Figure 16) always exists when superficial oil velocity of 2.5 m/s and superficial water velocity less than 0.20 m/s. All the water phase is entrained by the flowing oil phase. Water-in-oil dispersed flow forms. Figure 17 shows the relationship between water cut and phase wetting.

The results of water concentration from wall sampling at superficial oil velocities of 1.5 m/s and 2.5 m/s are shown in **Table 4** and **Table 5**. It is found that oil and water form emulsion in the pipe. It took about 2 to 10 minutes for water and oil in the sample to separate. Water concentration in the sample is measured after its complete separation. It should be noticed that the stability of emulsion at the superficial oil velocity of 2.5 m/s is higher than that at superficial oil velocity of 1.5 m/s. At superficial oil velocity of 1.5 m/s, the water concentration in the sample increases from 1 % to 60% with increasing the superficial water velocity from 0.019 m/s to 0.22 m/s. The type of emulsion for the oil-water mixture close to the bottom of pipe can be determined from the water concentration in the water samples. When the water concentration in the sample is lower than 20%, the local oil-water mixture close to the bottom of pip wall is water-in-oil emulsion, which oil phase is continuous phase and water is dispersed, and apparently oil wets the bottom of pipe wall. This is consistent with the information obtained from wall conductance probes. However, when the water concentration in sample is higher than 40%, the local oil-water mixture close to the bottom of pipe could be in the transition area from water-in-oil to oil-in-oil emulsion since the phase inversion point for LVT200 oil occurs at water cut of 40% to 60%. In this case, oil and water alternatively wets the bottom of pipe wall. This also confirms the results that intermittent wetting are detected by wall conductance probes. Similarly, since the

water concentration in wall samples at superficial oil velocity of 2.5 m/s is ranged from 2% to 5%, the local oil-water mixture close to the bottom of pipe wall is water-in-oil emulsion and oil always wets the pipe wall, which confirms the results from wall conductance probes.

Corrosion Measurement. In order to check and confirm the results from wall conductance probes and wall sampling, another technique, Fe^{2+} concentration monitoring, is adopted in this study. Table 6 shows the results of Fe^{2+} concentration changes at oil wetting, intermittent wetting and water wetting, which are determined by wall conductance probes and wall sampling. It is seen that the Fe^{2+} concentration most likely constant under the condition of oil wetting. It means that no corrosion most likely occurs and oil always wets the pipe wall. However, an increase of 1.32ppm and 0.57 ppm for Fe^{2+} concentration within 30 min. testing time is detected at water wetting and intermittent wetting, respectively. Obviously, corrosion process exists and of course it happens only when water wets the bottom of pipe wall. The information obtained from Fe^{2+} concentration monitoring validates the results from the previous two techniques. On the other side, from the corrosion point of view, a corrosion problem exists at intermittent wetting.

Phase Wetting Map. Figure 18 shows the phase wetting map generated from the tests with LVT200 oil and 1% NaCl water in horizontal pipe flow. The solid line represents the transition line from stable oil wetting to intermittent wetting and the dashed one indicates the transition from intermittent wetting to stable water wetting.

It is clear that intermittent wetting is dominant at oil-water mixture velocity lower than 1.5 m/s and water cut less than 10%. Water wetting occurs when water cut is higher than 10% at same oil-water mixture velocity range.

Water entrainment occurs when oil-water mixture velocity is higher than 1.5 m/s and water cut lower than 10%. In this case all the water phase flows as water droplets in the oil phase. Oil and water form stable oil-water dispersion. At this velocity range, increasing water cuts leads to intermittent wetting since the coalescence of water droplets is stronger and bigger water droplets wet the bottom of pipe wall.

Conclusions

Four main techniques (flow pattern visualization, wall conductance probes, wall sampling and Fe^{2+} concentration monitoring) are used to detect phase wetting at different superficial oil and water velocities in large diameter horizontal pipe flows. According to those experimental results, the following main points can be concluded:

- A phase wetting map was obtained based on the overlapping information from these techniques.
- Four flow patterns were observed: stratified flow, stratified flow with mixed layer, semi-dispersed and dispersed flows.
- Three types of phase wetting regimes (water wetting, intermittent wetting and oil wetting) were determined..

- The critical oil velocity of water entrainment increases with increasing input water cuts.
- Based on the results of Fe^{2+} concentration monitoring, it is found that no corrosion only occurs under oil wetting. Corrosion exists when intermittent wetting and water wetting occur.

Acknowledgement

Nomenclature

$N_{waterwetting}$	Number of Probes wetted by water phase
N_{test}	Number of tests
N_{row}	Number of rows for wall conductance probes
ρ	Density, kg/m^3
μ	Viscosity, Pa.s
ε	Water cut, %
ψ	Average phase wetting indicator
ζ	Phase wetting indicator
V_{so}	Superficial oil velocity, m/s
V_{sw}	Superficial water velocity, m/s

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Table 1 Main test parameters

Oil phase	LVT200 oil
Water phase	1% NaCl solution
Superficial water velocity, V_{sw}	0 ~ 0.22 m/s
Superficial oil velocity, V_{so}	0.5 ~ 2.5 m/s
Water cut, ε	0 ~ 20%
Pipe inclination	Horizontal
Pipe diameter	4"
System temperature	25 ^{o}C
System pressure	0.13 MPa

Table 2 Water concentration in the fluid samples at superficial oil velocity of 0.5 m/s and different superficial water velocities

V_{so} (m/s)	V_{sw} (m/s)	Water concentration in the fluid sample (%)
0.5	0.0185	99
0.5	0.022	99
0.5	0.0259	99
0.5	0.037	99
0.5	0.056	99
0.5	0.074	100
0.5	0.0925	100
0.5	0.111	100

Table 3 Water concentration in the fluid samples at superficial oil velocity of 1.0 m/s and different superficial water velocities

V_{so} (m/s)	V_{sw} (m/s)	Water concentration in the fluid sample (%)
1	0.0185	50
1	0.026	50
1	0.037	75
1	0.056	90
1	0.074	95
1	0.093	99
1	0.111	99
1	0.13	99
1	0.148	99
1	0.167	100
1	0.185	100
1	0.204	100

Table 4 Water concentration in the fluid samples at superficial oil velocity of 1.5 m/s and different superficial water velocities

V_{so} (m/s)	V_{sw} (m/s)	Water concentration in the fluid sample (%)	Comments
1.5	0.0185	1	Unstable emulsion
1.5	0.037	1	Unstable emulsion
1.5	0.074	10	Unstable emulsion
1.5	0.111	20	Unstable emulsion
1.5	0.148	40	Unstable emulsion
1.5	0.167	40	Unstable emulsion
1.5	0.185	60	Unstable emulsion
1.5	0.222	60	Unstable emulsion

Table 5 Water concentration in the fluid samples at superficial oil velocity of 2.5 m/s and different superficial water velocities

V_{so} (m/s)	V_{sw} (m/s)	Water concentration in the fluid sample (%)	Comments
2.5	0.0185	5	Emulsion
2.5	0.056	5	Emulsion
2.5	0.093	4	Emulsion
2.5	0.10	2	Emulsion
2.5	0.11	2	Emulsion
2.5	0.13	2	Emulsion
2.5	0.167	2	Emulsion
2.5	0.204	2	Emulsion

Table 6 Fe^{2+} concentration change and corrosion rate under different phase wettings in LVT200 oil-water horizontal flow

LVT200 oil-Water Horizontal Pipe Flows					
Oil-water mixture Velocity (m/s)	Water cut (%)	Testing time (Min.)	Fe2+ change (ppm)	Phase wetting	pH
0.6	15.8	30	1.32	Water wetting	4.71
0.8	13.8	30	0.57	Intermittent wetting	4.86
1.6	6.8	30	0.05	Oil wetting	4.82
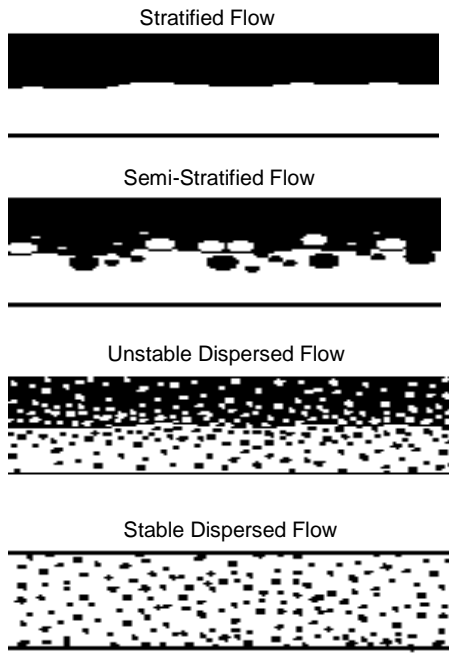
Figure 1. Flow patterns in oil-water horizontal flows

Figure 2. Schematic of 4-inch I.D. fully Inclinable multiphase fow loop

Figure 3 Schematic of internal components in oil-water separator
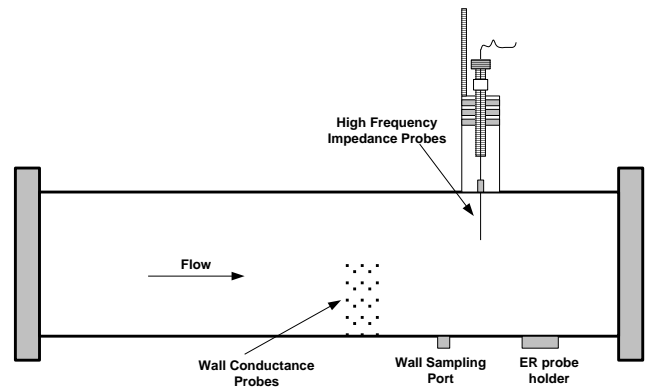
Figure 4 Schematic of test section

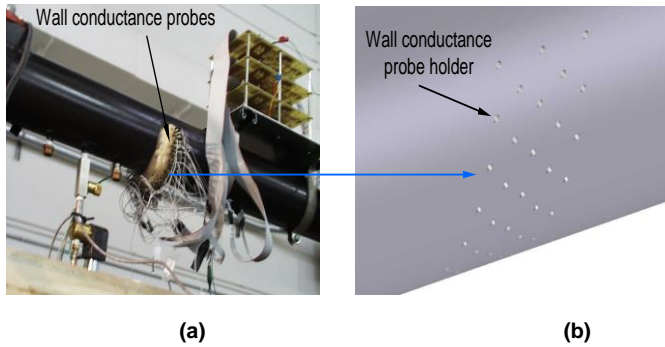**(a)**   **(b)**

Figure 5 Wall conductance probes
(a): wall conductance probes on the test section
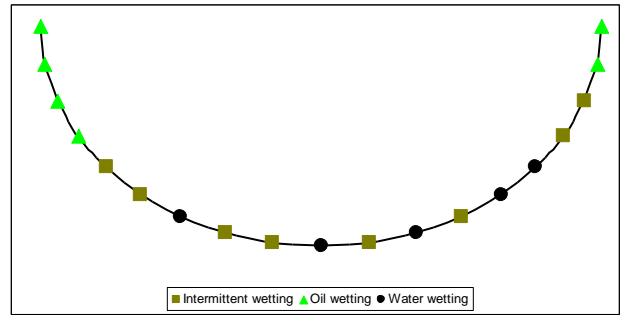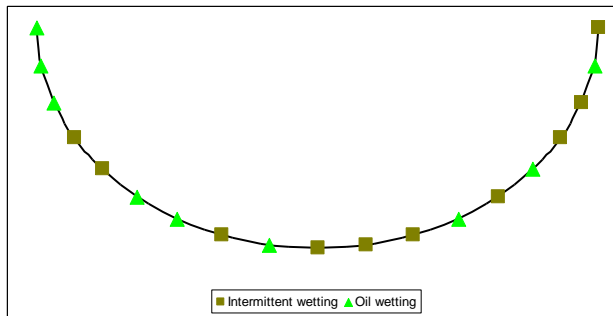**(b): 5 rows of staggered configuration of probe holders**

Figure 7 Results of one row of wall conductance probes on the bottom half of pipe circumference at superficial oil velocity 0.5 m/s and superficial water velocity 0.074 m/s (water cut of 12.89%)
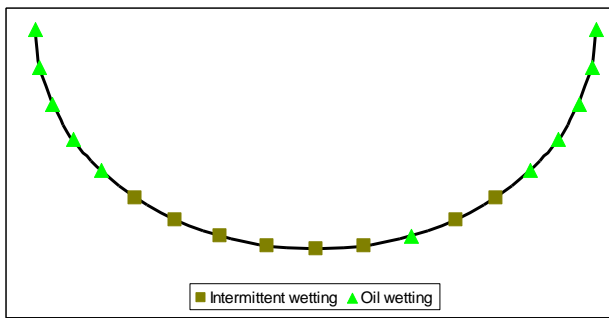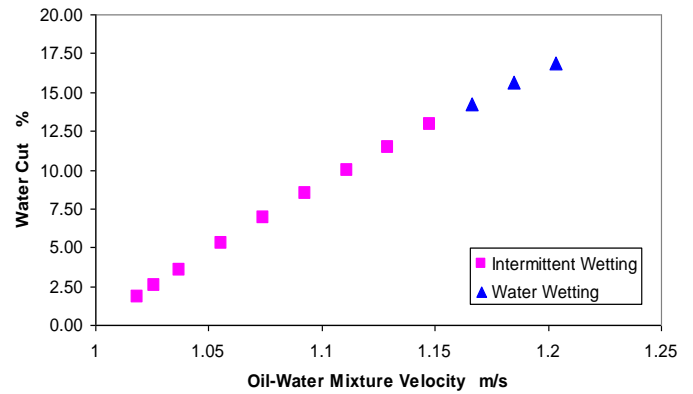

Figure 6 Results of one row of wall conductance probes on the bottom half of pipe circumference at superficial oil velocity 0.5 m/s and superficial water velocity 0.022 m/s (water cut of 4.25%)
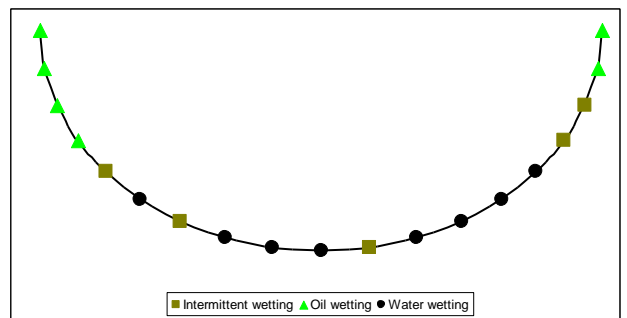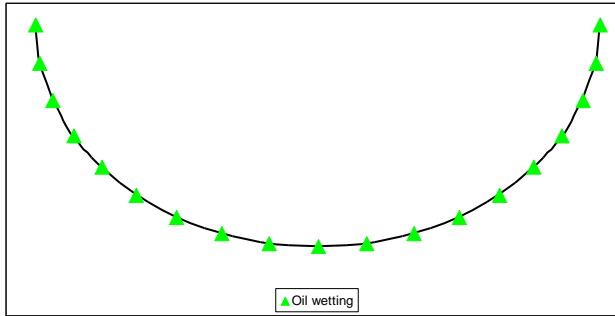

Figure 8 Results of one row of wall conductance probes on the bottom half of pipe circumference at superficial oil velocity 0.5 m/s and superficial water velocity 0.11 m/s (water cut of 18.17%)
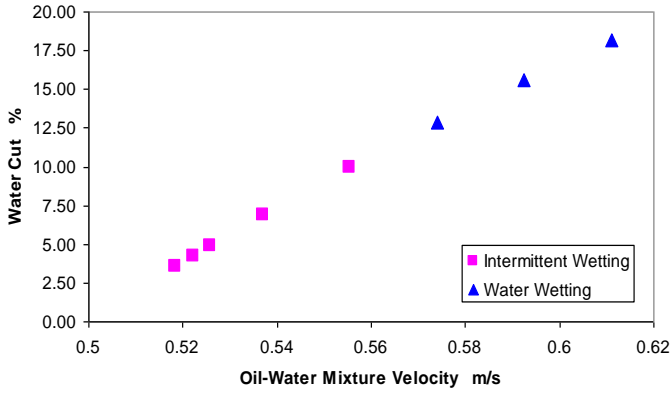
Figure 9 Relationship between water cut and phase wetting at superficial oil velocity of 0.5 m/s
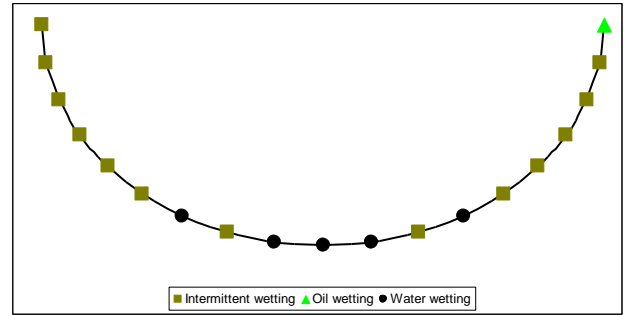
Figure 11 Results of one row of wall conductance probes on the bottom half of pipe circumference at superficial oil velocity 1.0 m/s and superficial water velocity 0.204 m/s (water cut of 17%)

Figure 10 Results of one row of wall conductance probes on the bottom half of pipe circumference at superficial oil velocity 1.0 m/s and superficial water velocity 0.148 m/s (water cut of 13%)

Figure 12 Relationship between water cut and phase wetting at superficial oil velocity of 1.0 m/s

Figure 13 Results of one row of wall conductance probes on the bottom half of pipe circumference at superficial oil velocity 1.5 m/s and superficial water velocity up to 0.11 m/s (water cut up to 6.9%)
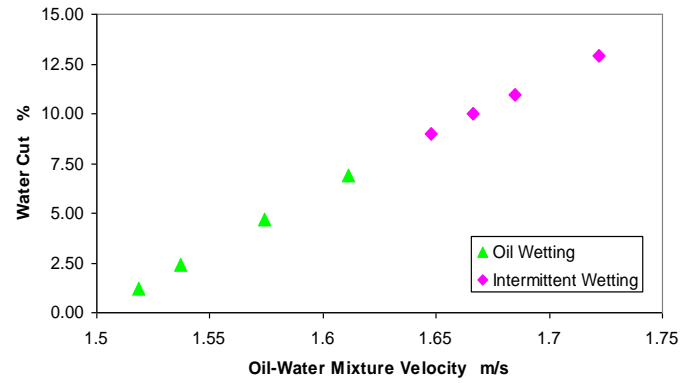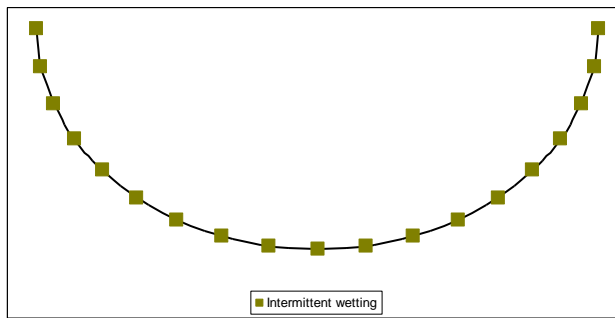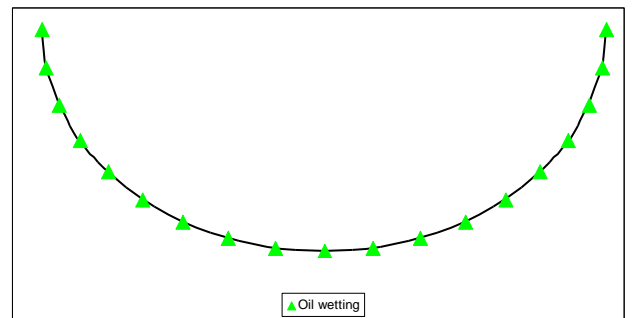

Figure 15 Relationship between water cut and phase wetting at superficial oil velocity of 1.5 m/s

Figure 14 Results of one row of wall conductance probes on the bottom half of pipe circumference at superficial oil velocity 1.5 m/s and superficial water velocity up to 0.22 m/s (water cut up to 12.89%)

Figure 16 Results of one row of wall conductance probes on the bottom half of pipe circumference at superficial oil velocity 2.5 m/s and superficial water velocity up to 0.21 m/s (water cut up to 7.5%)
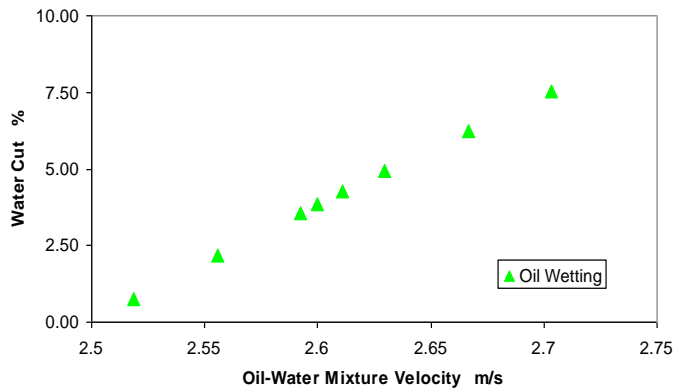
Figure 17 Relationship between water cut and phase wetting at superficial oil velocity of 2.5 m/s
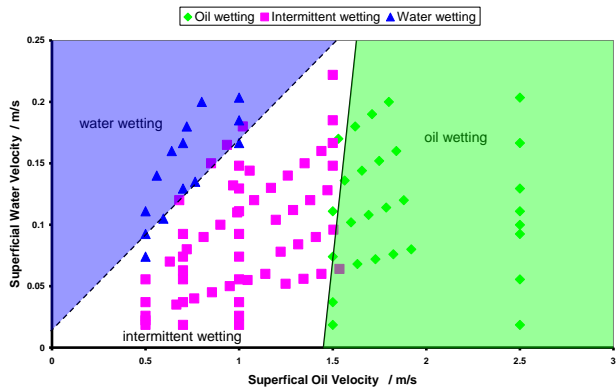

Figure 18 Phase wetting map at different superficial oil and water velocities in the horizontal oil-water two-phase flow