EFFECT OF OIL TYPE ON PHASE WETTING TRANSITION AND CORROSION IN OIL-WATER FLOW

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ABSTRACT

This paper describes an experimental study of water wetting in large diameter horizontal oil-water two-phase flows. Four types of oil, one model oil and three crude oils, have been used in conjunction with a 1 wt% NaCl brine as working fluids. Flow pattern visualization, wall conductance probes, corrosion monitoring and wall fluid sampling were successfully applied in this investigation. Based on the overlapping information from these four techniques, three types of phase wetting regimes (stable water wetting, intermittent wetting and stable oil wetting) were observed. Comprehensive phase wetting maps were constructed where and the boundaries between these water wetting regimes are identified. It was found that the oil type has a significant effect on the transition from stable oil wetting to intermittent wetting and that much of the influence can be ascribed to the physical properties of the oil: density, viscosity and surface/interfacial tension. No corrosion was detected in the stable oil wetting regime, while the corrosion rate in the full water wetting regime was typically twice that observed for the intermittent wetting.

Keywords: corrosion, water entrainment, water wetting, oil-water flow, crude oil

INTRODUCTION

The simultaneous flow of crude oil and water in crude oil production and transportation pipelines as well as corrosive gases such as carbon dioxide (CO_2) and hydrogen sulfide (H_2S) are commonly present in oil gas pipeline systems. The dissolution of corrosive gases into water phase forms a corrosive environment that attacks mild steel pipe walls. Different oil-water flow patterns, which lead to different distributions of oil and water phases on the cross-section of pipe, could exist. Typically at low water cuts corrosion is not an issue because water-in-oil dispersion is observed or all of 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. Once water wets the pipe inner wall, corrosion could exist in these pipelines. The likelihood of corrosion generally increases with the volume fraction of water. Of course, the wetting behavior of the water phase and corrosion rate are affected by other factors, such as water chemistry, type of oil, additives, flow regime, fluid velocity and surface condition of pipe wall.

However, water wetting is one of most important missing link in our current understanding of internal corrosion in the oil and gas mild steel pipelines. In the past, no systematic extensive experimental studies on this topic have been done. It is a difficult challenge for corrosion engineers to determine the flow conditions leading to corrosion and the conditions leading to entrainment of the water layer by the flowing oil phase.

As recently pointed out by Nesic et al.[1] only a handful of studies are available on this topic[2-7] even if it has long been known that water wetting is an issue in CO_2 corrosion. For example, in the well known corrosion prediction model[6] from 1993, the authors included a simple water wetting factor based on water cut and mixture velocity, but pointed out that the effects of a number of other parameters such as protective corrosion productive films, pH, flow pattern, and flow rate should be accounted for in the future. C. de Waard[7] proposed a new empirical model in 2001 by linking the API gravity to the water-in-oil-emulsion stability and considered the effects of the water cut, fluid velocity, and angle of deviation of the tubing. Although this model agreed well with specific set of field data, it does not consider the effects of pipe diameter, oil properties, surface state, and system temperature on the critical velocity of the flowing oil phase required for water entrainment. In 2004 and 2005, a comprehensive hydrodynamic water wetting model was proposed by Cai et al.[1,8] where the effects of many key parameters such as flow rates, water cut, pipe diameter, pipe inclination, oil density, oil viscosity and surface tension are all considered. The model did not account for the effect of steel surface state or chemicals in the water phase that effect the corrosion rate such as corrosion and scale inhibitors or various compounds present in the crude oil.

Clearly, the rather small body of work on water wetting as related to CO_2 corrosion is predominantly of modeling nature. Notwithstanding some anecdotal field experience, there is no systematic empirical on the effect of water wetting.

In order to validate and improve the existing water wetting model (Cai et al.[1,8]), a comprehensive long-term experimental program was initiated at Ohio University in 2004 to study the key factors related to water wetting in two- and three-phase flow. Work on both large and small scale is ongoing and covers model oils as well as crude oils. In this paper, a sample of some recent results obtained in large diameter horizontal oil-water pipe flow is presented. Based on the experimental results, comprehensive phase wetting maps for different oils were developed. These phase wetting maps are critical for liquid ICDA and were used for improving the existing water wetting model[8] and can also be useful references for corrosion engineers and pipeline operators.

EXPERIMENTAL SETUP

The experiments have been conducted at the Institute for Corrosion and Multiphase Technology at Ohio University in a 50 m (200 in) long, 10 cm (4 in) ID multiphase flow loop mounted on a fully inclinable rig specially designed to investigate corrosion and multiphase flow under realistic flow conditions found in the field. FIGURE 1 shows the schematic of the rig. The same experimental setup was used for experiments by Cai et al.[9].

Oil is stored in a 1.2 m^3 stainless steel storage tank. The tank is equipped with two 1 kW heaters and a heat exchanger to maintain a constant temperature. Water with 1 wt% NaCl is stored in a separate 1.2 m^3 stainless steel storage tank with independent temperature control. Oil is pumped through the system using a positive displacement 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 other pumps are used to pump water through the system from the water storage tank.

Oil and water mix in a static T-mixer and the oil-water mixture flows through to a 3 m length flexible hose, which allows the inclination to be set at any angle for this fully inclinable rig. The mixture enters the 10 cm (4 inch) I.D., 14 m long stainless steel straight line section where the phases settle into a stable flow/water wetting pattern before entering a 2 m long "upstream" mild steel test section, where all measurements are carried out. A 2 m long transparent pipe section immediately follows the mild steel section and is used to visualize the flow pattern. After the oil-water mixture flows through a 180 degree bend, it enters into another 14 m long stainless steel pipe section and another 2 m long "downstream" mild steel test section followed by another 2 m long transparent section. The oil-water mixture then flows through a 20 m long 4 inch I.D PVC pipe returning to the oil-water separator. After separation, the water accumulates in the water boot and flows through the valve at the bottom of water boot back to the water storage tank. The separated oil phase flows through the oil outlet at the top of the separator 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).

In order to minimize the effect of oxygen on the corrosion process, the whole flow system is de-oxygenated using pure carbon dioxide (CO_2) before experiments are started. The oxygen concentration in the system is always controlled below 25 ppb.

The two mild steel test sections used in the current study are shown in FIGURE 2. During the experiments, the test section may be corroded which leads to an increase of Fe^{2+} ion concentration in the water phase. Five rows of wall conductance probes (with a staggered row arrangement), a wall sampling port and an ER probe holder are installed and located at the downstream portion of test section. The test sections are connected with the rest of the piping with clamp flanges, which allow the test sections to be rotated by any angle.

Four main techniques were used to determine the water wetting regime on the internal pipe wall at different superficial oil and water velocities in horizontal oil-water flow:

- flow pattern visualization,
- wall conductance probes,
- wall fluid sampling, and
- corrosion rate monitoring.

Visual recordings were made at the transparent test section just downstream of the mild steel test section. Artificial coloring of the water was used to enhance the contrast between oil and water phases. This visual technique works very well with clear model oils, but is not suitable for the tests with crude oils.

The flush mounted wall conductance probes are used to detect the nature of the fluid covering the surface of the pipe internal wall. FIGURE 3(a) shows the wall conductance probes. The probes are epoxy-coated stainless steel pins with 0.45 mm O.D. threaded through a 0.5 mm I.D. hole in the pipe. On the downstream test section, five staggered rows of 18 probes (total of 90 probes) are flush-mounted on the bottom half of the pipe wall covering 180° of the internal circumference. On the upstream test section, five staggered rows of 32 probes (total of 160 probes) are flush-mounted on the whole internal circumference of the pipe wall covering 360°. FIGURE 3(b) shows the staggered configuration of wall conductance probes. This particular arrangement with a large number of spatially distributed probes is used to minimize the errors that plagued such similar effort in the past such as the effect of a water phase deviating or "snaking" around individual probes. Also, this redundant configuration is very useful for characterizing intermittent wetting and for eliminating outliers..

A wall fluid sampling method is used to measure the water/oil content very close to the surface of pipe inner wall by extracting the fluid from the bottom of pipe. A combination of a very precisely controlled needle valve and a solenoid valve used to extract the fluid very close the wall surface through the wall sampling port is shown in FIGURE 3(a). The instrumentation is carefully calibrated so the proper extraction time and amount of suction are applied to minimize erroneous readings.

Since a CO_2 saturated water/oil mixture is circulated through the flow loop it is straightforward to conduct corrosion measurements on the mild steel test section. The corrosion process enables an alternative way to determine water wetting. If water wetting occurs in a given test, corrosion of the mild steel pipe spool occurs and will manifest itself as a rapid 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 to determine the concentration. This increase in ferrous ion concentration over time along with the determined area of water wetting provides an approximate in situ corrosion rate. An ER probe mounted in the test section was also used to monitor the corrosion rate and indirectly determine the water wetting, however the specific values obtained with this probe were not considered accurate and only the trends were used.

Each of these four very different techniques for detection of water wetting has their strengths and weaknesses. For example: the visual technique works very well with clear model oils, but it is not suitable for the tests with crude oils. Fluid sampling at the wall can easily lead to errors if the applied suction is too intense and draws liquid from the upper layers of the fluid or is too weak and allows for escape of the oil from the sample tube. Wall conductance and ER probes both have composite surfaces which may not represent the mild steel corrosion surface properly. The intention was therefore to use the overlapping information from the four techniques to corroborate the various pieces of evidence and to strengthen the confidence in the conclusions.

RESULTS AND DISCUSSION

Four series of experiments were conducted with different oils using 1 wt% NaCl brine and a variety of flow rates. The most important parameters and the test matrix are shown in TABLE 1. The properties of the oils are shown in FIGURE 4 - FIGURE 8. All the results were cross validated with the four different techniques and will be presented below in the following order:

- LVT 200 model oil test series
- SA1 crude oil test series
- SA2 crude oil test series
- SA3 crude oil test series

LVT200 model oil test series

After cross validation by the various techniques, the wall conductance probe data were pulled together in the form of phase wetting maps as shown in FIGURE 9 and FIGURE 10. The details on how the phase wetting maps were created are given previously by Li et al.[10]. The map in FIGURE 9 is generated with water cut and oil-water mixture velocity as the variables while FIGURE 10 shows the same information with superficial oil and superficial water velocities on the axis. It is clear that intermittent wetting is dominant at oil-water mixture velocities lower than 1.5 m/s and water cuts less than 10%. Water separation occurs when the water cut is higher than 10%. It is obvious that at the same oil-water mixture velocity, increasing the water cut leads to a much higher possibility for the coalescence of water droplets and the oil phase does not carry sufficient turbulent energy to disperse the water phase. Stable oil-water stratified flow exists at low velocities although there is still some mixing at the oil-water interface.

Full water entrainment occurs when the oil-water mixture velocity is higher than 1.5 m/s and water cut is lower than 10%. In this case all the water phase flows as water droplets dispersed in the oil phase. In this oil-water mixture velocity range, increasing the water cut leads to a possibility for intermittent phase wetting and corrosion.

It should be stressed that the phase wetting map shown in FIGURE 10 is valid only for the particular oil in horizontal flow with no chemical additives and for clean steel surface conditions. Results generated subsequently show that the map can change substantially as some of the conditions change. However, from the phase wetting map shown in FIGURE 9, it is clear that the commonly used rule of thumb which states that water entrainment occurs at oil velocity higher than 1 m/s at water cut less than 30% is not generally valid.

TABLE 2 shows the fluid sampling results for LVT200 oil and 1 wt% NaCl water in horizontal pipe flow and TABLE 3 shows the corrosion rate results (obtained via the Fe^{2+} concentration monitoring) for LVT200 oil and water in horizontal pipe flow. The results in these two tables, which are discussed at length by Li et al.[10], roughly validate those obtained from wall conductance probes.

SA1 crude oil test series

In comparison with the LVT200 model oil, the SA1 crude oil is lighter (see FIGURE 4), slightly less viscous (see FIGURE 6) and has a significantly lower surface/interfacial tension (see FIGURE 7 and FIGURE 8). On one hand, the lower density of this oil would suggest a higher propensity for separation from water; on the other hand, the lower surface tension points to the opposite effect, i.e. this oil would be easier to "mix" with water.

The phase wetting maps for SA1 crude oil and 1 wt% NaCl in water at different superficial oil and water velocities in horizontal pipe flow are shown in FIGURE 11 and FIGURE 12 as obtained by the wall conductance probes. From these two plots, it is seen that for very low water cuts (<3%) water entrainment happens readily already at 0.8 m/s mixture velocity. However the entrainment velocity

rapidly increases with water cut what is in stark contrast with the behavior of the LVT200 model oil. At water cut of 10% this light oil is unable to entrain the water even at 2 m/s mixture velocity.

The results from the wall fluid sampling method for SA1 crude oil and 1 wt% NaCl water at different superficial oil and water velocities in horizontal pipe flow (shown in TABLE 4) are roughly consistent with those obtained from the wall conductance probes. At an oil-water mixture velocity of 0.8 m/s and water cuts of 1% and 4%, the water concentrations in the fluid samplings were up to 60% and 80%, respectively. The wall conductance probes showed intermittent wetting at those flow conditions. With increasing water cuts to 5% and 10% at the same mixture velocity, water concentrations in the fluid samplings increase to 90% and 99%, which indicates that stable water wetting occurs and a pure water layer formed at the bottom of pipe. When the results for a water cut of 10% are compared under mixture velocities of 0.8 m/s and 1.3 m/s, it is seen that the water concentration in the fluid sample decreases from 99% to 70%, which indicates that more water is entrained in the oil phase since higher oil flow rate leads to higher turbulence and higher mixing. From results of the wall conductance probes, the phase wetting changed from stable water wetting to intermittent wetting. However in many instances where stable oil wetting was detected, some water was seen in the samples. This shows that while the fluid sampling technique results show trends which are consistent with the wall conductivity measurements, they alone cannot provide the information to identify which fluid is wetting the wall.

TABLE 5 shows the corrosion rate results (via Fe^{2+} monitoring) for SA1 crude oil for an oil-water mixture velocity of 0.7 m/s and water cut of 15%. These conditions are expected to produce water wetting according to the phase wetting map of SA1 crude oil in horizontal pipe flow (FIGURE 11). The increase in Fe^{2+} concentration during flow loop tests confirmed the water wetting results obtained from the wall conductance probes. The ER probes showed the same behavior.

SA2 crude oil test series

The SA2 crude oil is similar to the LVT200 model oil, in terms of density (see FIGURE 4), however it is significantly more viscous than the LVT200 or the SA1 crude oil (see FIGURE 6) suggesting that it may be more effective in entraining water. Similarly to the SA1 crude oil, the SA2 exhibits rather low surface/interfacial tension (see FIGURE 7 and FIGURE 8) reinforcing the same expectation.

In FIGURE 13 and FIGURE 14 the phase wetting maps for SA2 crude oil and 1 wt% NaCl water at different superficial oil and water velocities in horizontal pipe flow are shown based on the wall conductance probe data. From these two phase wetting maps, it is seen that for the lower end of water cuts (<5%) this oil is able to entrain all of the water at 0.7 m/s mixture velocity. However, as more water is added, the entrainment velocity increases to 1 m/s at 10% water cut and 1.3 m/s at 20% water cut.

In order to confirm the accuracy of results obtained from the wall conductance probes, fluid sampling at the wall is shown in TABLE 6. At mixture velocity of 0.6 m/s and water cut up to 5%, it is seen that liquid sampling recovers about 90% water and 10% of oil. This is consistent with the occurrence of intermittent wetting determined by wall conductance probes. When the input water cut is between 8% and 10%, it is seen that liquid samples have about 99% of water and 1% of oil. When the input water cut is 15% or higher, the fluid sample only contains water. This denotes a pure water layer formed at the bottom of pipe. At a mixture velocity of 1.0 m/s and a 3% water cut, which are conditions with stable oil wetting according to the water wetting maps, the water concentration in the sample is still 10%. Even at a mixture velocity of 2 m/s and low water cuts, the water concentration in the fluid sample is still measurable at about 5%. This suggests that the oil-water mixture close to the bottom of pipe wall can be characterized as water-in-oil suspension with oil wetting the pipe wall.

TABLE **7** shows corrosion rate results (obtained via the Fe^{2+} concentration monitoring) for SA2 crude oil and water in horizontal pipe flow. At a high mixture velocity of 0.9 m/s and water cut of 4% where oil wetting is seen, no corrosion is detected (the Fe^{2+} does not increase with time). If the water cut is increased to 8% at the same mixture velocity, which was identified as intermittent wetting, corrosion occurs and a corrosion rate of 1.8 mm/y is measured. When even more water is present (water cut of 12%) and leads to stable water wetting, the corrosion rate increases to 3.9 mm/y i.e. the corrosion rate under stable water wetting is almost double of that under intermittent wetting condition. The ER probes qualitatively confirmed this behavior.

SA3 crude oil test series

The SA3 crude oil is the heaviest oil tested in this series (see FIGURE 4), and it is significantly more viscous than the rest (see FIGURE 6) suggesting that it should be the most effective in entraining water. The SA3 exhibits the same surface/interfacial tension as the other two lighter crude oils tested (see FIGURE 7 and FIGURE 8).

FIGURE 15 and FIGURE 16 show the phase wetting maps for SA3 crude oil and 1 wt% NaCl water at different superficial oil and water velocities in horizontal pipe flow. While some data for the very low water cuts are not available, it can be seen that this oil is more effective in entraining when little water is present, e.g. at 7% water cut all water was entrained already over 0.5 m/s. When more water is present this threshold velocity increases but even for very high water cuts it is just over 1 m/s/. TABLE 8 shows the fluid sampling results for SA3 crude oil and 1 wt% NaCl water in horizontal pipe flow. Similar trends were seen as with the other oils with water present in the samples even in conditions where stable oil wetting was measured.

TABLE 9 shows the corrosion measurements (via Fe^{2+} concentration monitoring) for SA3 crude oil and 1 wt% NaCl in horizontal pipe flow. In the case when oil wetting is detected by the conductivity probes, no corrosion could be measured. In intermittent wetting conditions, the corrosion rate was measured to be 1.3 mm/y while under stable water wetting it increased to 2.8 mm/y.

Summary

It appears that the transition line between stable oil wetting and intermittent wetting, which is really the demarcation line of corrosion/no-corrosion, was different for all the oils tested. Notwithstanding any arguments based on oil chemical composition, it seems that the differences in the physical properties of the oils give us some clues why the various water wetting outcomes appear.

The surface and interfacial tension clearly are very significant parameters which were easy to distinguish in the present series of experiments. All three crude oils have a significantly lower surface tension and oil/water interfacial tension when compared to the LVT200 model oil. This resulted in much easier entrainment (at lower crude velocity) particularly at lower water cuts (<10%). Lower oil/water interfacial tension generally denotes an oil which will more readily "mingle" with water. More precisely lower oil/water interfacial tension means that the interface between oil and water is "looser" and easier to breakup by the mechanical action of fluid turbulence resulting in smaller droplets. In the case of a water-in-oil suspension, smaller water droplets are easier to keep entrained as the effect of gravity on

them is diminished. Lower surface tension suggests that the oil will more readily wet the steel surface and displace the water from it.

Oil density and viscosity also seemed to play a role although it is more difficult to distinguish them in the present series of experiments. It is believed that the differences in these two parameters, seen amongst the three crude oils, played a significant role particularly at the higher water cuts where increased density and viscosity helped entrain the large amounts of water and keep it in suspension. High density oils will clearly make it is easier to keep water suspended as any gravity effects are diminished as the density of the oil approaches that of water. While oil density may also have some effect on momentum exchange between oil and water, it is thought that viscosity plays a major role here, i.e. it leads to easier entrainment of water.

CONCLUSIONS

Comprehensive phase wetting maps for model oil and three crude oils were built based on the overlapping information obtained from four different techniques. Three types of phase wetting regimes: stable water wetting, intermittent wetting and stable oil wetting were identified and the boundaries between these regimes were determined.
- No corrosion occurred when the pipe wall is fully wetted by the oil, whereas intermittent wetting and full water wetting lead to significant corrosion, the latter being twice the rate of the former.
- The oil type has a significant effect of the wetting behavior and corrosion; some of the effects can be readily explained by the differences in their physical properties.

ACKNOWLEDGEMENT

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TABLE 1. Main test parameters for LVT200, SA1, SA2 and SA3 oils.

Oil phase	LVT200, SA1, SA2 and SA3 oils
Water phase	1 wt% NaCl brine
Superficial oil velocity	0.5 - 2.0 m/s
Superficial water velocity	0 - 0.22 m/s
Water cut	0 - 20%
Pipe inclination	horizontal
Pipe diameter	10 cm (4 in)
System temperature	25 °C
System pressure	0.13 MPa

TABLE 2. Water concentration in the fluid samples for LVT200 oil in horizontal pipe flow at different superficial oil velocity and different superficial water velocities.

Oil-water mixture velocity (m/s)	Water cut (%)	Water concentration in the fluid sample (%)	Comments	Phase Wetting From Wall Conductance Probes
0.519	3.66	99		Water wetting
0.522	4.21	99		Water wetting
0.556	10.07	99		Water wetting
0.574	12.89	100		Water wetting
0.593	15.68	100		Water wetting
1.019	1.86	50		Intermittent wetting
1.037	3.57	75		Intermittent wetting
1.056	5.30	90		Water wetting
1.15	13.04	99		Water wetting
1.17	14.53	100		Water wetting
1.19	15.97	100		Water wetting
1.2	16.67	100		Water wetting
1.519	1.25	1	Unstable emulsion	Oil wetting
1.574	4.70	10	Unstable emulsion	Intermittent wetting
1.61	6.83	20	Unstable emulsion	Intermittent wetting
1.65	9.09	40	Unstable emulsion	Intermittent wetting
1.69	11.24	60	Unstable emulsion	Intermittent wetting
1.72	12.79	60	Unstable emulsion	Intermittent wetting
2.519	0.75	5	Emulsion	Oil wetting
2.556	2.19	5	Emulsion	Oil wetting
2.593	3.59	4	Emulsion	Oil wetting
2.6	3.85	2	Emulsion	Oil wetting
2.67	6.37	2	Emulsion	Oil wetting
2.7	7.41	2	Emulsion	Oil wetting

TABLE 3. Fe^{2+} concentration change under different phase wettings in LVT200 oil-water horizontal flow.

Oil-water mixture velocity (m/s)	Water cut (%)	Testing time (Min.)	Fe^{2+} change (ppm)	Phase wetting	pH	CR (mm/yr)
0.6	16	30	1.32	Water wetting	4.71	1.6-1.8
0.8	14	30	0.57	Intermittent wetting	4.86	0.8-1.1
1.6	7	30	0	Oil wetting	4.82	0

TABLE 4. Water concentration in the fluid samples for SA1 crude oil-water in horizontal pipe flow at different oil-water mixture velocities and water cuts.

Oil-Water Mixture Velocity m/s	Input Water Cut %	Water Concentration by Volume %	Phase Wetting From Wall Conductance Probes
0.8	1	60	Intermittent Wetting
0.8	4	80	Intermittent Wetting
0.8	5	90	Water Wetting
0.8	10	99	Water Wetting
0.9	3	10	Oil Wetting
0.9	5	80	Intermittent Wetting
0.9	10	99	Water Wetting
1.0	4	5	Oil Wetting
1.0	7	80	Intermittent Wetting
1.0	10	95	Water Wetting
1.3	6	5	Oil Wetting
1.3	10	70	Intermittent Wetting
1.5	6	5	Oil Wetting
1.5	10	70	Intermittent Wetting
2.0	8	5	Oil Wetting
2.0	10	50	Intermittent Wetting

TABLE 5. Fe^{2+} concentration change under water wetting in SA1 crude oil-water horizontal flow and the estimate of the corresponding corrosion rate.

Oil-water mixture velocity (m/s)	Water cut (%)	Testing time (Min.)	Fe^{2+} change (ppm)	Phase wetting	CR (mm/y)
0.7	15	30	1.9	Water wetting	2.3
0.7	15	30	2.4	Water wetting	

TABLE 6. Water concentration in the fluid samples for SA2 crude oil-water in horizontal pipe flow at different oil-water mixture velocities and water cuts.

Oil-Water Mixture Velocity m/s	Input Water Cut %	Water Concentration by Volume %	Comments	Phase Wetting From Wall Conductance Probes
0.6	5	90		Intermittent Wetting
0.6	8	99		Water Wetting
0.6	10	99		Water Wetting
0.6	15	100		Water Wetting
0.7	3	5		Oil Wetting
0.7	5	90		Intermittent Wetting
0.7	8	99		Water Wetting
0.7	10	99		Water Wetting
0.7	15	100		Water Wetting
0.8	3	5		Oil Wetting
0.8	5	5		Oil Wetting
0.8	8	90		Intermittent Wetting
0.8	10	90		Intermittent Wetting
0.8	15	99		Water Wetting
0.9	3	10		Oil Wetting
0.9	5	10		Oil Wetting
0.9	8	10		Oil Wetting
0.9	10	90		Intermittent Wetting
0.9	15	99		Water Wetting
1	3	10	unstable emulsion	Oil Wetting
1	5	10	unstable emulsion	Oil Wetting
1	8	10	unstable emulsion	Oil Wetting
1	10	80	unstable emulsion	Intermittent Wetting
1	15	80	unstable emulsion	Intermittent Wetting
1	20	99	unstable emulsion	Water Wetting
1.1	3	8	unstable emulsion	Oil Wetting
1.1	5	8	unstable emulsion	Oil Wetting
1.1	8	8	unstable emulsion	Oil Wetting
1.1	10	7	unstable emulsion	Oil Wetting
1.1	15	80	unstable emulsion	Intermittent Wetting
1.1	20	80	unstable emulsion	Intermittent Wetting
1.3	5	5	unstable emulsion	Oil Wetting
1.3	10	8	unstable emulsion	Oil Wetting
1.3	13	8	unstable emulsion	Oil Wetting
1.3	15	8	unstable emulsion	Oil Wetting
1.3	17	80	unstable emulsion	Intermittent Wetting
1.7	5	5	unstable emulsion	Oil Wetting
1.7	10	5	unstable emulsion	Oil Wetting
2	5	5	unstable emulsion	Oil Wetting
2	10	5	unstable emulsion	Oil Wetting

TABLE 7. Fe^{2+} concentration change under different phase wettings in SA2 crude oil-water horizontal flow and the estimate of the corresponding corrosion rate.

Oil-water mixture velocity (m/s)	Water cut (%)	Testing time (Min.)	Fe^{2+} change (ppm)	Phase wetting	CR (mm/y)
0.9	4	10	0	Oil wetting	0
0.9	8	10	0.2	Intermittent wetting	1.8
0.9	12	10	0.4	Water wetting	3.9

TABLE 8. Water concentration in the fluid samples for SA3 crude oil-water in horizontal pipe flow at different oil-water mixture velocities and water cuts.

Oil-Water Mixture Velocity m/s	Input Water Cut %	Water Concentration by Volume %	Phase Wetting From Wall Conductance Probes
0.6	7	5	Oil Wetting
0.6	10	70	Intermittent Wetting
0.6	15	99	Water Wetting
1.0	10	5	Oil Wetting
1.0	13	80	Intermittent Wetting
1.0	15	95	Water Wetting

TABLE 9. Fe^{2+} concentration change under different phase wettings in SA3 crude oil-water horizontal flow and the estimate of the corresponding corrosion rate.

Oil-water mixture velocity (m/s)	Water cut (%)	Testing time (Min.)	Fe^{2+} change (ppm)	Phase wetting	CR (mm/y)
0.6	5	30	0	Oil wetting	0
0.6	8	30	0.18	Intermittent wetting	1.3
0.6	15	30	0.44	Water wetting	2.8
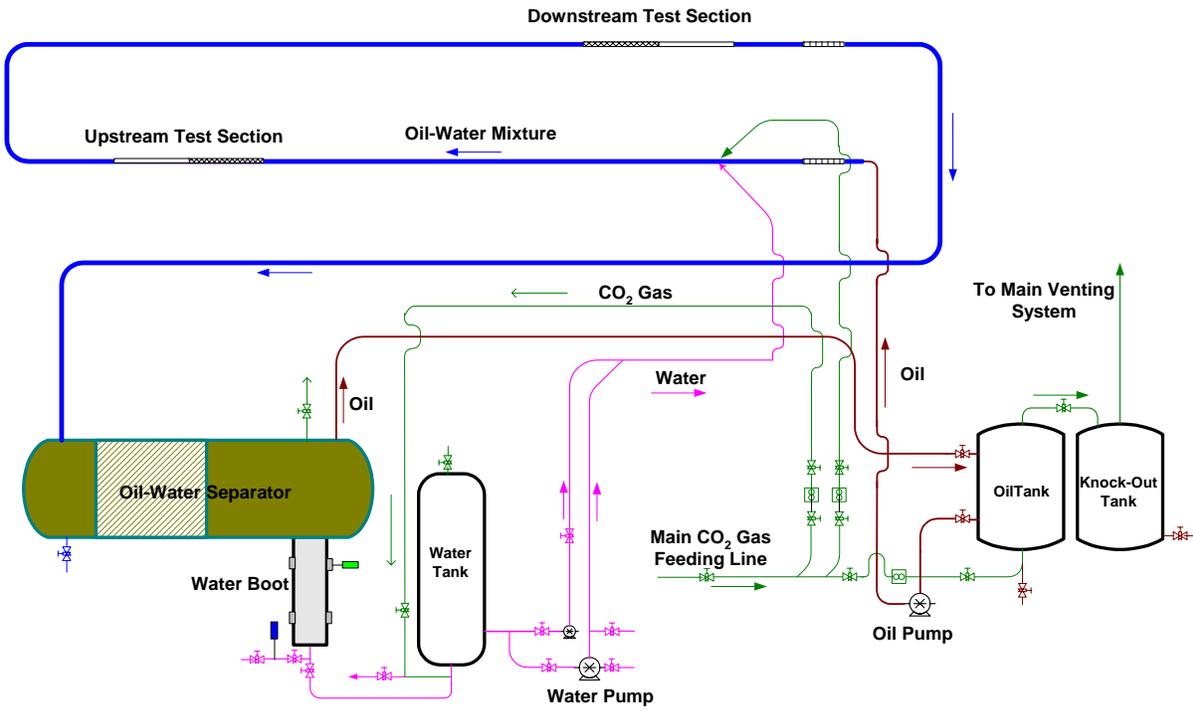
FIGURE 1. Schematic of 4-inch I.D. fully inclinable multiphase flow loop.
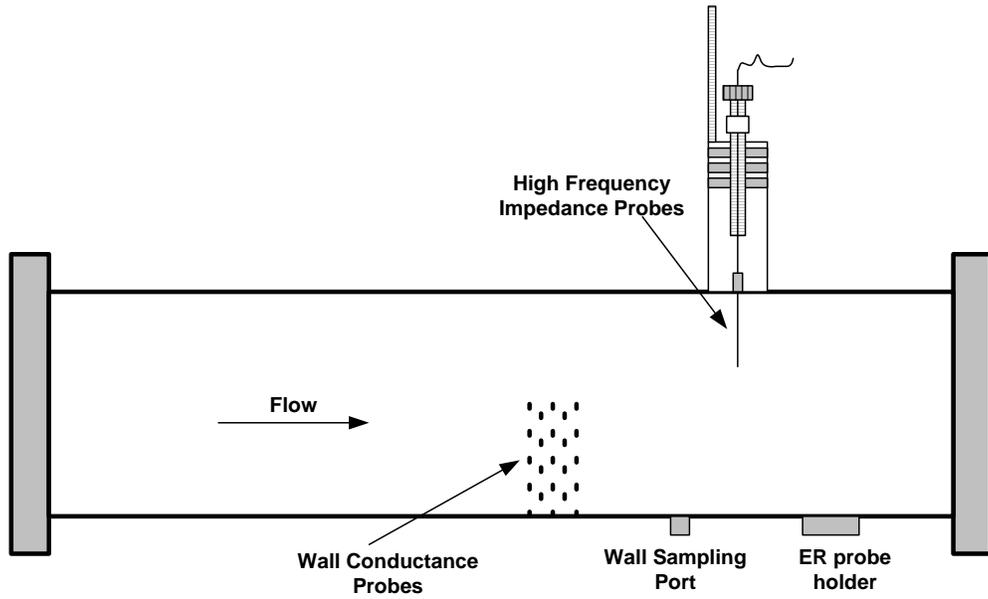
FIGURE 2. Schematic of the test section.
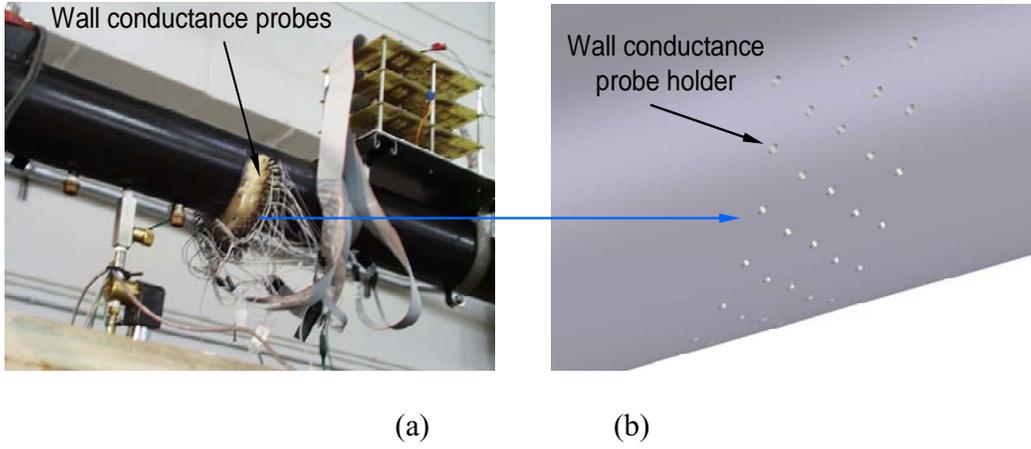
FIGURE 3. Wall conductance probes.

(a) wall conductance probes on the test section
(b) 5 rows of staggered configuration of probe holders
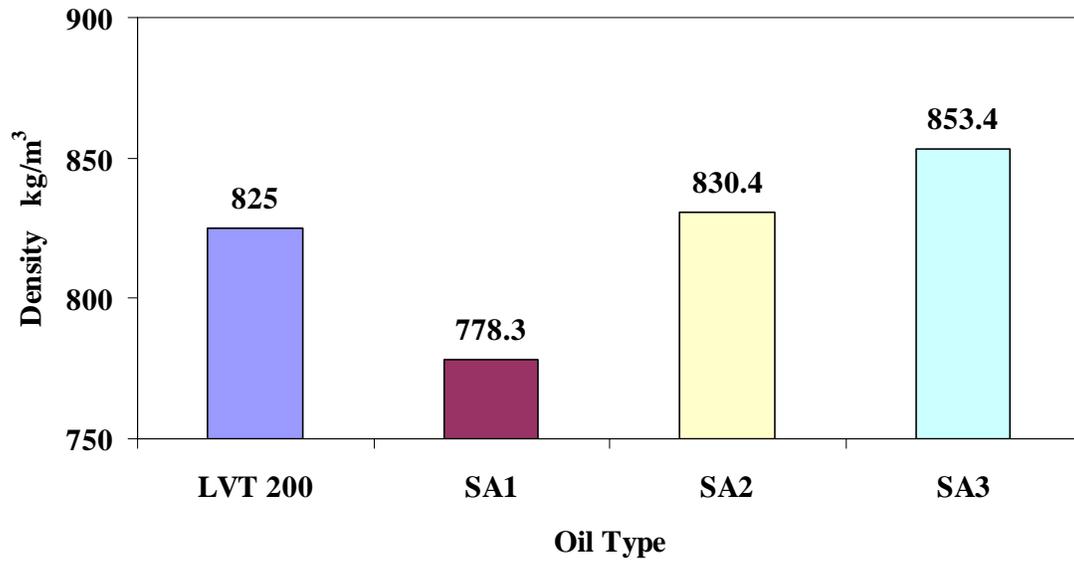
FIGURE 4. Densities of the oils at 80 $^{\circ}$F.
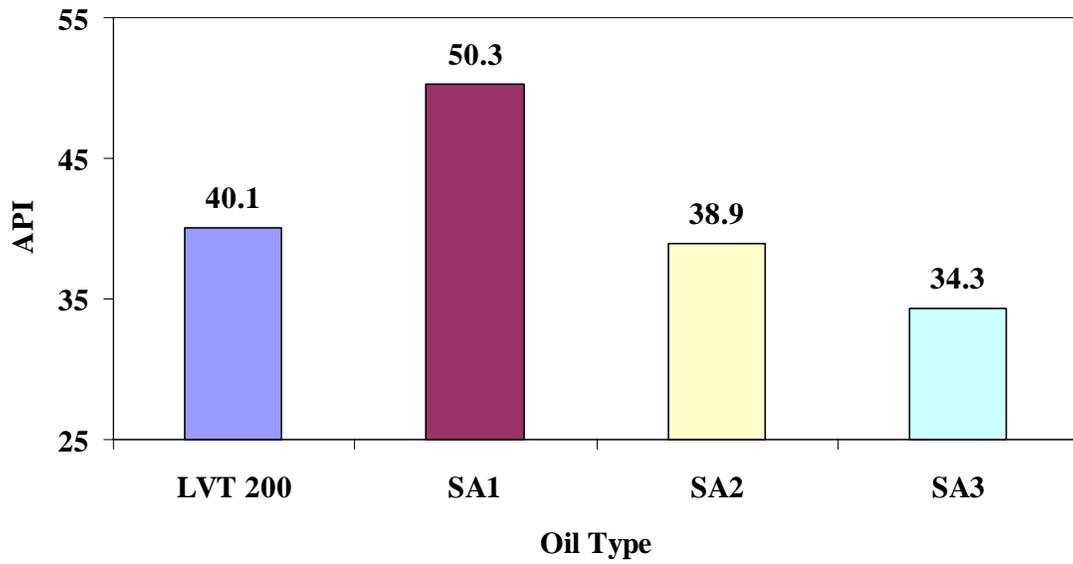
FIGURE 5. API Gravities of the oils at 80 ^{o}F.
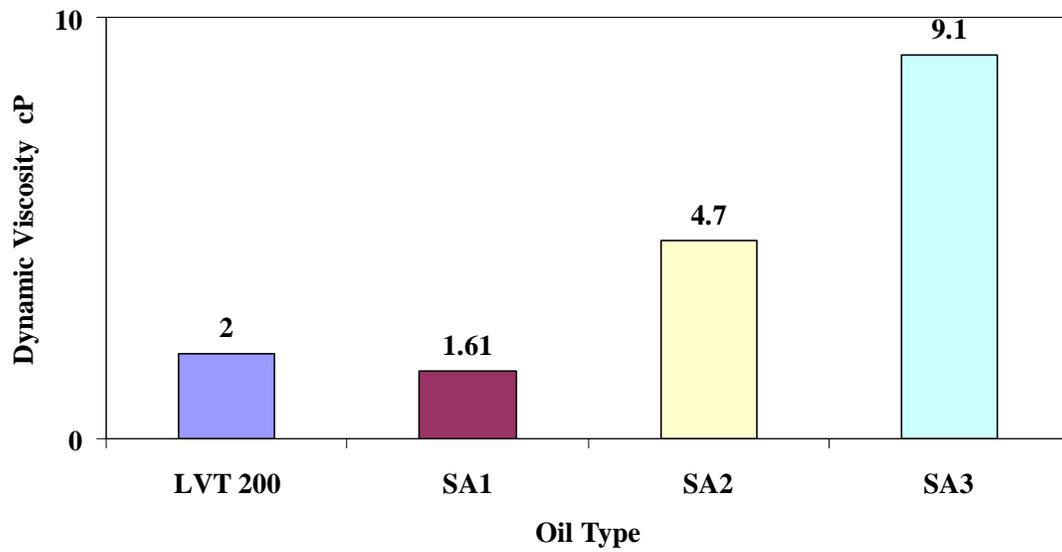
FIGURE 6. Viscosities of the oils at 70 ^{o}F.
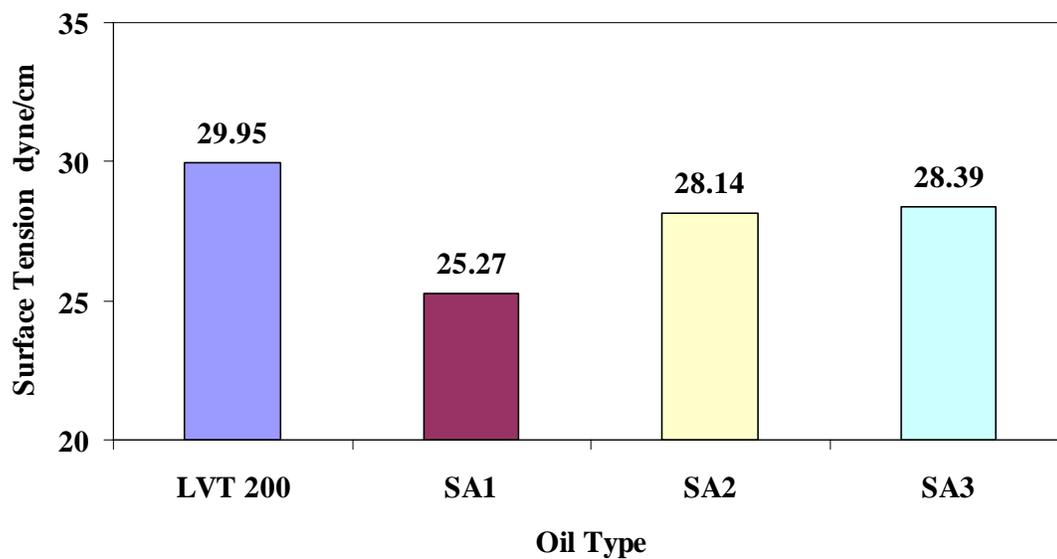
FIGURE 7. Surface tension of the oils at 80 ^{o}F.
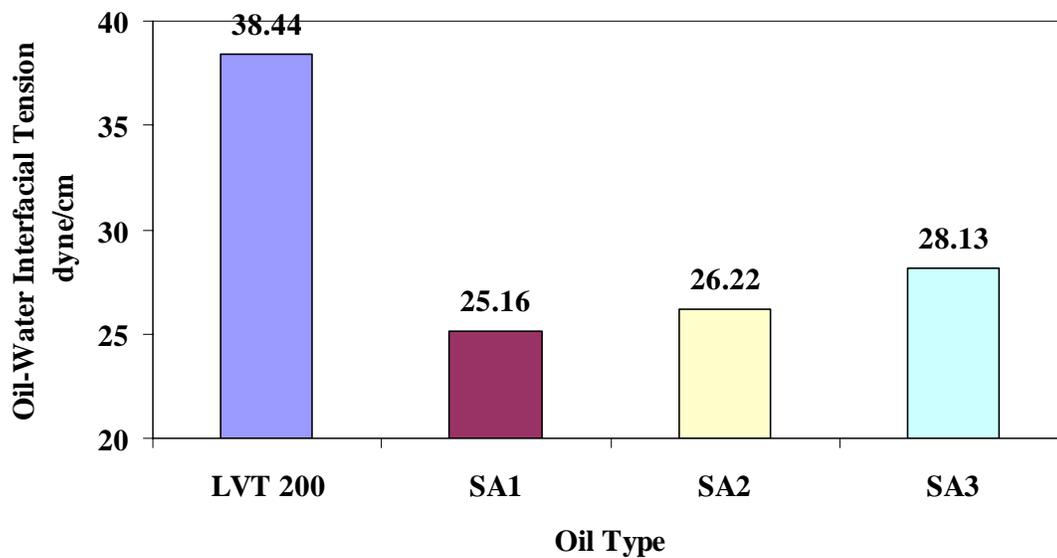
FIGURE 8. Oil-water interfacial tension of the testing oils at 80 ^{o}F.
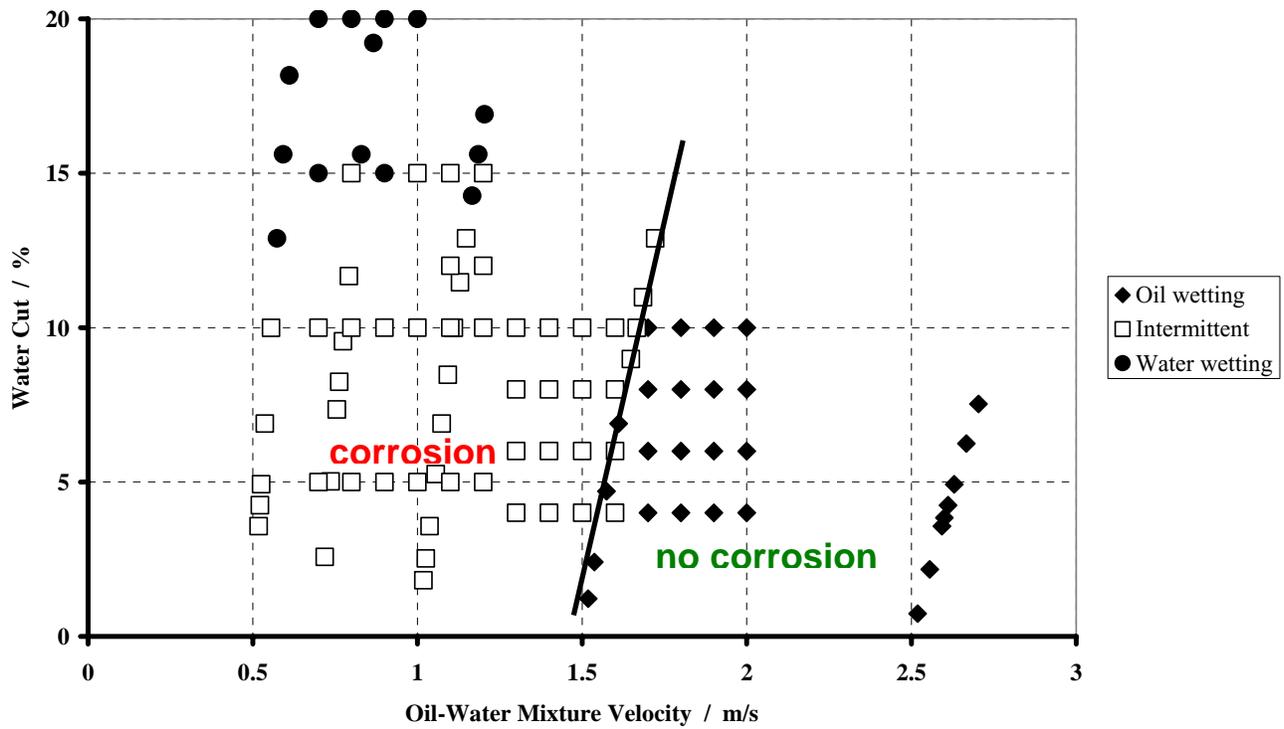
FIGURE 9. Phase wetting map for LVT200 oil at different oil-water mixture velocities and water cuts in the horizontal oil-water two-phase flow.
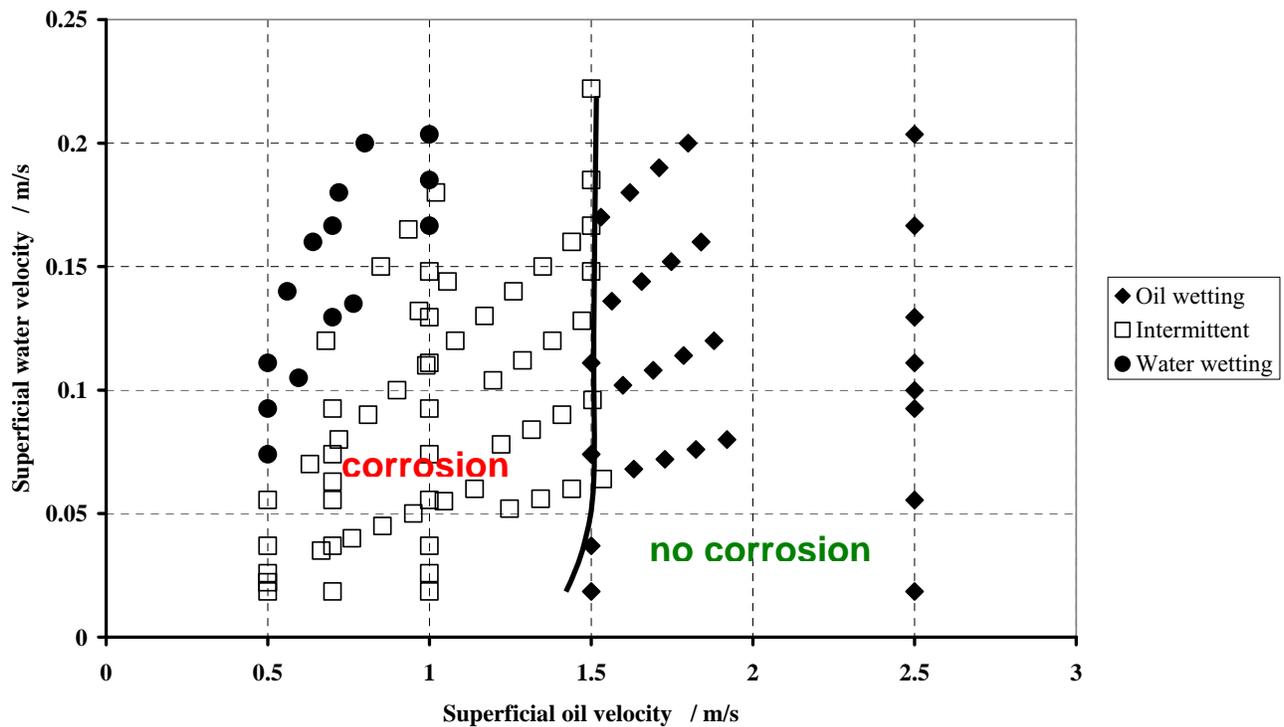
FIGURE 10. Phase wetting map for LVT200 oil at different superficial oil and water velocities in the horizontal oil-water two-phase flow.
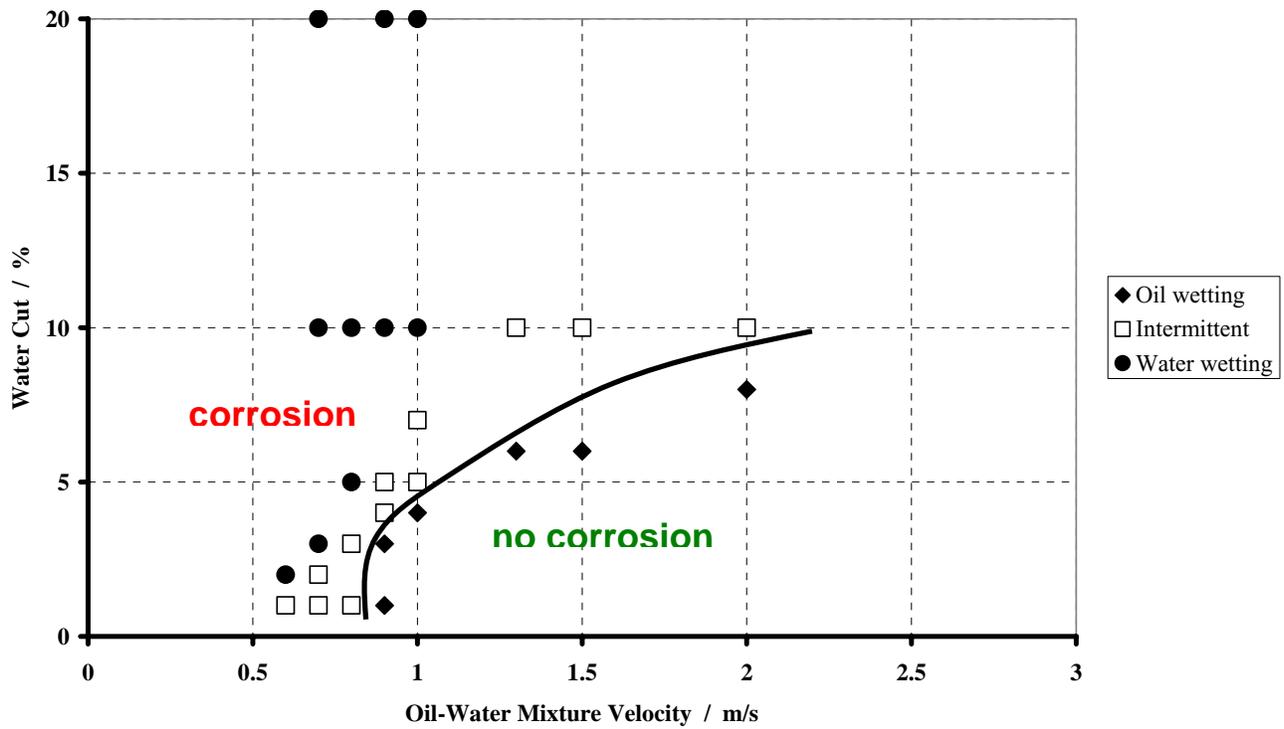
FIGURE 11. Phase wetting map for SA1 oil at different oil-water mixture velocities and water cuts in the horizontal oil-water two-phase flow.
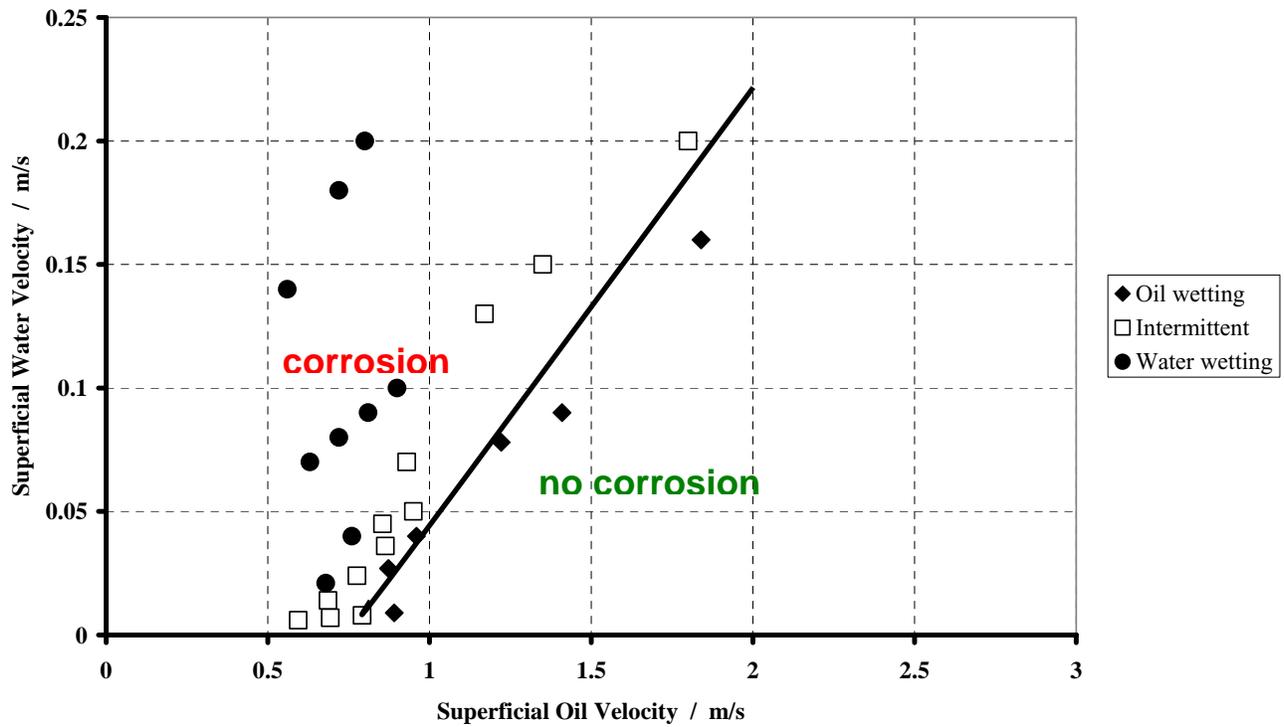
FIGURE 12. Phase wetting map for SA1 oil at different superficial oil and water velocities in the horizontal oil-water two-phase flow
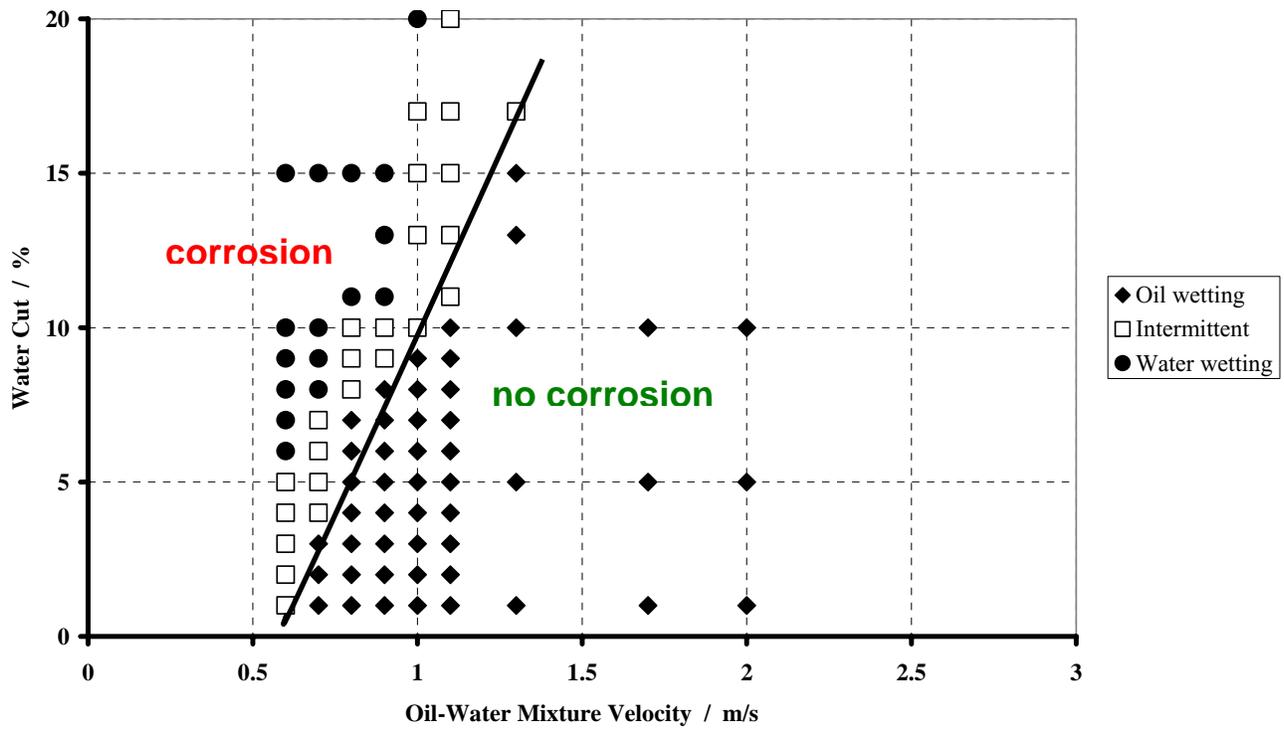
FIGURE 13. Phase wetting map for SA2 oil at different oil-water mixture velocities and water cuts in the horizontal oil-water two-phase flow.
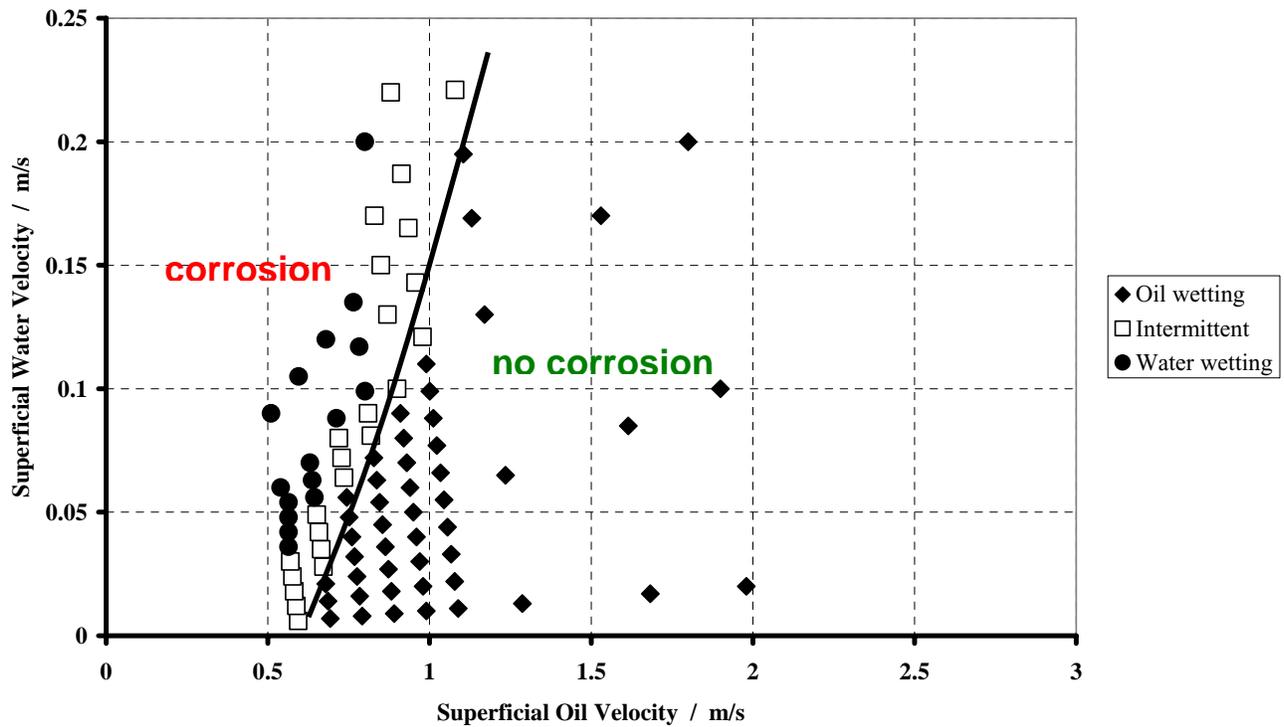
FIGURE 14. Phase wetting map for SA2 oil at different superficial oil and water velocities in the horizontal oil-water two-phase flow.
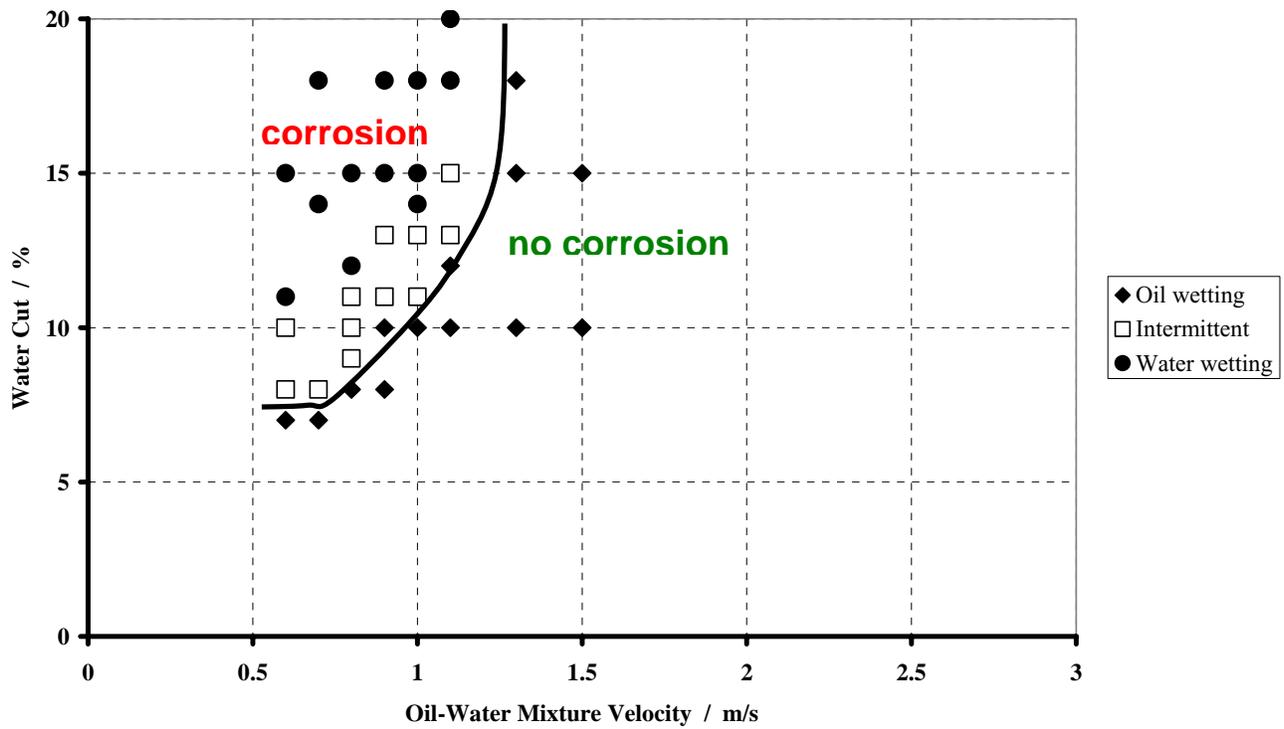
FIGURE 15. Phase wetting map for SA3 oil at different oil-water mixture velocities and water cuts in the horizontal oil-water two-phase flow.
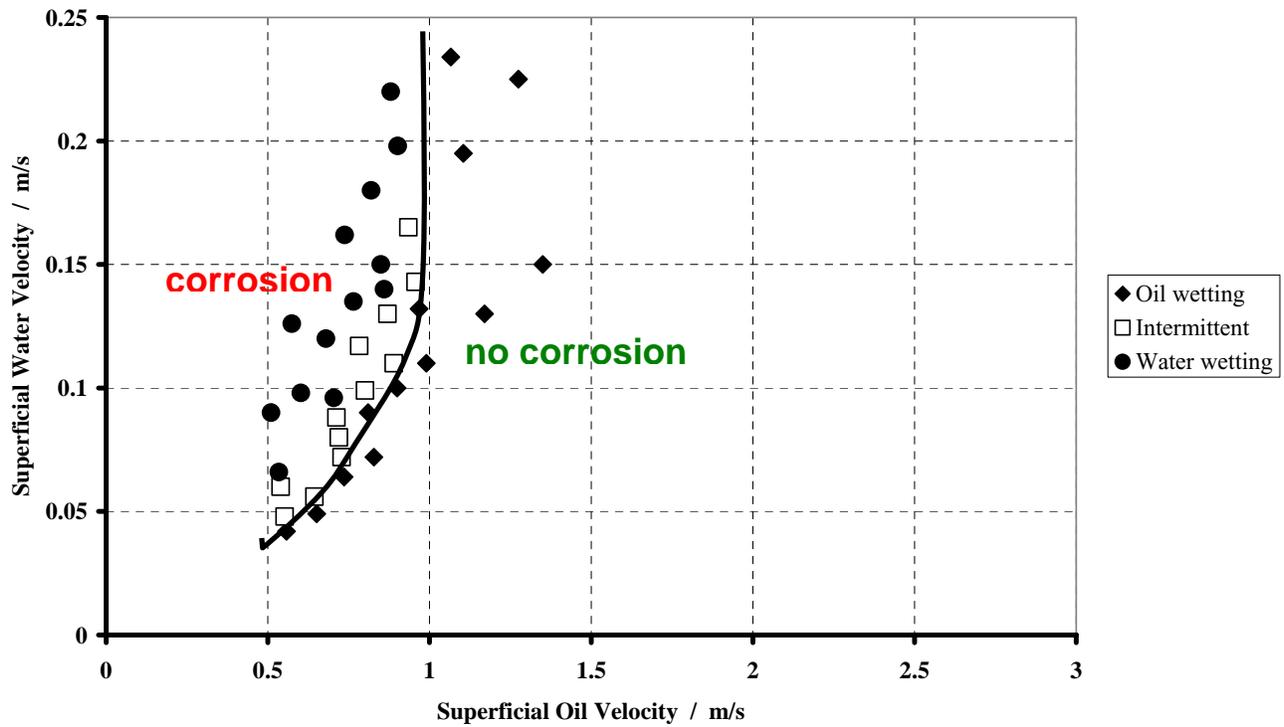
FIGURE 16. Phase wetting map for SA3 oil at different superficial oil and water velocities in the horizontal oil-water two-phase flow.