SPE-171079-MS

Flow Assurance Applied Research Proposal for Heavy Oil Crudes from Green Offshore Naturally Fractured Reservoirs to Delivery Points

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This paper was prepared for presentation at the SPE Heavy and Extra Heavy Oil Conference - Latin America held in Medellin, Colombia, 24–26 September 2014.

Abstract

This paper presents a research project proposal to ensure the optimum flow assurance for the development of heavy crudes, from offshore reservoirs to delivey points, considering several field facilities, which include optimum application and performance of chemicals to suppress or attenuate the precipitation of organic and inorganic deposits, corrosion inhibitors, as well as the treatment of emulsions produced due to the presence of formation water during production. The interaction between chemicals employed in well stimulation treatments and those used for crude dehydration is also considered.

This proposal intends setting the basis to optimize flow assurance by minimizing the chemical dosage in the production and transportation facilities, maximizing the useful life of the employed chemical products. In order to achieve this goal it is necessary to include;

- Laboratory studies to characterize heavy oil, water and gas properties and the interactions between the different fluids present, which allow evaluating the generation and stability of emulsions, hidrocarbons stability, and corrosion index of water, for example.
- Evaluation of chemicals for flow assurance in the reservoir, lifting fluids in production wells, including artificial lift systems, as well as surface transportation and treatment fluids, and the interaction between these chemicals at different points during hydrocarbons production.
- Generation of reservoir, well completion, wellbore and surface transport models.

Pressure analyses show that production is dominated by high porosity vugs, and that the vertical permeability of vuggy areas is relevant for fields sharing an aquifer due to water channeling and the possible formation of emulsions inside the reservoir in the reion close to the producing wells.

The assessement of the aforedmentioned issues can lead to the control and/or prevention of emulsion formation, solids deposition and corrosion. Besides, addressing each of these issues individually, it is important to assess the influence of a mixture of several chemicals at the bottomhole and surface facilities, providing useful information to anticipate and avoid additional complications derived from the application of several chemicals to address flow assurance problems from the reservoir to the delivery points.

Table 1—Fields of heavy and extra-heavy oil divided in different development phases.

Property / Fields	M	A-1	A-DL1	T	K-1	Kan	Nab	N	Y	B	Pi-1	Pi-DL1	Ts- K	Ts JSK	P-K	P-JSK
°API	13.7	10.5	11.1	11	8.1	6.0	8.8	9.2	9	9.6	9.6	11.4	8.2	8.0	8.5	12
Viscosity (cp)	12	17.1* 118 °C	42 122 °C	42 110 °C	550 83 °C	1539 78 °C	310 78 °C	2437 80 °C	112 103.1°C	292 80 °C	404.7 101 °C	46.6	82.48 102.9 °C	59 83 °C	35 96 °C	-
RGA@Pb (m^3/m^3)	60	20.3	21.7	16.6	14.1	16.5	14.2	15	28.8	18.2	13.3	22.7	42.9	45.7	35.4	75.09
Pb (kg/cm^2)	138	48	55.05	42.09	37	33	34	34	54	42	57.37	82.47	143	151.3	92	-
T (°C)	118	119	122	110	85	78	71	80	103.1	82	101	112	95	102.9	98	120
Water depth (m)	100	121	121	125	154	450	681	175	159	160	125	-	100	100	100	100
H_2S (% mol) gas	4.84	7.06	21.012	28.8	4.1	9.5	0.51	7.11	11.8	5.1	1.4	3.2	7.5	11.7	10.4	
CO_2 (% mol) gas	5.23	18.7	16.2	20	11.1	7.1	0.93	3	6.2	4.9	5.7		8.6			
Bo@Pb (Vol/Vol)	1.25	1,159	1,139	1,099	1,126	1,078	1,083	1,046	1,111	1,093	1,112	1,121	1.13	1.18	1,202	-
C_{12}^+ (% mol)	34.42	56.8	49.82	51.46	63.1	65.13	62.74	64.09	48.04	57.83	63.86	47.02	42.4	41.86	48.11	-
kh (mD-ft)	1.25 e6	2.25 e6	3.37 e5	8.36	2.72 e6	N/D	7.73 e5	2.15 e6	12.3 e6	3.86 e6	24.3 e6	-	22.7 e6	16.6 e6	0.3 e6	6.78 e5
PI ($bpd/kg/cm^2$)	1102	1152	327	384	85	N/D	28	1	214	142	95	-	761	57	10	-
Oil rate (bpd)	7000	3712.5	3822	6206	2300	<100	2000	518*	2953	2018	3216	8078	3192	3071	194	1709
P_i (kg/cm^2)	320	252.6 @4000m	261.8 @4217m	186 @3242m	310	283	272	291	376	316	342 @3325m	387 @3770m	224	249	202	147
Reservoir depth (m)	3030	3800	4235	3285	2570	2577	2590	2425	3081	3005	3375	3820	2575	2883	3070	3700
			Phase 1				Phase 2				Phase 3			Phase 4		

Introduction

In the South-East Gulf of Mexico there is a heavy crude development project that includes 18 fields. The closest and the farthest fields to the coast are 130 and 145 km from the coast, respectively. The majority of the wells drilled in this area are exploratory. Up to date, two types of reservoirs have been found, one in the Cretaceous and another one in an oolitic bank of the upper Jurassic Kimmeridgian. In the Cretaceous, the main productive formation is a brecchia, which is made up of fragments of mudstone-wackestone, occasionally packstone with intercrystalline porosity, and secondary porosity in networks of fractures and dissolution cavities (vugs). Although, the porosity in the matrix is low, the secondary porosity is high due to diagenetic processes; especially vugular porosity is abundant, observing in some cases dissolution caves.

These offshore fields have crude oil viscosities ranging from 42 to 1220 cP, with water depths of 100 to 681 m, and a high content of H2S, from 1.72 to 28.79% mol gas, and CO2, from 4.45 to 31% mol gas (see Table 1).

From the 18 fields, the two closest to the coast exhibit lower water depths and higher API density (10.5 and 13 oAPI), and they will be developed during the first stage of the project (Phase 1). After Ref. 1

The A-1 well penetrated 160 m of the brecchia, in the Cretaceous, producing 4126 STB/d of 10.5°API oil. In addition, for the A-DL1 well, the water-oil contact was determined in the Cretaceous at 4228 m depth, using resistivity logs. While the T-1 well produced 13° API oil.

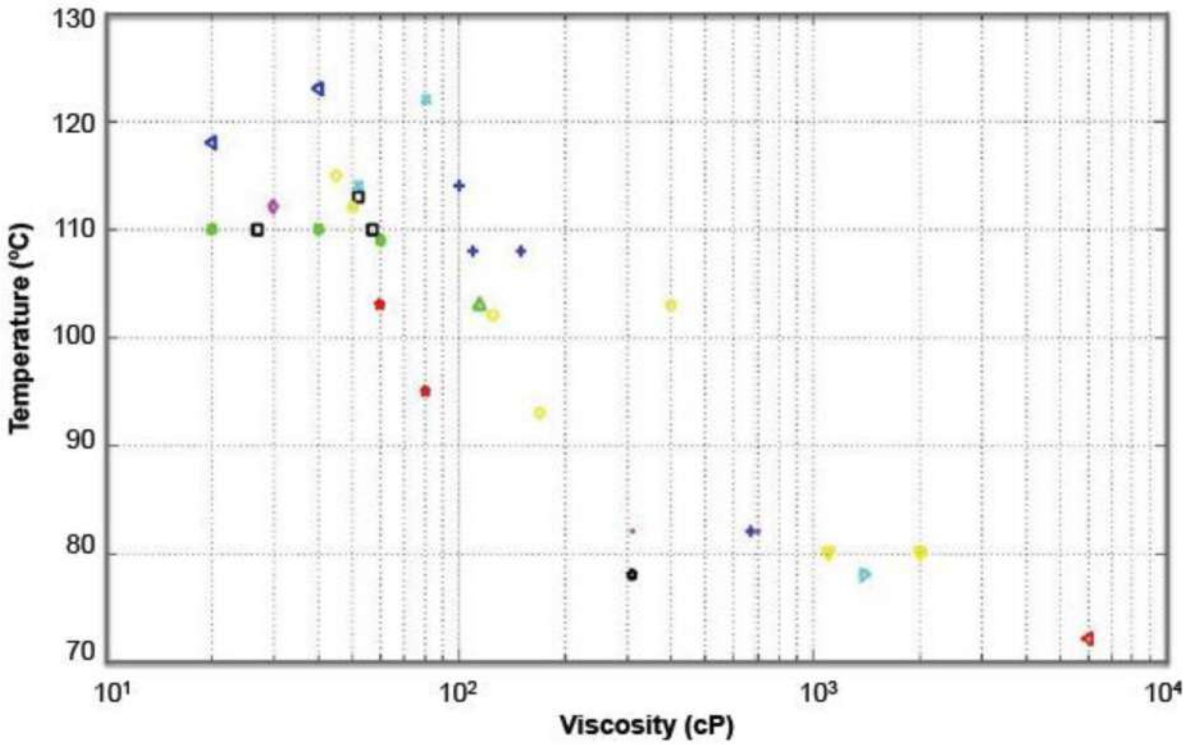

Figure 1—Reservoir viscosity vs. temperature behavior for different fields of heavy and extra-heavy oil, After Ref. 1

These heavy oil reservoirs are currently in their initial stage of development with oils in a density range between 8 and 13° API. It is worth to mention that most of the fields in this project share a regional aquifer.

The most significant factors involved in the production of heavy oils with artificial systems of production (ESP) are the geological characteristics of the formation, scale deposits, well architecture (vertical to horizontal), well completion (shoots, slotted linner), together with the oil characteristics, which include temperature, pressure, API, viscosity, besides the presence of corrosive gases (e.g., CO_2 and H_2S), and composition of connate water. The abovementioned factors are related to the precipitation of asphaltenes and paraffins, the formation of emulsions, and corrosion problems[2].

Given the complexity of components in these reservoirs, and the difficulties confronted during the recovery of the crude oil is inevitable to employ of different chemical products to ensure and improve the production as well as transport of crude oil from the well to the surface. Therefore it is extremely important to establish an effective methodology, which allows undertaking the potential problems that may arise in an efficient manner. Consecuently, it is necessary to carry out, first of all, the physicochemical and rheological characterization of oil and the different species formed due to the resulting conditions that imposes exploitation of heavy crude oil.

Heavy and extra-heavy oils are characterized by their high viscosity at reservoir conditions; see Fig. 1, so primary recovery of these crudes is generally low. That is, for heavy oil exhibiting a viscosity greater than 100 cP, the primary recovery by solution-gas-drive will be around 7–8% of the original volume of oil.

Generally as oil is produced, the pressure decreases until the bubble pressure is reached, releasing lighter components and dissolved gases (N_2, H_2S, CO_2). This solution-gas-drive process supports the oil recovery by the expansion of the released gas from oil. In the case of heavy oils, gas bubbles remain dispersed in the oil phase for a long period of time, thus affecting viscosity and foaming properties of oil[3]. The comprehension of this phenomenon in oil rate and recovery is of great interest in the oil industry[4-5].

In heavy oil reservoirs, water and gas drives are not favorable, since the mobility of water and gas are extremely high compared with the mobility of the oil, so displacement efficiency is poor. Additionally, in many cases at least one aquifer is associated with the reservoir so the effect of the water properties in the process of hydrocarbons production is of great importance.

In the presence of an aquifer underlying the heavy oil reservoir, critical rate and water irruption time are irrelevant since critical rates are very low for both vertical and horizontal wells, and as a result, the irruption of water is fast (often a few weeks or months), especially if there are channels of high connectivity of the reservoir with the aquifer such as networks of fractures or vugs or even both. In these reservoirs, an important aspect to assess is the evolution of the water cut after the irruption and determine the influence of the main parameters on the recovery of reserves as: the length of horizontal wells, production rate, water/oil ratio mobilities, spacing between wells, reservoir thickness, and permeability anisotropy. This evaluation is carried out to the economic limit usually defined by a minimum oil rate or a maximum water rate.

During the production process, the fluid is subject to diverse shear rates, which combined with heat, pressure, and chemicals, present in water or oil, may result in the formation of emulsions. The viscosity effects exhibited by emulsions tend to be complicated due to its variable composition, average drop size and its distribution within the emulsion, and viscosities of each phase. Thus, measurements of viscosity in a wide range of temperature and shear conditions are necessary. As temperature grows, the viscosity decreases exponentially[6-7].

Previously, it has been reported in the literature the blocking of the porous medium by the presence of emulsions in the vicinity of producing wells in clastic reservoirs[8-9]; however, the presence of emulsions in naturally fractured reservoirs (NFR), including the presence of vugs (NFVR), has not been reported until now. The generation of emulsions within the reservoirs represents a significant problem since large reserves of heavy oil are related to NFR and NFVR, which normally present associated aquifers. Also, the connectivity of the network of fractures and vugs might impose suitable mixing scenarios for the formation of emulsions, especially in the vicinity of the producing wells.

Emulsions can be generated at many locations of the production system such as in the wellbore region, within the well, surface facilities, transportation and refining. Therefore, it is important to comprehend the properties of the formed emulsions to control or inhibit their formation, so as to improve the recovery and production processes. Despite the large number of studies on this subject, there are still many uncertainties related to the generation and the behaviour of emulsions derived from hydrocarbons production[10].

It is known that the deposition of paraffin and asphaltenes increases as the hydrocarbons production progresses. The asphaltenes are complex aromatic compounds that are almost always associated with paraffins along the production system. These compounds are characterized by their high molecular weight and their solubility in solvents such toluene or xylene. Under reservoir conditions, resins and maltenes in the oil act as natural dispersants of asphaltenes; however, up to date it is not well understood how these components stabilize/interact with the asphaltenes to avoid their precipitation[11].

An alternative to prevent the organic scale deposition in the production system is by using diluents such as light oil, kerosene or naphtha (47° API), which are injected through a capillary pipe to the bottom-hole and mixed with heavy oil to act as asphaltenes dispersants and reduce oil viscosity. Subsequently, the diluted mixture is raised to the surface by an electro-centrifugal pump (ESP). Note ESPs are not suitable for lifting oil with high viscosity, hence it is common to use these type of pumps to lift cold production of diluted fluid with reduced viscosity after injection of solvents.

All the abovementioned, combined with the presence of connate water and the potential generation of emulsions, together with the deposition of inorganic scales, and the corrosion by-products obtained due to the reaction between gas (H_2S, CO_2) and water, represent a major challenge for the development offshore-heavy oil projects. For example, so far it is not completely understood the relationship between asphaltenes deposits and corrosion; however, it is considered that corrosion may promote the aggregation of asphaltenes. Thus, the prevention and control of corrosion through the application of chemical additives may be useful for preventing asphaltene deposits. In this regard, the prevention and study of asphaltene deposits should be considered as an open area for research and technological development[12].

Flow assurance strategies are an integral part of production operations that incorporate a wide range of techniques to optimize production. The purpose of this proposal is to set the basis for optimizing the flow assurance, minimizing the dosage of chemical compounds in the production facilities and maximizing the useful life of chemical treatments. Note that it is also important to consider and assess the potential interaction between various chemicals used for the diverse treatments during the different stages of oil production and processing. In this regard, the development and production of heavy and extra-heavy oil offshore fields represents a major challenge to guarantee flow assurance, this proposal presents a research project for laboratory assessment, pilot testing and implementing the optimum design of flow assurance for heavy crudes from green offshore reservoirs to delivery points, considering the whole production system of several fields. Therefore, research and development, of different chemical products is required in order to suppress or attenuate the problematic displayed in this paper.

Background

Heavy crude oil is characterized by diverse properties such its boiling point (above 350 °C) and its API density, which normally is less than 20. Molecules containinig long carbon chains (C30+) constitute this type of oil, presenting structural variety and, thus, complexity, in addition to the high content of polar species (e.g. asphaltenes and resins). All the characteristics described result in the increment in the boiling point, molecular weight, density, viscosity, as well as the refractive index. The rheological response of a heavy crude oil depends strongly on the physical and chemical characteristics like strength of particle interactions, volume fraction, size and shape of the particles, among others[12-13].

In the cases where asphaltene and paraffin deposits are formed, the most common method to attack such deposits involves the use of xylene or kerosene, which have been quite successful for dissolving the organic deposits, however, since these solvents are expensive this method it is not always accessible. Consequently, the application of this method is reserved for cases where the methods of hot oil and water are not successful[14].

Another approach, to attack the formation of organic deposits is by the introduction of paraffin crystals modifiers, which often affect the estabilization of asphaltenes in solution/oil, leading to their precipitation. On the contrary, the use of asphaltene dispersants distresses the paraffin solubility, resulting in precipitation issues[12].

On the other hand, variable fluid shear rates may cause the deposit of paraffins and asphaltenes in the formation, wellbore, superficial lines, treatment ships, and storage tanks. In addition, discontinuous surfaces act as points of formation for paraffin crystals and asphaltene deposits. Furthermore, asphaltenes shown to be shear-stress sensitive, thus it is necessary to minimize the turbulence in the production and transportation lines in order to avoid the generation of asphaltene aggregates. For instance, sudden expansions in lines and a large number of valves should be avoided, since they enhance turbulence to the fluid, hence the deposition of asphaltenes. Inherently, ESPs produce plenteous turbulence, leading to the formation of asphaltene deposits and emulsions. During hydrocarbons production, these are disturbed, as with the use of ESP, maltens and resins are destabilized due to shear stress and shear rates, as well as electrostatic interactions, resulting in the formation of asphaltene aggregates and precipitates. If in the production process, the flow rate is too low, the likelihood of paraffin deposit increases. On the contrary, if the speed of the fluid is too high, the probability of asphaltenes deposit is increased[13,15]. Additionally, it is recommended to apply chemicals upstream, thus it is necessary to use capillary tubing to inject these chemicals at the bottom of the well.

Some aspects to consider in the process of de-asphaltening and solvents to be used are the thermal behavior of heavy oils, the response of pressure-viscosity as well as the influence of resins[11,16]. Asphaltene precipitation is favored by the use of n-alkanes.

Asphaltene deposits may be formed in chokes, on the vacuum side of pumps, storage tanks, and the well tubing. The molecular weight of the asphaltene and its great dispersion through the crude determine the oil viscosity. Since asphaltene viscosity is high, there are difficulties associated with its deposit, production rate and pumping power, which have a considerable impact on the production of hydrocarbons[11,13,16].

Other types of solid deposits formed along the production system are inorganic scales, which may lead to the obstruction of the production lines. Depending on several factors, such the rock type and the composition of connate water, it is possible to observe different sorts of inorganic scales (e.g. $CaCO_3$, $CaSO_4$, $BaSO_4$, SrSO4). These deposits may be in the reservoir, the production tubing, or surface facilities. The problems associated with scale deposits include the formation damage, blockage in perforations or gravel packs, constrained/blocked flow lines, safety valves, chokes, and pump failure and corrosion issues. As a consequenece and depending on the severity of the scale deposition, the mechanism to remove such scales may vary from chemical treatment to mechanical removal. For instance, in the case of calcium carbonate scale ($CaCO_3$), the method commonly used to remove this scale is by addition of hydrochloric acid (HCl). Since the geology of these heavy oil reservoirs are constituted by carbonates, it is expected to observe the formation of $CaCO_3$ in the production lines during the increment of water ratio. The application of hydrochloric acid to remove deposits of inorganic salts, in wells containing asphaltenes results in coagulation of these aggregates, therefore it is of great importance to carefully select the best chemical method in order to avoid the generation of additional problems. Since the geology of several heavy oil reservoirs are formed by carbonates, these are often subject to acid stimulation, resulting in the formation of asphaltene deposits in the porous medium[17-19].

It is a common practice at offshore fields to combine stimulation treatments with scale inhibitors, which might result in severe reservoir damage due to chemical-rock-brine incompatibility during the stimulation treatment at low pH environments. Thus it is required chemical compatibility between scale inhibitors and the overflow brines with the rock and fluids in the formation. The basic mechanisms of interaction between the aforementioned chemicals and the reservoir components are adsorption-desorption and precipitation-dissolution. For instance, in dolomitic reservoirs, the dissolution of calcium and magnesium carbonates lead to an increment of water pH, along with a concentration raise of Ca and Mg ions in water. Squeeze treatments must be developed based on laboratory tests and the generated data should be used to determine the best chemicals and conditions to be applied for each proposed system. In addition, it is necessary to asses the performance of these chemicals under different parameters, including compatibility between these and other chemicals, (injected throw the line up to tank conditions), as well as the influence of pH on inhibitors chemistry, inhibitor return profile, inihibitor dosage, and impact on produced brine composition. There are different methods to predict scale formation index of water samples, which turn to be useful tools to determine the source of the scales precipitation and it is helpful in the screening criteria of different inhibitors[20-22]. Some models have the ability to predict the squeeze behavior for some years[23-24].

In a mature field close to the heavy oil fields, objective of this work, a great portion of production maintenance is based on stimulation treatments and gas conformance. These treatments, commonly based on sea water, are flushed into the reservoir to improve well productivity index. Once these chemicals and their reactions byproducts are sweeped away and recuperated on the surface it is usually found a variety of minerals and salt species, such iron carbide (Fe_3C), pyrite (FeS_2), calcite ($CaCO_3$), halite (NaCl), siderite ($FeCO_3$), anhydrite ($CaSO_4$), gypsum ($CaSO_4{\cdot}2H_2O$). The aforementioned species affect the efficiency of crude oil stabilization and dehydration process since these byproducts form precipitates that alter the separation stage of crude oil, which might result, for example, in sales revenue penalties due to

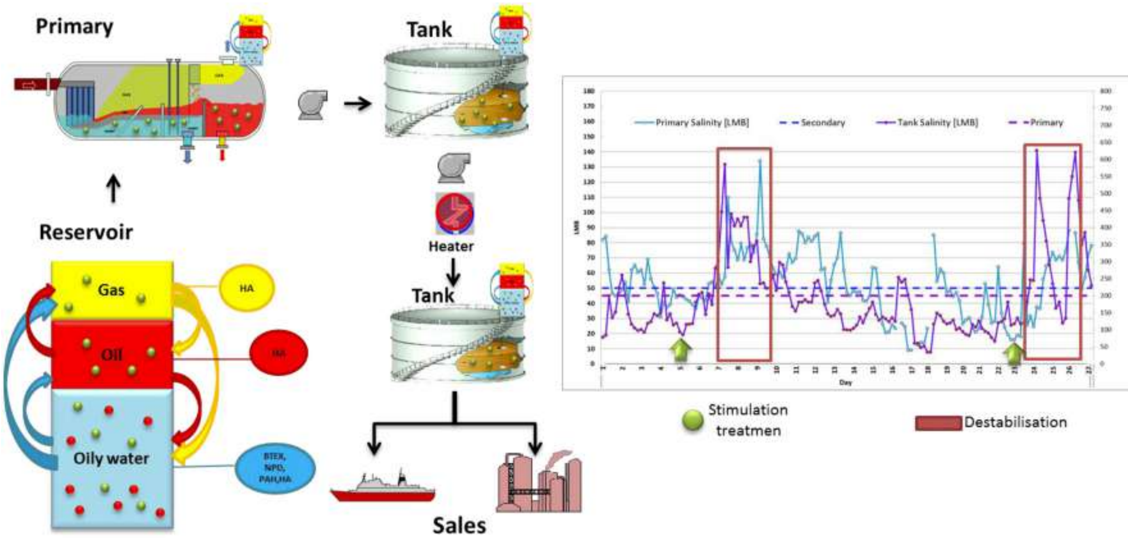

Figure 2—Stimulation treatment influences separation process.

an excess of salt amounts present in the in the processed crude oil (140 – 90 PPB) exceeds the standard limit (50 PPB). Fig. 2 illustrates this phenomenon, in which the reservoir stimulation treatment modifies the chemical equilibrium. Iron control is one of the major concerns in the stimulation treatments, to avoid iron precipitation, sometimes polymers are used to increase fluid viscosity. Also, surfactants are used to improve the contact between the live and spend acid with reservoir rock. These chemical products and some other additives, used in stimulation treatments, need to be studied in order to determine their interaction in the destabilization of connate water separation process.

On the other hand, the presence of water along with the hydrocarbons productions may lead to the generation of emulsions. Either oil in water (O/W) or water in oil (W/O) emulsions, often require the use of mechanical, heating or chemical methods to release the oil from the water, which could imply a significant investment in energy, equipment, and resources. Note that infrastructure is needed for storing chemicals (demulsifiers), as well as heaters to separate the water from the oil. It is necessary to take great care in the study of the properties of emulsions since, depending on the conditions and properties of the fluids (e.g. salinity, pH, water composition, oil density and viscosity) as well as the water-oil ratio it is possible to observe different types of emulsions, such W/O, O/W, and it is even possible to form multiple emulsions W/O/w, and O/W/o. Although a predominant form of emulsion will be present, the existence of both forms in the same system can take place through the inversion point of the emulsion. The selection of the demulsificator is crucial for breaking emulsions, and to date its mechanism of action still is not fully understood. In this regard, it is crucial to understand the behavior and properties of the potential formation of emulsions in the system and the role and effect that different chemicals might play during the treatment of emulsions[10,25, 26].

The demulsifiers are chemicals containing solvents, surfactants, flocculants, and wettable agents. The types of chemicals and the operational conditions to treat emulsions are important factors to consider since the selection of an inappropriate method might generate either no effect or detrimental results, leading to the generation of other problems of contamination or precipitation of organic solids. The accurate dose will depend on the oil characteristics and the particular type of emulsion. Another aspect to consider in the control of emulsions is the introduction of chemicals into the process. For example, the insertion of chemicals into the well has a significant impact on the costs of completion, since these must be injected into the bottom of the wellbore. Hence, the location of capillary tubes along the well is critical. Besides it is required the utilization of pumps to inject such chemicals[10,25,27].

Some of the most common demulsifiers are based on propylene and ethylene oxide monomers. A variety of substrates can be used with propylene and ethylene oxide to form polymeric demulsifiers; examples include polyols, polyamines, and alkiyphenosl-formaldehyde resins. In addition to the surfactants, solvents such as xylenes and toluene and co-solvents such as methanol and ethylene glycol or monobutyl ether are often employed for the formulation of the demulsifiers.

Currently, there are three main solutions for the transportation of the heavy crude oil. The preferred option for transporting highly viscous crude is dilution via the addition of lighter hydrocarbons, as the implementation of this method is simple and convenient. The other proposed solutions for heavy oil transportation are heating of pipelines, the generation of O/W emulsions via the use of surfactants and preprocessing. There is an exponential relationship between the viscosity of the resulting mix and the diluent volume fraction, which makes dilution a very efficient method. However, to obtain acceptable limits for transport, a fraction as high as 30% (v/v) of diluent is required, involving two affairs; a large capacity of the pipeline, as well as the availability of the diluent. Thus, it is required to develop solutions to reduce the volume and cost of the diluent. A recent idea for the transport of heavy oil is the use of friction modifiers/viscosity modifiers in combination with dilution for optimization, enabling a substantial increase in the capacity of the pipeline[28-32]. In the case of heavy crude oil fields, in the Basin under study, it is planned to mix the oil with light crude to dilute it and get a mix of 21° API.

The formation of emulsions as a heavy oil transportation method consists in the dispersion of the heavy oil in water with stabilized droplets, which leads to a significant reduction in the viscosity. A typical emulsion is composed of 70% oil, 30% water, and 500-2000 ppm of chemical additives (surfactants). The resulting emulsion has a viscosity in the range of 50 to 200 cp to the operating conditions and is stable. However, the process to separate the oil from water phase is complex. Besides, it is necessary to consider the investment for treatment and cleaning of the water used. When this process is not successful, the costs for the producer can be high due to the economic penalties introduced by the presence of water in crude oil. Therefore, before the application of chemicals to produce or treat emulsions it is essential to assess the properties of chemicals to be employed, as well as the stability, properties and rheology of emulsions produced. Incidentally, the rheology of emulsions is of great importance for transport. Some of the parameters that control the rheology of emulsions are the fraction of dispersed oil volume and the distribution of the size of the drops. Stability and rheology of emulsions depends on several parameters and require further research to understand the relationship between microscopic interaction and emulsion macroscopical rheological properties[33].

Oliveira and Gonçalves[34] present the main rheology models, applicable for characterization of emulsions in the laboratory. While, H.P. Ronningsen[35] obtained a correlation to predict the viscosity of W/O emulsion in the North Sea.

It is important to mention that oil demulsification, for heavy crude oil emulsions, represents a considerable challenge for three main reasons[36-39]:

- The density of the oil is very close to the water; the smaller the density difference of the phases, the more stable emulsion is obtained.
- Heavy oils contain a large amount of asphaltenes; asphaltenes act as surfactants, which might lead to extremely stable emulsions.
- The inversion of the emulsion is difficult to control, which leads to the dispersion of fine droplets of water in oil, increasing stability of emulsion, due to the high oil viscosity.

The complexity of the mixture present in heavy oil requires the use of different chemicals to confront the problems that arise during the production and transportation of these crudes such as the formation of emulsions, asphaltenes and paraffins deposition, corrosion and generation of inorganic scales. It is common to find combinations of these problems, thus it is vital to determine economic and effective chemical methods to use, in order to guarantee the flow assurance from the reservoir to superficial facilities.

Research Proposal

The proposal consists of four main areas: I- Laboratory Characterization Studies, II –Research and Development of Chemicals, III - Numerical Modeling, and IV – Health, Safety, and Environment (HSE) manual.I.

I. Laboratory Characterization Studies

(A) Chemical characterization of heavy oils and their gas

- Characterization of the rheological properties, with live and dead oil, depending on pressure, temperature, shear velocities, in the absence and presence of different types of solvents, viscosity reducers, and other fluids employed during the production process.
- Characterization of asphaltene and resin contents in heavy oils. Evaluation of the asphaltenes stability in oil, with and without solvents used for the de-asphaltening. Study of the thermal behavior of heavy oils, considering the viscosity dependence of the oil with temperature described by Arrehenius equation.
- Colloidal characterization of heavy oils to obtain information about the stability of the asphaltenes and other suspended particles. The required parameters are the polidispersividad in mass and/or volume, aggregation state of asphaltenes. The following or other techniques may be used: scanning X-ray and neutrons (SAXS and SANS), NMR, rheology and fractionation (such as ultra-centrifugacion, and fractionation by solvents) techniques
- The characterization of hydrocarbons must include, but not be limited to: Expansion at constant composition (CCE), for the determination of bubble point, compressibility, and density, separation testing, compositional analysis, (SARA) liquid chromatography, gas chromatography, nuclear magnetic resonance (NMR), infrared spectroscopy, UV spectroscopy studies of equilibrium vapor-liquid with live oil and solvent and/or water at high temperatures, as well as calculations of molecular modeling.
- Development of correlations applicable to extra-heavy and heavy crudes by experimental means (e.g. viscosity, flow, surface tension, etc., rheological behavior patterns) physical and computer modeling to be used in the process and transport simulators.

(B) Characterization of water

- Characterization of formation water under reservoir conditions and atmospheric conditions. Measurement and monitoring of water properties at different periods of time under several pressure and temperature conditions. The analysis should include chemical composition, determination of physical and chemical properties, prediction of scale formation index (e.g. $CaCO_3$, $CaSO_4$ $BaSO_4$) along the well, and prediction of the corrosion index of water.
- The geochemical evolution of formation water and its interactions with the rock.
- Characterization and study of the different types of water-based fluids employed during drilling, stimulation, production and processing, and their effect in the presence of formation water. Analysis of the interaction between formation water and the aforementioned fluids.
- Determination of the present bacteria in the formation water. Quantification of bacteriological growth due to the mixture of formation water with seawater. Measurement of the blockage and corrosion effects produced by the bacteria along the production process.
- Determination and validation of sour gases (CO_2 and H_2S) dissolved in water, using different salinity concentrations and chemical compositions, under various pressure and temperature con-

ditions. Characterization of CO_2 and H_2S through isotope ratios quantification. Determination of pH and dissolved gases (CO_2, H_2S) in water to model the scale tendency along the well.

(C) Studies of the formation, rheological behavior, and stability of the different types of emulsions

- Rheological characterization of emulsions, with live and oil dead, using different fractions of water (connate water and seawater) and various conditions of pressure, temperature, shear velocities, including shut-in and starting conditions. Analysis of the effects of mixing rate and the time of emulsification, by means of average droplet size measurement and distribution of droplets, and emulsions stability.
- Development of a general viscosity correlation for heavy crude oils for both, W/O and O/W, types of emulsions, at temperatures between 5 and 130 °C, with water cuts between 5 and 80%, and shear rates between 30 and 500 sec^{-1}. Comparison of predicted values, obtained with this correlation, and experimental data. It would be desirable that the correlation can be established in terms of the molecular weight of the heavy oil only, or perhaps it might also consider the content and type of resins and asphaltenes present in the oil.
- Comparative analysis of the effect of different demulsifiers, and selection of the most appropriate chemicals by means of: dynamic simulators, lab testing, and pilot plant tests.

(D) Solution-gas-drive tests in fractured-vuggy formations

- Taking into account reservoir pressure and temperature conditions, it is desired to examine the presence of foamy flow, given the components of the reservoir, that is, light and heavy hydrocarbons (eg. CH_4, C_2H_6), corrosive gases (CO_2, H_2S), and the inteactions with formation water.

(E) Stability studies of hydrocarbons in contact with treatment fluids (carbonate stimulation, corrosion inhibitors, viscosity reducers, demulsifiers, among others)

- Considering reservoir pressure and temperature conditions measure and validate asphaltenes deposition in cores of fractured vuggy formations, in the presence of various inorganic acids and organic solvents used in acid stimulation.
- Evaluate how the chemical stimulation treatments reacts with materials inside the wellbore, in order to avoid operational problems, such as tripping of separation equipment in gas oil separation plants, off-specification crude oil, and high pressure drops in flow lines.

II-Research and Development of Chemicals

(F) Flow assurance at the reservoir

- Using vuggy and fractured carbonate cores, investigate the paraffin and asphaltene depositions in the reservoir nearby the producing wells, and develop chemicals to inhibite or control the formation of these organic scales. Additionally, study the formation of organic scales due to acid stimulation in carbonate reservoirs. The elaboration of different chemicals to dissolve or avoid asphaltenes clusters and precipitation should be compatible with those employed during acid stimulations.
- Perform different tests of proposed stimulation-inhibition treatment tests to avoid formation damage and incompatibility with reservoir fluids, with the minimum concentration.
- Development of chemicals or surfactants to control oil emulsification at different cuts of water and production rates, for their application in fractured reservoirs (NFR), as well as in fractured vuggy reservoirs (NFVR) with different properties of matrix and fractures, vugs, respectively, in the area nearby to the producing well, including various completion types of shooting, slotted piping, etcetera (see Figures 3 and 4).
- Develop environmentally friendly alternatives compared to existing commercial systems[41].

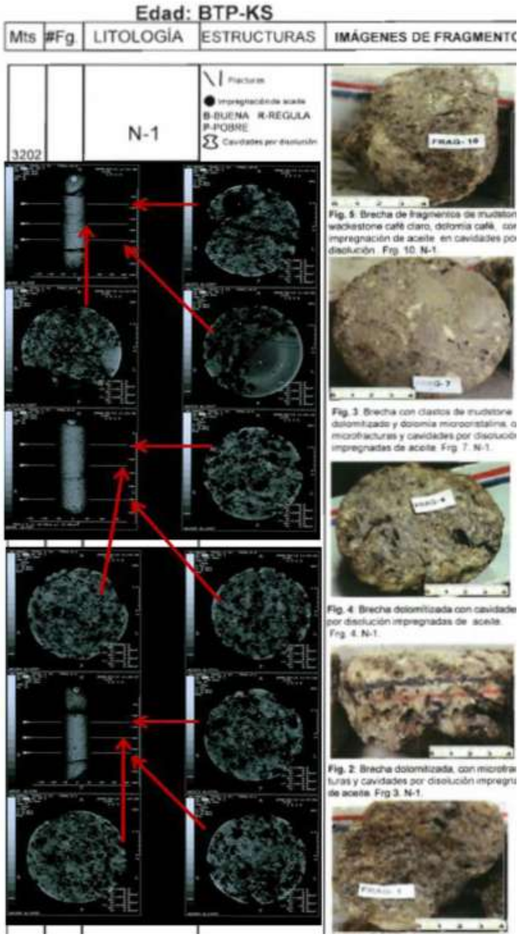

Figure 3—Brecchia from the upper Cretaceous, showing vugular porosity determined through tomography. After Ref. 40

Figure 4—Brecchia core from the upper Cretaceous, showing vugular porosity. After Ref. 40

(G) Fluid lifting in wells

- Generation of emulsions with live and dead oil, O/W, W/O, O/W/O, W/O/W, using synthetic brine samples exhibting the reservoir water composition and various water cuts (up to 80% water) in order to reach the inversion point to get the maximum viscosity of the mixture. Development of chemicals to control or suppress the formation of emulsions, and different demulsifiers for breaking the emulsions obtained. In particular the chemicals to be used should be compatible with oil and not produce undesired precipitates and/or other associated problems. Camparisons of the cost and efficiency of applying chemical methods with thermal, mechanical, electrical methods used to break emulsions should be developed. It is desired to considerate the use of combined methods (e.g. chemical and electrical), in order to evaluate the performance of the various chemicals.
- Development of different flow additives for the operation conditions of the heavy oil fields (eg. ionic liquids), involving different modifiers of the formation of paraffin crystals in the case of oils with a high content of these species. It is essential to test different temperature conditions in order to evaluate the additives performance.
- Determination of CO_2 and H_2S concentrations in the fluids, and the assessment of corrosive potential in the presence of different water cuts, so as to maximize the useful life of the pipe, by using dynamic tests with corrosion inhibitors in test circuits. It is required to develop corrosion inhibitors compatible for heavy crude oil at offshore fields and assess their performance in the

presence of O/W and W/O emulsions at different temperature and pressure conditions. It is also necessary to evaluate the implementation of such corrosion inhibitors in the presence of bacterial, inorganic and organic deposits. Establish the optimal conditions for the application of corrosion inhibitors during operating conditions.
- Evaluation of inorganic and organic scaling at the operating conditions.
- Assessment of the influence of the mixture of different chemicals (e.g. diluents, solvents, flow improvers, corrosion inhibitors, demulsifiers, organic and inorganic deposit inhibitors, stimulation acids) injected at the bottom of the well. Study of the effects deriving from the joint application of these chemicals in the problems mentioned previously. In particular, when such chemicals are co-injected through a single injection line. To successfully develop this point it is recommended to take into account the following:
  - Different temperature and pressure conditions.
  - Free and dissolved gas content.
  - Several compositions and concentrations of water
  - Different shear rates imposed by production rates, including shut-in and opening wells, and different artificial lift systems such ESP.
  - Different configuration angles of wells and the presence of chokes and valves.

(H) Surface transport

- Dilution of heavy crude oil with lighter oils represents the easiest solution for oil transportation on the surface in this Basin. However, this is not a sustainable solution given the expected volume of heavy oil produced compared to the light oil availability. Therefore two issues need to be addressed, first of all, it is required to investigate the precipitation of asphaltenes and other organic deposits due to the mixture with lighter hydrocarbons under different conditions of temperature and pressure, and second, it should be considered the effect of dissolution of wet gas with sour gases (CO_2 and H_2S) in the light oil and the impact of such gases in the mixer and multi-stage pump.
- Alternatively, it is required to assess the performance of friction and viscosity modifiers in the resulting diluted heavy oil mixture to significantly reduce pressure loss by friction under turbulent flow conditions. In addition it is recommended to compare the functioning of these products in the presence of different types of emulsions such as O/W, W/O, O/W/O, W/O/W and simulate their behavior through the producing system, analyzing the modifiers efficiency and emulsions stability.
- Control and monitoring of deposits of paraffin and asphaltenes in subsurface and surface lines, treatment ships, and storage tanks.
- Breaking of emulsions using different chemicals. The development of these chemicals will depend on the composition of the oil and water, pH, temperature, content of organic and inorganic suspended solids, viscosity, emulsion type (W/O, O/W, or multiple) and their properties. Evaluation of the costs associated with the implementation of these chemicals and the comparison with the thermal, mechanical, and electrical methods is acclaimed.
- Determination of the concentrations of H_2S and CO_2 present in the hydrocarbons mixture and its corrosive potential, for diverse water cuts and different pressure and temperature conditions. It is required to consider the presence of wet gas bubbles in heavy crude oil, in the case of dilution with light oils, and the effects of turbulence during the mixing (e.g. multiphase pump, mixer). In order to accomplish the aforementioned it is necessary to determined the solubility of H_2S and CO_2 in different types of oil under different conditions.
- Research and development of chemicals evaluated under dynamic conditions similar to those expected during the operating conditions of heavy oil fields for this project. Determine optimal

conditions for the application of corrosion inhibitors during operating conditions. Finally, it is important to avoid the formation of undesired effects or by-products (e.g. precipitation of solids and/or generation of emulsions), hence the complete understanding of the performance mechanism of the chemical products and their interaction with other components of the system is essential.

III - Numerical Modeling

I) Numerical modeling in naturally fractured vuggy reservoirs and well completion in the vicinity of the producing area

- Modeling of solution-gas-drive in naturally fractured vuggy reservoirs[42] (NFVR), to investigate possible presence or generation of foamy flow.
- Discrete and continuous modeling for analysis of generation of emulsions at different water saturations, pressure, and production rates, in both fractured (NFR) and fractured vuggy reservoirs[42] (NFVR), with different properties of matrix, fractures and vugs, respectively, in the vicinity of the producing well, including completion like slotted liner.
- Modeling the possible asphaltene deposits in the porous medium, due to the presence of various chemicals used during acid stimulation.
- Discrete and continuous modelling for the analysis of asphaltene deposits at different pressures, and production rates, in both, NFR and NFVR, exhibiting diverse properties of matrix, fractures, and vugs, in the vicinity of producing well, including completion like slotted liner.
- Modeling of rock dissolution as function of the pH and temperature, taking care of re-disolution, adsorption-desorption process, under wormhole flow geometries, considering both NFR and NFVR.

J) Numerical modeling inside wellbore

- Employment of commercial simulators of flow in pipes in stationary and transient regimes to study the behavior of non-Newtonian fluids and its viscosity properties, as well as different types of emulsions under diverse conditions, including the inversion point. For the generation of emulsions it is required to consider the existing experimental data, available correlations in the simulator of flow in pipelines, as well as additional data required to predict the generation of emulsions, their effects, stability and the mechanical condition of the wells. Note that the water cut, temperature, pressure, and shear velocity (due to ESP systems) will favor the generation of emulsions. It is recommended to estimate the effect of various inhibitors of emulsions and demulsifiers under conditions of shut-in and start of production.
- Prediction of the effect of temperature, pressure and shear velocity (due to flow rates and instruments that will manage the various systems of production such as the ESP), in the deposition of paraffins and asphaltenes, considering lab data and available correlations for heavy oil flow in the simulator, evaluating the accuracy of these correlations. The range of the variables should consider from the bottom of the well to the wellhead, including different positions of the ESP, storm valve, the seabed, and the water surface towards the platform. Consideration of the flow rate effects on precipitation and deposition of organic solids (paraffin and asphaltenes) is required.
- Determination of the viscosity of the heavy oil and and different types of emulsions with different water cuts at different flow rates, pressures and temperatures, including shut-in and opening conditions (including heat losses along the pipe), considering the presence and absence of different diluents and flow improvers, and their effect on the ESP efficiency.
- Simulation of electric heating in the well with and without flow improvers.
- Modelling of the corrosive rate of H_2S and CO_2 in the presence of different water cuts, with and without the presence of different amounts of corrosion inhibitors used during production. It is

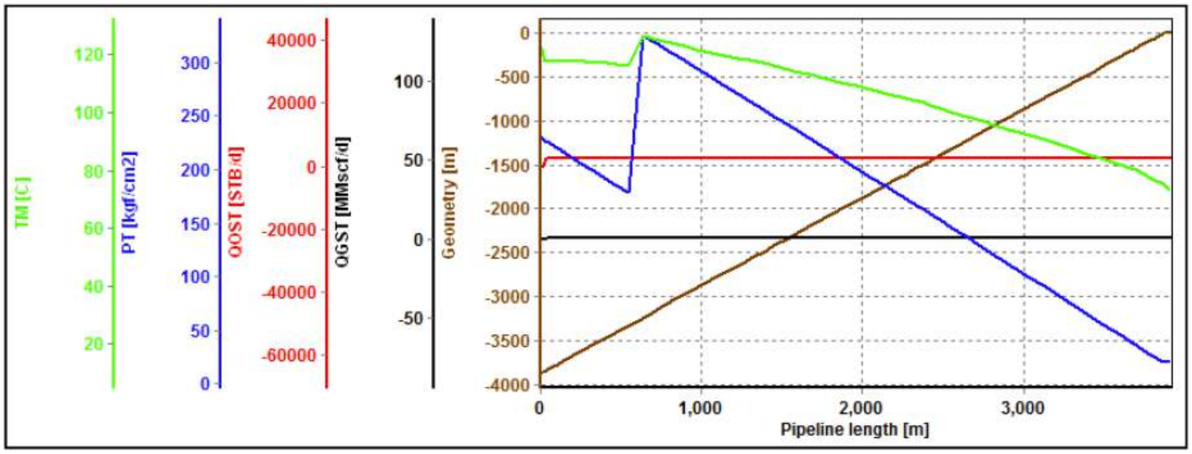

Figure 5—Numerical wellbore modeling of pressure and temperature profiles. An increment is observed due to the ESP, exhibiting a production rate of 2560 BPD.

desired to simulate the presence of O/W and W/O emulsions at different temperature and pressure conditions. It is also necessary to evaluate the ocurrence of inorganic and organic scales deposits.

- Modelling the effect of strong pressure drops, as those occurred in the ESP, when the precipitation of inorganic deposits is present, and how the scale inhibitor affects the life of the ESP. In addition it is desired to evaluate the presence of emulsions such as O/W, W/O, O/W/O, W/O/W and simulate their behavior through the producing system.

(K) Numerical modeling of surface transport

- Make use of commercial flow simulators in pipes to study the behavior of the dilution with lighter oils, use of drag reducer, and generation and breaking of emulsions.
- Prediction of deposits of paraffins and asphaltenes in superficial lines, treatment ships, and storage tanks, considering the influence of different pumps, and different conditions of temperature and pressure.
- Simulation of the electrical heating in superficial lines, treatment ships, and storage tanks for both crude transport and breaking of emulsions.
- Modeling the corrosive rate of H_2S and CO_2, in the presence of different water cuts, together with the presence of different dosages of anti-corrosive chemicals, and including the absence of these. Also, modeling the removal of H_2S and CO_2 from the gas stream using physical solvents and amines.
- Modeling of the presence of free wet gas bubbles in the heavy crude oil before mixing with light oil, including the mixer and multiphase pump. Investigate the corrosive potential of this wet gas and its dissolution capacity in the light oil.
- Modeling the influence of the mixture of different chemicals (diluents, solvents, flow improvers, demulsifiers, corrosion inhibitors, and friction reducers), injected in the bottomhole and at surface to control the generation of emulsions, the deposition of asphaltenes and paraffins, corrosion, in the solution of each of these problems.

IV-Integrated HSE Manual

The application of chemical products should be accompanied by an HSE manual that shall contain at least the following:

- All reports and documents required to obtain the chemicals and be used in appropriate form and time.

- It is required to generate the procedures for the personnel protection on board and the environment, as well as the management of waste produced in the facilities. It should contain the evacuation plans in case of contingency, training and maintenance strategies and its periodicity and detailed description of appropriate security signaling.
- A monitoring plan should provide the detailed description of the well instrumentation and surface facilities, involved in the chemical/treatment to be implemented; including, for example, the use of portable mini-separators for testing of demulsifiers. This section should establish the variables to be registered.
- The production design may consider in advance the field characteristics before, during and after the application of the chemicals, reflecting costs of the chemicals injection, treatment duration, well and facilities conditions. Additionally, it should include the measures to be considered in case the wells are closed during a certain period of time, together with the safety procedures. Depending on the chemicals and the injection methods the restoration of injection wells it might be required as well.
- For the pilot evaluation section it is required to monitor the tests over all execution time, assessing the different variables as flow rate, before, during, and after treatment, economic indicators.

This HSE manual will be used for field applications.

Concluding Observations

The development of different chemicals, and the analysis of their joint effect on the different components of production (reservoir, well, pipes and surface facilities), requires to perform studies and analysis on the chemical and physical processes involved during the production process as well as modeling their behavior. It is essential to investigate the minimum concentrations of all products and maximize the efficiency of the chemical treatments, through lab experiments, numerical simulation and pilot tests. Additionally, it is necessary to carry out the economic analysis for each of the chemicals proposed.

It is important to emphasize that for each proposed chemical is required to develop laboratory and field tests. The chemical products to be employed should perform in efficient, economic and environmental friendly manner. In addition, it is essential to carry out different laboratory and field evaluations with the various mixtures of proposed chemicals for the different problems herein described, leading to the determination of the optimal sequence of chemicals to be applied to obtain the most efficient results. Additionally, it is important to emphazise that the evaluation of the joint application of different chemicals may derive in other problems or undesired by-products affecting the performance of the employed chemicals.

Finally, the previously described issues confer considerable and unique challenges for heavy crude oil fields development, so the success of this project depends on a comprehensive study that allows the design and implementation of an action plan, minimizing risks and uncertainties, as well as their associated costs. It is necessary the collaboration between different areas of study to elucidate the best conditions and practices to confront the problems associated to the production and transportation of hevy crude oils, since the utilization of the different chemicals (e.g. diluents, solvents, flow improvers, corrosion inhibitors, demulsifiers, organic and inorganic deposit inhibitors, stimulation acids) into the well during the production may have great impact in all engineering areas involved.

For the developement of this propoasl is essential to consider the dosage of chemicals along with the residency time to be employed during the experimental tests, the modeling simulations as well as the technological design of the tests, since there are considerable operational and space restrictions at offshore plattaforms. The successful application of these considerations may facilitate the generation of more realiable data to be scalable to field conditions.

Acknowledgements
The support of Pemex E&P is acknowledged.

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