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# Evolution of Flow Assurance as a Technical Discipline to Mitigate Operational Risks in Offshore Production Systems: A Review

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## Abstract
In the last years, Petrobras has put onstream an expressive number of high-rate gas & crude oil wells in deep- and ultra-deepwaters scenarios of the Brazilian coastal waters. To face this challenge, a suite of flow assurance (FA) techniques, operational procedures, and techniques as well, had to be brought in, updated, adapted, and revised; on a fast-track basis. Our impetus was to come up with a collection of suitable solutions to help mitigating a myriad of FA problems that creep around offshore scenarios. This paper reviews the challenges that our FA pundits had to go through to permanently be a step ahead of the FA-related demands, thence achieving an economic and trouble-free gas & crude oil production on such demanding offshore scenarios.

## Keywords
FA solutions; trouble-free gas & oil production; ultra-deepwaters

## Introduction
According to Spinelli [1], early in the 1990s, a group of professionals working with Petrobras R, D & Innovation Center, were focused on preparing a lecture for an international conference. At some point in this process, these specialists have realized the lack of a terminology that could embrace the suite of activities oriented to the many defies they were facing to put onstream a series of gas & crude oil wells located in deep- and ultra-deepwaters. For that, the terminology "*Garantia de Escoamento*", was then coined in our mother Portuguese language. Later, the same group of professionals have translated this expression to the English language as "Flow Assurance (FA)", which has become a worldwide jargon in the gas and oil production industry.
As a starting point to discuss FA-related issues, it is useful to contextualize that a high CAPEX is a rule to set up an offshore production system, especially when it comes to operating high-rate gas- and crude-oil wells located in deep- and ultra-deepwater scenarios. A well-conceived, properly designed production facility must be projected to meet the high-standard technical specifications, safe operational issues, and be economically attractive. Besides, this planned production facility must comply with regulatory laws and standards dictated by both Federal & State´s Environmental Protection Agencies. So, it must necessarily be a highly complex engineering project. Some pundits even say the complexity of such offshore production facilities can be only surpassed by the ultra-complex aerospace projects.[2] However, the only way to keep the profitability of such entrepreneurship is by adopting a zero-tolerance approach in terms of production losses caused by FA-related problems.
The best way to rule out any possibility of production hurdles associated to FA-related issues, is to carry out a comprehensive diagnostic to anticipate/prevent all the FA issues. With that in mind, a focused holistic diagnosis must involve the following steps: -identification of the FA problem(s); - to unfold the suite of solutions to mitigate them, and last; - to foresee how often it will be necessary to reentry/workover the well to keep the FA-related problems at bay. Simply put, it is the recipe to issue a series of prescriptive guidelines to achieve the maximum production throughput throughout the well´s lifetime. Wrapping up, a comprehensive and accurate FA-oriented diagnosis is the starting point to choose the most suitable production technology uptakes to prevent/mitigate FA-related problems.

## The fast-track production demand and its consequences.
The urgency to produce the "first oil" is incessantly harsher nowadays. The so-called fast-track production philosophy, which has been adopted by Petrobras, comprises to put onstream, as fast as possible, the largest number of producing wells to achieve the company production goals.
Not to derail any expectation, every member of our FA team of specialists has made their best efforts to work in synchrony with the company´s main institutional objectives. However, as often happens in practice, a large demand for FA solutions has been the norm of our basket of daily tasks.

It is noteworthy that the characteristics of the Presalt produced fluids are kind of different from the Postsalt ones. Therefore, not all the FA solutions that had been successfully developed for Postsalt wells are suitable for immediate application in the Presalts ones. In many instances we have to rule out any possibility of adaptation of previously developed FA solutions at all. In many aspects these production scenarios are quite different from each other.

Arguably, the most striking differences between the produced fluids of Postsalt fields and Presalt ones are formation water composition and salinity, $CO_2$ concentration, $H_2S$ (sour gas) concentration, flow rate range, BHTP, and tie-back length. Besides, the API density of Postsalt crudes is relatively smaller than the API gravity of the Presalt ones.

One of the Achilles' heels of our research for FA solutions, however, is the need of meeting the fast-track field demands for the development of pacesetting oilfield chemicals suitable for the Presalt scenario. However, one is aware that research work, due to its inherent nature, is not always 100% predictable.

In fact, our FA pundits have exhaustively been challenged to work fast and hard, most of times in a non-perfect-storm scenario. It is noteworthy that there are occasions when there are no more than a short interval of time for carrying out a minimum number of dry runs of the FA innovations before packing and making them available to the field. To make things even more complicated, not always our operational personnel is in real conditions to take further FA-related risks. A trade-off between the envisioned FA-alternative and the operational hurdles that would be derived from not applying the FA innovations to the field scenario, has to be stricken between the parties involved.

On the other hand, in-house expertise had also to be quickly developed to help meeting the manpower demand to put in practice a new basket of FA solutions. To that end, the aid of Academia, JIPs, and the cooperation with chemical suppliers were of paramount importance to help accelerate our learning curve in essential FA-related issues. Furthermore, a selected number of our researchers have been assigned to participate in continued education programs oriented to study FA-related disciplines provided by different academic centers. Arguably, remarkably fast-track results were obtained through this pivotal research approach.

Little does one realize that to address the FA issues, an integrated (analytical) characterization job must be carried out with all produced fluids. Hydrodynamic flow simulations, as well, are of quintessential importance to predict the hot spots for FA-related problems within the production system. Further on, it is also important to map and interpret the continuous phase equilibria, and multiphase overlapping, that the produced fluids can go through during the production process. See Fig. (1). Second, the predicates and limitations of the available analytical equipment for crude oil characterization have always been considered: revamping lab equipment and/or purchasing state-of-the-art analytical ones has been our solution of choice. Finally, steps have also been taken to grasp the contribution of cutting-edge thermodynamic simulators to set tailored guidelines for issuing FA-related problems.

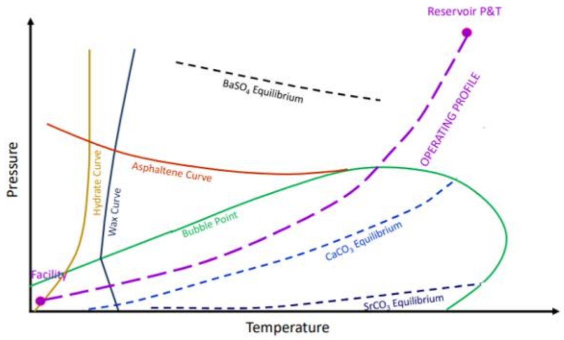


Figure 1. Flow Assurance Integrated View - Typical Phase Envelopes Presented by Well Fluids During the Production Process (Adapted from A. Jamaluddin SPE Short Course on Flow Assurance Management, 2023).

## The main advances granted by Petrobras in FA-related technologies.

Early on, we realized that a comprehensive characterization of the well-produced fluids is the key point to address FA-related issues. An emphasis has been placed on identifying and studying the behavior of different production deposits, whether inorganic, organic, or mixed ones. Typical production (mixed) deposits include wax(paraffin), asphaltenes, emulsions, naphthenates, hydrates, and a basket of different inorganic scales.

It is straightforward, that extracting, separating, and quantifying each class/family of the so-called produced solids, comprise the initial procedures to the assessment of the physical and chemical properties of these materials. Broadly speaking, a series of physical and chemical tests/assays must be carried out with those materials to the development of a holistic FA-oriented mitigation strategy. In some instances, even state-of-the-art analytical tools must be used to shed light on some obscure aspects of the analytical characterization job. For instance, the notable analytical effort done to characterize the naphthenic acid species indigenous to crude oil. With the aid of bench-scale lab tests, test loops, and thermodynamic simulations, additional checks can be carried out to corroborate analytical results from lab tests. One important lesson we have learned firsthand is the need of considering the bottomhole hydrodynamic conditions to properly select FA additives. For instance, not only a given scale inhibitor chemical must be exhaustively tested in aqueous systems in lab conditions, but it is also mandatory to address if such chemical can diffuse through the oily external phase of a W/O produced emulsion before reaching the dispersed water droplets, which is the spot where it is expected to perform. If the scale inhibitor additive cannot diffuse at a desired rate in the oil phase, it is likely that it will not show a good performance in the dispersed water droplets of the emulsion at all. So, the partition coefficient for the additive must be also quantified. Furthermore, the likelihood of detrimental interactions between FA-additives must also be previously gauged in lab tests. In the wake of these finding, it was indisputable that a new *pout-pourri* of fit-for-purpose analytical methods had to be adapted and/or developed to address these chemical´s deleterious interference issues. .

## List of main FA-deposits found in the field

Real production deposits always present a mixed composition due to the overlapping of the depositional envelope of the different families of FA-solids. Report to Figure (1) As stated before, production solids such as paraffins (wax), asphaltenes, scales, corrosion debris, emulsified water, hydrates, inorganic salts, and formation clasts; can be part of the composition of these mixed production deposits.

For the sake of forthrightness only, the main FA deposits are subsumed, in a condensed manner, in the next sub sections, as follows:

**Paraffins** – crude oil paraffins (alkanes) can form a solid crystalline phase inside the production system because of the temperature drop (cooling) along the production process and/or during unpredictable production shutdowns. The accumulation of paraffin solids inside the production system can increase the friction losses/reduce the well flow rate, and even lead to a complete plugging of the producer well. The driving force for the paraffin deposition process is the so-called diffusion phenomenon, which is dictated by a temperature gradient that is created between the hot produced crude oil, and the cold internal surface of the production string and/or subsea flowline.

Petrobras has adopted mechanical pigs, chemical (paraffin solvents) and thermal methods (heating), - combined or not - as field solutions to cope with the FA-associated paraffin deposition phenomenon. Operational procedures to displace produced crude oil by marine diesel oil (ODM) in long time shutdown events have also been revised.

**Asphaltenes** - the crude oil´s asphaltenes fraction is formed by a solubility class of aromatic molecules of different molecular weights and stereo geometric structures. The molecules that make up the asphaltenes fractions show the solubility in aromatic solvents as their unique common point. Asphaltenes can form hard and brittle “non-piggable” deposits in different parts of the production system. The rather complex asphaltenes molecules are soluble in aromatic solvents and precipitated by low-molecular-weight alkanes. Pressure is the main driving force for asphaltenes agglomeration and destabilization in reservoir. Compositional changes of reservoir fluids can also destabilize crude oil´s asphaltenes in porous media The minimum solubility of asphaltenes in crude oil is observed around the bubble point pressure. Petrobras relies on the IP-143, and Petrobras in-house analytical standards testing methods, to quantify asphaltenes content in crude oil. Asphaltenes content in crude oil parameter is not proportional to the intensity of asphaltenes destabilization problems observed in practice. Paradoxically, light crude oils, with low content of asphaltenes, are the most problematic ones, when it comes to asphaltenes destabilization issues.

Petrobras main strategies to keep asphaltenes deposition problems at bay are: - to keep reservoir pressure as high as possible, during the well’s lifetime, as a preventive measure to avoid asphaltenes destabilization; -welllbore clean-up (bulheading) jobs with mixtures of aromatic solvents for re-solubilization of asphaltenes deposits.

As a matter of fact. Petrobras started large ($CO_2$, and WAG – $CO_2$) EOR projects In Presalt fields in the last years. However, when a large concentration of $CO_2$ (around 50 – 60 +) has been injected into reservoir, it can provoke the destabilization of crude´s asphaltenes at reservoir conditions.[3]. Therefore, the careful monitoring of asphaltenes concentration in producer wells, being submitted to $CO_2$, and/or WAG – $CO_2$. EOR methods, helps detecting deleterious asphaltenes x $CO_2$ interactions that occurs under downhole conditions. [4]

**Naphthenates** – FA-related naphthenate problems, during production and primary separation operations, have been observed by the crude oil industry in the last decades. Field cases of naphthenate problems are reported in China, Far East and West of Africa fields [5-7].

Concisely, the precipitation of calcium naphthenates, is dictated by the combination of the following factors: - presence and composition of the naphthenic acid species indigenous to crude; - high concentration of calcium in produced water, and; - the rise of the pH of produced water caused by $CO_2$ exudation to the gas phase below the bubble point pressure. In fact, Naphthenates deposition occurs at low pressure (topside) conditions. The rise of the pH of water shifts the naphthenic acids - naphtenate ions equilibrium. As calcium naphthenates are neither soluble in crude oil nor in water and shows an intermediate density (between oil and water), they seek out the O/W interface, where they can agglomerate and form a jelly layer, which jeopardizes the performance of the level control valves inside the primary separator.

Naphthenate problems are not recurrent in Petrobras fields. The only exception to this rule occurred in one Petrobras – operated FPSO some years ago, where two streams of incompatible Postsalt and Presalt crude oils were mixed in the production header, prior to being processed [8]. The implemented FA-solution to acid clean out the processing plant was straightforwardly simple and consisted of acidizing the produced water by on-the-fly dosing corrosion-inhibited 5% acetic acid upstream the production header. The reduction of the pH of water shifts the equilibrium of the naphthenic species towards the non-ionized naphthenic acid ones. This inhibits the formation of calcium naphthenates in the train of separators.
A series of corrosion assays was previously carried out to determine the corrosion intensity in the FPSO processing plant promoted by the corrosion-inhibited 5% acetic acid solution. Finally, to rule out the calcium naphthenate problem a selected combo of chemicals (naphthenates inhibitor + demulsifier) was injected upstream into the production header. Also, the crude processing parameters were slightly modified: the separator temperature was lowered, and the separator pressure was increased, thus reducing the gaseous $CO_2$ concentration in the gaseous phase. These parameters changes can reduce the pH of the produced water phase, and the chances of calcium naphthenates build up in the processing plant.

**Emulsions** - It is well-established that an emulsion is a thermodynamic unstable system formed by two immiscible fluids.[9] Produced water emulsified in crude oil (W/O), or even free-water, are co-produced in different proportions during the different stages of the crude oil production process. The produced W/O emulsions are stabilized by indigenous -or added - emulsifiers and fine solids. [10] These emulsions can be highly stable and exhibit high viscosities, thus causing high pressure drops, resulting in challenges to transportation, pumping, and separation of W/O emulsions. In addition, stable emulsion production may cause deposition of inorganic and organic fractions (scales, waxy and asphaltenes), which are physically different from the ones observed with dehydrated (water-free) crude oil. Petrobras FA team has developed a successful practice of (subsea) injecting demulsifiers to start up the W/O separation at subsea conditions. Such a practice has been a successful field-proven FA initiative to increase the performance of oil producers in offshore scenarios. In some instances, the production gains can exceed 60 %.
**Gas Hydrates -** are crystalline solids formed by the combination of water molecules with the light components of natural gas, and other light gases like $CO_2$, $N_2$, and $H_2S$. The water molecules are grouped together forming a three-dimensional structure that encapsulates the gas, under given conditions of pressure and temperature.
The occurrence of hydrates can also damage and block pipelines, valves, and other instruments. The consequences of this fact range from a reduction in production flow to a total production stoppage and even damage to the mechanical integrity of the production system. The prediction of hydrate formation in a hydrocarbon system is performed by thermodynamic modeling of solid/liquid/gas equilibrium using as input data the composition of gas and water, the type and concentration of inhibitors. From these data, the equilibrium curve (PxT) hydrate/water/gas, the optimal concentration of inhibitor and the maximum concentration of moisture allowed in the gas at the operating conditions are obtained.
The most effective method of preventing hydrate formation is to design and operate the production system outside the hydrate formation envelope, but this is not always possible. Therefore, the most appropriate prevention strategy depends on operational circumstances such as pressure, temperature, type of fluid (gas or oil), and the presence of water. Thermodynamic inhibitors can be used to change hydrate equilibrium conditions at low temperature and high pressure, but in some cases, kinetic inhibitors, to increase the formation time, and anti- agglomerates can be a good alternative to mitigate hydrate formation problems.

**Inorganic scales -** Produced waters can contain different concentrations of ionic salts and dissolved gasses, and, therefore, can be corrosive and prone to form precipitates because of the pressure and temperature changes, evaporation, pH variation, and other phenomena that take place along the process of production. Most produced waters behave like non-ideal solutions due to their high degree of saturation. According to the thermodynamic solubility principles, once the saturation ratio (SR) of a given salt in water has been exceeded, its precipitation will occur. Besides, the transformation of a precipitate into a scale is an intricate process, which involves a series of dimly understood steps. The most common inorganic scales found in the field are: Alkaline-earth Sulfates – Barium Sulfate (Barite), Strontium Sulfate (Celestite), Calcium Sulfate (Anhydrite), and Calcium Carbonate (Calcite).
Scale formation can provoke a huge impact on productivity, well integrity, and operational safety issues. Laboratory tests and assays have also been developed and employed to properly deal with scale-associated problems and to measure the scaling potential of water mixtures, such as: tubing block test, the incompatibility test, the threshold concentration test, and the crystallization temperature test, to name a few. Field-proven practices show that: - the use of nanofiltration to remove sulfates from seawater is a good practice to prevent sulfate scales; - anti scaling chemicals are good to prevent carbonate scaling problems; and de-scaling chemical squeezes can efficiently

dissolve and remove different scales from porous medium.

## Conclusions

It is mandatory to adopt a comprehensive approach to address FA-related problems.

We have tailored a series of fast-track solutions to FA-related problems that creep around offshore production scenarios.

Performance evaluation of FA additives must always take into account the multi-phase equilibria that exist under downhole conditions, and deleterious interactions with other FA-chemicals.

To meet the ever-growing demand of the offshore production industry, we strongly suggest the creation of academic under-graduation flow assurance engineering courses. The FA specialist is a wanted and valued professional nowadays.


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## Responsibility Notice

The authors are the only responsible for the paper content.

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