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Nicolas Passade-Boupat, Léa Delance, Hoai-Phuong Tran, Mélanie Arangalage, Roel Belt, et al.. Foaming of organic liquids: from advancement in theoretical understanding to practical applications. 2024. hal-04851938

HAL Id: hal-04851938

<https://hal.science/hal-04851938v1>

Preprint submitted on 20 Dec 2024

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Foaming of organic liquids: from advancement in theoretical understanding to practical applications

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Abstract

Foaming of non-aqueous liquids, particularly in the energy sector, presents significant challenges due to the transient stability of these systems. Despite being free of surfactants, non-aqueous liquids are observed to foam in practice. This phenomenon is observed during the simultaneous production of gas and liquids, affecting transportation and separation processes. The stability of foams can impact pressure drops, production efficiency, and safety.

The study of foam stability in organic liquids has focused on understanding the factors that enhance stability within liquid films. Solid or solid-like particles within the liquid film, such as fat crystals or asphaltenes, can stabilize oil foams. Recent advancement on particle-free liquids have also shown that blends of organic liquids, even when totally miscible, can produce surfactant like effects stabilizing foams.

Experimental methods, including depressurization tests and surface tension measurements, were employed to study the foaming behavior of various crude oils, and the results were compared with the learnings from the literature.

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1 The present results indicate a correlation between viscosity and foam stability, with higher
2 viscosity fluids generally producing more stable foams. While viscosity controls the thinning of
3 the films in any liquid, other parameters contribute to foam stability and depend on their precise
4 formulation, such as the presence of solid particles or the thermodynamics of blends.

5 In conclusion, advances in the theoretical understanding of foam stability in organic liquids have
6 led to practical applications in the energy sector, such as the use of simple surface tension
7 measurements of blends of crude oils to anticipate the stability of the foams through
8 depressurization. By identifying and mitigating foaming issues, it is possible to improve
9 production efficiency, safety, and overall performance in various industrial processes.

10 **Introduction**

11 As very well explained in [1] - [2], non-aqueous liquids do generally not foam due to the lack
12 of stabilizing effects in the liquid film between two gas bubbles. However, a transient stability of
13 these systems is observed in many practical cases. It is particularly the case in the energy sector
14 with the simultaneous production of gas and liquids: depending on the properties of fluids, very
15 different foam stabilities can be observed either during the transportation of the fluids in the
16 pipelines and risers, or in separators. These changes in stability can have important consequences:
17 during transportation, changes in the flow patterns can affect the pressure drops and have direct
18 consequences on the production; in the topside installations, insufficient level of gas/liquid
19 separation can lead to liquid carry over in the gas stream with potential safety concerns, or to gas
20 carry under to the liquid stream with potential damages to the pumps and production losses. But it
21 can also be the case for organic formulated fluids, such as the problem of foaming when filling a
22 gasoline tank, or foaming issues with lubricants in gearboxes, especially for electric engines for
23 which the rotational speed of gearboxes is much higher than for thermic engines. It is thus

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1 important to identify the potentially problematic cases to implement mitigating solutions. During
 2 a field development lifetime, this question can be answered at different times: when a project is
 3 under development (“green field”), it will be important to determine the “foamability” of the initial
 4 “blends” that will be produced, as a single reservoir is seldom developed alone – later on (“brown
 5 field”), it is possible that tie-in projects will bring additional productions from fluids with different
 6 characteristics to already existing facilities for which it will be difficult to adapt the size of the
 7 separators.

8 For aqueous systems, the physics of foam has been a subject of studies both experimental and
 9 theoretical for many years. The point of this article is not to give an overview of this research.
 10 However, Reference [3] gives a very interesting description of the physics of foams as illustrated
 11 in Figure 1, and will be helpful for the results and discussion parts:

12 In a pure liquid separated from a gas by two interfaces, the film drains in plug flow and the
 13 lifetime of the liquid film scales as:

14 Equation 1
$$\tau \sim \frac{\mu R_b}{\gamma}$$

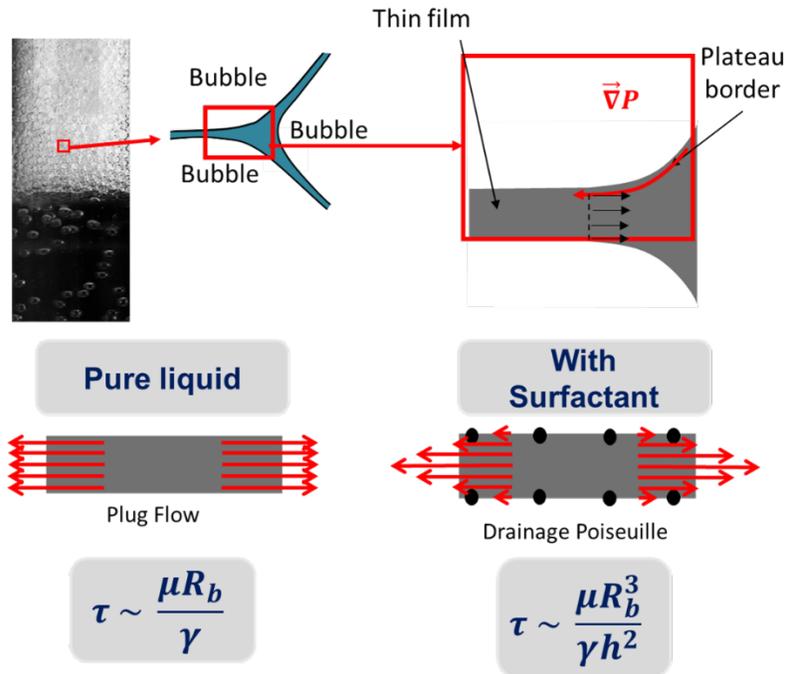
15 In the presence of surfactants adsorbed at the air/liquid interface, the liquid film is expected to
 16 drain in Poiseuille flow and the draining time becomes:

17 Equation 2
$$\tau \sim \frac{\mu R_b^3}{\gamma h^2}$$

18 Where τ is the film lifetime, μ is the viscosity, R_b is the radius of the bubble and γ is the surface
 19 tension of the liquid and the gas, h is the film thickness.

[Insert Running title of <72 characters]

1 To give an order of magnitude, with values of $\mu \sim 10^{-3} Pa.s$, $R_b \sim 10^{-3} m$,
 2 $\gamma \sim 10^{-2} N.m^{-1}$, and $h \sim 10^{-6} m$, τ is about $10^{-4}s$ without surfactants and 1s with surfactants,
 3 explaining easily why pure low viscosity organic liquids do not foam: the lifetime of the films
 4 between bubbles is too small compared to other characteristic times of the flow.



5
 6 **Figure 1: Schematic representation of the drainage of liquids and dependance of the foam lifetime**

7 As the surface tension of organic liquids and low pressure gas does not vary to a very large
 8 extent, the viscosity of the liquid phase, which can vary over several orders of magnitude, will be
 9 a “physical” effect to take into account when comparing different situations.

10 Over the years, studies on foaming of organic liquids have been dedicated to better understand
 11 the origin of the foamability, and many of them were focused on what could enhance the stability
 12 of the liquid films, with a special interest on systems for which the foam “stability” is not limited
 13 to a viscosity effect slowing down the drainage time.

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1 In different systems, it is shown that solid or solid-like particles within the liquid film, which
2 accumulate at the gas-liquid interface could be responsible for an enhanced stability [2] - [7]. It
3 is interesting to note that fat crystals are among the different solids able to stabilize oil foams, as
4 it will be relevant later on.

5 In [8], the authors describe several parameters that can play a role in the foamability of the
6 different crude oils and cite the fact that blending of different liquids can lead to increased
7 foamability. They cite “incompatibility” between the crudes as the reason for the increase,
8 referring to incompatibility towards asphaltene stability. In that paper, crude oils even without
9 asphaltenes are found to significantly foam. The authors find a correlation between foamability
10 and surface tension, but with a very strong increase of the foam volume for a marginal change in
11 surface tension (4 times more foam for a 1.5 mN/m difference in surface tension). A similar
12 behavior is also seen in [9], variations of surface tension, with only minimal changes of surface
13 tensions during the time frame representative of the foaming, leading to significant changes in the
14 foam stability.

15 Reference [10] studies model systems with asphaltenes, starting from heptane/toluene (heptol)
16 solutions and then replacing heptane by a mineral oil. The paper states that the change was due to
17 the fact that heptol blends were not able to produce “stable” foams, which is of course very
18 dependent on the timescale that is considered as a criterion for stability.

19 In [11], it is demonstrated that indeed asphaltene solubility state can influence foaming,
20 although without having to actually adsorb at the interface but mainly to act as a barrier towards

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1 coalescence within the liquid film. Nevertheless, the influence of asphaltene on foamability was
2 mainly an “add on” to a more fundamental reason for the foaming of the organic liquid blend.

3 In [12] - [13], the authors developed a depressurization test to study foaming on non aqueous
4 liquids and crude oils to complement “traditional” Bikerman tests. A good correlation is found
5 between viscosity and the lifetime of the foams. Other factors influencing the stability of the foams
6 are more difficult to enlighten.

7 Recently, studies have been focused at explaining why organic solvents, and in particular their
8 blends, can foam. In [14], the authors show that a blend between two oils (Hexadecane and Heavy
9 oil), one of them not foaming at all (Hexadecane), foams more than each individual oil, even while
10 the blends exhibit a lower viscosity than the Heavy Oil alone (see figure 1 A, C and D without
11 Additive).

12 In references [15] - [17], it is shown that for some blends of organic liquids, the evolution of
13 the surface tension does not follow a linear behavior and these blends are foaming in Bikerman
14 tests or during depressurization, while other blends that follow a linear evolution of the surface
15 tension with the composition are not foaming, as pure liquids. The reason behind the foamability
16 of the “non linear” blends is that, due to the difference in partition of the different molecules
17 between the interface and the bulk, the system will be out of equilibrium when new interfaces are
18 created upon foaming: Marangoni flows are then created due to the differences in surface
19 concentrations along the film interfaces to come back to equilibrium. These flows are opposing
20 drainage and thinning so that they stabilize the foam by delaying the film thinning and its break-
21 up. The authors also demonstrate for different systems that it is possible to link the extend of the

[Insert Running title of <72 characters]

1 stability of these foams with the extent of the deviation of the surface tension to the linear variation.
2 Similarly, it is shown in [18] that preferential evaporation of one of the components of an organic
3 blends can be at the origin of Marangoni flows stabilizing a foam.

4 These different advances have been used to improve the production chemistry studies trying to
5 evaluate the risk of foaming, when fluids coming from different reservoirs are to be produced
6 together.

7 **Experimental Methods**

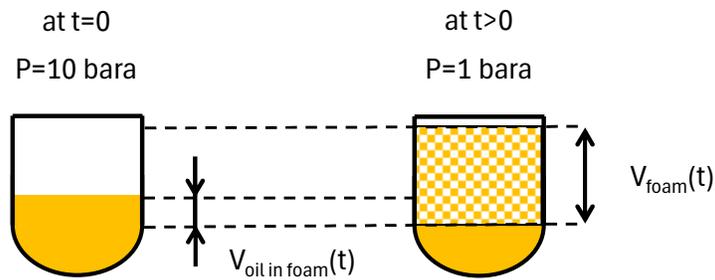
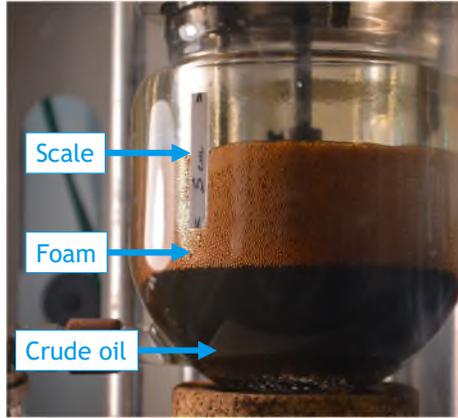
8 **Foaming tests by depressurization**

9 The depressurization measurements were carried out with the following protocol:

- 10 • 220 mL of the considered organic liquid are introduced into a glass double-jacketed reactor
11 equipped with an agitation system. The reactor is placed inside a protective enclosure, with
12 a volume of 1 liter and an inner diameter of 10 cm.
- 13 • The internal temperature of the reactor is adjusted to the desired temperature using a heat
14 transfer fluid circulating in the reactor's double jacket from a thermostat. The fluid can be
15 heated or cooled down depending on the study to perform.
- 16 • The reactor headspace is then purged with nitrogen to remove oxygen initially, followed
17 by methane to eliminate nitrogen.
- 18 • Subsequently, the reactor is pressurized with CH₄ at an absolute pressure of 10 bars for 24
19 hours under agitation.
- 20 • The reactor is then rapidly decompressed to atmospheric pressure, while a camera
21 positioned in front of the reactor captures one photo per second to track both foam
22 formation and disappearance, as illustrated in the sketch in Figure 2.

[Insert Running title of <72 characters]

1 Image processing allows the construction of foam quantity vs. time curves for each of the
 2 conducted experiments. A volume vs height curve has been established to take into account the
 3 spherical shape of the bottom of the reactor that can be seen in Figure 2.



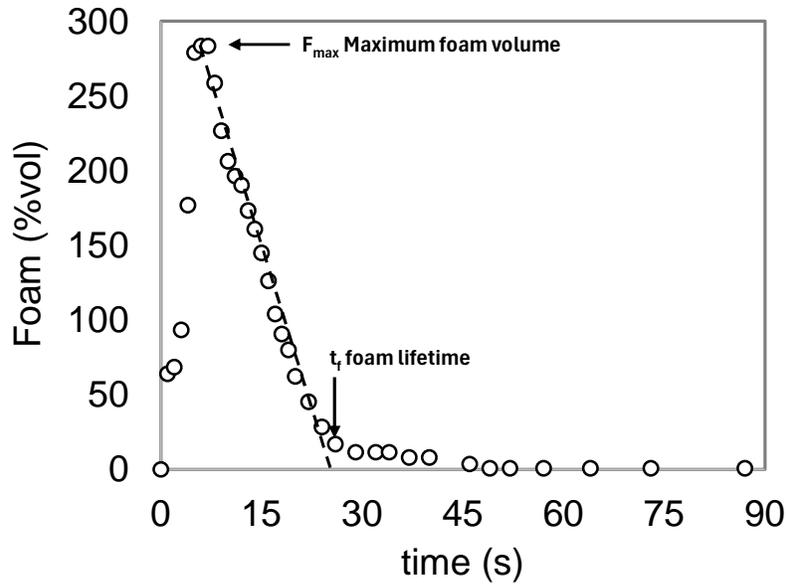
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5

6 **Figure 2: Picture and sketches of the reactor after depressurization of crude oil N at its maximal foam height**

7 A typical foam percentage (in volume) versus time is represented in Figure 3, with the definition
 8 of the maximum foam volume F_{max} and the foam lifetime t_f : the foam lifetime is defined as the
 9 time after depressurization where the extrapolation of the fast foam decay reaches 0. The maximum
 10 foam volume fraction is denoted F_{max} . In certain cases, a very small amount of foam can remain
 11 “stable” for a long time, it was decided not to take it into account.

12



1

2 **Figure 3: Example of foaming curve**3 **Surface tension measurement**

4 Surface tension measurements were performed over 1 hour, even if values of surface tension at

5 shorter times, more relevant with the time scale of the foam lifetimes will be reported. They were

6 carried out with a Tracker Teclis pendant drop tensiometer at room temperature (20°C). Note that

7 tensiometry at controlled temperature is usually done in the reverse configuration where a rising

8 bulle is held into the thermostated liquid of interest. For most crude oils in this study, their opacity

9 prevents us from imaging the rising bubble so that only room temperature measurements of surface

10 tensions with pendant drops could be obtained in these cases. The tensiometer uses image analysis

11 to fit the shape from the shadow image of a 20 μL drop with the hydrostatic Young-Laplace

12 equation.

13 **DSC, viscosity & density measurements**

[Insert Running title of <72 characters]

1 The differential scanning calorimetry were performed on a DSC8000 PERKIN ELMER at a
 2 cooling rate of 2°C/min from an initial temperature of 80°C in order to measure the Wax
 3 Appearance Temperature and crystallinity when relevant.

4 Depending on the level of viscosity, the viscosity measurements were performed either on an
 5 Anton Paar SVM 3000 or on an Anton Paar rheometer MCR 302.

6 All density measurements were performed on an Anton Paar SVM 3000.

7 **Materials**

8 The main properties of the series of 14 crude oils, labelled from A to N, used in this study are
 9 given in Table 1. As explained in [19], the Asphaltene Stability Class Index (ASCI) is an
 10 evaluation of the “quality” of the asphaltenes (the closer to 20, the most soluble they are), whereas
 11 the density of the crude oil can serve as a proxy for its solubilizing power (the higher it is, the
 12 better solvent for asphaltene it is) : Figure 4 shows that most crude oils in this study have low level
 13 (<0.5 %) of stable asphaltenes (ASCI > 15), Crude oil N being the “worse case” (low density of
 14 the crude oil and low ASCI of its asphaltenes).

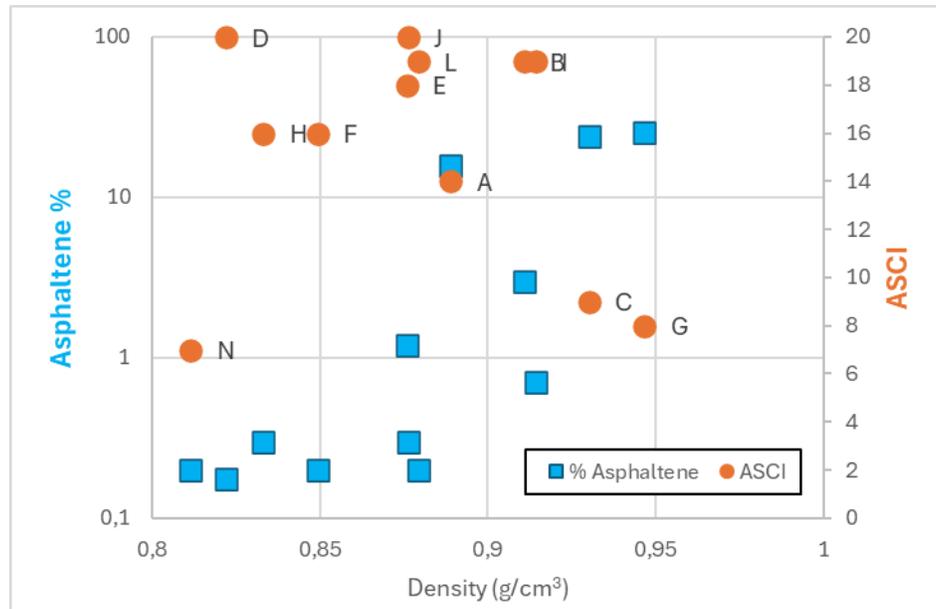
15 **Table 1 Properties of the main crude oils and condensates used in the study**

| Crude | Viscosity at test T(cP) | density (g/cm3) | ASCI | Asphaltene (w%) |
|-------|-------------------------|-----------------|------|-----------------|
| A | 51.3 | 0.8890 | 14 | 15.7 |
| B | 64.1 | 0.9108 | 19 | 3.0 |
| C | 41.6 | 0.9302 | 9 | 23.9 |
| D | 3.9 | 0.8218 | 20 | 0.2 |
| E | 19.9 | 0.8758 | 18 | 1.2 |
| F | 8.3 | 0.8493 | 16 | 0.2 |
| G | 120.0 | 0.9465 | 8 | 25.4 |
| H | 15.1 | 0.8330 | 16 | 0.3 |
| I | 29.0 | 0.9141 | 19 | 0.7 |
| J | 18.4 | 0.8764 | 20 | 0.3 |
| K | 1.4 | 0.7641 | 20 | 0.05 |
| L | 22.7 | 0.8792 | 19 | 0.2 |

[Insert Running title of <72 characters]

| | | | | |
|---|-----|--------|----|-----|
| M | 0.9 | 0.7613 | 20 | 0.1 |
| N | 3.3 | 0.8113 | 7 | 0.2 |

1



2

3 **Figure 4: % of Asphaltene and ASCI of these asphaltene vs Density for the crude oil of the study – labels with**
 4 **the reference of the crude oils in Table 1**

5 The foaming test temperature is adapted to the field conditions to be evaluated: the sample can
 6 either be heated to the gas/liquid separator temperature we want to evaluate, or it can be cooled
 7 down to represent the temperature of the fluids during their transport within a subsea pipeline. The
 8 data in Table 1 are thus indicated at test temperature, without indication of its value. When
 9 possible, the surface tension (SFT) measurements have also been performed at the same
 10 temperature. If it was not possible to measure SFT at the foaming temperature, and the temperature
 11 value is significantly different, it is indicated in the legend of the SFT graphs or tables.

12 **Results & discussion**

13 **Effect of viscosity & differences between crude oils**

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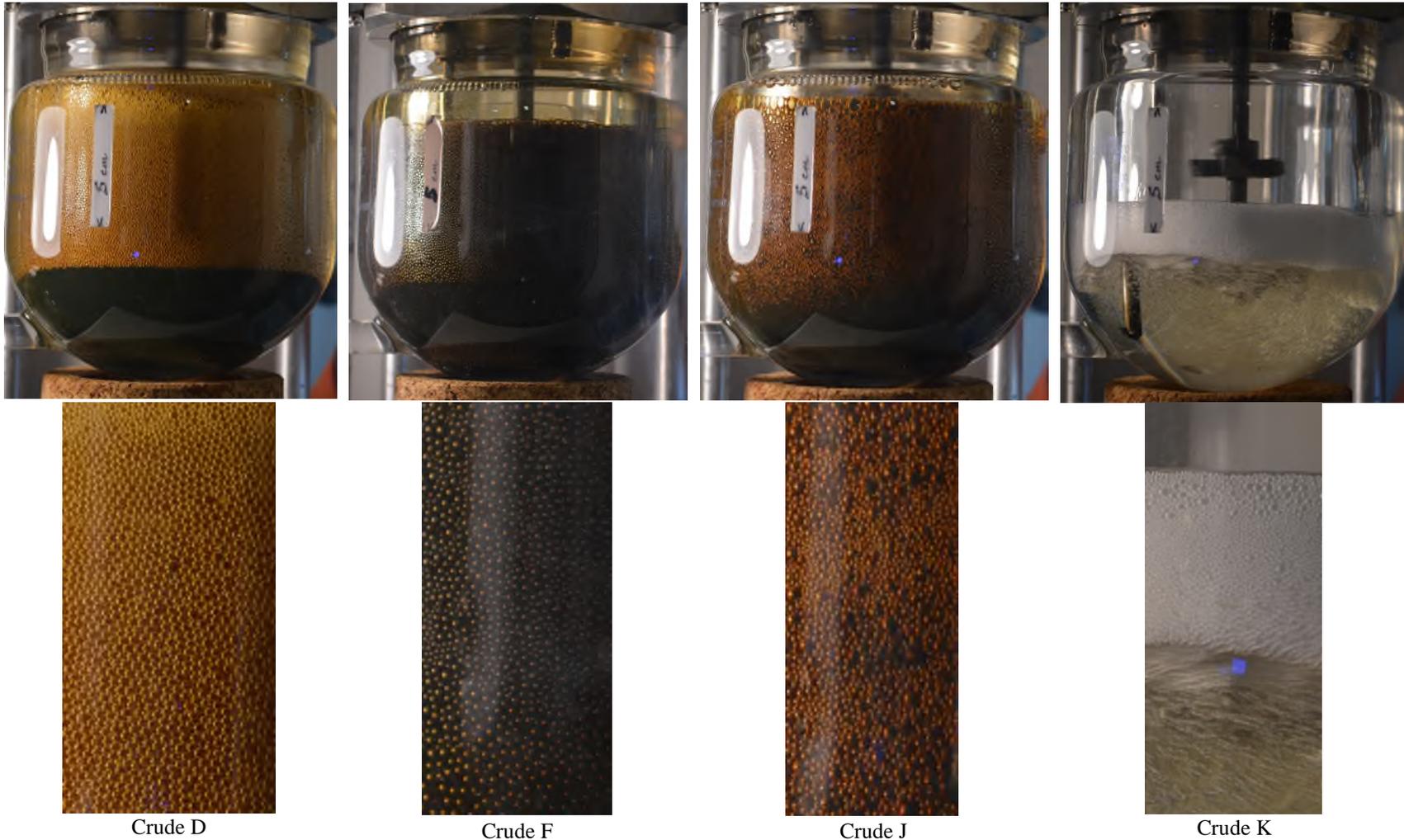
1 Examples of the foams obtained for different crude oils from Table 1 is shown in Figure 5. The
2 curves of foam stability vs time is illustrated in Figure 6: the foam produced by some of them
3 break right away, while others produce very stable foams compared to the residence time in gas
4 liquid separators.

5 In Table 2, the maximum foaming height F_{\max} and foaming time t_f are given for the different
6 organic liquids ranked by decreasing viscosity, and Figure 7 shows the same data plotted as a
7 function of viscosity for all the organic fluids in our internal database. There is obviously a general
8 correlation between the viscosity of the fluid and the foaming time in a). But, even for similar
9 viscosities, there can be a dispersion of nearly one order of magnitude between the foaming time.
10 In Figure 7 b), the maximum foam height does not show any clear dependence with viscosity.

11 Another interesting factor that can be better seen in the inlet of Figure 6 in log scale, is that the
12 nucleation time of the bubbles, and hence the time to reach the maximum of foaming, can differ
13 from crude oil to crude oil. As it will be discussed later, the presence of wax crystals can accelerate
14 the nucleation, but in the results shown in Figure 6, all the samples are well above their WAT,
15 and there is no simple explanation for why gas bubbles in crude oils G or I take so much time to
16 nucleate.

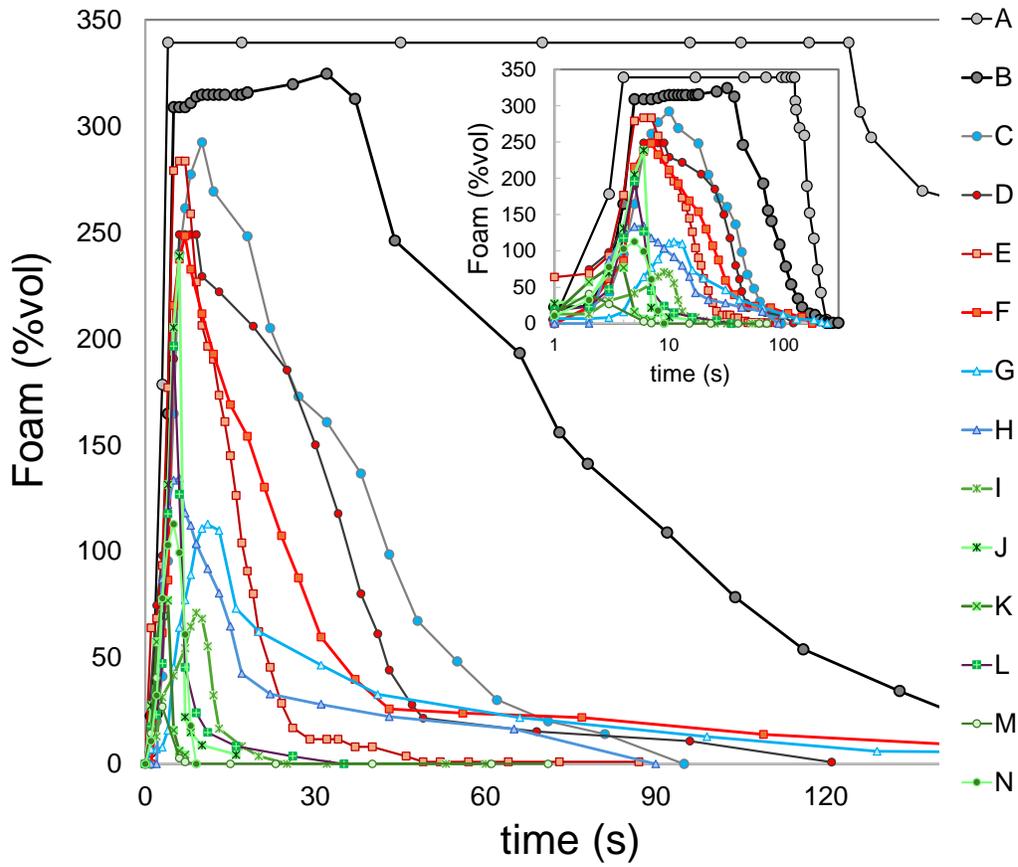
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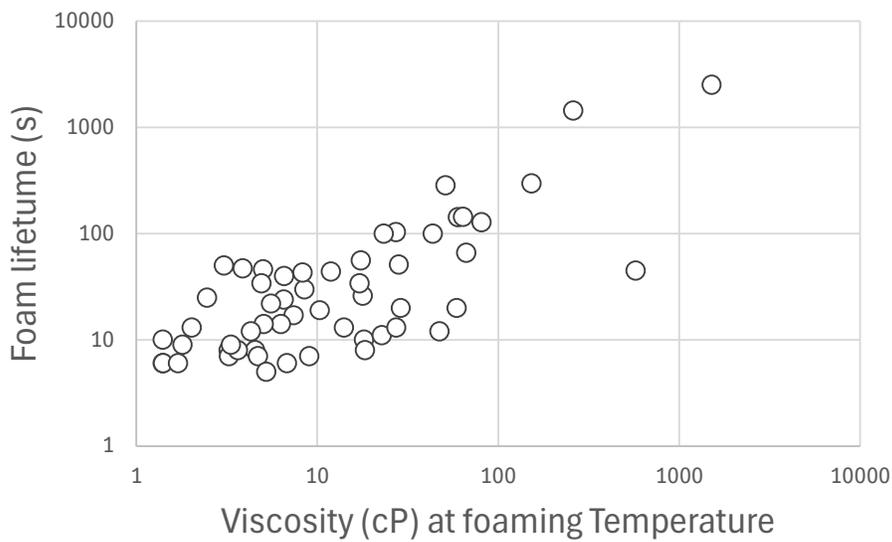
2 **Figure 5: Example of foams at the maximum height – top : whole reactor / bottom : close up on the foam with a 5 cm scale**

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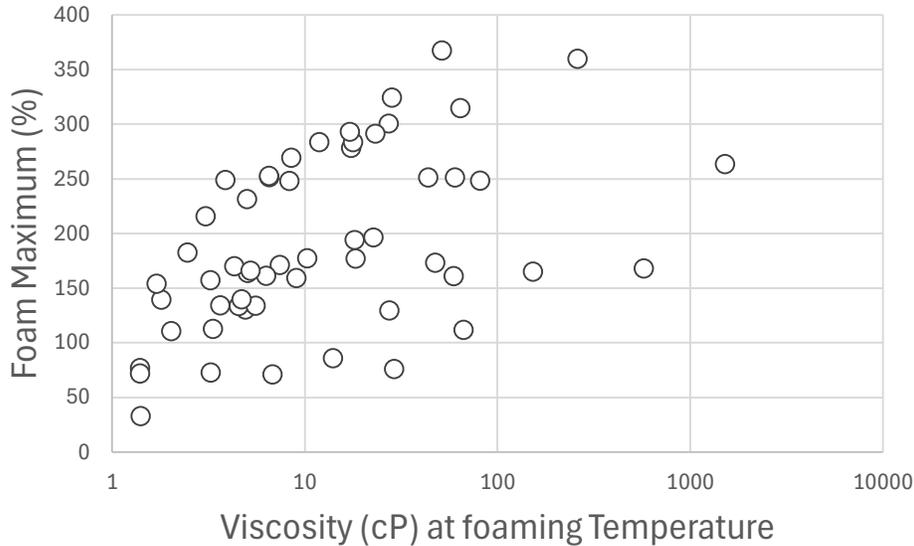
1

2 **Figure 6: Volume fraction of foam vs time for the organic liquids of Table 1 (inlet : time in**
 3 **log scale)**



4

a)
 [Insert Running title of <72 characters]



1 b)

2 **Figure 7: Foaming of the organic liquids of our internal database versus viscosity at**
 3 **foaming temperature a) foam lifetime, b) foam maximum**

4 **Table 2: Maximum height of foaming and foaming time for the organic liquids of Table 1**
 5 **ranked by decreasing viscosity**

| Crude | Viscosity at test T(cP) | Fmax (%) | tf(s) |
|-------|-------------------------|----------|-------|
| G | 120,0 | 112 | 66 |
| B | 64,1 | 325 | 168 |
| A | 51,3 | 350 | 235 |
| C | 41,6 | 295 | 65 |
| I | 29,0 | 170 | 12 |
| L | 22,7 | 196 | 11 |
| E | 19,9 | 280 | 35 |
| J | 18,4 | 240 | 10 |
| H | 15,1 | 160 | 40 |
| F | 8,3 | 250 | 43 |
| D | 3,9 | 250 | 50 |
| N | 3,3 | 112 | 8 |
| K | 1,4 | 75 | 7 |
| M | 0,9 | 40 | 6 |

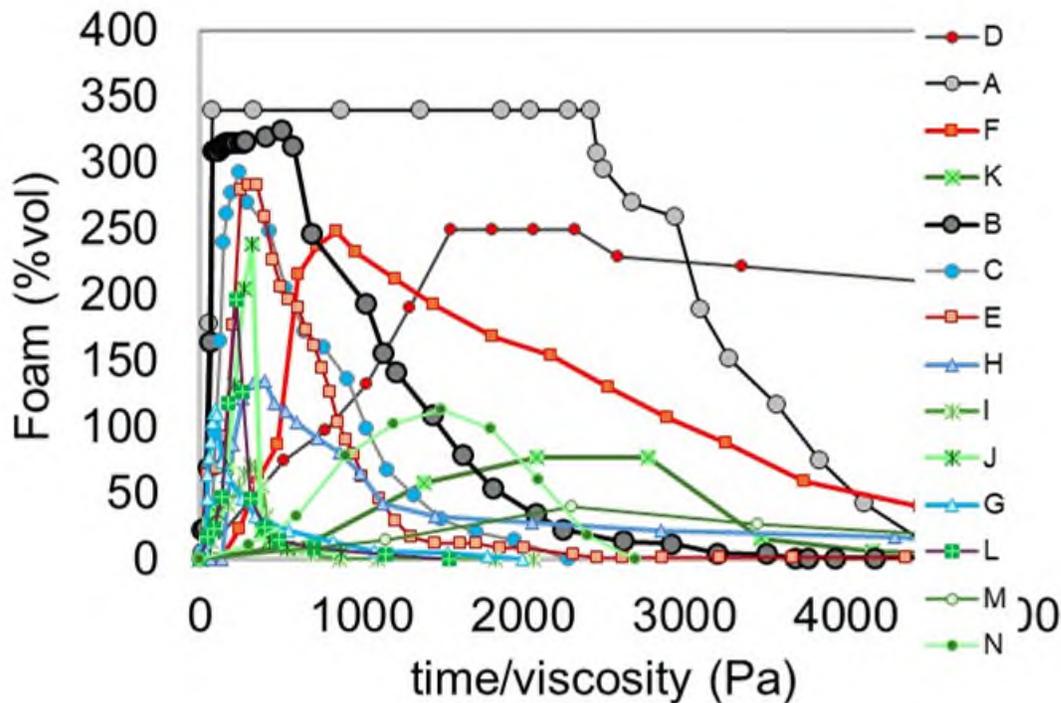
6

7 A way to take into account the potential difference due to drainage time and viscosities between

8 the systems is to normalize the time by the viscosity of the liquid as illustrated in Figure 8: it

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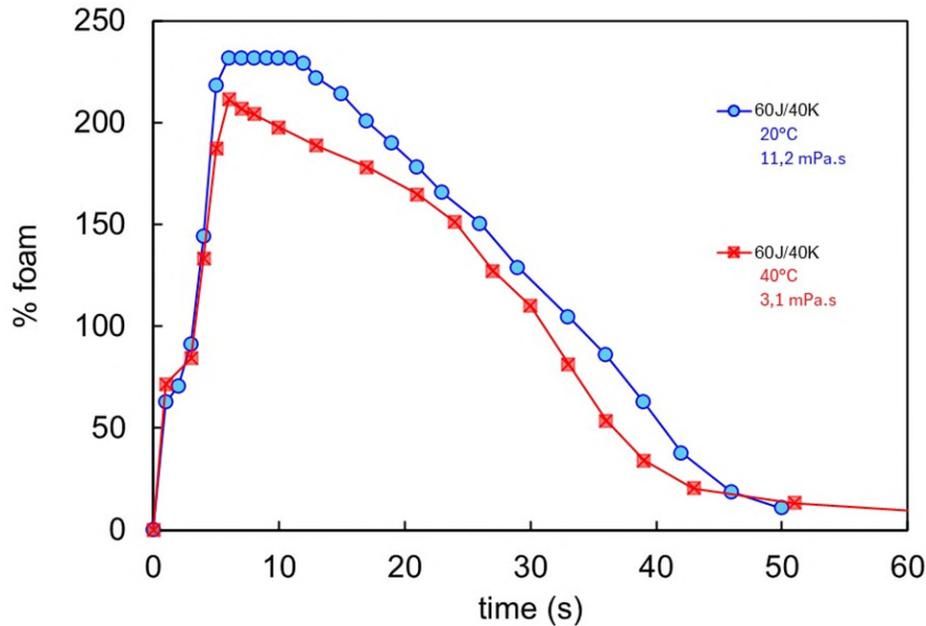
1 enlightens that for some of these liquids the foam stability is coming from other factors than their
 2 mere viscosity. On the contrary, crudes D and F for example have foams that are significantly
 3 more stable than expected from a simple viscosity effect. And the reasons for these added stabilities
 4 are to be found outside of viscosity-induced slowdown of drainage.



5
 6 **Figure 8: Foaming vs time normalized by viscosity for the organic liquids of Table 1**

7 A practical guideline for operations is that raising the temperature is often a good way to
 8 mitigate foaming issues, if no other solution is found. But, it is not always the case, in particular
 9 for “difficult” foams for which temperature can have little impact on the foam stability, and a better
 10 understanding of the reasons behind that is necessary : as illustrated in Figure 9, in spite of the rise
 11 of temperature by 20°C resulting in a decrease in viscosity by a factor 4, the foaming of a blend
 12 between crude J and K shows nearly no difference in stability.

[Insert Running title of <72 characters]



1

2 **Figure 9: Foaming vs time of blend between 60% J and 40% K at 20°C (viscosity = 11.2**
 3 **mPa.s) and 40°C (viscosity=3.1 mPa.s)**

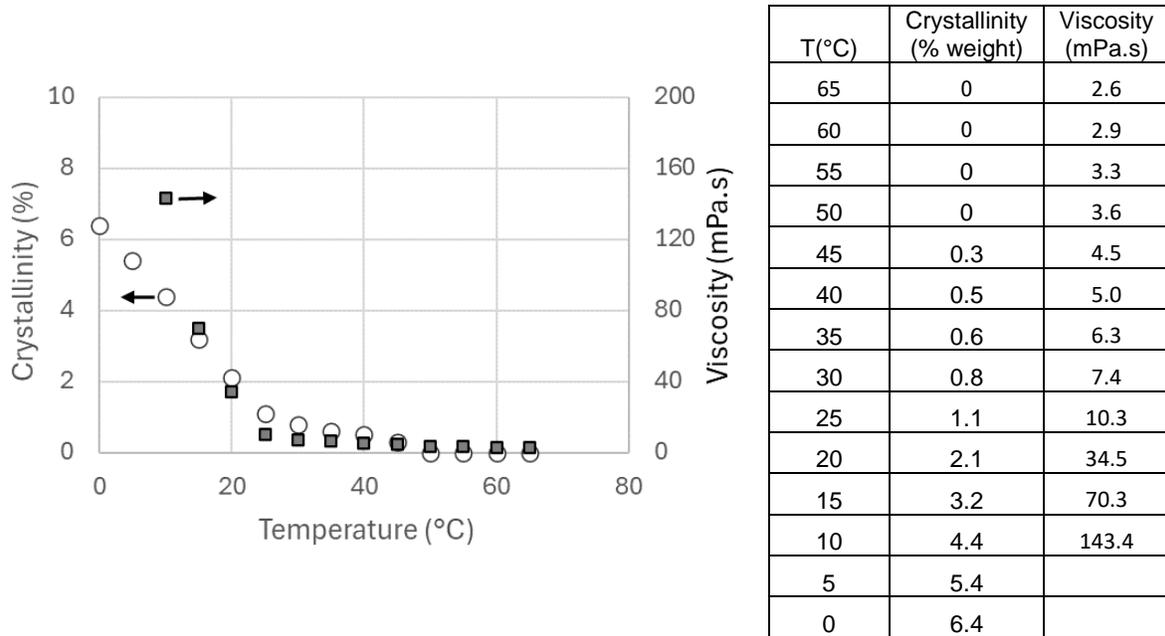
4 **Effect of waxes & temperature**

5 As explained in references [2],[5]-[6], [19]-[20], paraffin crystallization can have a very
 6 important effect on the stability of organic liquid foams. Depending on their origin, crude oils can
 7 present a very broad range of paraffinic molecules, both in terms of chemical structure and of
 8 quantities. In order to study how relevant was this parameter for oil & gas systems, a systematic
 9 study of the effect of temperature, and therein of wax crystallization was performed on Crude Oil
 10 N of Table 1.

11 The distribution of the wax crystals of Crude Oil N versus temperature is illustrated in Figure
 12 9. When the temperature drops below 20°C, the viscosity of the crude oil is not Newtonian
 13 anymore. In order to represent the variation of viscosity versus temperature, it was decided to use
 14 the viscosity at 100 s⁻¹ for temperatures below 20°C (as measured in MCR 302) and the Newtonian

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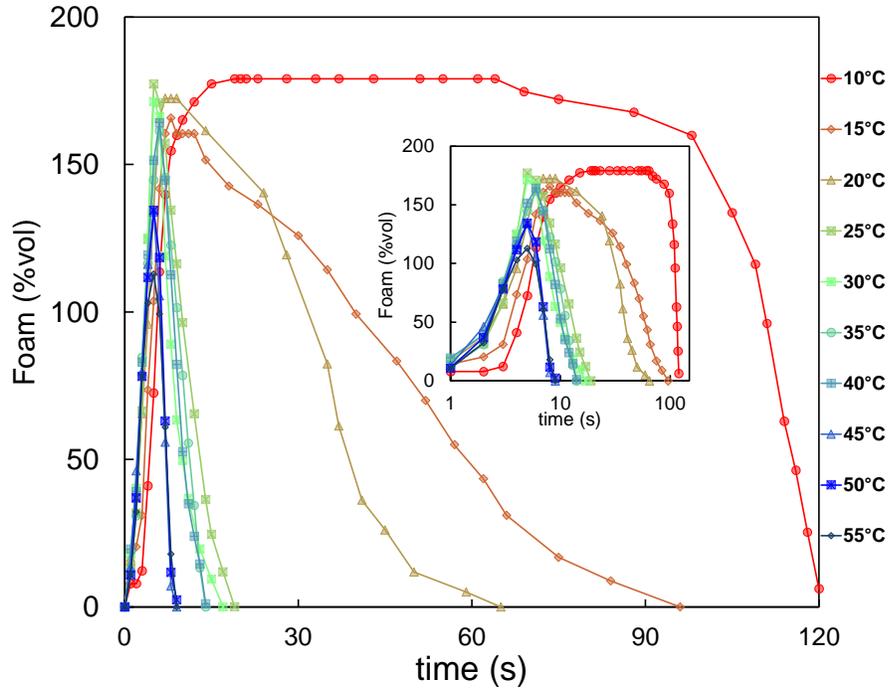
1 viscosities measured with the SVM 3000 above 20°C. From Figure 10, it is clear that the viscosity
 2 starts to increase strongly as soon as the paraffins contained in the crude oil start to significantly
 3 crystallize below 20°C.



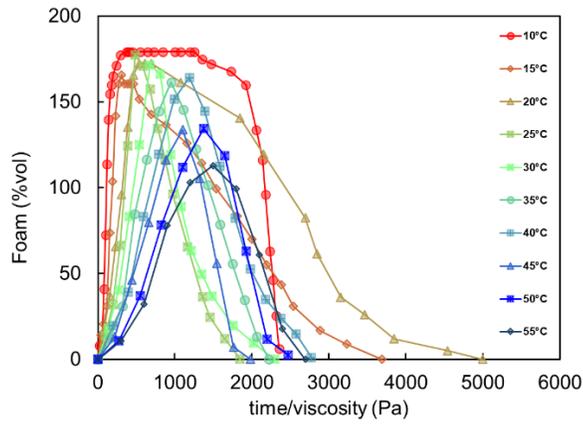
4
 5 **Figure 10: Crystallinity and Viscosity vs Temperature of Crude Oil N**

6 Foaming tests were conducted at temperatures ranging from 55°C down to 15°C. The evolution
 7 of the foam versus time is shown in Figure 11 a/. It is obvious that there is a significant change in
 8 the foam stability when the temperature drops below 25°C.

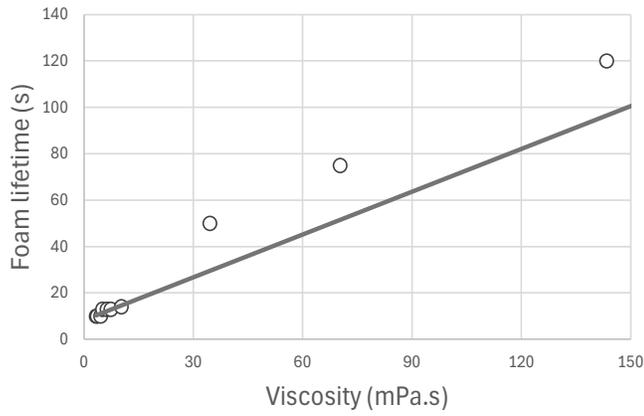
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a)



b)

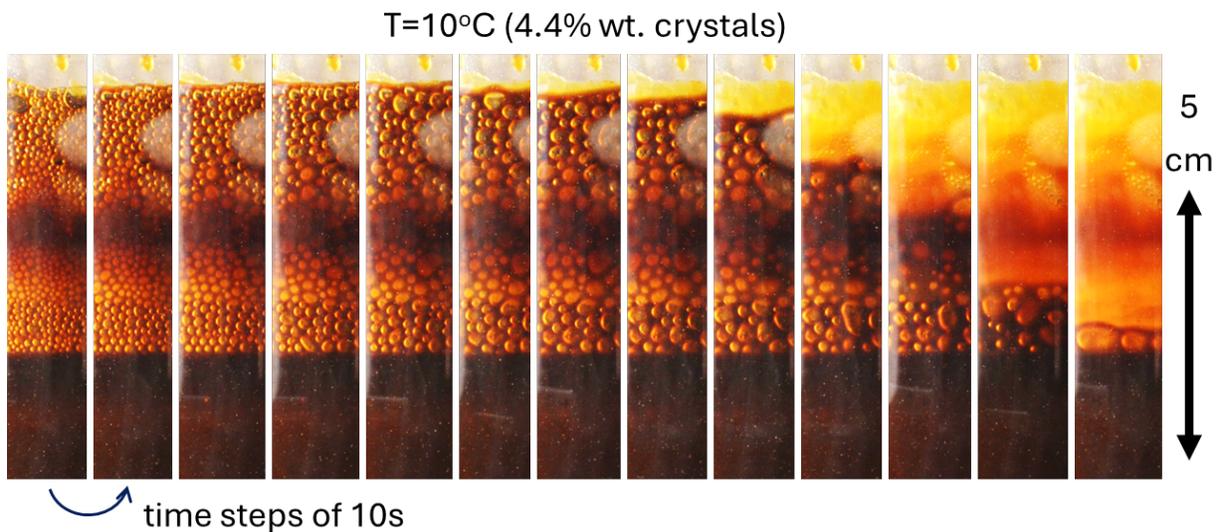


c)

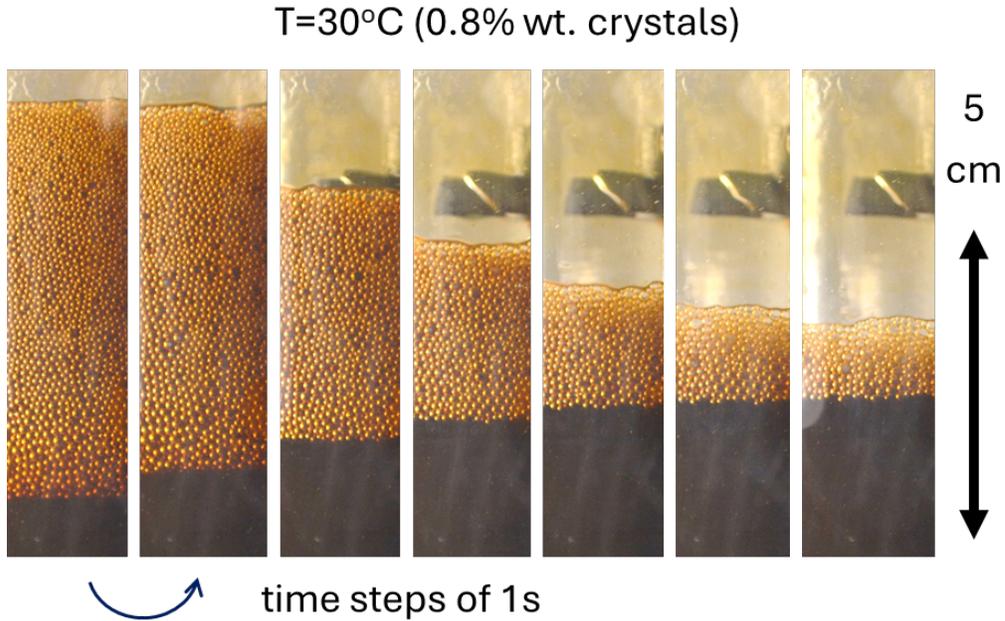
1 **Figure 11: Foam stability for various test temperature for Crude Oil N a) vs time (inlet :**
2 **log scale of time), b)vs time/viscosity, c) foam lifetime vs viscosity at test temperature – the**
3 **grey line is the extrapolation of the linear behavior at short times**

4 It is interesting to associate this change of stability to the change of mechanism of the rupture
5 of the foam. At 10°C (Figure 12 a)), the level of the foam does not change for a long period of
6 time, the foam is already quite dry with little variation of the liquid height along the time.
7 Coalescence events happen between gas bubble, up to a time when catastrophic rupture of the
8 foam takes place. At 30°C (Figure 12 b)), the foam is initially quite wet with drainage of the liquid
9 over time. There are less coalescence events between the gas bubbles within the foam but a
10 continuous coalescence from the gas bubbles with the gas/foam top interface.

a)



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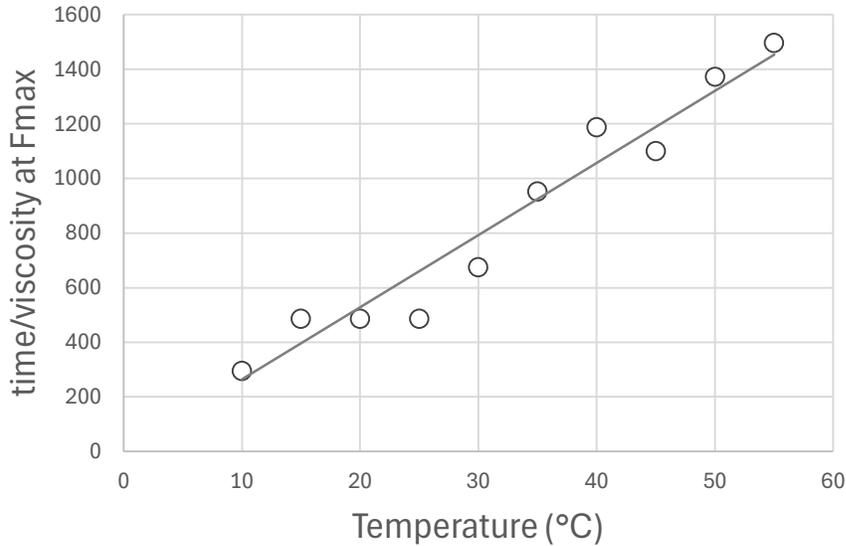


b)

1
2 **Figure 12: Images taken after the maximum of foamability showing the foam above the**
3 **liquid for Crude Oil N a/ 10°C, b/ 30°C**

4 Another very interesting feature of the mechanism is seen in Figure 11 b) with the normalization
5 of the time in abscisse by the viscosity. It can be seen for the short times that the presence of the
6 wax crystals allows a “faster” nucleation of the gas bubbles, even at a very low level: in Figure 13,
7 the foaming maximum is reached at shorter times when the temperature decreases, or equivalently
8 when more wax crystals are present.

[Insert Running title of <72 characters]



1

2 **Figure 13: Evolution of the time/viscosity to reach the maximum height of foam vs**
 3 **temperature for Crude Oil N**

4 These results are in very good agreement with the results in references [5] or [21]. As in these
 5 references, foaming properties are mainly affected by the presence of wax crystals when the wax
 6 content becomes higher than a few percents, even if at those low percentages the viscosity of the
 7 fluid would still be manageable.

8 Practical messages for flow assurance studies are that the presence of wax nuclei can play a
 9 significant effect on the nucleation of gas bubble within the organic liquid, even at very low
 10 percentages, and that foam stability will be significantly affected if the concentration of wax
 11 crystals reaches 2 to 4%. Hence, specific considerations have to be taken into account during
 12 multiphase transportation in pipelines when the flow pattern predicts a dispersed state.

13 **Blends of organic liquids**

14 The understanding of the foamability of organic liquid blends developed in [15] - [16] offers
 15 an insight into the foamability of oil & gas hydrocarbons, with a limitation however: as all those

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1 hydrocarbons are naturally very complex blends of different molecules, it is possible to understand
2 that they foam more or less, but it is not yet possible to predict this foamability, even with a
3 description of their composition, either a “global” analysis such as their SARA composition or
4 with a PVT composition or more precise LC-MS descriptions of the molecular composition.
5 Indeed, the blends are too complex to reproduce to determine if its surface tension follows a
6 “linear” behavior or not, and how far from the linearity it is.

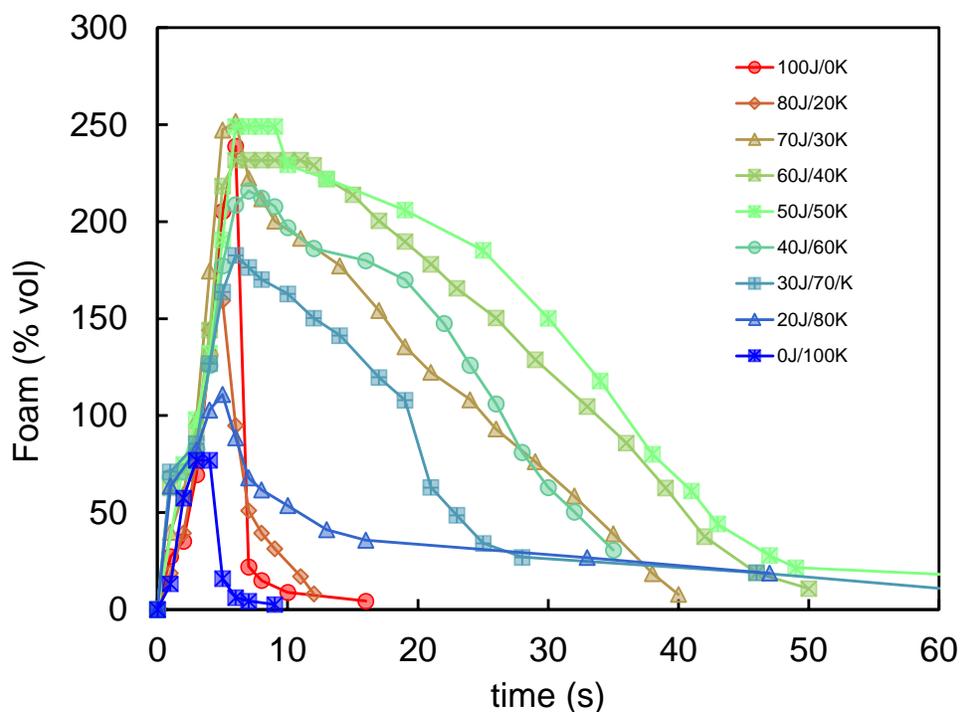
7 On the other hand, a hydrocarbon reservoir is seldom developed alone as the most common
8 scenario is that several hydrocarbons coming from different reservoirs will be mixed to be
9 transported and produced together. “Brown field” redevelopments or new tie-backs to an existing
10 production units will also aim at producing mixtures of hydrocarbons. In those cases, samples of
11 each fluid are usually available, and it is possible to study the foaming properties of the blends
12 either to adapt the sizing of the gas/liquid separators in case of “Green Field” developments or to
13 make sure that the existing facilities will be adapted for the new production to be comingled with
14 the existing fluids. In all these cases, it is possible to have separate individual organic liquids, albeit
15 these liquids being already blends in themselves, and thus to study if the learnings obtained on
16 model systems in [15] - [16] can be applied to these complex ones as illustrated below.

17 The first case is a “Green field” study for which the production of two different reservoirs was
18 supposed to change over the lifetime of the field. A systematic study of the foaming of the blend
19 between fluids J and K of Table 1 was performed, for which the variation of the ratio between the
20 two fluids was much higher than the predicted variation to be encountered on the field.

21 The foaming tests at the different percentages are shown in Figure 14: while each individual
22 crude oil does not produce stable foams, the stability of the foams produced by their blends is
23 much higher and passes through a maximum with the composition, while the viscosity is varying

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1 regularly. So, the change in stability does not result from a simple viscosity effect, and the situation
 2 is very similar to what was observed with model solvents in [15].

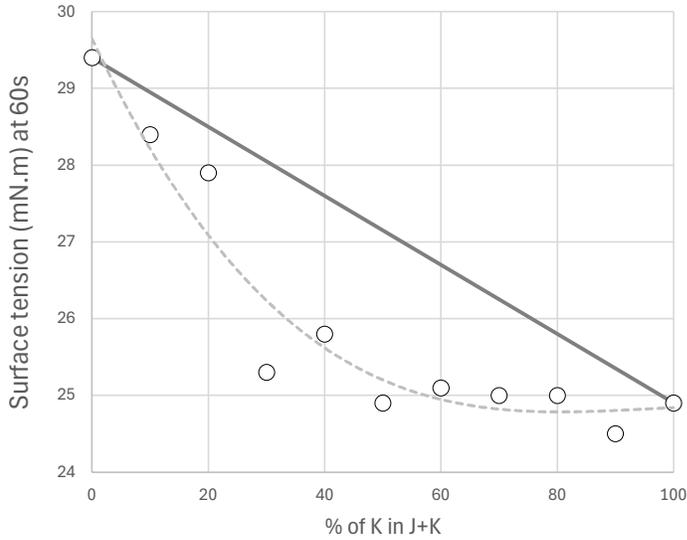


3

4 **Figure 14: Foaming for various blends between fluids J and K vs time**

5 Surface tension measurements were performed over time on the blends with varied relative
 6 compositions. As the tension is decreasing over time, it was decided to report the values at 60s,
 7 quite similar to the stability of the foams described above. Choosing a shorter time would have
 8 produced similar trends. The corresponding variations of surface tension versus the composition
 9 of the blend is plotted in Figure 15. As in [15], the surface tension of the blend is sub-linear with
 10 an over representation of molecules coming from fluid J at the interface.

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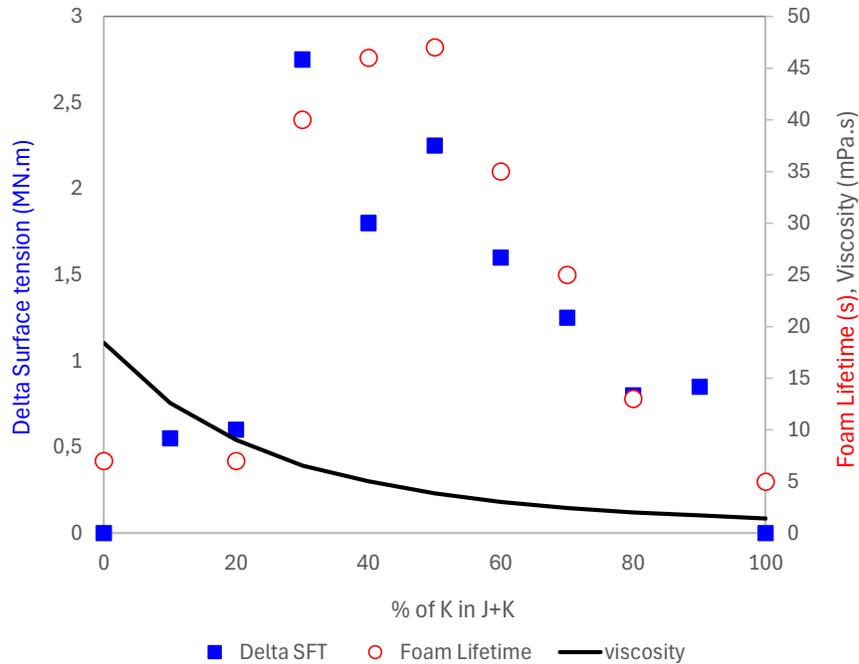
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2 **Figure 15: Surface tension measurements after 60s versus composition of blends between J**
3 **and K (the lines are just to guide the eyes)**

4 Figure 16 gives the representation of the deviation from the linear behavior of the surface
5 tension, measured as the distance between the straight line and the measured data in Figure 15, the
6 foam lifetime, and the viscosity variation for the different blends. As for model fluids, there is a
7 close relationship between the magnitude of the deviation of the surface tension and the foam
8 lifetime that has been explained in [16] for model systems. The correlation between the
9 foamability and delta SFT is considerably enhanced as compared to that between foamability and
10 viscosity.

11

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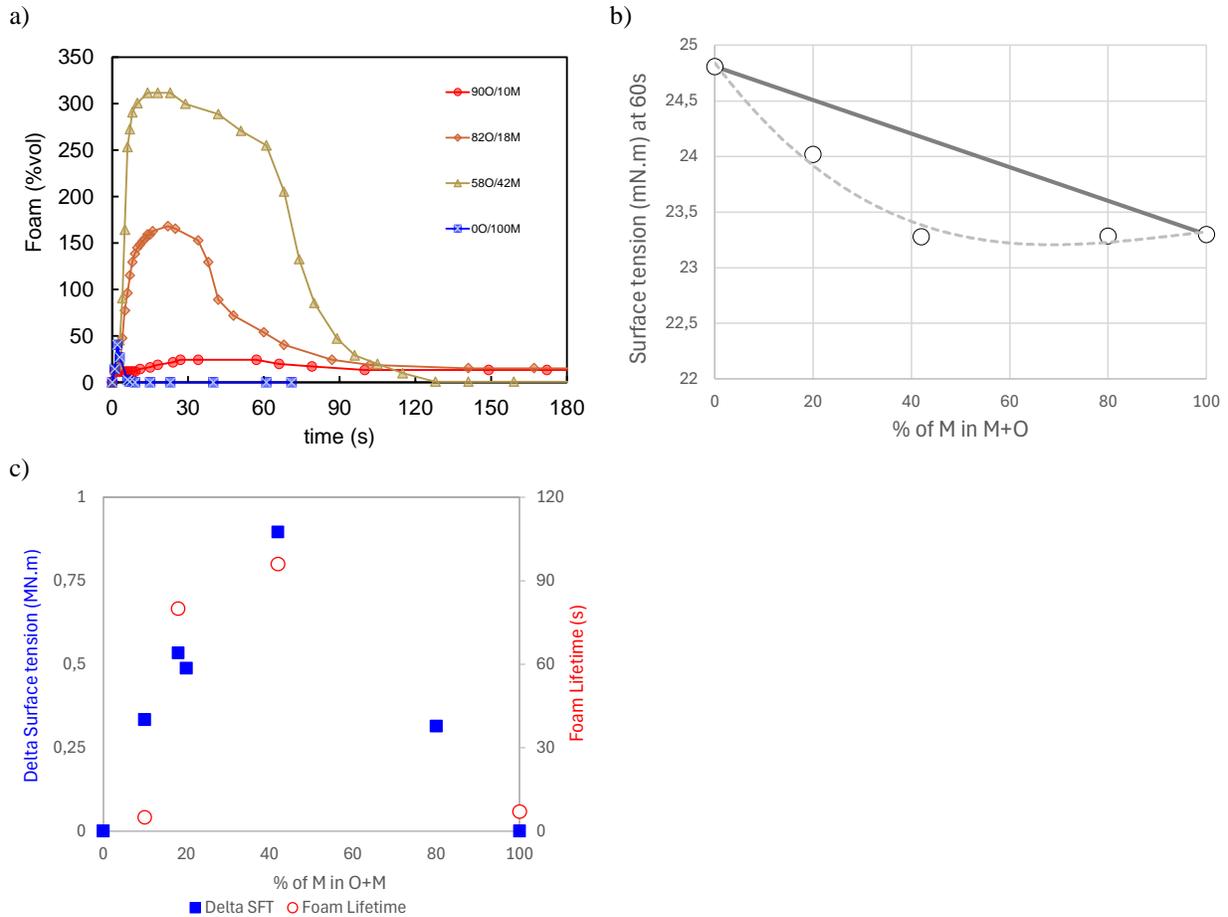
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 2 **Figure 16: Surface tension deviation from the linear behavior (blue filled squares), foam**
 3 **lifetime (red open circles) and viscosity (black line) versus composition of blends between J**
 4 **and K**

5 Over time, similar studies have been conducted on different systems either to study new
 6 developments, or for brownfield projects. The results are presented in Figure 17 to Figure 19, with
 7 the foam volume vs time for the different blends, the surface tension measurements and the
 8 comparison between the deviation from the linear behavior of the surface tension and the foam life
 9 time, these last graphs, labelled c) have been plotted with the same axis ranges for easier
 10 comparison of the results between the different systems.

11 The foam produced by the blends between O and M are very stable as shown in Figure 17. It is
 12 to note that it was not possible to study the foam properties of fluid O alone. In this case also, and
 13 as in the model systems that have allowed the theoretical understanding of the foaming behavior,

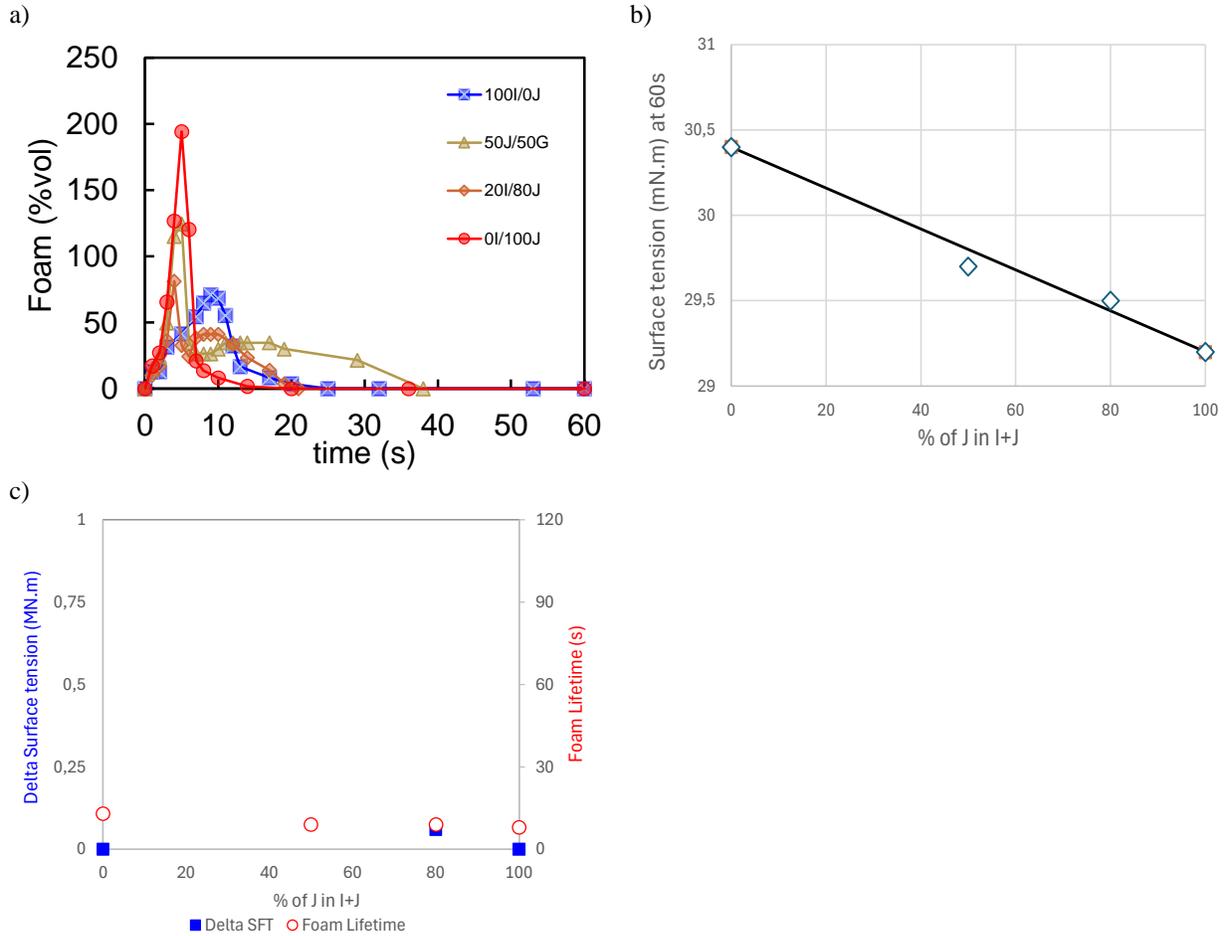
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- 1 there is a very good correlation between the deviation from the linear behavior of the surface
- 2 tension and the foaming properties of the blends.

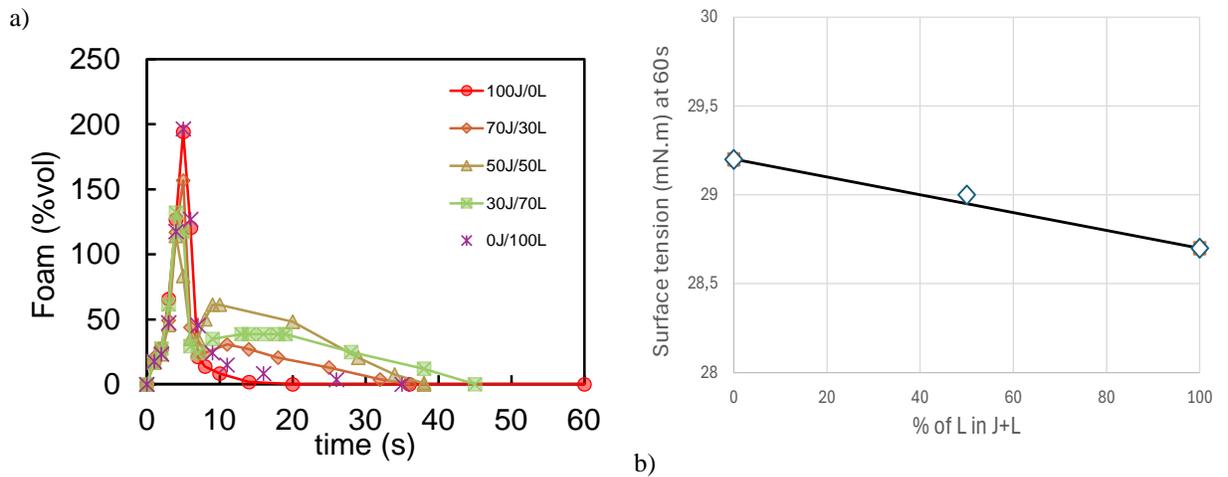


3
 4 **Figure 17: a) foaming versus time, b) surface tension versus composition c) surface tension**
 5 **deviation from the linear behavior and foam lifetime, versus composition of blends between**
 6 **O and M**

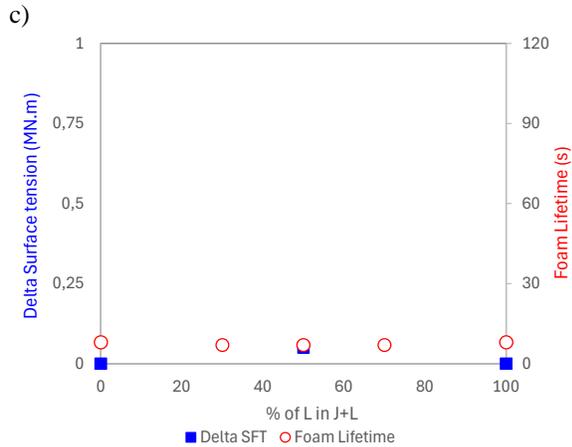
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1
 2 **Figure 18: a) foaming versus time, b) surface tension versus composition c) surface tension**
 3 **deviation from the linear behavior and foam lifetime, versus composition of blends between**
 4 **I and J**



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1
2 **Figure 19: a) foaming versus time, b) surface tension versus composition c) surface tension**
3 **deviation from the linear behavior and foam lifetime, versus composition of blends between**
4 **J and L**

5 This correlation is kept for the blend studied in Figure 18 and Figure 19, although in these cases,
6 the surface tension of the blends varies linearly with the composition, and, in accordance, the foam
7 produced are not stable. It is also important to note that the same crude oil J can produce either a
8 blend for which there is no deviation of the surface tension to the linear behavior with I or L or a
9 blend for which there is a deviation, and very stable foams consequently, with K.

10 These cases illustrate that, even if each of the crude oils presented above is already a blend of
11 molecule with various chemical composition or molecular weights, their blends will follow a
12 similar behavior as mixtures of pure liquids according to the affinity for gas/liquid interfaces their
13 blends will demonstrate.

14 From a practical perspective concerning flow assurance risk assessment, experimental
15 depressurization test campaigns are often time consuming, with still a residual risk linked to the
16 manipulation of fluids under pressure even with the best practice. In case of a development that
17 would lead to the mixing, either in the flow line or in separators, of fluids coming from different

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1 reservoirs, and necessitate to evaluate the foaming risk, it would be far more efficient and safe to
2 start the study by determining the surface tension properties of the blends in order to determine
3 which are the blends that exhibit the higher deviation from the linearity, to finally determine their
4 foaming tendencies through the depressurization tests.

5 Another important learning, also similar to what observed on the model systems, is that it is not
6 sufficient to determine the properties of each individual fluids to know about the foaming
7 properties of their blends, and it would be wrong to assume that if two (or more) fluids are not
8 foaming, their blends are safe.

9 **Conclusion**

10 Advancements in the fundamental understanding of foam stability in organic liquids have led
11 to practical applications in the energy sector. Theoretical learnings often developed on much more
12 simple systems were applied successfully to understanding the foaming behavior of crude oils and
13 their blends.

14 Regarding crude oil blends, which may be encountered when several reservoirs are produced
15 within the same installations, it is not yet possible to predict when a blend will lead to transient
16 foam stability. It is possible that by having more data, such as SARA composition or PVT pseudo
17 component composition, the prediction will be available in the future.

18 At the time being, surface tension measurements are a quick and easy way to screen for potential
19 foaming issues of the blends of organic liquids, which can happen even if each individual liquid
20 does not foam.

21 By identifying and mitigating foaming issues, it is possible to improve production efficiency,
22 safety, and overall performance in various industrial processes.

23 **Author Contributions**

[Insert Running title of <72 characters]

1 Didier Laurensen performed the experimental tests and contributed to their interpretation. The
2 manuscript was written through contributions of all authors. All authors have given approval to
3 the final version of the manuscript.

4 **Acknowledgements**

5 The authors would like to thank TotalEnergies SE for permission to publish some of the results.

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