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Processamento submarino como ferramenta para redução de custos de projetos em águas profundas

Subsea processing as a tool for cost reduction of deepwater projects

El subsea procesamiento como herramienta para la reducción de costos de proyectos en aguas profundas

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Resumo

Para que a produção e os lucros das empresas de petróleo não diminuam, novos campos de precisam ser descobertos e explorados. Muitas dessas novas descobertas são campos offshore em águas profundas. No entanto, a queda nos preços do petróleo nos últimos anos fez com que esse tipo de exploração, que já é um desafio em si, seja ainda mais difícil, de modo que as

empresas estão postergando ou até mesmo cancelando vários projetos em águas profundas. Inovação, novas tecnologias e novos conceitos de produção e processamento de petróleo e gás são necessários para viabilizar projetos em águas profundas e aumentar sua competitividade. O objetivo do presente artigo foi analisar o processamento submarino da produção de petróleo como uma estratégia para reduzir custos, tanto de capital quanto de operação, para viabilizar a exploração de campos offshore remotos. Além disso, uma discussão sobre os benefícios e desafios dessa estratégia também foi realizada. Também inclui um estudo de caso no campo de Lula, no pré-sal brasileiro. Os resultados demonstram que o uso de separação submarina tem grande potencial para reduzir o OPEX e o CAPEX em projetos offshore. O presente estudo de caso demonstra uma redução de custos devido ao investimento nos separadores de cerca de US $ 6,1 bilhões, uma redução de cerca de 6 a 12 vezes na energia necessária para elevar a produção e uma redução de cerca de 5 a 7 vezes nos gastos com gás natural como combustível para os cenários avaliados.
Palavras-chave: separação subsea; decisão de investimentos; OPEX; CAPEX; Pré-sal.

Abstract

In order that the production and profits of petroleum companies do not decline, new oil field need to be discovered and exploited. Many of these new discoveries are offshore deepwater fields. However, the drop in oil prices in the last few years has made this type of exploration, which is already challenging in itself, even more difficult, so that companies are postponing or even canceling several deepwater projects. Innovation, new technologies and new concepts of oil and gas production and processing are necessary to make deepwater projects feasible and increase their competitiveness. The aim of this paper was to analyze the subsea processing of oil production as a strategy to reduce both capital and operating costs to enable remote offshore exploration. In addition, a discussion of the benefits and challenges of this strategy was also presented. It also includes a case study at the Lula field, in Brazilian pre-salt. Results demonstrate that the use of subsea separation has great potential to reduce OPEX and CAPEX on offshore projects. The current case study demonstrates a cost reduction due to the investment in the separators of around US$ 6.1 billion, a reduction about 6 to 12 times in the power needed to lift the production and a reduction of about 5 to 7 times in the expenditures with natural gas as fuel for the evaluated scenarios.
Keywords: Subsea separation; Investment decision; OPEX; CAPEX; Pre-salt fields.

Resumen

Para que la producción y los beneficios de las compañías petroleras no disminuyan, es necesario descubrir y explotar un nuevo campo petrolero. Muchos de estos nuevos descubrimientos son campos de aguas profundas en alta mar. Sin embargo, la caída de los precios del petróleo en los últimos años ha hecho que este tipo de exploración, que ya es un desafío en sí mismo, sea aún más difícil, por lo que las empresas posponen o incluso cancelan varios proyectos de aguas profundas. La innovación, las nuevas tecnologías y los nuevos conceptos de producción y procesamiento de petróleo y gas son necesarios para hacer factibles los proyectos de aguas profundas y aumentar su competitividad. El objetivo de este documento fue analizar el procesamiento submarino de la producción de petróleo como una estrategia para reducir los costos de capital y operativos para permitir la exploración remota en alta mar. Además, también se realizó una discusión sobre los beneficios y desafíos de esta estrategia. También incluye un estudio de caso en el campo de Lula, en pre-sal brasileña. Los resultados demuestran que el uso de la separación submarina tiene un gran potencial para reducir OPEX y CAPEX en proyectos offshore. El estudio de caso actual demuestra una reducción de costos debido a la inversión en los separadores de alrededor de US $ 6,1 mil millones, una reducción de aproximadamente 6 a 12 veces en la potencia necesaria para elevar la producción y una reducción de aproximadamente 5 a 7 veces en los gastos con gas natural como combustible para los escenarios evaluados.
Palabras clave: Separación submarina; Decisión de inversión; OPEX; CAPEX; Pre-sal.

1. Introdução

According to the Brazilian Petroleum, Natural Gas and Biofuel Agency (ANP, 2017a), Brazilian oil production was 2.676 million barrels per day (MMbbl /d). The 821 offshore oil wells, less than 10% of all Brazilian oil wells, were responsible for 95% of the country's total oil production. The pre-salt fields corresponded to 46% of Brazilian production, about 1,233.3 Mbbl/d by means of only 74 wells (ANP, 2017a). The pre-salt is a set of huge hydrocarbon reservoirs found in deepwater reservoirs below a thick layer of rocks and salt located about 300 km off the Brazilian southeastern coast. It is one of the largest oil discoveries in the last decade. According to some analysts, the amount of recoverable oil is about 50 billion barrels (EIA, 2014; Seabre et al., 2015). The area has a high commercial value since it contains high quality and quantities of light oils at depths greater than 7 km, which includes 2 km of water, as in the case of Lula field (Petrobras, 2017a).

This discovery has inspired an intense discussion among sectors of Brazilian society on how such resource gains could be maximized to accelerate the country's socioeconomic development, since it has the potential to generate new revenues (Rodrigues and Sauer, 2015).

However, pre-salt exploration is not an easy task. The development of the oil and gas industry has become increasingly challenging, not only in Brazil, but also in several other countries, due to exploratory frontier being more remote and dangerous, deepwater exploration, and more stringent environmental laws. This has caused the increase of average cost of offshore exploration in the last decades; for instance, it was four times higher in 2014 than 2003 in the Gulf of Mexico region (Prescott et al., 2016a). This fact coupled with the falling oil prices of recent years has made offshore exploration more challenging and prone to strategy changes. In fact, these changes have already begun, and deepwater operating costs have been falling over the last three years. However, the cost is still an obstacle to the advancement of offshore exploration (Gyllenhammar et al., 2017; Prescott et al., 2016a).

Among the challenges to be overcome in deepwater exploration is the processing of the fluids efficiently. Usually, if not always, the production contains oil and formation water, more like as brine. In pre-salt, it may have a lot of CO2 also The volumetric fraction of the produced water tends to increase with time, and there are brown wells where water production corresponds to 90% or more of the total volume of produced fluids (Frising et al., 2006; Gyllenhammar et al., 2017, Noïk et al., 2013, Rodrigues and Sauer, 2015).

Due to the oil recovery and production, the formation of oil and water emulsions may happen. (Khatri et al., 2011; Oji and Opara, 2012). The formation of emulsions during the production process generally leads to negative economic effects (Keleşoğlu et al., 2012). Some examples are contamination of the catalysts during refining, pipeline corrosion, viscosity increase, and the pumping of a larger amount of fluid due to the extra mass of the water (Chrisman et al., 2012; Gylenhemamar et al., 2017; Kilpatrick, 2012; Maia Filho et al., 2012; Plasencia ET AL., 2013; Sjöblom et al., 2014).

In addition to water, the oil production also incorporates gas and solids, and the separation of these substances is necessary in order to obtain only the most valuable elements, which are oil and gas (Prescott et al., 2016b, 2016c). This multiphase processing gives rise to numerous challenges that can generate bottlenecks in production operations. When fluid separation takes place on land, the size of the separator is not a problem, so the effort required to design it is less than that employed in offshore projects. But separators that operate on offshore platforms or on the seabed face size constraints. A subsea separator has financial limits related to the cost of manufacturing materials as well. In addition to these constraints, environmental factors demand the increase of this equipment's efficiency (Frising et al., 2008;

Lavenson, et al., 2016). Moreover, due to the high pressure on the seafloor, the subsea separator should be compact, which means that the fluid residence time will be smaller than for a regular separator. This makes the separation more challenging, especially with the formation of emulsions.

Offshore processing usually occurs on a floating production unit (FPU). However, processing on the seabed has been gaining visibility in recent years. Subsea technology is not specific to a single company or applicable to only one type of reservoir. It can be employed at many sites around the globe and requires contributions from many companies of the supply chain. Figure 1 shows some subsea separation and pumping projects in various locations and in operation by different companies around the world.

Figure 1. Subsea separation with boosting projects.

Source: Hendricks et al., 2016, p. 2.

Hence, as can be seen subsea production techniques has been increasing at an accelerated pace, and it has made exploration projects around the world possible, especially in deepwater, remote, extreme climatic and low pressure reservoirs with heavy and viscous oils, whether they are green or brown fields (Hendricks et al., 2016; Kondapi et al., 2017). Some examples are localities such as the Arctic, where the thick ice layer makes the installation of surface platforms difficult (Li et al., 2014) and also the Brazilian pre-salt, because its water depth and distance from the coast (Dalane, et al., 2017).

The Brazilian company Petrobras is one of the world’s leading deepwater oil operators. Its experience in this area has enabled it to develop pioneering exploratory and development projects in areas in which other operators have little or no experience. It has developed many pioneer technologies in order to exploit the pre-salt. As a result, the company has won its third OTC Distinguished Achievement Award for Companies, Organizations and Institutions, the highest award given to an offshore company, due to the merit of its various pre-salt technologies (Petrobras, 2017a). One of the strategies chosen by the company to overcome the challenge of extracting oil from the pre-salt in an economically viable way in times of low oil prices is to invest in improvement and development in subsea technology. From the US$ 236.7 billion foreseen by Petrobras in its management plan from 2013 to 2017, 15% was directed to the deployment of subsea systems. As a result, Petrobras has already saved about US$ 500 million between 2014 and 2015 in the scope of subsea equipment on its projects. In addition, it also achieved a CAPEX (capital expenditures) reduction of approximately 25% on pre-salt projects (Gomes et al., 2017). As a result of the experience acquired by Petrobras over the last decade exploring the pre-salt, the drilling time of pre-salt wells fell from 310 days to 89 days, from 2010 to 2016, a 71% reduction. The production cost per barrel, which was US$ 9.10 in 2014, was reduced to US $ 8.00 in the first quarter of 2016, making the operation more competitive (Petrobras, 2017a).

It is important to evaluate the possibility of using equipment, especially separation devices, on the seabed as a tool to make exploration projects less expensive by means of OPEX and CAPEX reduction. The objective of this article was to compares the OPEX related to the energy expenditure of pumping the oil production with and without the use of subsea separation and the CAPEX related to the replacement of the initial production units by storage units together with subsea systems by means of a case study of a Brazilian pre-salt field, so the feasibility of the subsea strategy may be evaluated. In order to situate the reader, a review of the subsea technology, including its advantages and challenges, was also performed.

2. Subsea Processing

A definition of subsea processing (SSP) is any activity of treatment of produced fluids on the seabed, or below it, in order to increase the reservoir recovery factor. Among these processes are pumping and compression (boosting), separation of gas and liquids, and water injection. These processes generally take place at the topside infrastructure, with the exception of pumping (Kondapi et al., 2017; Wu et al., 2016).

As fluid recovery advances, the reservoir pressure decreases to the point where it is not enough to overcome the height of the production column. In order to maintain production, the wells may be equipped with artificial lift equipment, such as gas lift or electrical

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submersible pump (ESP) to overcome the production static height and head loss (Vedachalam, 2015). Subsea pumping has gained prominence and applicability in recent years among companies in the sector and it has been frequently used together with topside facilities (Kondapi et al., 2017). As an example, the use of a submersible centrifugal pump can double well production compared to other methods such as gas lift, depending on the characteristics of the reservoir. In 1993, Petrobras installed the world's first submersible centrifugal pump in a subsea well at the Carapeba field, in the Campos Basin (Petrobras, 2013). In this way, the production in many fields occurs with subsea pumping and topside separation.

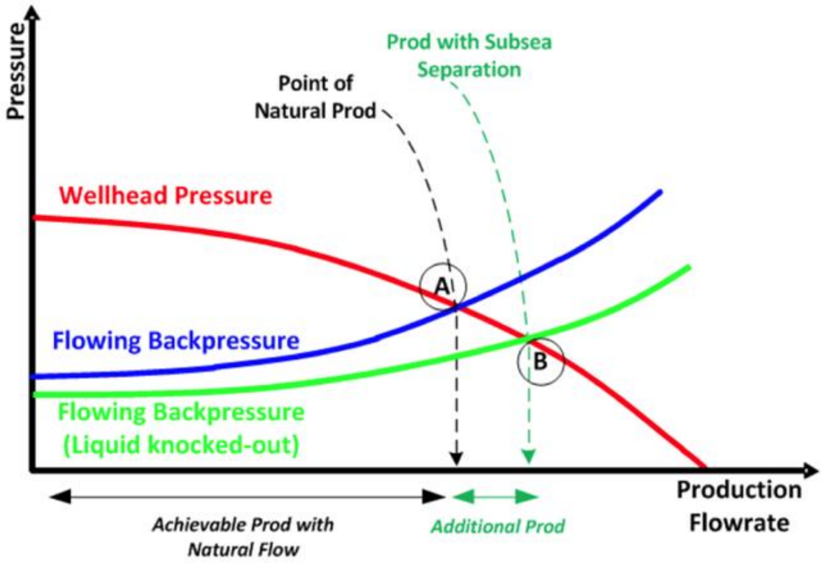
On the other hand, underwater separation is a more complex procedure and requires a higher capital investment, but it generally does not contain moving parts and therefore it presents fewer risks (such as leakage) than pumping (Hendricks et al., 2016). Although subsea separation and boosting can improve production processes separately, it is the employment of both together that can make subsea operations even more advantageous than the traditional topside structure (Hendricks et al., 2016; Wu et al., 2016).

2.1. Subsea Separation

Pumping liquids with gases is a costly and difficult task (Hendricks et al., 2016; Kondapi et al., 2017). According to Haheim and Gaillard (2009), pumping the production without gas can increase the efficiency of this operation by up to 4 times. Therefore, prior separation of the phases will reduce the energy expended to lift the production. Additionally, separate transport of oil and gas avoids other problems, such as hydrate formation, slug flow, cavitation, and erosion, thus increasing the safety and flow control in risers and pipelines (Gyllenhammar et al., 2017; Hendricks et al., 2016; Lavenson et al., 2016; Parks and Amin, 2012; Prescott et al., 2016b, 2016c; Wu et al., 2016). This allows the transportation of the gas for great distances and at low temperatures by pipelines on the seabed. Although the low temperatures on the seabed are often damaging, they have the advantage of increasing the time between failures of the electrical components that control, drive and transfer energy to the integrated subsea systems (Vedachalam, 2015). Thus, it is possible to reduce the additions of chemical products and heat to avoid the formation of hydrates. Furthermore, the pipelines will require less thermal insulation and, consequently, have reduced costs (Parks and Amin, 2012). Although onshore gas and liquid separation techniques are well established, their development still requires a lot of progress when it comes to compact submarine equipment (Lavenson et al., 2016).

In addition to the separation of gases and liquids, separation of water and oil can also happen on the seabed. In this case, pumping and subsea separation can further help the well recovery rate and the total accumulated production in green and brown fields, thus working as an enhanced oil recovery method (Gylenhemam et al., 2017; Hendricks et al., 2016; Li et al., 2014). According to Hendricks et al. (2016) and Prescott et al. (2016c), this is due to a decrease of the pressure imposed by the column of fluids on the risers at the wellhead, which facilitates recovery and thus increases the rate of return. This increased output is exemplified in Figure 2, which similarly exemplifies how the flow rate provided by a pump with a given characteristic curve can be increased by changing the system curve on which it is installed.

Figure 2. Increased recovery rate with the use of subsea separation and pumping due to pressure drop at the production wellheads.



Source: Hendricks et al., 2016, p. 7.

Thus, by reducing the system energy requirement (blue line to the green line), the flow rate may be increased keeping the same wellhead pressure curve. An example in the real world is the technology developed by CDS Engineering in partnership with Statoil and FMC Technologies that in 2007 already allowed an increase from 5% to 10% of the total recoverable oil from a reservoir. Another benefit is that, according to the companies, less oil would be discharged at sea because of the separator’s efficiency and reliability (FMC, 2007). Another important point is that in addition to the growth, a production increase also occurs, which allows an earlier decommissioning of the infrastructure necessary to start production and, consequently, a CAPEX reduction (Hendricks et al., 2016; Kondapi et al., 2017; Vedachalam, 2015).

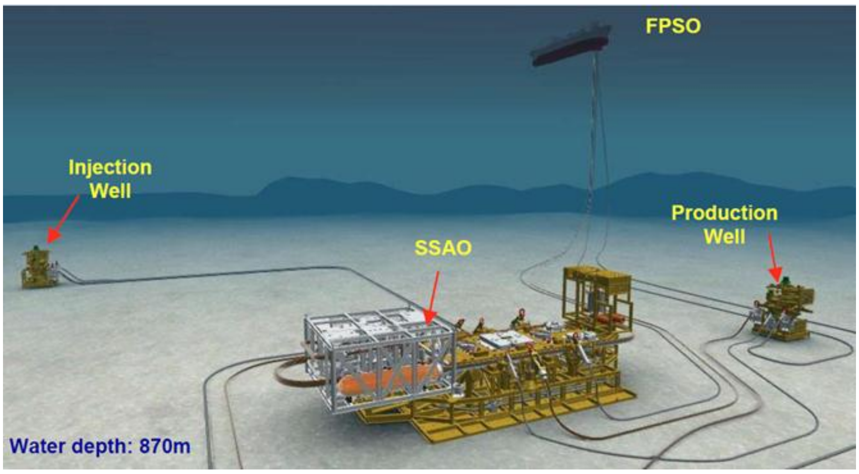
Once there is the subsea separator installed, the wellhead pressure drop is reduced, when compared with conventional system, because the fluid is conveyed up to the seafloor, while the conventional system brings up the sea surface. Gyllenhammar et al., (2017) relates the pressure drop to the reduction in the pressure on the wellhead due to the lower concentration of water and the lower density of the oil compared to the water. With more water in the risers, more mass needs to be pumped at a greater speed. Furthermore, the formation of emulsions at the wellheads tends to increase the viscosity of the mixture (Chrisman et al., 2012; Kilpatrick, 2012; Maia Filho et al., 2012; Plasencia et al., 2013; Sjöblom et al ., 2014). Consequently, water flow in the risers tends to increase the energy losses by friction. These losses can be significant, especially for long-distance transport (Gyllenhammar et al., 2017). Thus, subsea separation saves pumping energy by allowing less mass flow and head losses.

As the subsea separation of the liquid is performed near the wellhead, it enables the construction of longer pipelines and the reduction of the FPU along with saving pumping energy. (EIE, 2015; Gyllenhammar et al., 2017; Kondapi et al., 2017; Li et al., 2014; Prescott et al., 2016a, 2016b). By doing so, it reduces both manufacturing (CAPEX) as well as operating (OPEX) costs (Prescott et al., 2016a, 2016c). In some cases, the need for surface units may be completely eliminated (Kondapi et al., 2017). The reduction of CAPEX related to pipelines is of great importance. According to Gomes et al. (2017), flexible oil production tubes are the most expensive subsea infrastructure. Subsea separation and pumping have other advantages, such as (Gyllenhammar et al., 2017; Hendricks et al., 2016; Prescott et al., 2016a; Vedachalam, 2015):

- Increase of the flexibility of the oil field project with the possibility of connecting it to the existing infrastructure or reducing the initial investment in new projects.
- Reducing the risk of accidents and disasters in hostile environments.
- Removal of the need to pump production residues (water and sediment) to the surface.
- Reducing the diameter of risers and pipelines.
- Reduction of the size of the platforms and its space constraint limits.

Figure 3 shows a layout of a compact subsea separation system, or Sistema de Separação Submarina Água-Óleo in Portuguese (SSAO), employed by Petrobras at the Marlim field in Brazil.

Figure 3. Conceptual layout of a subsea processing system.



Source: Orlowski et al., 2012, p. 1.

As can be seen, the SSAO receives the raw production of more than one well, removes the water, and then it sends the oil to the FPSO. Since the volume flowing from the seabed to the surface is smaller, the head loss is consequently smaller, and the pipes length may increase, so the FPSO may receive oil from wells located farther.

The SSAO receives the fluids of the production wells through a manifold and then sends the oil to an FPSO (floating production storage and offloading) and the water to the injection wells. Usually, in the conventional system, the oil and gas flow in separate flowlines to the surface unit, and the water, follow Environmental Law, may be discarded into the sea. According to Lavenson et al. (2016), compact separators are advantageous because their structural parts are less thick, making the area exposed to the pressure on the seabed smaller. In addition, if the separator is too heavy, removing it from the seabed for possible maintenance or to relocate it to other fields could be a complicated task.

Capital expenditures for offshore projects may vary depending on factors such as water depth and the number of wells. In projects with conventional processing (at the topside) CAPEX related to the floating units does not vary much with an increase of the number of wells, however, it increases significantly with an increase of the water depth. On the other hand, the cost of subsea processing projects tends to remain constant with increasing water depth and to be more sensitive to the number of wells (Bai and Bai, 2010). Thus, investment in subsea technology can reduce capital expenditures on pre-salt projects, since these fields are in ultra-deepwaters and this region contains a small number of highly productive wells (compared to other regions in Brazil) (Petrobras, 2017a).

In brown fields, this processing strategy can remove platform bottlenecks due to their water handling limit capacity (Gyllenhammar et al., 2017; Li et al., 2014). Water production can reach a volumetric fraction up to 90% or more of the fluid produced by a reservoir at the end of its life (Gyllenhammar et al., 2017; Rodrigues and Sauer, 2015). The use of these technologies in brown fields has the benefit that the reservoir production history (including the production of sand and other solids) is known, which facilitates the design and the choice of subsea equipment to be used (Gyllenhammar et al., 2017). Additionally, subsea strategy may include oil storage, especially in concrete constructions on the seabed. Another important point is that subsea treatment also reduces water injection costs as an improved oil recovery method (IOR), since it is not necessary to pump it up to the surface and then down to the reservoir (EIE, 2015; Wu et al., 2016).

Due to the formation of emulsion, liquid separation is not always an easy task. Even with the advances in technology, emulsion treatment, especially of heavy and medium oils, is still a challenge, which can compromise the efficiency of the separator. As a consequence, these mixtures require a longer residence time inside the separator (Grave and Olson, 2016; Noik et al., 2015; Olson et al., 2015). In deep waters, compact subsea gravitational separators with a small residence time are preferable, although the small size reduces the efficiency (Noik et al., 2015). However, a subsea gravitational separator may have its capacity and efficiency increased by adding enhancement treatment technologies to it.

Olson et al. (2015) showed that a gravitational subsea separator may have its capacity greatly increased by means of electrocoalescers. The use of hydrocyclones together with the gravitational separator can also minimize emulsion problems since they allow part of the emulsion to leave the gravitational separator before complete separation, reducing the necessary residence time, which should be about 3 to 5 minutes, as required for a compact subsea separation system (Grave and Olson, 2016).

2.2. Technology Development

The development of these technologies, supported by governmental entities such as the United States Department of Energy and companies interested in expanding their business horizons, have already allowed water disposal directly into the sea (Prescott et al., 2016a, 2016c). Given the above, and the natural lowering of the cost of the technology over time, it is possible to observe a trend in the oil industry towards subsea technology rather than the traditional topside infrastructure (Hendricks et al., 2016; Prescott et al., 2016a, 2016b, 2016c; Wu et al., 2016). The market for subsea separators is still small, but in full growth with some companies standing out in the employment and patenting of these technologies (Prescott et al., 2016c, WU et al., 2016). According to experts, the number of subsea processing projects in the world may double by 2020 (Kondapi et al., 2017).

Major companies such as Petrobras and Exxon Mobil have been investing in subsea processing as a strategy to make feasible projects in remote fields and fields with prohibitive operating costs (due to low oil prices). The two companies have been standing out in recent years for their research, development and improvement of subsea equipment (Gomes et al., 2017; Olson et al., 2015). For example, Exxon Mobil aims to develop technologies applicable to several oil fields, rather than developing a specific technology for each field (Olson et al., 2015). By doing so, it is possible to reduce equipment-commissioning time in new exploration areas (Hendricks et al., 2016; Olson et al., 2015).

Subsea separator projects installed in the world in recent years have demonstrated a high degree of reliability and maturity (Kondapi et al., 2017). The subsea separator operated by Total in the Pazflor field in Angola has shown how the strategy of subsea separation reduces the size (diameter), the isolation and the head losses along the pipelines and can make deepwater projects feasible even with low oil prices. A second example is the Perdido oilrig in the Gulf of Mexico, which recovers oil to a sea depth of about 3,000 m and uses a caisson subsea separator to separate gases and liquids in order to make the operation feasible. The oil is pumped (without gas) vertically to the platform in a highly efficient process.

Another important project is the Marlim three-phase subsea separator in Brazil, Figure 4, in operation since 2011.

Figure 4. Marlim three-phase subsea separation system.

Source: Orlowski et al., 2012, p. 6.

This device uses a horizontal separator of gas, oil, water and solids with a capacity of 22,000 barrels per day. Among the reasons for its employment are: increasing water production, platform water capacity limit, high viscosity of the oil, production of sand and wish to increase production. (Hendricks et al., 2016). This system was the first of its type, since it allows the separation of heavy oil (API degree between 17 and 21) in deep water (about 870 m) with water reinjection to the same reservoir. It uses the pipe separator strategy with small residence time, which allows a smaller path traveled by the droplets until its continuous phase, integrated with a set of hydrocyclones (Kondapi et al., 2017; Wu et al., 2016). According to the analysis of Prescott et al. (2016b), the pipe separator scheme can cost, in some cases, about 5 times less than other traditional separator design. The pipe separators do not have moving parts, so they can operate continuously with a minimal need for maintenance interventions (Prescott et al., 2016c). However, it has at least two pumps, namely, water injection pump and petroleum lift pump.

2.3. Cost and Capacity Challenges

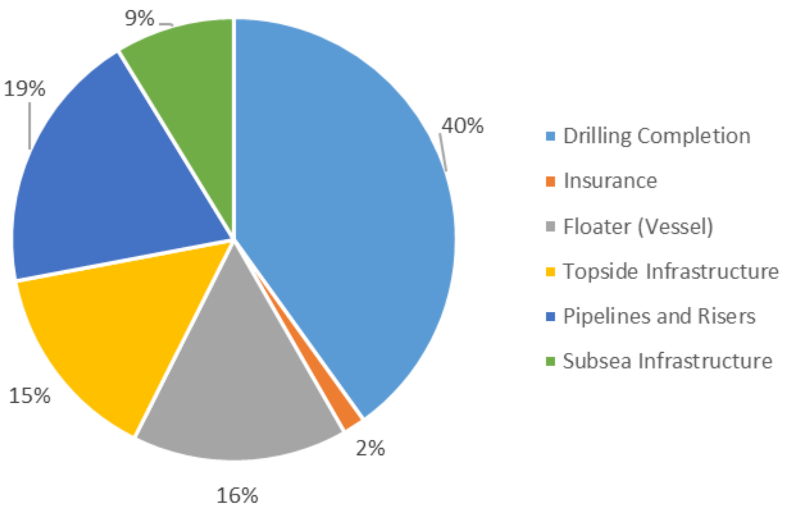
Subsea operations are getting space and importance, especially in deepwaters due to their economic benefits. However, they are accompanied by risks inherent to their application in the rigorous underwater environment, such as: low temperatures (about 4oC) (Vedachalam, 2015), high pressures, (Prescott et al., 2016b), greater environmental damage caused by leakage compared to surface platform or onshore stations, maintenance and repair difficulties, and spreading of much equipment over a wide area (Hu et al., 2012). Due to these risks, technical uncertainties related to these operations require great effort and time to be solved (Olson et al., 2015). In order to overcome these challenges, partnerships between universities and research centers are necessary (Petrobras, 2017a).

Must have a high degree of reliability because interventions related to malfunction and inadequate operation can cause greater financial and environmental damage than if they were on a surface platform. Therefore, the downtime and the amount of planned interventions should be as minimal as possible. In addition, if the system does not work properly, even if it does not come to a complete standstill, its operating program is likely to be compromised, as well as its financial return (Gyllenhammar et al., 2017; Kondapi et al., 2017; Prescott et al 2016b). Even with the advance of technology and the successes of already operational equipment that have proven to be reliable and efficient, subsea separation still faces problems related to the paradigm of the high risk of having equipment on the seabed (Hendricks et al., 2016).

Although subsea separation and pumping may reduce the capital expenditure investments in topside infrastructures and pipelines, the separators may be costly because of their displacement from the surface to the seabed. Thus, a balance between the cost of the processing equipment in the topside and the seabed should be made. Each type of processing has its cost drawbacks. Equipment on the surface tends to have its cost increased due to the limited space on the deck, which receives the production of several wells. On the other hand, subsea equipment may receive the production of a smaller number of wells; however, a larger number of separators would be required. In addition, the cost of developing and commissioning underwater separation systems is also high and a separator of the same size and capacity operating on the surface would have a lower cost (Hendricks et al., 2016; Olson et al., 2015).

The increased expense on a subsea system has the potential to make production feasible, reducing OPEX and even CAPEX (depending on the balance between the costs on the topside, of the risers, and of the subsea systems). According to Prescott et al. (2016a), in a typical deepwater project, the percentages of capital expenditures (CAPEX) on operating units, risers, and subsea equipment are 30.29%, 19.26% and 8.73%, respectively, as shown in Figure 5.

Figure 5. Typical distribution of CAPEX for a deepwater project



Source: adapted from Prescott et al., 2016a.

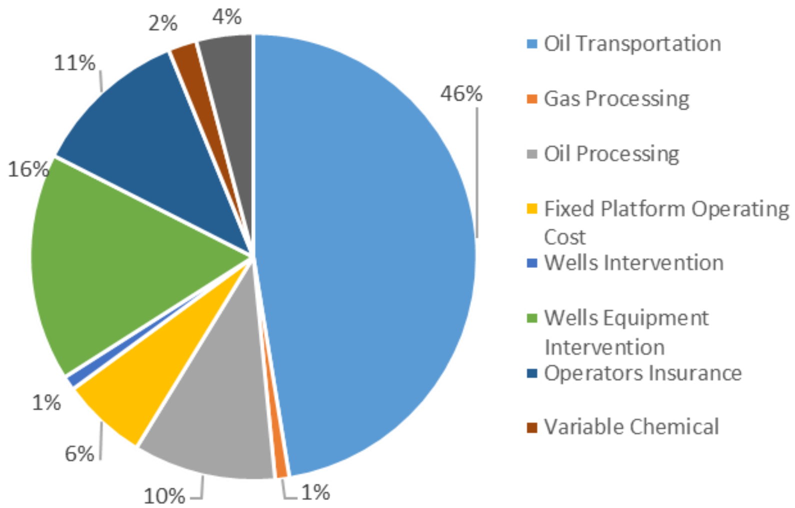
Since the cost of operating units, risers, and subsea equipment corresponds to about 58.8% of the total CAPEX cost, any savings in one of those is significant to the total exploration cost. The rest of the capital expenditures are due to the well drilling and completion and insurance. The capital invested in the production units, about 48% (14.61% of the total CAPEX), is due to the infrastructure installed on the vessel, while the vessel itself corresponds to 52% of the CAPEX of the production unit (15.68% of total CAPEX). According to Lin et al. (2013), connecting existing infrastructure such as tiebacks to the new fields is a means of extending the equipment's operational life and reducing the CAPEX of new projects. Risers and pipelines represent a high percentage of capital expenditure, so it is preferable, if possible, to use existing risers and pipelines rather than build new ones in the case of the existence of a neighbouring green field.

Another strategy is to substitute the original production unit by a storage unit plus a subsea processing system. Assuming that an FSO (Floating Storage and Transfer Unit) costs about half of an FPSO (Floating Production Storage and Offloading Unit) (Petrobras, 2005; Prescott et al., 2016a), this strategy has the potential to reduce the total CAPEX if the cost of the separators is less than the cost of the processing surface infrastructure. As subsea processing allows lifting less liquid and longer pipelines, it is possible for a unit on the surface to receive the production of more distant wells, which reduces the number of floating units required. This means that with the discovery of a new neighbouring field, it is possible to transport its production to the existing floating unit by means of subsea boosting (Lin et al., 2013).

On the other hand, for the fraction of operating costs in a typical project, shown in

Figure 6, the cost of transporting oil may account for about half of the total OPEX, and the expenditure on topside and subsea equipment accounts for 17% and 12%, respectively.

Figure 6. Typical distribution of OPEX for a deepwater project.



Source: Prescott et al., 2016a.

As transport cost is the highest in OPEX and with the increasing distance of the remote fields, subsea processing has the potential to decrease OPEX in deepwater projects by allowing cheaper transportation.

According to Rodrigues and Sauer (2015) of the total invested in exploration of a pre-salt field, approximately 75% corresponds to CAPEX and 25% to OPEX. According to the authors, due to interest and depreciation, the CAPEX present value, present cost since it is money spent, may become about 44% higher, e.g., if US$ 90 billion is invested, the real investment cost can be about US$ 142.5 billion (depending on the interest rate and discount). On the other hand, due to depreciation, the OPEX present value, over the life of a reservoir may be 60% lower (depending on the depreciation rate). That said, there is a principle in the oil industry that the reduction of capital expenditure can consequently generate an increase in operating costs and that this is advantageous. Therefore, the reduction of infrastructure in platforms and pipelines due to increased investment in subsea infrastructure tends to make offshore exploration more competitive (Prescott et al., 2016a), even though the cost of operation may increase.

According to Kondapi et al. (2017), oil companies focus on reducing CAPEX. As the deepwater and ultra-deepwater exploratory contexts become increasingly challenging, capital expenditures are steadily increasing. Therefore, companies aim to increase the production of the fields in the short term so that the investment interest may be reduced. However, this exaggerated production at the outset may cause the period of declining production to be sharp and short. So thinking about this problem, companies are investing in subsea technology for deepwater projects since it has the potential to reduce both CAEPX and OPEX. Expected cumulative spending on these technologies in the period from 2014 to 2018 is US$ 260 billion, about 130% higher than that of the period from 2009 to 2013 (Vedachalam, 2015).

The current development of the subsea technologies already allows their use at depths of 3,000 m and with transport distances of 160 km and pumping pressures of 100 MPa on the seabed. The main factors that have prevented an even greater advance of these technologies are the costs, risks, and complexity of the projects. In addition, the absence of standardized norms to guide projects tends to increase their degree of risk (Kondapo et al., 2017).

However, increasing interest in the subject and consequent increase in research and development have made the cost and architecture of the equipment economically feasible, as well as improving its reliability. Even in real development conditions, many oil fields could use subsea separation and boosting technologies to enhance their production, and they do not use it yet. The capacity and reliability of current subsea projects must still increase for the number of reservoirs that may be operated more efficiently in the future to grow (Kondapi et al., 2017; Wu et al., 2016). For instance, the industry is moving towards employing subsea transport over distances about 500 kilometers by using pumps and compressors with powers of 6 MW and 15 MW, respectively.

The future of subsea processing will depend on a balance between innovation, cost and reliability. This necessitates the development of new equipment and improvements of the current systems, as well as their standardization. In order for this technology to succeed, its development must be interdisciplinary, as it demands knowledge of several engineering areas due to the various devices involved, such as mono and multiphase pumps, injection pumps, gas compressors, integrated connection systems, compact separation systems, subsea cooling systems, and power distribution systems, among others. There is an expectation that investment in subsea processing will grow as the industry becomes more acquainted with this technology and its market. As their investment involves high costs, risks, and state-of-the-art technology, its choice should be made carefully, whether for green or brown fields (Kondapi et al., 2017). Hence, partnerships between companies are necessary to help and to accelerate the technological development as well as to share the risks.

3. Study Case: Lula Field

The following case study aims to analyze the feasibility of using a subsea separation system in a Brazilian pre-salt field. Three scenarios have been compared by varying the oil/water ratio produced. In each scenario, the energy to raise the fluids was analyzed by comparing the pumping in two cases, one of oil plus water and the other only oil. In the oil plus water pumping scenario, processing takes place on FPSOs so that both oil and water flow through the pipelines and risers. In the second case, the production system has a subsea separator that injects the water produced in the reservoir or discards it at the bottom of the sea, so that only oil flows through the pipelines and risers and is then stored in FSOs. The discards water must comply with current legislation. Since in many cases the gas separation occurs at the bottom of the well by systems such as vertical annular separation and pump (VASP), the gas flow in the pipelines and risers was not taken into account (Kondapi et al., 2017; Prescott et al., 2016c). The efficiency of all separators was assumed to be 100%, e.g. the separation of oil and water is total.

After the study of the energy pumping cost which is part of the CAPEX assessment for a system composed by a FSO with subsea production system, the economic feasibility analysis was carried out as a function of the cost of natural gas used as fuel for energy generation and the cost of surface platforms and subsea separators.

Another important point for the definition of the scenarios is that the strategy chosen in this case study for the use of subsea separators in the Lula field was the same one used by Petrobras in the Marlim field. According to Euphemio et al. (2012) and Morais (2013), the installation of the subsea separator developed by Petrobras for the Marlim field becomes interesting once the volumetric fraction of water in the fluids produced reaches 65% to 70%.

3.1. Analysis of the Field and its Production

The chosen pre-salt field for the case study was the Lula field, due to its high production and water depth of approximately 2,200 m. According to the field development plan approved by the ANP in 2016, the field operators is Petrobras, with 65% share, BG E & P Brasil, with a 25% share taken together, and Petrogal Brasil, with a 10% share. It is expected that field would be carried out by 10 production modules, as in to Table 1.

Table 1 Processing capacity of Lula field production units in exploratory project.

Unit	Production Capacity (bbl/d)
FPSO Angra dos Reis	100,000

FPSO Paraty	120,000
FPSO Mangaratiba	150,000
FPSO Itaguaí	150,000
FPSO Maricá	150,000
FPSO Saquarema	150,000
P-66	150,000
P-67	150,000
P-68	150,000
P-69	150,000

Source: ANP 2016; Petrobras, 2016; 2017b.

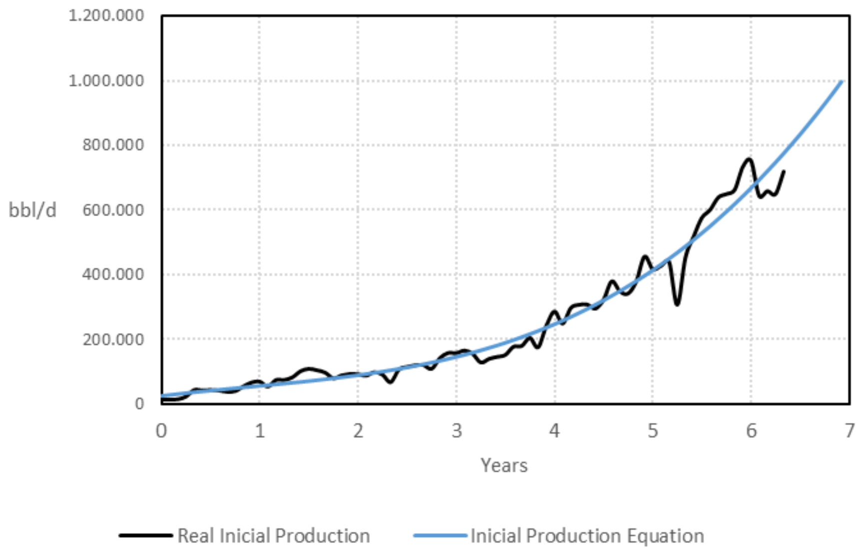
As shown in Table 1 the Lula field has only ten production modules that receive a huge amount to oil. This way the energy cost of taking the production to the surface is high due to the great volumes of fluid and the distances traveled by it.

The field started production on December 29, 2010 and the forecast for the end of operations is in 2060, with the original volume of oil being approximately 17,763 billion barrels (ANP, 2016). The expected average production per well is 15,000 to 20,000 barrels per day, with 28 to 30 API degree and viscosity of 1 cP (Brasil, 2009). Initially, the recoverable oil estimation from the field was in the range of 5 to 8 billion barrels (Gbbl). However, the current forecast for total recoverable oil is around 6.5 Gbbl (Petrobras: Tupi Field, in the Santos Basin, is Brazil's largest oil and gas reserve, 2012; Lima, 2008; Schutte, 2012).

3.2. Scenarios

Three field production scenarios were proposed for this case study. The initial production was determined based on the ANP database until May 2017 and it is presented in Figure 7.

Figure 7. Lula field oil production from January 2011 to May 2017.

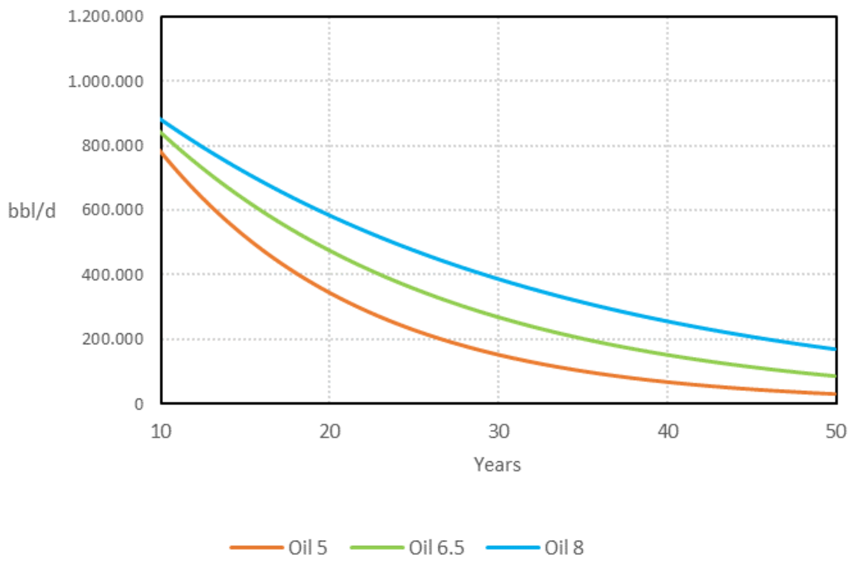


Source: based on ANP, 2017b.

As can be seen, the filed has not yet reached it production peak and still has room to grow.

The period of production of interest in this paper (above 65% of water fraction) occurs when the field is brown. Thus, the three production scenarios consist of the three decline curves as shown in Figure 8, each curve with a distinct total of oil recovered from the reservoir in all its lifespan.

Figure 8. Oil production scenarios.

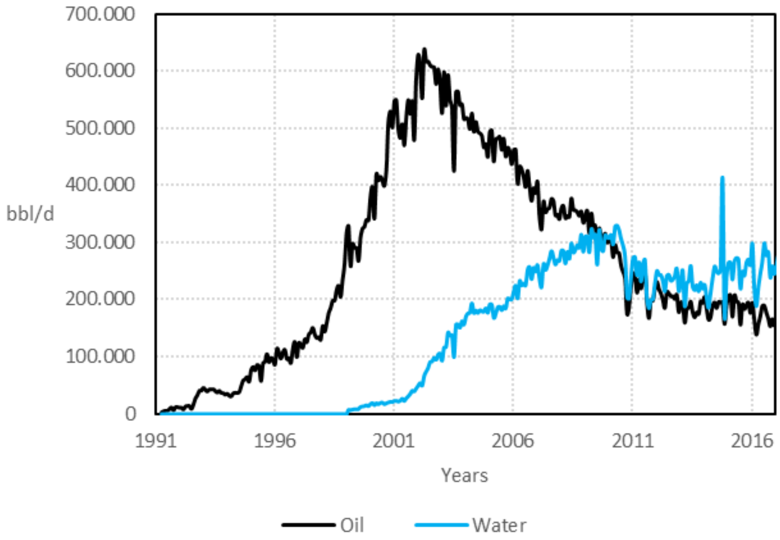


Source: Authors.

The production rate profile at the beginning of the reservoir life is the same for all scenarios, but then becomes distinct from the production peak. In order to estimate the period of declining production, the rising production rate period served as an estimation start point. For this, a trend line of the production beginning was determined and represented by a polynomial that went until December of 2017 (7 years of production) (Rodrigues and Sauer, 2015; Gyllenhammar et al., 2017). That way, the oil production would begin to decline in January 2018 until December 2060. The profile of production during the decline, based on the declining curve technique, made use of an exponential function to represent its production (Brito et al., 2012). The decline profiles were estimated by making the exponential function start from the production peak, in December 2017 until December 2060, so that the accumulated production during the 50 years of production activity was 5, 6.5 and 8 billion barrels, which are the previous and present estimates of total recoverable oil from the field.

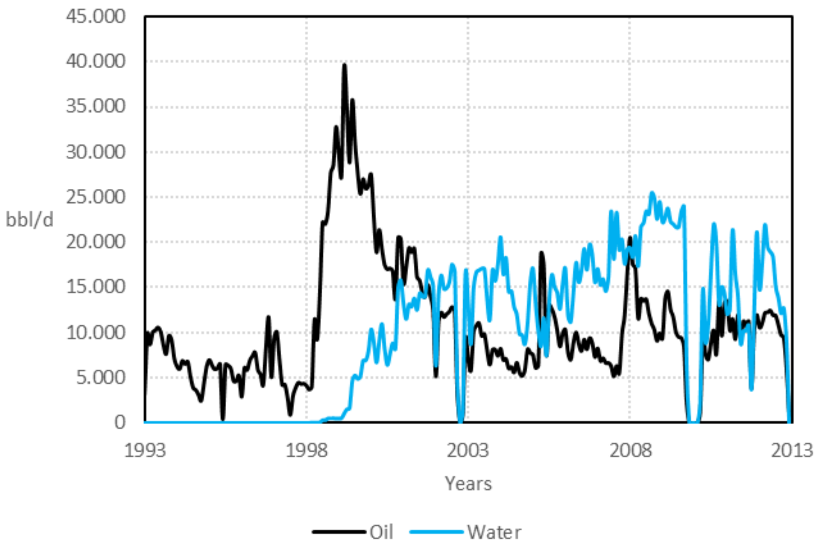
In order to complete the estimation of the production in these scenarios, the water production profiles must also be determined. This is a difficult task and may even be unpredictable. The water production may take on different values in fields in the same basin and even in neighbouring wells in the same reservoir. In general, when the water production increases, company intervenes in the well to minimize its water production. For example, the fluid production of the Marlim and Voador fields, both in the Campos basin in Brazil, are presented in Figures 9 and 10.

Figure 9. Marlim field oil and water production.



Source: ANP, 2017b.

Figure 10. Voador field oil and water production

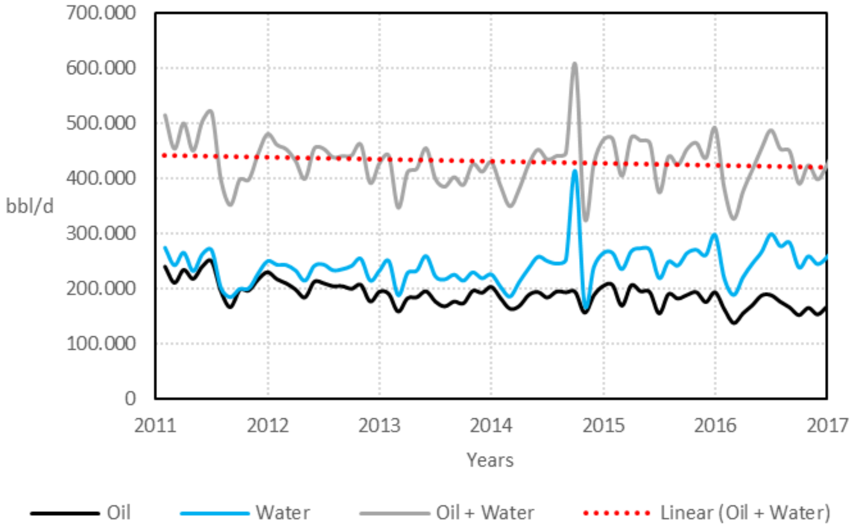


Source: ANP, 2017b.

Thus, although in the same basin, the production profile of each field is different.

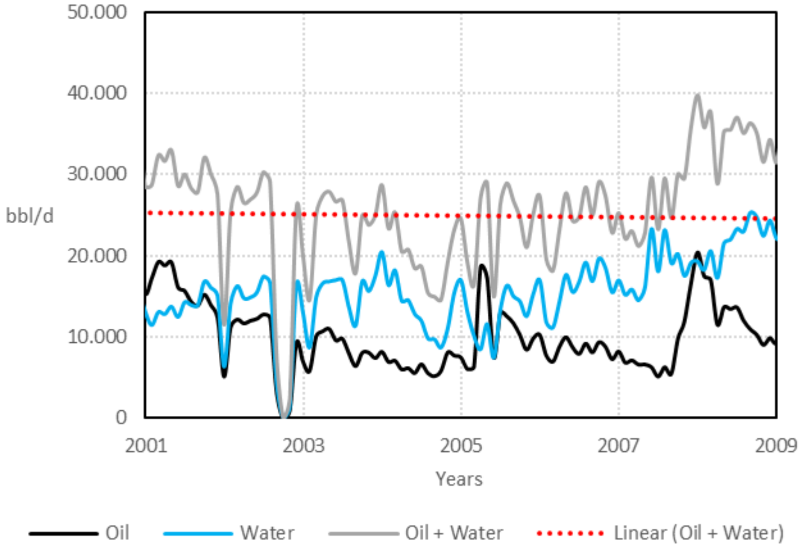
Figures 11 and 12 show the behavior of the oil, water and total liquid production for the Marlim and Voador fields. In addition, a generic profile of liquid production from a well given as an example by Gyllenhammar et al. (2017) can be seen in Figure 13.

Figure 11. Marlim field liquid productions in the period of declining oil production



Source: ANP, 2017b.

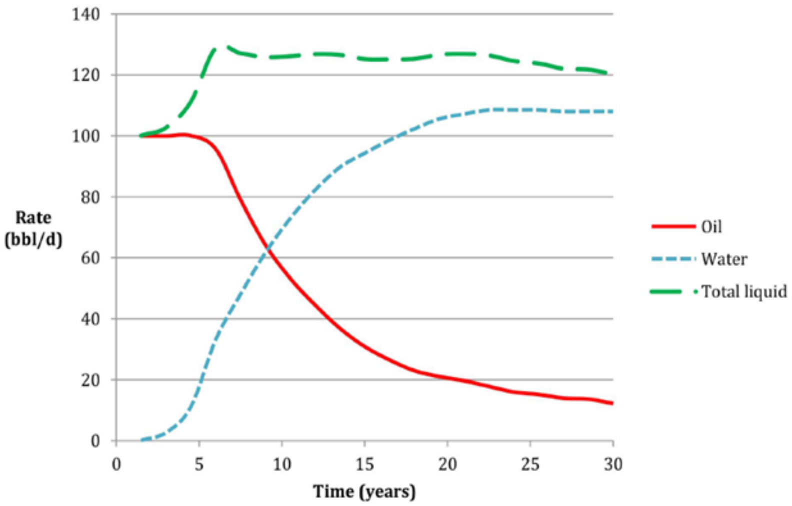
Figure 12. Voador field liquid productions in the period of declining oil production



Source: ANP, 2017b.

Figure 13. Example of the production profile of an oil field with an increase in water

production over time.

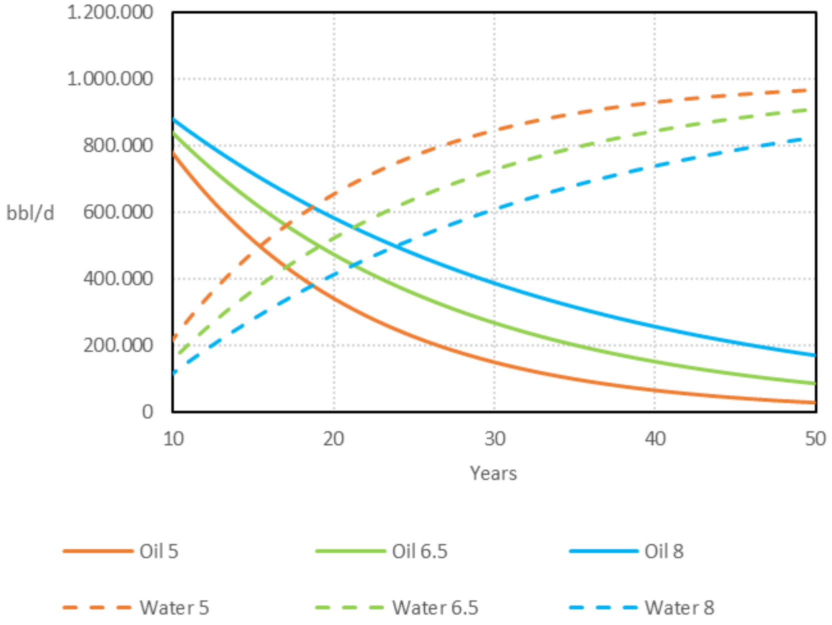


Source: Gyllenhammar, 2017, pp. 2.

It can be seen from Figs 11 to 13, even at first glance, that the total production of liquids at the end of the productive life of these fields tends to fluctuate around a constant average and that a linear trend line of liquid production is almost horizontal.

Even if the recoverable oil fraction is different for the three scenarios, as the volume of the reservoir is constant and as the injection of water as a recovery method tends to keep the field pressure constant, the water production profile was determined in such a way that the total liquid production was constant. The total volume of liquid produced during the period of declining oil production was estimated to be the same volume of fluids produced when the field reached its production peak in December 2017. The production profiles for the three scenarios can be seen in Figure 14. Furthermore, in the proposed scenarios, the water production would begin to be significant on January 2018.

Figure 14. Oil and water production for all three scenarios.



Source: Authors.

Thus, the scenario with the total oil recovery of 5 Gbbl presents a larger amount of water produced compared to the 6.5 and 8 Gbbl scenarios. Consequently, the 8 Gbbl scenario produces less water than the others. Hence, the volume of liquid processed by the separators will be constant and, according to Figure 14, about 1,000,000 barrels per day.

Given the maximum processing capacity estimated of the subsea separator, 22,000 barrels per day (Euphemio et al., 2012; Morais, 2013), the scenarios demand a total of 45 separators. In addition, the evaluated cost of a separator was US $ 90 million, based on the separator operating in the Marlim field (ANP, 2013). Since the average expected flow per well is approximately the maximum flow rate of a separator, each separation unit would receive the production of one or two wells.

The volumetric fraction of water reached 65% at different times in the three scenarios. In the 5 Gbbl/d scenario, this percentage of water occurs at the end of the 19th year of operation, but in the middle of the 25th and 32nd years for the 6.5 Gbbl/d and 8 Gbbl/d scenarios, respectively.

3.3. Energy Spending Analysis

To raise production, the fluid bulk has to receive energy by means of pumps. This energy must be sufficient to raise the fluid mass from the bottom of the sea to the surface. Equation 1 gives the energy per unit time.

$$\dot{W}_{ced} = \rho g H Q \tag{1}$$

where W˙_ced is the power supplied to the fluid, ρ is the specific mass of the fluid, H is the elevation gauge height and Q is the flow. The procedure for obtaining H and Q is defined below.

First, the gauge height, H, can be defined by Equation 2:

$$H = \Delta Z + h_f \tag{2}$$

where ΔZ is the static height and h_f is the head loss in the pipe. For the Lula field, ΔZ is about 2,200 m, which is the average water depth. Equation 3 gives the head loss h_f along the pipelines and risers. It is a function of the Darcy friction factor, which depends on characteristics of the flow, such as the Reynolds number, as well as on the characteristics of the pipe, such as its diameter and relative roughness. Equation 4 gives the friction factor (Pritchard, 2011).

$$h_f = f \frac{L}{D} \frac{V^2}{2V} \tag{3}$$

$$\frac{1}{\sqrt{f}} = -1{,}8l \log\left[\left(\frac{\epsilon/D}{3{,}1}\right)^{1{,}11} + \frac{6{,}9}{Re}\right] \tag{4}$$

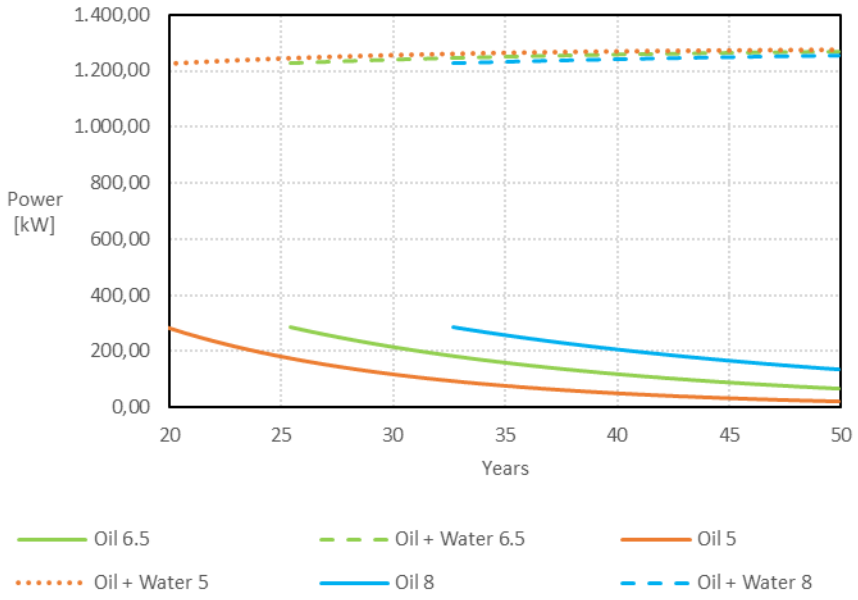
In Equations 3 and 4, f is the friction factor of Darcy, L is the pipe length, D is the pipe diameter, V is the flow velocity, g is the acceleration due to gravity, Re is the Reynolds number and, ε is the pipe roughness. Based on the literature, the mean horizontal distance from the separator pipelines to the FPSO was set at 2,500 m, the internal diameter of the tubes was chosen equal to 0.152 m (6 in) and the roughness of the pipelines and risers were estimated to be 0.5 mm (Bai and Bai, 2010; Euphemio et al., 2012; Leão et al., 2014; Silva, 2015).

Modeling the multiphase flows occurring in the production of oil is a difficult task and the correlations used are usually experimental, so that the use of a physical foundation or an analytical equation to choose an appropriate model rarely happens (Matos and Nascimento, 2011). Thus, the correlations depend on the boundary conditions of the experiment. According to Gyllenhammar et al. (2017), the head loss in the pipeline is more significant for long distances (dozens of kilometers), which is not the case for the pipe lengths analysed in the present study, about 4,700 m. If production pumping is directly from the seabed to onshore stations, the distance to the pre-salt fields would be about 300 km, which would makes the energy lost through friction in the pipeline much more significant. For short distances, the static height demands most of the energy and not the friction losses. Furthermore, although oil and its emulsion with water are non-Newtonian fluids (whose viscosity depends on the flow), for simplicity, the head loss model applied here is for Newtonian fluids and only for major losses along the pipe.

Finally, the flow, Q, is given as a function of the production of the wells and was determined from the oil and water production profile of the reservoir, which can be visualized in Figure 14. The total field production divided by the number of separators gives the flow per riser.

It is possible to observe in Figure 15 the analysis results for the power needed by the fluids from a separator with and without subsea separation for the three scenarios.

Figure 15. Power given to fluids in both cases of each scenario.



Source: Authors.

It is shown that the power needed to raise the production with subsea separation is much less with subsea separation than with surface separation; subsea separation is about 12.3, 8.4, and 6.2 times lower than the energy expenditure with the surface separation in the average of the operation periods of the separators for the 5, 6.5 and 8 Gbbl scenarios, respectively.

In the case of subsea separation, the difference between the total energy delivered to the oil in all three scenarios is due to the start date of the separator's operation and the amount of oil recovered. On the other hand, with surface separation, since the volumetric fluid flow for the proposed scenarios is constant, the small difference in power is only due to the difference in the specific mass of the oil and water mixtures in the three scenarios.

3.4. Fuel Cost Analysis

The necessary reduction in the power needed to lift the production can be seen by the analysis of Figure 15. However, to quantify the savings in monetary values, it is necessary to analysis the Real Cost or Updated Cost (PC) as a function of the amount of fuel burned for energy generation. The chosen fuel for this study is natural gas. The monetary savings depend on the volume of gas burned to drive the engine and the pumps times the Petrobras sales gas prices to the industrial sector, according to Table 2. The lower calorific power of the natural gas considered is 39,386 kJ/m3 (Petrobras, 2017b).

Table 2 Natural gas tariff for the industrial sector.

Class	Monthly Volume (m^3)	Fixed Cost (R$)	Variable Cost (R$/$m^3$)
1	0 a 1,000	40.29	1.8326
2	1,000.01 a 5,000	413.49	1.4594
3	5,000,01 a 50,000	2,075.99	1.1269
4	50,000.01 a 300,000	3,285.99	1.1027
5	300,000.01 a 500,000	8,175.99	1.0864
6	500,000.01 a 1,000,000	16,275.99	1.0702
6	1,000,001 a 10,000.,000	24,375.99	1.0621
8	over de 10,000,001	245,375.99	1.0400

Source: Petrobras, 2017c.

The gas price is a function of the volume of gas bought by the client monthly, so the savings in gas with subsea separation, which affects the OPEX analysis, is not a simple linear function of the volume of gas saved.

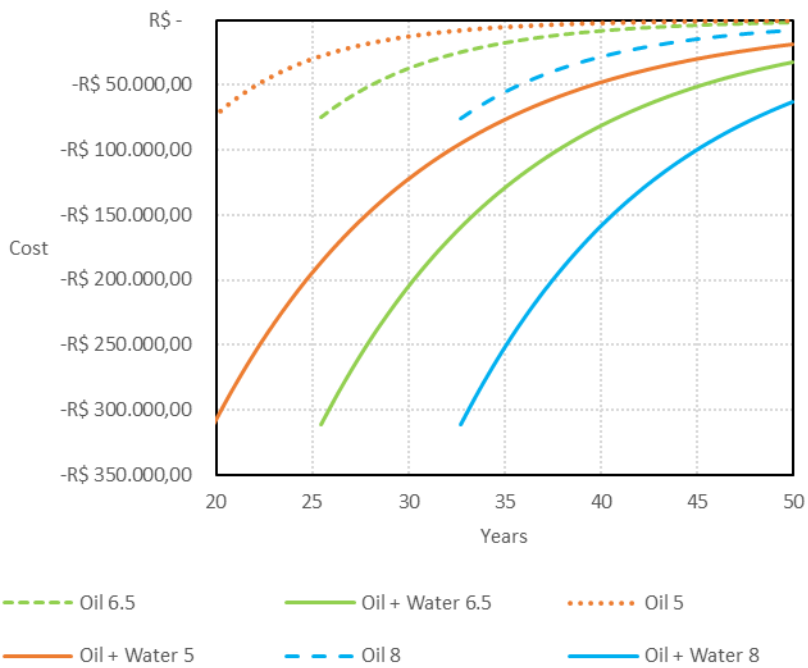
3.5. OPEX analysis

Since the energy given to the fluids correspond to just a portion of the thermal energy liberated from the burning gas, the volume of gas required is also going to depend on the equipment's efficiency. The turbine (GE, 2015) and the centrifugal submersible pump (Centrilift, 2014; GPS, 2010) efficiency were estimated at 38% and 76%, respectively. The savings on gas in present cost was the first parameter to validate the subsea separator's feasibility. To do so, the considered discount rate was 10% per year (Brazilian Central Bank, 2016; Rodrigues and Sauer, 2015). Equation 5 gives the RC, where GEP is the gas expenditure per month, n is the operating month of the separator and i is the discount rate per month. The RC value is always negative, since it represents an expense. In order for the project to be feasible, the absolute value of RC must be higher than the cost of the separators.

$$RC = \sum \frac{-GEP}{(1+i)^n} \quad (5)$$

Figure 16 shows the total gas expenditure to raise the fluids in present cost for the whole Lula field each year for the three scenarios.

Figure 16. Gas expenditure for the three scenarios and cases.



Source: Authors.

Thus, as presented in Figure 15, due to depreciation, even with a constant flow volume in the cases without subsea separation, the CP fell. The total real cost with subsea separation and pumping in the 5 Gbbl scenario over the years was R$ 231.6 million and with topside processing the cost would be R$ 1,716.9 million. Thus, the savings for this scenario was approximately R$ 1,485.3 million, or US$ 495 million taking the Dollar/Real ratio as 1/3. Table 3 presents the real cost per separator and for the whole field, as well as the gas savings due to subsea separation for all three scenarios.

Table 3 Gas cost for fluid lifting in all scenarios. Obs.: o = oil and w = water.

Scenarios	Gas Cost per Separator (R$ millions)	Cost with Gas for the Whole Field (R$ millions)	Savings (US$ millions) [US$ 1 = R$ 3]
5 o	- 5.1	- 231.6	495.8
5 o+w	- 38.2	- 1,716.9	
6.5 o	- 5.8	- 262.5	457.8
6.5 o+w	- 36.4	- 1,636.0	
8 o	- 6.0	- 270.6	394.8
8 o+w	- 32.3	- 1,454.4	

Source: Authors.

It is then shown that the present cost for the three scenarios indicates that the more water the field produces, the greater are the savings on pumping fuel achieved by subsea separation.

This savings per separator is given by dividing the values of the fourth column of Table 3 by the number of separators. For the 5 Gbbl scenario, the savings per separator is approximately US$ 11 million and for the 6.5 and 8 Gbbl scenarios it is US$ 10.1 million and US$ 8.8 million, respectively. As the estimated cost of a separator is US $ 90 million, the gas savings are about 10% to 12% of the separator’s price, which would made the subsea separation system unfeasible. However, this fuel saving analysis is just one of the many ways in which a subsea processing system may reduce costs. As discussed throughout the present paper, these systems have the potential to make production feasible in both green and brown fields, either by reducing OPEX and/or CAPEX. To illustrate, another OPEX reduction could also come about by reducing employee transport and subsistence expenses on platforms due to having less topside operations. Moreover, in the present case study, the increase in production due to the reduction in the pressure on the wellhead, which is another advantage of subsea processing, was not taken into accounted. Such a factor can increase the rate of return on investment and prolong the well’s life.

3.6. CAPEX Analysis

Finally, the feasibility study of subsea separation from a CAPEX perspective has been carried out. In many cases, at the end of a field’s life, it still has the capacity to produce oil, however, as the amount of water produced becomes very large, installed at the beginning of the field’s productive life, makes production unfeasible. Gyllenhammar et al. (2017) propose a CAPEX reduction strategy by replacing the initial, high capacity and high CAPEX FPSOs by lower capacity FPSOs together with a subsea separation system. Following this line of thought, the strategy adopted for the present case study replaces FPSOs by FSOs, which cost approximately half, plus the subsea system. By doing so, the installation of new riser and pipeline lines or major modifications in existing ones are not necessary, only connecting them to the new units.

As seen in Figure 5, the FPSO represents approximately 15.7% of the total CAPEX and the topside structure (installed on the vessel decks) represents about 14.6%. In this way, the scenario analysis assumed the cost of an FSO to be half the cost of an FPSO (Petrobras, 2005; Prescott et al., 2016a), since FSOs only store the oil, which reduces the surface infrastructure significantly.

The proposal for the elaboration of CAPEX analysis scenarios is founded on the fact that Petrobras is eventually going to explore new production fields; consequently, the company will acquire new production units. Thus, instead of buying large-capacity FPSOs, the company would relocate the old Lula field units to operate in the new field, where water production is still small. Lula’s production would continue by means of the FSOs and the subsea separators. As the oil processing already would take place on the seabed, the FSOs are only going to store the production. Therefore, the CAPEX reduction proposed here is not necessarily a Lula field CAPEX reduction, but a global reduction for the company involving other exploration and production projects.

Thus, the scenarios for the evaluation of capital expenditure compared to the cost related to the 10 original production units of the field project approved by the ANP, Table 1, with the cost of 10 FSOs (half of the FPSOs price) plus the subsea separators. Table 4 shows the estimated cost of an FPSO according to its production capacity.

Table 4 FPSO price per production capacity.

Production capacity (bbl/d)	US$ billions
100,000	1.6
120,000	1.8
150,000	2.0
180,000	2.5

Source: Almeida et al., 2016, p. 22.

Hence, according to Tables 1 and 4, the CAPEX related to the 10 production original platforms was US$ 19.40 billion and the CAPEX related to the 10 FSOs plus the 45 separators is US$ 13.75 billion. Thus, the CAPEX reduction is about US$ 5.65 billion. Adding the production pumping savings, the total savings with subsea processing is about US$ 6.148 billion for the 5 Gbbl scenario, US$ 6.108 billion for the 6.5 Gbbl scenario and US$ 6.045 billion for the 8 Gbbl.

4. Conclusions

The pre-salt is an important oil reservoir in Brazilian waters, with the potential to generate wealth for the country. However, due to the low oil prices in the last years and the challenges of deepwater exploration, its exploration is often subject to questioning by several sectors of Brazilian society withregard to its feasibility. Investments and partnerships by and between companies, governments, universities and research centers have the potential to develop technologies that will make its production feasible.

Subsea processing is a challenging and powerful tool that by treating the production on the seabed, has the potential to reduce capital and operating expenditures by reducing, for instance, the need for topside infrastructure and the amount of mass lifted.

A case study of the feasibility of subsea processing in the Lula field in the Brazilian pre-salt, for the scenarios evaluated, demonstrated that pumping savings grows with the amount of produced water, as exemplified in the scenario with cumulative production of 5 Gbbl. The average reduction in power delivered to the fluids in this scenario may be about 12 times. However, the results indicate that, taken by itself, the OPEX savings related to the cost of natural gas as fuel for energy generation is much less than the investment in the separators. Thus, to make subsea processing feasible, a CAPEX reduction also had to be evaluated. Such a strategy consisted of replacing the initial production units of the field by storage units together with subsea separation systems and relocating the initial production units to another field at the beginning of its productive life. Thus, the OPEX and CAPEX savings together, about US$ 6.1 billion, validated the subsea processing technologies as important tools to make deepwater far-from-shore projects more competitive in the current market conditions.

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