PONTIFÍCIA UNIVERSIDADE CATÓLICA DO RIO DE JANEIRO
DEPARTAMENTO DE ECONOMIA

MONOGRAFIA DE FINAL DE CURSO

A Valuation of Pre-Salt Fields: Lula, Libra and Búzios

Felipe Soares de Carvalho
Matrícula: 1112293
Orientador: Ruy Ribeiro

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Agradecimentos

Agradeço aos meus pais, Pery e Suely, a minha namorada, Karina, meu orientador Ruy Ribeiro, e meus amigos pelo apoio durante esta longa jornada.

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0. Introduction

Historically, the global economy has demanded more oil and gas than its supply capacity. This fact has been partially due to the technical difficulties to increase production, on the supply side of the market, and partially due to the cartel alike trade policies of the biggest producers of hydrocarbons in the world, through the organization called OPEC. For many years, this organization effectively controlled a great slice of the world's production volumes, and thus, the global price of the commodity. Recently, however, there has been a structural change in the market's dynamics.

The introduction of new techniques of production, new technology, along with the sustained high prices of oil and gas over the years, has made economically feasible the production of the so called unconventional reservoirs - the ones, which due to their technical challenges, were impossible to produce or simply not economically attractive. Examples of such reservoirs are the American shale, the Canadian Oil sands, and the Brazilian Pre-salt fields. The new production from these fields shifted the supply curve of the markets provoking an immense decrease in prices of the commodity, and consequently, jeopardized the economic viability of many new projects being developed around the world.

In 2007, the discovery of the world class pre-salt reservoirs, a gigantic accumulation of hydrocarbons situated in the ultra-deep waters of the Brazilian territory, promise to turn Brazil into one of the world's biggest energy producers. The promises of huge volumes of oil and gas production came along with the promise of a bright future for the nation, guaranteed by the investment of the production's proceeds in the welfare of the society. The volatility of prices followed by record low levels, however, put in doubt the value of the Brazilian pre-salt reservoirs, and therefore, the so celebrated bright Brazilian future.

In face of the new market's reality and oil prices, and given the political and economic importance that Petrobras, and consequently the pre-salt, has in the Brazilian society, the question of how much the pre-salt reservoirs are worth, and how their values behave given the change of key macroeconomic variables, becomes fundamental.

The purpose of this dissertation is to assess the fair value of key pre-salt projects in development, and to understand how their value change related to key variables. A deep analysis of the reservoirs characteristics, capital expenditures, operational expenditures, and other fundaments, along with assumptions of future variables, will be used as input in order to estimates the reservoirs' fair value. Moreover, an exercise of comparative statics analysis will demonstrate the behavior of the reservoirs' value given a change of its key variables.

In Chapter One will introduce the basic concepts of the oil and gas industry. Chapter Two describes the valuation method and the model used to estimate the fields' fair value. Chapter Three, Four and Five introduce each analyzed fields and describe the key assumptions of their valuation models and perform a sensitivity study. Finally, Chapter 6 demonstrates the mains results.

1. The Exploration and Production Industry

1.1 Introduction to Hydrocarbons

1.1.1 Petroleum and its Characteristics

Petroleum is a substance which is within a mixture of other substances called Hydrocarbons. It is formed in sedimentary basins, usually located underneath lakes and oceans, in a long process lasting millions of years.

The petroleum produced around the world, however, is not equal. The crude oil has different characteristics which determine its end products, and therefore, its market value. The two most important aspects that determine the crude's quality are: Density and Sulfur content. The density usually varies between light, medium, heavy and extra heavy. The density is measured by a scale called API gravity, idealized by the American Petroleum Institute along with the National Bureau of Standards. The crude's density classification follows: extra heavy oil has less than 10 API, heavy oil ranges from 10 to less than 22,3 API, medium oil ranges from 22,3 to less than 31,1 API, and light oil ranges from 33,1 to above. The crude oil, regarding its sulfur content, is classified either sweet or sour. The sweet crude oil contains less than 0.5% sulfur.

These characteristics directly determine the petroleum's value. The light and sweet oil is usually more expensive than the heavy and sour. Part of the reason is related to the oil's refined products value. Gasoline and diesel fuel are easily and cheaply produced by sweet crude oil, and these fuels are typically more valued than residual fuel oil and others less noble products. Sweet crude can also be processed by fairly less sophisticated and energy intensive refineries, which is a very desirable feature.

1.1.2 The formation of Hydrocarbons

A Hydrocarbon reservoir is a combination of three factors: a source rock, a reservoir rock and a cap rock or structural trap, such as a salt dome. The lack of one of three factors may inhibit the formation of Hydrocarbons.

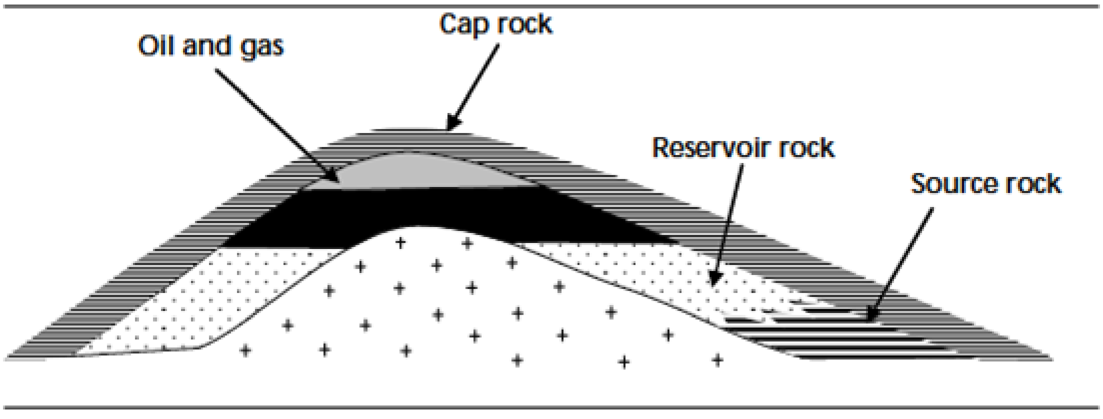

Figure 1. UBS Investment Research (2008) *Permeable reservoir rock* In: *Global Oil and Gas – Introduction to the oil industry* p. 79

A source rock is the location where the hydrocarbons are formed. These rocks are formed in environments abundant of organic matter; examples are continental shelves, river deltas and basins. As the marine organisms die, the majority being Plankton and algae, it settles on the basin floor, where it is buried and compacted by layers of clay particles.

Specific conditions are required in order to enable hydrocarbons' formation. In addition of the correct rock, the organic matter has to be buried rapidly enough not to oxidize. The stratigraphic, or rock laying, has to provide enough pressure and temperature in order to transform the organic matter into hydrocarbons. Over millions of years, the simple organic molecules are transformed in more complex ones called kerogens. Over the time, kerogens are transformed by pressure and heat into petroleum. The quality of the oil is determined mainly by two factors; temperature and time. Chemical reactions increase gradually their speed given higher temperatures, thus, the higher the temperature of the rock, the less time it is required to generate oil. The source rock, if exposed to the heat for a long period of time, can have its hydrocarbon chains broken down, thus degrading the quality of oil. Light and mature crude, the most desirable type of oil, is produced by high temperatures. Temperatures above 150 °C, however, can only produce gas.

The reservoir rock is where the hydrocarbons are held, and it is usually located above the source rock. Typical reservoir rocks are sandstone and limestone. Reservoir rocks display two main characteristics: porosity and permeability. Porosity refers to the space between the grains that constitute the rock, whereas permeability is the ability of fluids to move within the rock. There is a positive relationship between porosity and permeability.

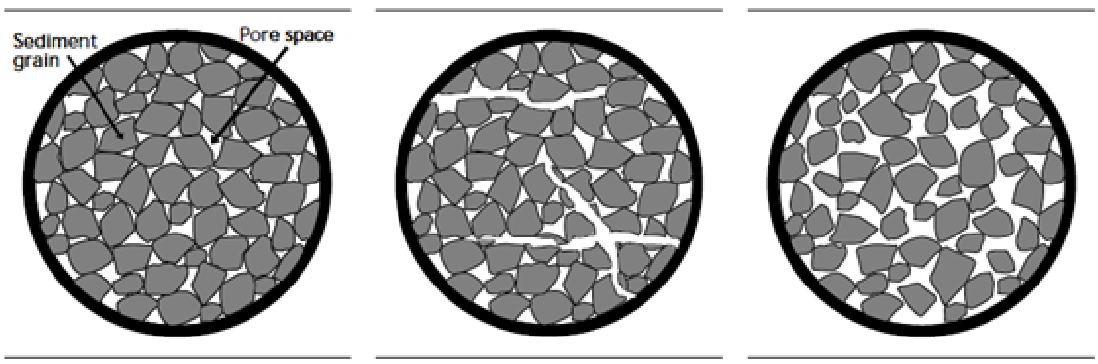

Figure 2. UBS Investment Research (2008) *Low porosity,low permeability* In: *Global Oil and Gas – Introduction to the oil industry* p. 80
Figure 3. UBS Investment Research (2008) *Low porosity, permeability increased by micro-fractures* In: *Global Oil and Gas – Introduction to the oil industry* p. 80
Figure 4. UBS Investment Research (2008) *High porosity, high Permeability* In: *Global Oil and Gas – Introduction to the oil industry* p. 80

The cap rock is an impermeable rock that contains and traps the flows of oil and gas in the reservoir rock. It has to be three dimensional, otherwise the flows can mitigate laterally and vertically until it reaches the surface. The cap rock is typically made of shale, micrite or salt. All of which displays the non-porous or non-permeable characteristics necessary to trap the flows.

1.1.3 The Location of Hydrocarbons

Hydrocarbons can be found all around the world. Even though the type, quality and producing rocks may differ, the physical conditions required are the same. Hence, it is possible to identify prospects of reservoir through common geographic features. Since hydrocarbons are originated by compressed and heated organic matter, reservoirs are most often found in sedimentary basins, places where organic matter are deposited and compacted over the years. Examples of sedimentary basins are continental margins and deltaic environments.

Sedimentary basins are mostly depressed areas that accumulate sediments originated in higher areas in its surroundings. A classic example is a river canyon or a lake. An alternatively way that sedimentary basins are formed is through the movements of the tectonic plates. Over millions of years, these plates, that form the earth's crust, move on their own dynamics. As a result, oceans are opened and closed, mountains are built and former continent shelves are buried, consequently providing the ideal geographic features for sediments accumulation and compression.

As an example, the formation of mountain ranges can be associated with the advent of an ocean close. Basins are usually found in the shadow of mountains ranges, for mountains provide the basin with a source of sediment. The remainder water becomes more and more saturated with salt, given the sea water evaporation. This process results in thick layers of salt deposited on the existing sediments, which may become the cap rock for an eventual reservoir of oil and gas. This example illustrates the formation of a pre-salt basin type.

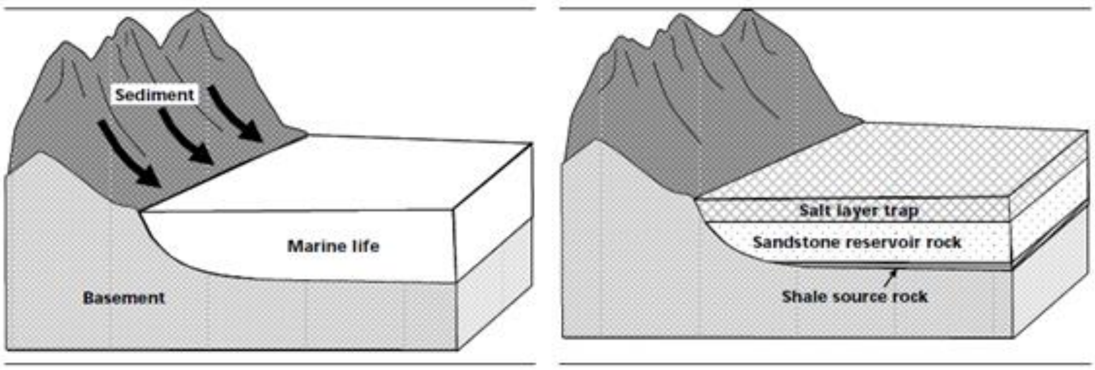

Figure 5. UBS Investment Research (2008) *Basin* In: *Global Oil and Gas – Introduction to the oil industry* p. 81

Two common locations of sedimentary basins, as aforementioned, are continental shelves and river deltas. Continental shelves are rich of marine life and provide a perfect area of organic matter accumulation. As the ocean closes, the shelves are uplifted and buried underneath the sandy basin sediments. The deltas, on the other hand, cover the finer sediments found in the seabed with organic matter brought from the land. A subsequent change in sea level floods of the delta buries the sediments, providing them with pressure and heat.

1.1.4 Sedimentary Basins in Brazil

Brazil presents a great number of sedimentary basins. Petrobras, the national oil and gas producer, along with its partners, explore 21 of these basins. By the end of the first quarter of 2015, there were 127 exploratory blocks, 306 fields in production (85 offshore), 16.2 billion boe (Barrel of Oil Equivalent) of proved reserves and 2.8 million boe of production.

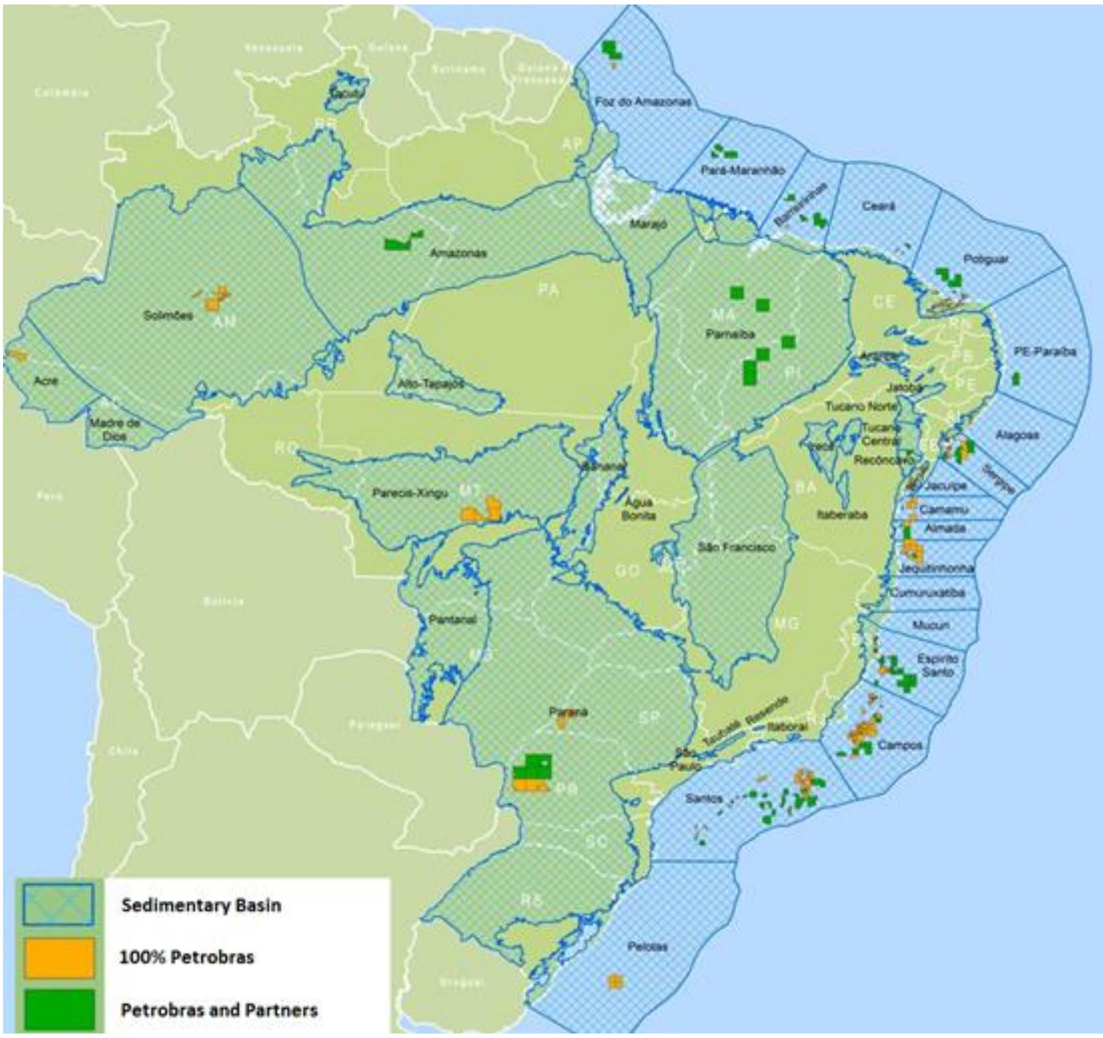

Figure 6. Petrobras (2015) Sedimentary *basins in Brazil* In: *O Segmento de Exploração e Produção da Petrobras* p. 4

The most important basins regarding oil production, however, are: Espirito Santo Basin, Campos Basin, Santos Basin and Pelotas Basin. Petrobras along with its partners have delineated these basins in operational units – Operational Unit Espirito Santo (UO-ES) in Espitiro Santo basin, Operational Unit Rio de Janeiro (UO-Rio) and Operational Unit Campos (UO-Campos) both in Campos Basin, Operational Unit Santos (UO-Santos) in Santos Basin and Operational Unit Sul (UO-Sul) in Pelotas Basin. By the end of first trimester of 2015, UO-ES with 6 platforms has produced 349 thousand barrels per day, UO-Rio with 11 platforms has produced 853 thousand barrels per day, UO-Campos with 33 platforms has produced 405 thousand barrels per day, UO-Santos with 9 platforms has produced 280 thousands of barrels per day and UO-Sul with 1 platform has produced 58 thousand barrels per day.

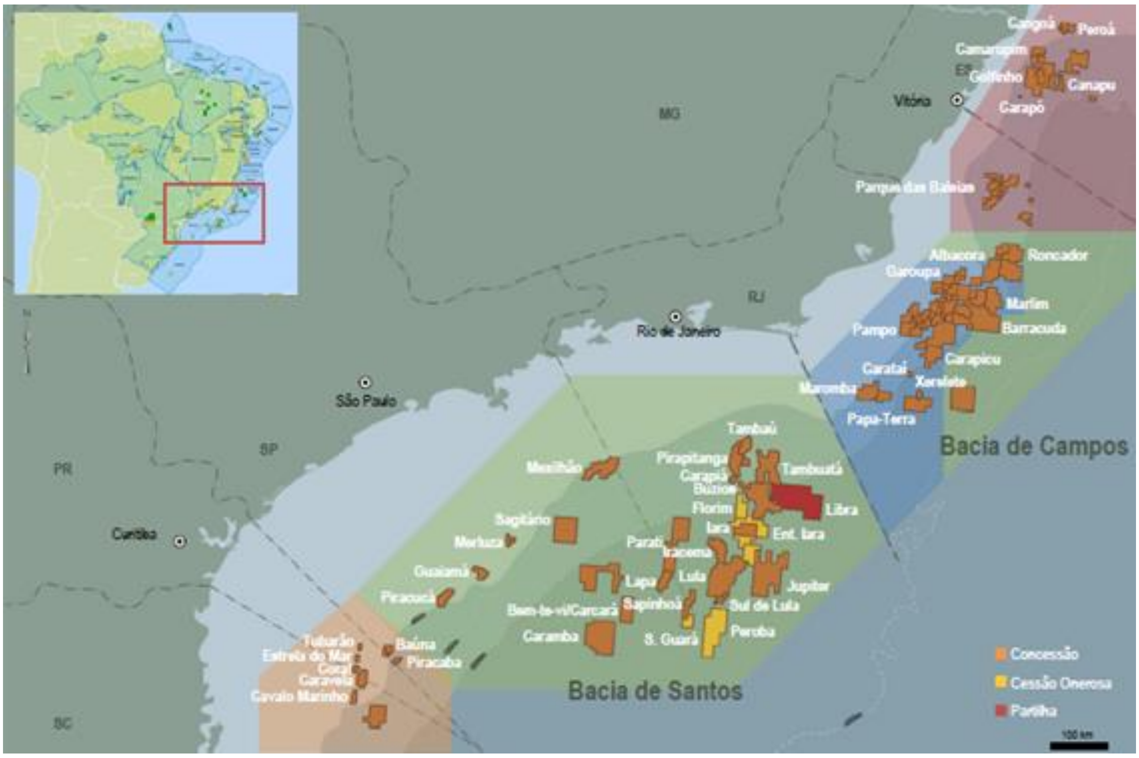

Figure 7. Petrobras (2015) Operational units in Brazil In: *O Segmento de Exploração e Produção da Petrobras* p. 16

1.2 Exploration and Production Cycle

The segment of the oil and gas industry responsible for exploring and producing new oil and gas fields is called Upstream. The value of these companies lies on their portfolio of exploration acreage, development projects and producing fields. As a result, these companies are constantly in one of the phases of the exploration and production cycle – exploration, development or production.

As these companies reach the production phase, they start generating positive cash flow. In order to maintain their longevity, the companies are compelled to reinvest the cash in new opportunities. To evaluate new prospects is a very difficult task, for the risks involved are immense. As the time evolves and the world demands more energy, commercial reservoirs are becoming more scarce and more technically challenging to develop. The pre-salt in Brazil and the shale in United States, for instance, are called unconventional reservoirs, part of the new exploration frontiers. Notwithstanding, other factor also contribute to increase the risk of new prospects, such as signing bonuses, royalties, taxes, exploratory costs, geopolitical instabilities, or hydrocarbon prices. In face of this problem, the industry uses proxies for project replacement. The most widely used is the annual reverse replacement, which is the reserve added divided by the reserve produced in a year. This is a major metric for the companies of the industry.

There are basically two ways of replacing reserves, by acquisition and exploration. The acquisition method is simply the act of buying equity, or a piece, of a field. The price of the transaction mainly depends on the percentage of the field acquired, on the characteristics of the field and on the current and expected hydrocarbons' prices. If the company decides to explore, on the other hand, it will go through a complex process called the Field Life Cycle.

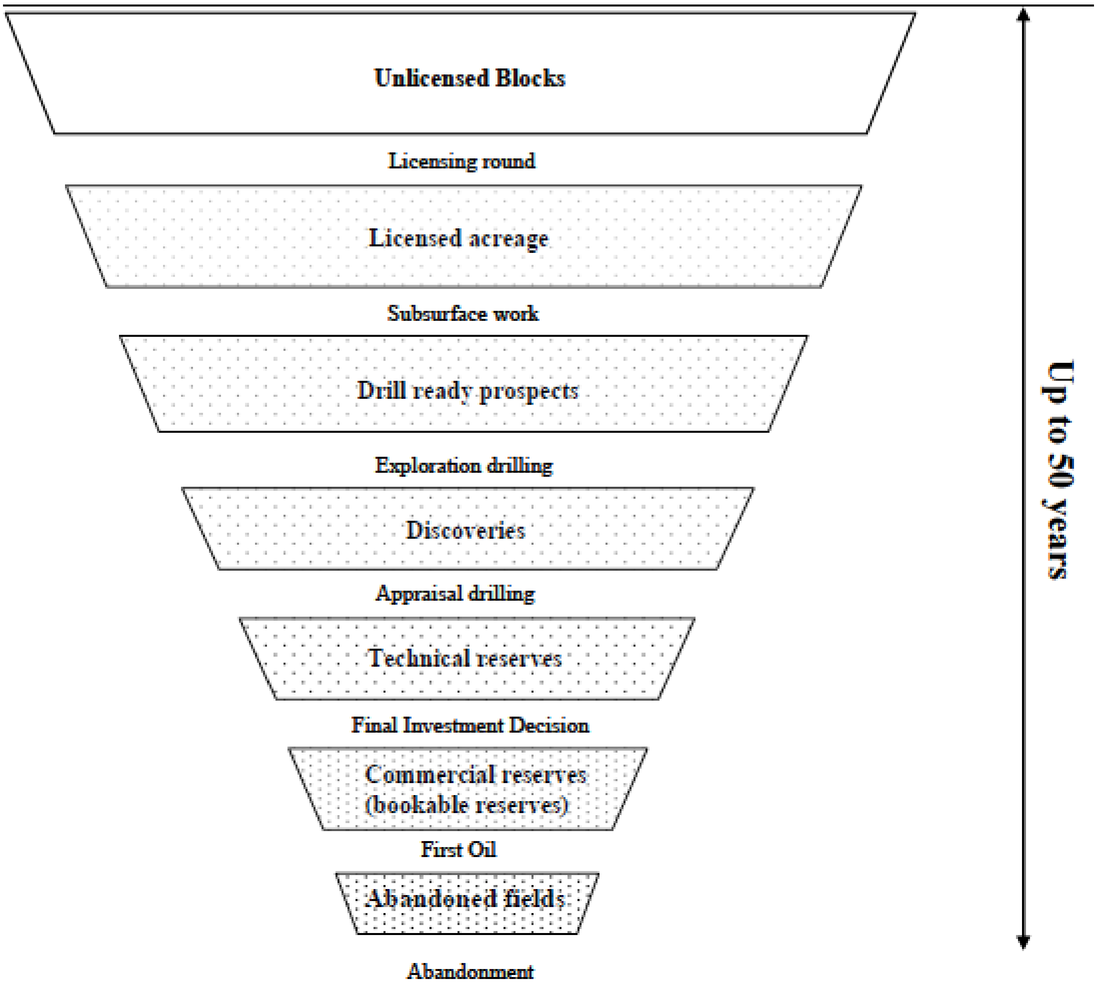

Figure 8. UBS Investment Research (2008) *Upstream companies work hard to keep the 'funnel' of opportunities full* In: *Global Oil and Gas – Introduction to the oil industry* p. 84

1.2.1 Acquisition of Acreage and Negotiation of Fiscal Framework

The acquisition of acreage is the first step towards exploration and production of a reservoir. The legal rights to explore and produce are usually acquired by bidding in licensing rounds. The companies bid on prospects of their interest, mainly driven by their promising seismic surveys or their proximity to existing fields. During these licensing rounds, the fiscal framework is also determined. It usually consists on signature bonuses, work commitments (such as seismic surveys and exploratory wells), government take and possibility to farm-out (to share the equity of the field, and thus its costs, in order to mitigate the financial risks). Brazil has experienced so far three different frameworks regarding its licensing rounds.

1.2.1.1 Concession Contract Regime

After the extinction of Petrobras' monopoly over Brazilian petroleum in 1997, the first fiscal framework constituted was the Concession Regime, by Law no. 9,478 (the Concession Law). The regime awards exploration and production rights, as well as obligations, to blocks onshore, in shallow water fields and in part of pre-salt (the main portion of pre-salt, as well as strategic areas, are left apart). The model is mainly used in case of high or medium exploratory risk, and the concessionaire takes all risks and investments in exploration and production. After the payments to the Union, however, the oil lifted is solely propriety of the concessionaire. Offshore oil fields regulated by this framework are Roncador, Papa-terra, Marlim, Jubarte and others.

The concession regime grants access to any company or consortium that meets legal, technical and financial requirements establish by ANP (Agência Nacional de Petroleum), the Brazilian hydrocarbon regulatory agency. The winning bidders are determined based on different aspects, such as the amount of signature bonus, investment in the exploratory program and the local content of equipments used in the endeavor. The concession contract in addition to the signature bonus, nonetheless, requires of the concessionaire a retention fee proportional to the field size, royalties equal to 10% of the production of oil and gas, and special participation for blocks with high profitability or production.

The concession contract determines two phases; the exploration and the production. For each phase, there are obligations and commitments to be followed. The exploration phase should take no longer than seven years and can be divided in two periods. The concessionaire is obligated to perform an exploratory program, which includes seismic works, exploratory drilling, and appraisal of discovery, if applicable. The production phase encompasses the declaration of commerciality and the development of activities necessary to produce oil and gas. It may not take longer than 27 years and may only begin after the exploratory program is completed.

1.2.1.2 Production Sharing Regime

The Production Sharing Agreement (PSA) regime was created in 2010 and it exclusively applies to Pre-salt fields and "strategic areas", as defined in the legislative article Law no. 12,351. It is usually used in cases of low exploratory risk; notwithstanding, the concessionaire takes the exploratory risk own his expense.

In the PSA regime, the companies are entitled to an amount of oil that covers their exploration cost and investments (oil cost), in case of discovery. The remainder of the production is divided between the Union and the concessionaire. The Profit Oil is the amount of oil that the concessionaire is entitled after the share of cost oil, royalties and special participation is deducted of the total production. Typically, the bidding winners are the one who offer the most attractive shares of the total production to the Union. In addition to the royalties, the companies are also to pay a signature bonus. The signature bonus, however, is established beforehand by the government and it is not a bidding one of the criteria to determine a bidding winner.

In all blocks encompassed by PSA, Petrobras is to be the sole operator, with a minimum interest of 30%. Petrobras, along with other possible partners, are to form a consortium with Pré-sal Petróleo S.A, a national entity responsible to represent the Union's interest in the PSA contracts. The company is also responsible, directly or indirectly, of all project-related exploration, appraisal, development, production, and abandonment activities. The remainder of the blocks' interests is to be divided between tenders through bidding rounds.

The PSA regime also determines the creation of a social fund to manage the revenues generated by the oil and gas production. This fund is meant to provide means of investments to promote the permanent benefit of the country. So far, the sole field in the PSA regime is Libra.

1.2.1.3 Transfer of Rights

By the end of 2007, Petrobras discovered a massive reservoir of oil and gas, namely Tupi, in the pre-salt layer. Along with later discoveries, the estimated pre-salt reserves were so vast that, if successfully explore, it would position Brazil, and Petrobras consequently, as one of the major energy producers of the world. In 2010, in order to finance its exploratory and production plan of the pre-salt, Petrobras made the largest capitalization in the world and amassed 70 billion dollars through equity. The Federal Union, in order not to have its Petrobras' participation diluted, sought with the company a contract awarding the rights to explore up to five billion BOE in designated pre-salt areas in exchange of equity. This contract required a special framework that is known as Onerous Transfer of Rights.

The blocks originally encompassed in the onerous transfer of rights were – Franco, Florim, Northeast of Tupi, South of Tupi, South of Guará, Iara's surroundings, and the contingent clock of Peroba. After the declaration of commerciality, the onerous transfer of rights area were renamed to – Itapu (Ex-Florim) , Búzios (Ex-Franco), Atapu (Ex- Iara's surroundings), Sépia (Ex- Northeast of Tupi), South of Sapinhoá (Ex-South of Guará), and South of Lula (Ex-South of Tupi). During the execution of the mandatory plan of development, however, it was found that the limit of some reservoirs, on the block of Iara's surroundings, extended themselves outside of the Onerous Transfer of Rights Area, into the block BM-S-11, regulated by the Concession regime. As a result of the new delineation of the reservoirs, new fields were added to the

Onerous Transfer of Rights Area in addition to the original ones – North of Berbigão, South of Berbigão, North of Sururu and South of Sururu.

In the Onerous Transfer of Rights contract, Petrobras bears all costs and risks of the exploration and production, and the production right last 40 years, renewable for another five years. The values of the contract were determined vie negotiations between Petrobras and the Union based on technical reports of the reserves issue by independent consultants. The technical reports of the reserves, nonetheless, lacked trustworthy information regarding the fields since only initial studies were realized. Upon such circumstances, both parties agreed to review the terms of the contract after the delivery of the fields' declaration of commerciality, which fair terms would be drafted based on a vast amount of information provided.

The terms of the contract under possible review were – the value of the contract, the maximum volume produced, the duration of the exploration and production rights, and the required percentage of local content in the equipments. In case of contract's value change, the difference can be paid, either by the Union or by Petrobras, vie cash or production volumes. The negotiations are on-going and are expected to be settled in 2015 still.

1.2.1.4 Transfer of Rights Surplus

Petrobras, after extensive exploratory program in the Transfer of Rights' fields, reached the conclusion that the recoverable reserves of these fields were much larger than previously expected. Petrobras, according to its declaration of commerciality, estimated a ranging volume of 9.8 to 15.2 billion BOE recoverable in the Transfer of Rights area. The Union and Petrobras, once again, started negotiating a production sharing agreement to explore the additional volumes produced after their previously discussed 5 billion BOE.

The contract is known as Onerous Transfer of Rights Surplus, and it assumes different terms than the Transfer of Rights contract. The Surplus contract encompasses the exceeding volumes of four areas of Pre-salt - Búzios, Sépia, Atapu and Itapu. It entitles Petrobras to explore and produce the additional volumes for 35 years, and the contract terms will commence concomitantly to the beginning of the oil production in each aforementioned field. Petrobras is also required to pay a bonus signature of 2 billion reais in 2014, in addition to several payments – 2 billion reais in 2015, 3 billion reais in 2016, 4 billion reais in 2017, and 4 billion reais in 2018. The Union is entitled to different percentages of the surplus volumes of each field – 47.42% in Búzios, 48.53% in Atapu, 46.53% in Itapu, and 47.62% in Sépia. The ANP estimates that Búzios holds between 6.5 billion and 10 billion BOE of reserves, Atapu from 2.5 billion to 4 billion BOE, Itapu from 300 million to 500 million BOE, and Sépia from 500 million to 700 million BOE.

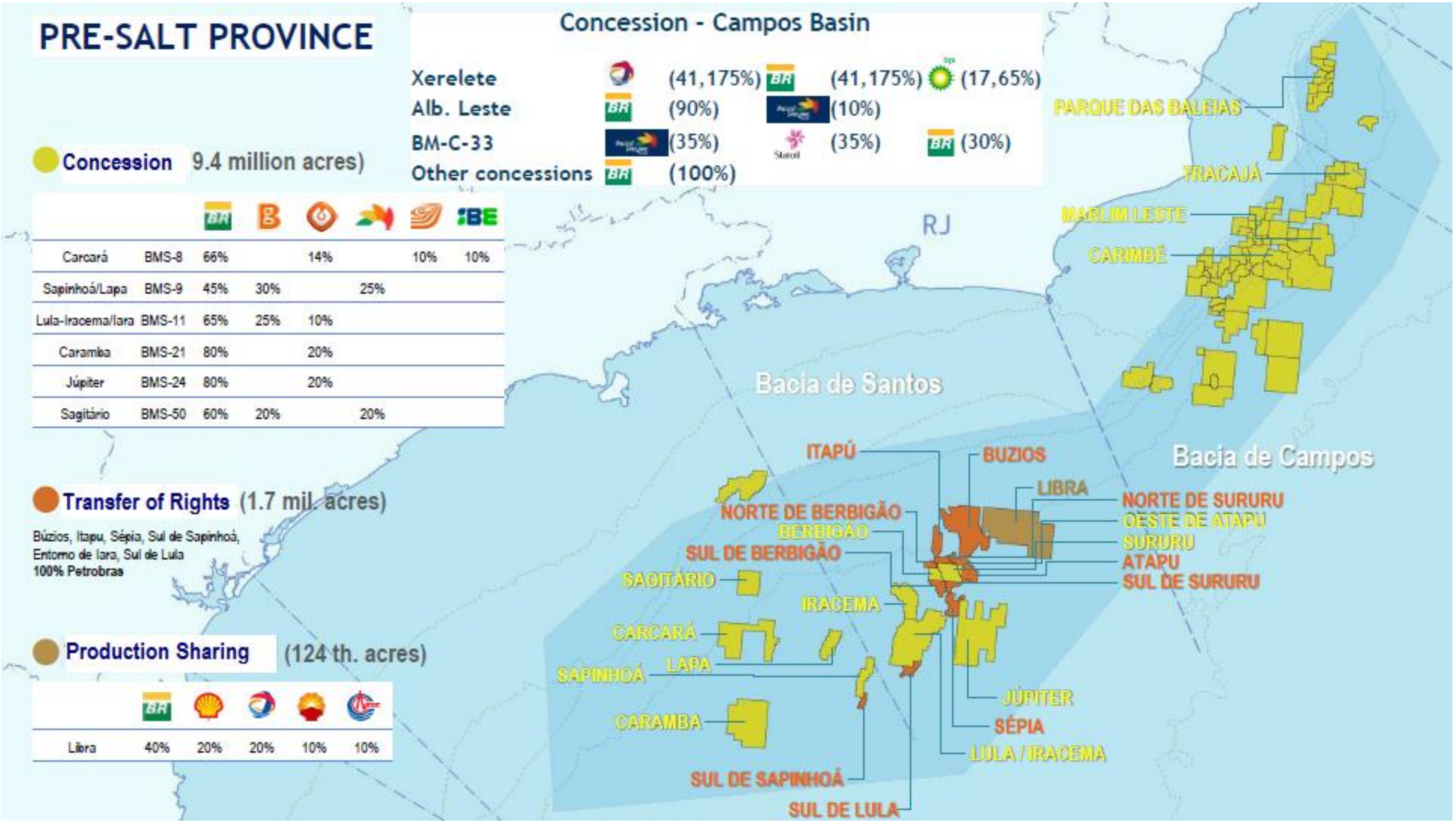

Figure 9. Petrobras (2015) *Key oil and gas fields in Brazil* In: *O Segmento de Exploração e Produção da Petrobras* p. 10

1.2.2 Exploration

The subsequent phase after the acquisition of exploration and production rights of a block is called Exploration. The purpose of the exploration process is to increase the probability of hydrocarbons, minimizing its risks and costs, by understanding subsurface of the block. Often, the blocks auctioned have already geological and geophysical surveys available, used to promote the blocks to probable buyers. These surveys, however, are usually superficial and further analyses are required in order to discovery and delineate prospective commercial reservoirs. Seismic surveys are the main tools used to select locations for wells and to determine the size of accumulations. Moreover, they also provide information regarding reservoir properties and fluid content. Seismic surveys, however, are not only conducted for exploratory drilling activities, they are also used on existing producing assets. As an example, they detect movements of hydrocarbons within the reservoir.

In order to access the subsurface structure of big areas, gravity or magnetic surveys are conducted, which are cheaper and simpler. Conversely, to investigate smaller areas, seismic surveys, a more sophisticated technique, are required. The technique consists of the detection of reflections of surface-generated compression waves through the earth's subsurface. The seismic data provides an image of the subsurface rock structure, and it can be processed as vertical slices (2D) or 3D cube (3D). The collection of the seismic shoots of an area over the time is called 4D, which are very useful to optimize recovery of a reservoir or perform further drilling.

Seismic activities can be divided in two parts – the acquisition of data, which is done by offshore vessels with streamers or by onshore arrays of geophones, and the data processing, which ultimately results in geological evaluation and modeling. If the prospect is offshore, a vessel carries submerged airguns that generate pulses of sound energy released in the water. These pulses of energy penetrate the different layers of the subsurface rock structure, and are reflect back at different speeds according to the geological and geophysical properties of the rocks. The hydrophones, located on the streamers trailed behind the boat, capture the reflections. Afterwards, the data collected by the hydrophones is transformed into a picture of the subsurface. This picture of the rock layers is essential to access the location and probability of hydrocarbons formation, its size and characteristics, which consequently, are fundamental to the companies' decision to initiate an exploratory drilling plan.

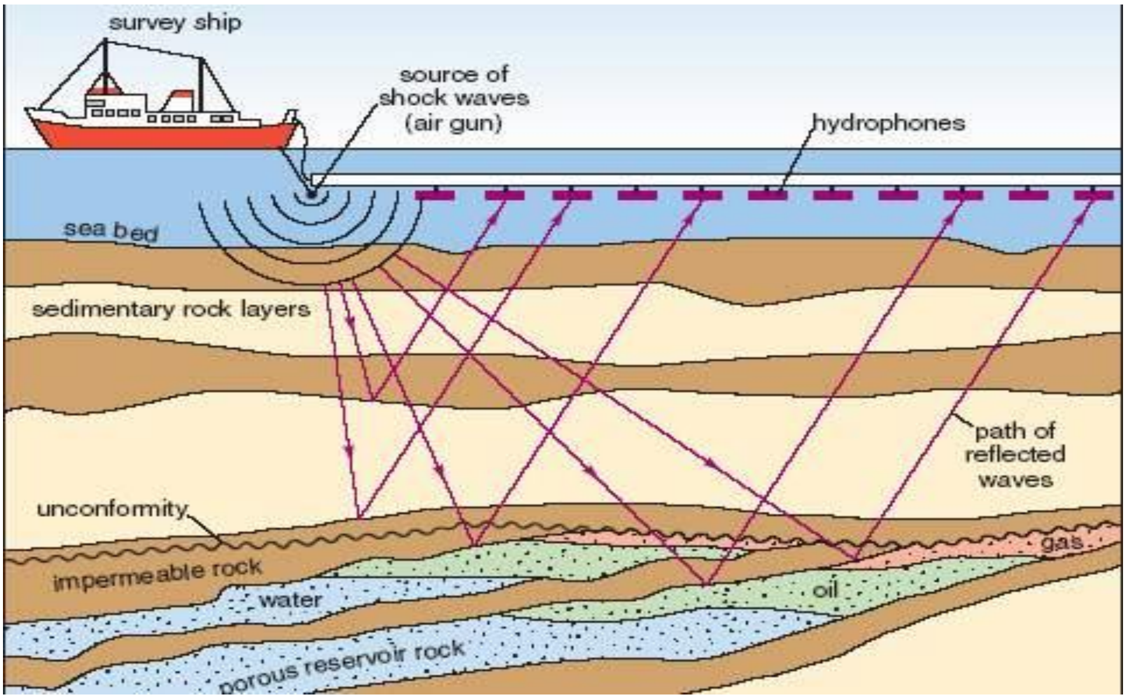

Figure 10. University Grants Commission (2015) *Offshore seismic survey scheme* In: *Oil and Gas Competency Building Workshop* p. 14

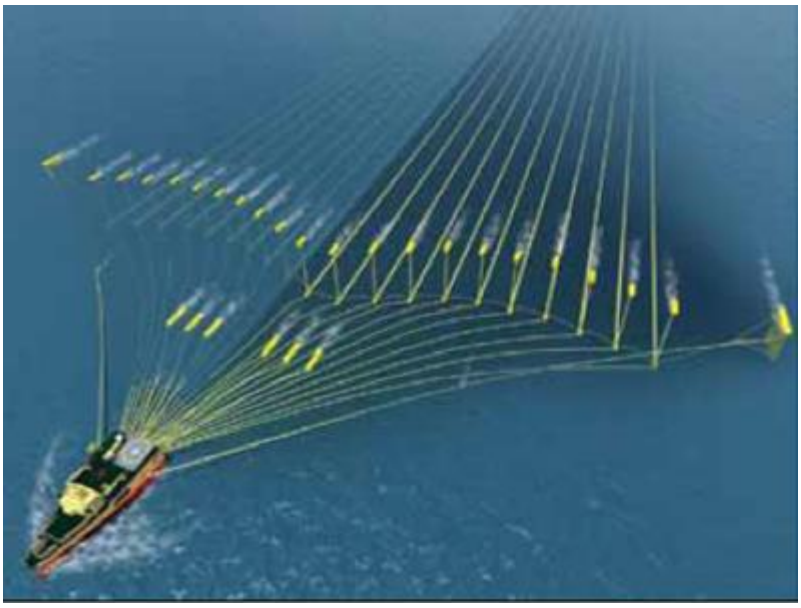

Figure 11. UBS Investment Research (2008) *Ramform marine seismic, schematic In: Global Oil and Gas – Introduction to the oil industry* p. 158

Figure 12. UBS Investment Research (2008) *Onshore 'thumper' trucks In: Global Oil and Gas – Introduction to the oil industry* p. 158

As the seismic data is collected and interpreted, resulting in a determine location of a probable accumulation, the next step is to drill an exploratory well. The exploratory well is the only way to verify there is, indeed, hydrocarbon's accumulation in the area. The exploratory well is a hole drilled on earth by a rig or a drilling ship, which is secured by cement and casing to prevent damages to the environment.

After the completion of the well, it is time to test it, which means to make the hydrocarbons flow to the surface. The purpose of this process is to gather further data in order to better understand reservoir. Productivity well tests are conducted, which involves the identification of produced fluids, the assessment of reservoir's pressure and temperature, and deliverability of the well. Reservoirs tests are mandatory. They evaluate the reservoir properties, assess its extent and geometry, and determine communication between wells.

1.2.3 Appraisal

The following phase of the E&P business lifecycle is the Appraisal. The objective of the appraisal is to provide an accurate estimate of the hydrocarbon's reserves and its characteristics, in order to decide if the commercial production is feasible or not. If it is, the question of how to optimize its production, respecting the restrictions and commitments required by ANP, is addressed in the development phase. The ultimate goal is the approval of the project.

The main tool to evaluate the volume and characteristics of the accumulation is a reservoir model. Geophysical, geological and engineering data collected during the process is used as input in models that simulate the reservoir's behavior. Estimating the hydrocarbons reserves is a complicated task, thus, the best suited method to use depends on the amount and quality of the existent data and the period of the field's lifecycle.

Usual estimation methods are – volumetric, material balance, production history and analogy. The properties of the rock play a fundamental role in the reserve evaluation; its samples are always subject of intense analysis.

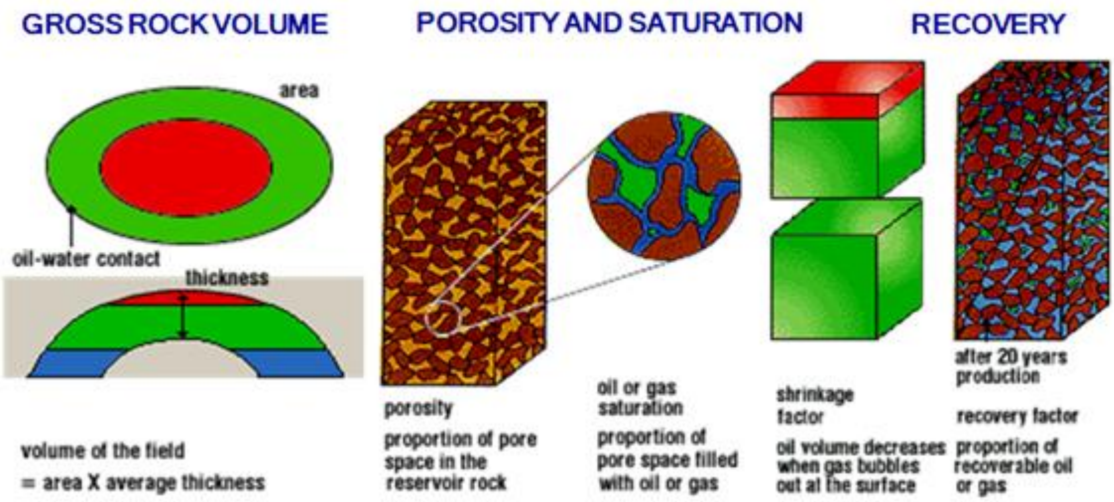

Figure 13. University Grants Commission (2015) *Reservoirs properties* In: *Oil and Gas Competency Building Workshop* p. 24

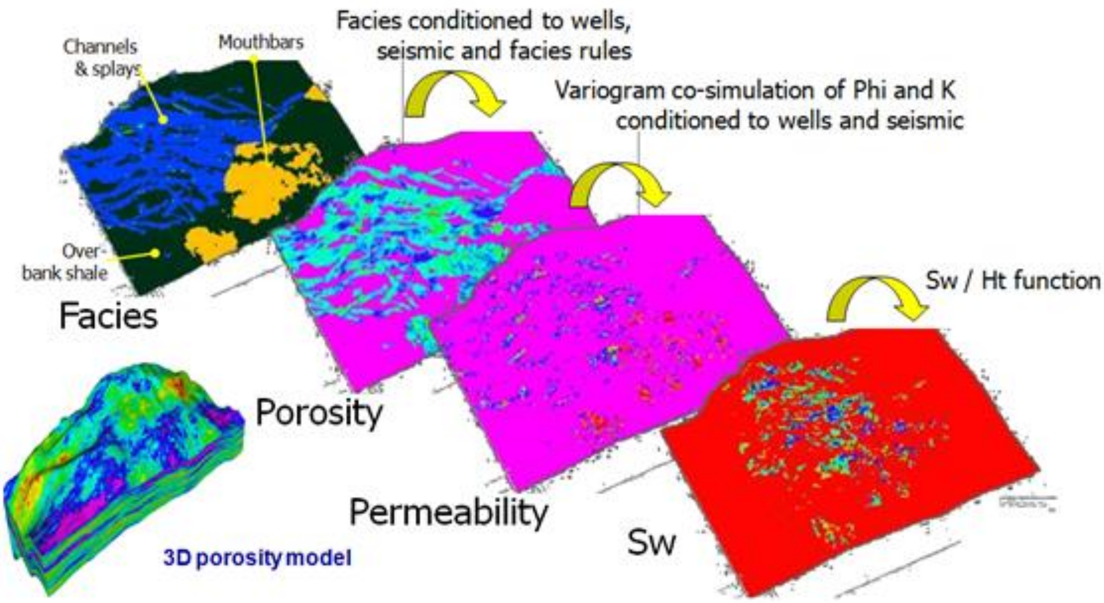

Figure 13. University Grants Commission (2015) *Reservoirs properties* In: *Oil and Gas Competency Building Workshop* p. 24

A subsequent part of the appraisal phase is the delineation of the field's limits. In addition to the reserve's estimation, few more wells are drilled to verify the extension of the reservoir, as well as to confirm its size. To delineate its limits is very important to the block separate it from other blocks which might have different ownerships. Lastly, if confirmed commercial amount of hydrocarbons, the E&P lifecycle moves to its next phase.

1.2.4 Development & Production

The development phase, as aforementioned, has the objective of designing the optimal way to safely and economically install the equipments and facilities responsible for producing oil and gas in the field. Ultimately, the company submits an extensive plan where it describes the implementation of its production equipment, the subsea and surface, its schedule of production, and its abandonment plan to be approved by the regulatory agency in Brazil, ANP. A fundamental part of this plan is the assessment of potential risks, and how to mitigate them. The environmental and social impacts of its activities in the following 10 to 30 years are also extensively considered. Companies are usually required to employ the population of adjacent communities and invest on their welfare as a way to compensate the possible risks.

The production phase, on the other hand, involves key stages – installing well production equipment, installing surface facilities (platforms, pipelines), testing and commissioning the facilities, producing hydrocarbons and delivery to pipelines or vessels. It is the longest of the E&P business lifecycle; it usually lasts from 10 to 40 years, and the most awaited by the companies. It is the phase when the cash flow finally turns positive, after an intensive period of capital expenditure.

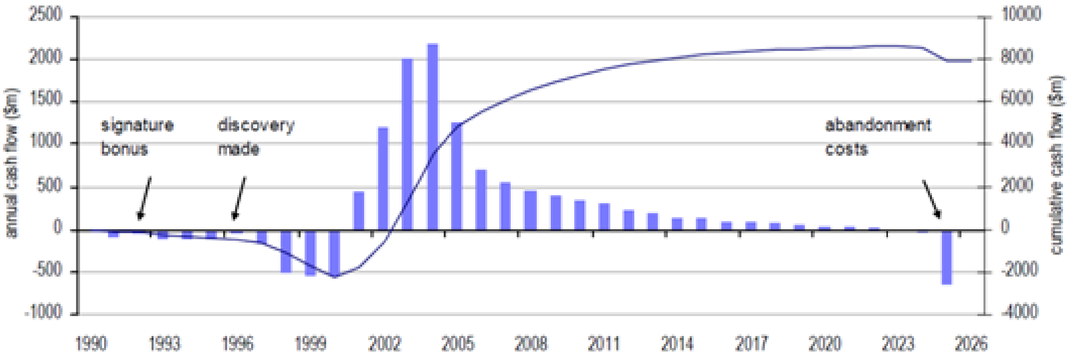

Figure 15. UBS Investment Research (2008) *Field life cycle example (Girassol field in Angola)In: Global Oil and Gas – Introduction to the oil industry* p. 84

The method of production is an important part of the process, and it solely depends on the characteristics of the reservoir, mainly porosity, permeability and pressure. The method chosen to be used is part of the production strategy, which is based on maximum economic results. The primary depletion is a method deployed in reservoirs at high pressure, joined to low pressure at surface by the well. The natural inner pressure of the reservoir pushes the hydrocarbons through the reservoir rock to the surface. The pressure, however, declines as the fluids are produced, a phenomenon called depletion. Pumping and compression is a method employed once the reservoir's pressure is not sufficient to expel the fluids, assistance is provided pumping, for oil fields, or compression, for gas fields. Secondary pressure maintenance, an additional production method, keeps the high pressure in the reservoir by injecting water of gas into it. The injection is made thorough dedicated wells called injection wells, and it is mostly used in oil fields nowadays. Finally, there are the tertiary production and special methods, which include steam or detergent floods. They are chiefly used for heavy or waxy oils only, because of their high cost and supporting technology.

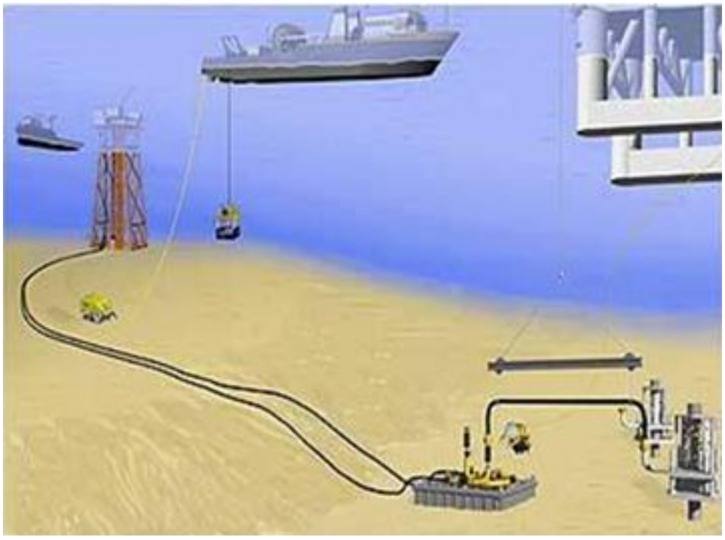

Figure 16. University Grants Commission (2015) *Offshore production scheme* In: *Oil and Gas Competency Building Workshop* p. 30

1.2.5 Abandonment of the Field

The abandonment of the field is the very last phase of the E&P lifecycle. Its objective is to safely and economically seal the wells and remove the facilities used through the production, according to company policies, local laws and international conventions. The decision to abandonment the field is made due to the non-viability to economically produce any more hydrocarbons. This decision is made based on key metrics such as safety, costs, schedule, environmental factors, and assisted by the reservoir model and production curve.

2. Oil and Gas Field Valuation Model

2.1 Discounted Cash Flow Method

The method of valuation chosen to estimate the intrinsic value of the Oil and Gas fields is the Discounted Cash Flow (DCF). The Discounted Cash Flow Valuation aims to estimate how much the stream of cash flow of an asset is worth today, which is theoretically its intrinsic value. The choice of the DCF method lays on the characteristics of the Oil and Gas fields as assets, for they provide periodically a stream of cash flow reasonably predictable until their terminal date.

Firstly, the DCF model attempts to estimate the annual revenue of the field. Its revenue is a function of the produced volumes and the oil price. The following step is to estimate its expenses, which are a function of royalties, government take, income taxes, lifting cost and depreciation. The net income of the field is found by subtracting its expenses from its revenue. The correct cash flow to estimate the asset's intrinsic value is the Free Cash Flow, which adds back the depreciation to the net income and subtracts the capital expenses. Finally, the free cash flow is brought to its present value by an appropriate discount rate.

The production of Oil and Gas is an activity intensely regulated by the government. Each Oil and Gas field follows a specific framework of regulations established by concession contract, production sharing regime, or transfer of rights. In addition, the DFC model is composed by different variables, which are projected in the future. In order to estimate these variables many different assumptions are required. The purpose of this chapter is to explain each step of Lula's DCF model, as well as its assumptions.

2.2 Oil and Field Model

2.2.1 Inputs

The Brent crude is an international index that represents the price of a basket of different sweet light crude oils produced in the North Sea (Brent blend, Forties blend, Oseberg and Ekofisk crude). The Brent crude index is considered the main international benchmark for oil prices with two thirds of the world's oil supply priced after it. The Brent crude is one of the most important variables of the model, for the average oil and gas realized price of the production it follows closely. In each field model's base scenario it is used the historical annual average prices from 2000 to 2014 and the Citigroup's Brent forecast for 2015 and beyond. The models assume Citigroup's forecast of 70 dollars per barrel as the long term oil price.

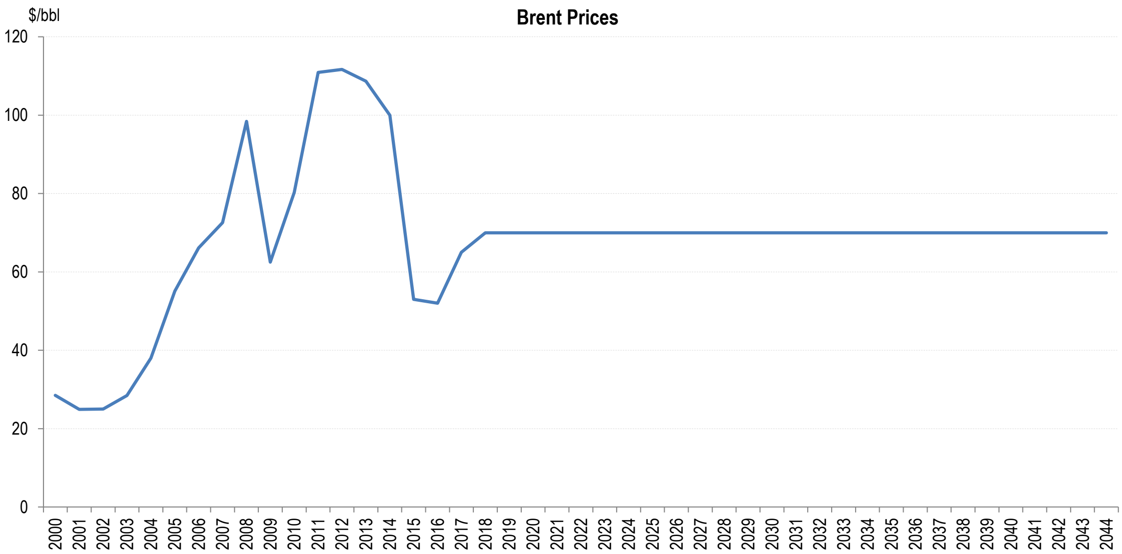

Figure 17. *Brent prices*

In addition to Brent, the models require different inputs related to production, royalties and taxes, realization price and valuation. The first of the production inputs is Field Size. The field size represents the proved plus the probable volumes in each modeled reservoir. The size of reserves is one of the most important drivers of value of the model, for it determines the total production of the field during its licensed period.

It is important to note that the reserve size includes oil and gas altogether, thus a breakdown of that amount in oil and gas reserves is necessary. Each model requires the percentage of total reserves are composed by oil and by gas. This distinction is important to assess the average realized price of the production.

The location of the field is an input important to consider as well. The government take, which will be further described in each field chapter, is a share of the production that belongs to the government according to each regulatory framework. The size of the share, among other criteria, depends on the location of the field. Finally, the last production input is the depletion rate of the wells, which determines how much the production of each well declines annually.

The following input section is dedicated to taxes and royalties. Each model assumes a field royalty according to its regulatory framework. The income tax used in the models, on the other hand, is 34%, which is the average income tax charged to Brazilian companies.

The last section of inputs is related to the average realization price of the production. The average realization price uses the Brent crude as a benchmark, as stated previously. The models assume a long time oil price (from 2018 onwards) of 70 $/bbl, in line with Citigroup's forecast. Realization price of oil and gas are estimated from Petrobras' reported revenue, which is a reliable estimation since the company is the field operator and has the biggest ownership of all fields analyzed. The fields' production is sold with a discount to the Brent crude due to the quality of its oil and gas, for the Brent crude is lighter (lower density) and sweeter (less sulfur). The models assume a discount of 5% to oil and 50% to gas in relation to the benchmark. The average realization is an average of the realization price of oil and gas weighted by their volumes in the total reserve.

Example of the Inputs Template - Lula Field

Field Size (mm boe)	8,373	<< Hoje em dia dado tx de recuperação, delineação entre outros gira mais de 10bn			
Oil Reserve (mm boe)	7,348			88%	Oil out of Total
Gas Reserve (mm boe)	1,025		100		
Peak Production (mm boe)	469.6	1286.5 kboe/d		30	Well Avg. Prod. (kboe/d)
Oil Peak Prod. (kboe/d)	412.1	1129.0 kboe/d		26.327481	Oil Avg. Prod. (kboe/d)
Gas Peak Prod. (kboe/d)	57.5	157.5 kboe/d		3.6725188	Gas Avg. Prod. (kboe/d)
Field Location	3	1) Onshore 2) Shallow 3)Deep Water			
Decline Rate (%)	9%				
Field Royalty (%)	10%				
Income Tax Rate (%)	34%				
Long Term Oil Price ($/bbl)	70				
Average Realization Price ($/bbl)	62.6				
Average Realization Price (% of Brent)	89%				
Oil Realization Price ($/bbl)	66.5	-3.5 Oil Discount/Premium			
Oil Realization Price (% of Brent)	95%				
Gas Realization Price ($/bbl)	35	-35 Gas Discount/Premium			
Gas Realization Price (% of Brent)	50%				
Development Cost ($/boe)	7.7				
Lifting Cost ($/boe)	10.2	9.9 << Relatório PBR E&P 2014			
Discount Rate (%)	12.5%				

Figure 18. *Example of Input Template*

2.2.2 Production

The production is a key value driver in all models, for it determines the volume of production, and ultimately the stream of cash flow. In order to estimate the volume produced and the pace of production a few other variables are required. The main drivers of production are the Floating Production Storage and Offloading (FPSO) vessels availability, their capacity of production, the average production flow of each well and their depletion rate.

Petrobras, as the operator of all analyzed fields, is responsible for developing them, and thus it indicates how many FPSO's are dedicated to produce in each field. The choice of how many FPSO's to install in a specific field depends directly to the acreage of the reservoir, its reserve size, geological characteristics (porosity and permeability for instance), as well as the maximization of free cash flow.

Moreover, in addition to the number of platforms and their delivery schedule, the dynamics of each production well is fundamental to the models' production forecast. Each platform is able to connect to a limited amount of production wells and injection wells, which are responsible to extract the hydrocarbons from the reservoirs and responsible to inject either water, gas or other fluids, in order to increase the reservoirs pressure, respectively. The amount of wells connected to each platform is a function of its production capacity and the production flow of the reservoir. The models assume a production flow rate of 12 to 35 thousand barrels per day (kbd) depending on the location of the platform in each analyzed field. These rates were assessed by historical production data and Petrobras own estimates of production flow in pre-salt reservoirs.

Each reservoir, due to its properties and characteristics, has a different production dynamics. In general, however, the models assume a production pattern. Each well, as well as each platform, has three production phases. The initial phase of the production well is called Ramp-Up. It is the period that comprises the production start-up until it reaches its full production capacity, which is determined by the reservoir. The production during this phases, as the name indicates, increases as the time passes. The initial production flow of the well is typically small in order to assess, in practice, specific characteristics of the well such as pressure and production flow, and to avoid unexpected events. The production gradually increases until it reaches its maximum production flow. The following phase is called Plateau, which is the period that the well stabilizes production in its maximum capacity. Finally, the well reached Depletion phase. The production flow decreases due to the lack of pressure caused by the depletion of the reservoir's reserves. In order to maximize production volumes and the development phase, injection wells are installed to increase the pressure in the reservoir, thus increasing or maintaining the production flow.

2.2.3 Capital Expenditures & Operational Expenditures

In addition to the production forecast, two important drivers of value in the models are the capital expenditures and operational expenses. They are the expenses that make the production possible. The capital expenditures are the investments made in facilities, infrastructure, equipment and installations necessary to produce the hydrocarbons. The operational expenses, on the other hand, are the expenses incurred in the utilization of infrastructure and facilities, and in the operation of the equipment.

Each reservoir has a specific development plan, submitted to the ANP by the winning consortium during the blocks bidding round, tailored to optimize its production. The way to model the capital and operational expenditures, therefore, will differ in each case. In all models, however, it will be attempted to find the historical capital expenditures of each field. In case the information in unattainable, estimations based on peer assets will be used. As to operational expenses, the historical costs will be projected to the future adjusted by inflation of services or exchange rate.

2.2.4 Cash Flow Calculation

The final part of the Oil and Gas Field valuation model is the Cash Flow Calculation. It is responsible to put assemble the field assumptions, in order to estimate a free cash flow stream and to discount it to present value. It starts with the calculation of the field's revenue, which is simply the produced volume times the average realization price.

The following step is to subtract the production cost off the field's revenue. The government royalties incur directly in the field's revenue at a rate stated by its regulatory framework. Another expense subtracted is the lifting cost, which is the sum of all expenses to "lift" the hydrocarbons from the reservoir to the platform, in other words, the operational expenses. Finally, the depreciation of the operational assets is discounted. The Oil and Gas industry has its specific set of accounting rules to treat depreciation. The models utilize the unit-of-production method, the most common used to deplete upstream oil and gas assets, which depletes the asset base in the same proportion of the annual production in relation to the estimate of reserves within that field. The subtraction of all these expenses of the revenue results in the Oil Profit.

In accordance to each regulatory framework, the government is entitled to a share of the field's revenue called "Government Take". Each regulatory framework has its own individual formula to calculate the government take. The following chapter will describe the details of the concession contract, the production-sharing contract and the transfer of rights.

The amount left after the government take is called the pre-tax income, which is the base that the income tax is deducted. Lastly, all models assume an income tax of 34%, the average percentage charged of Brazilian companies. The next calculation is to find the free cash flow, which it the addition of depreciation and the subtraction of capital expenditure to the net income. The final step of the model is to bring the stream of cash flow generated by production to net present value. The base year of the models is 2015. The discount factor of any year following 2015 is calculated by multiplying the previous year discount factor to the discount rate chosen in each model. The discount factor of 2015 is one. In relation to the years before 2015, the discount factor of the following year is multiplied by the discount rate. This system means to increase values of years before the base year and to decrease values after the base year, in order to bring these values to the present. The stream of free cash flow is multiplied by the discount factor and the net present value of these cash flows is found.

3. Lula Field Valuation Model

3.1 Field Description

Lula field was discovered in 2006. It lies on BM-S-11 block, 2,100m below the water and roughly 5,000 below a salt layer. It is one of the largest fields in Brazil, with estimated reserves of more than 8bn, including Iracema area. New production recovery techniques (Enhanced Oil Recovery technologies), however, promise a great upside risk to the field's reservoir with estimations asserting over 10bn recoverable barrels. Lula's oil is considered intermediate or medium (28-30º API) and sweet (less than 0.7% sulfur by weight). The BM-S-11 block was auctioned in the second bidding round of the concession contract, in 2010, and its signature bonus was around 15 million dollars. Five companies split the ownership of the field, namely Petrobras (65%), the operator, BG (25%), Galp (7%) and Sinopec (3%).

3.2 Lula Field Model

3.2.1 Inputs

The model considers Iracema area to be part of Lula field. The model conservatively assumes a total of 8,373 mmboe of reserves (approximately 6,500 mmboe of Lula + 1,800 mmboe of Iracema) as stated by Citigroup's[1] research report. The size of reserves is one of the most important drivers of value in the model, for it determines the total production of the field during its licensed period and development strategy. As aforementioned, the model's base case of 8,373 mmboe is very conservative, since recent studies point to a total up to 10,000 mmboe recoverable.

It is important to note that the reserve size of 8,373 mmboe includes oil and gas altogether, thus a breakdown of that amount in oil and gas reserves is necessary. The model assumes that 88% of the total reserves are constituted of oil, aligned with Citigroup's[2] estimates. The composition of the reserves is favorable to the field economics, since oil is more valuable than gas.

Lula field is located in ultra-deep water, thus the government take of the production is smaller given the same amount of production, if compared to onshore and shallow water fields. This is due to the difficulty and risk to explore deep and ultra-deep water fields. The government participation of Lula field will be explained in details later in this chapter. As mentioned before, Lula field is situated in the pre-salt area. Geological and Geophysical data has pointed out the great characteristics of this reservoir to produce Oil and Gas. Lula's base case scenario assumes a depletion rate of 10% explained by the reservoirs properties and EOR technologies developed in recent years. The depletion rate is a key variable in the model since it determines the production timeframe, directly influences the capital expenditure in the field, and thus, its intrinsic value.

The model assumes a field royalty of 10% of the production, which is the rate specified in the Lula Field concession contract. As aforementioned, the income tax used

[1] Citigroup. 2015. *Global Oil Vision 2015 – Project Book*
[2] Citigroup. 2015. *Global Oil Vision 2015 – Project Book*

in the model is 34%, in line with the assumptions of Gaffney, Cline & Associates[3], an independent consultant firm hired by ANP to estimate the pre-salt's discoveries value. The last section of inputs is related to the average realization price of the production. The average long-term realization price of Lula's production is $62.6/boe, due to the compositions of its reserves. The realization price formula is an average of the Oil's realization price and the Gas' realization price, weighted by their percentages of the field's total reserves. The Oil and Gas realization price is derived by the Brent price plus a discount, respectively of 5% and 50%.

3.2.2 Production

Petrobras, as the operator of the field, is responsible for its development plan, which indicates ten FPSO's dedicated to production. The FPSO's dedicated to Lula field are FPSO Cidade de Angra dos Reis (100 kbd), FPSO Cidade de Paraty (120 kbd), FPSO Cidade de Mangaratiba (150 kbd), FPSO Cidade de Itaguaí (150 kbd), FPSO Cidade de Maricá (150 kbd), FPSO Cidade de Saquarema (150 kbd), and the replicants P-66 (150 kbd), P-67 (150 kbd), P-68 (150 kbd), P-69 (150 kbd). Petrobras and its partners have a concession of 27 years to produce, which can be extended by the ANP in case there are still reserves available. Altogether, these ten FPSO's at their full capacity are able to produce roughly 1,420 kb per day. Four out of the tem platforms, namely FPSO Cidade de Angra dos Reis, FPSO Cidade de Paraty and FPSO Cidade de Mangaratiba and FPSO Cidade de Itaguaí are currently producing. FPSO Cidade de Maricá and FPSO Cidade de Saquarema are expected to start in the beginning of 2016. The uncertainty lays on the FPSO replicants, which are schedule to commence from 2019 to 2020.

FPSO	Total Production (mmboe)	Years of Production
FPSO Cid. Angra dos Reis	1,022	28
FPSO Cid. Paraty	1,314	30
FPSO Cid. Mangaratiba	1,697	31
FPSO Cid. Itaguaí	1,643	30
FPSO Cid. Maricá	1,588	29
FPSO Cid. Saquarema	1,588	29
FPSO P-66	1,533	28
FPSO P-67	1,478	27
FPSO P-68	1,478	27
FPSO P-69	1,424	26

Figure 19. *FPSO production profile*

In its latest Business and Management plan (2015-2019), Petrobras expects to deliver Lula's last FPSO in 2020. Much will be changed in their business plan, however, due to unexpected movements of macroeconomic variables that severely hardened Petrobras' conditions to meet its annual debt amortizations. As a result, capital expenditure reductions were implemented and new contracts with most of the domestic supply chain were suspended due to Car Wash investigations. In light of this tough scenario, Petrobras must prioritize its most profitable assets and reorganize its capital expenditure guidance, thus accelerating the development of its exploration and production assets in detriment to other areas, such as refineries and petrochemicals. Within its exploration and production portfolio, the company will most likely invest its

[3] Gaffney, Cline & Associates. 2010. *Review and Evaluation of Ten Selected Discoveries and Prospects in the Pre-Salt Play of Deepwater Santos Basin*

capital in profitable assets already in development, and sell assets unexplored and undeveloped, in order to increase its cash flow. The model assumes, therefore, a different delivery schedule to these FPSOs.

FPSO	Model's Delivery Schedule	Petrobras Delivery Schedule
FPSO Cid. Angra dos Reis	2010	2010
FPSO Cid. Paraty	2013	2013
FPSO Cid. Mangaratiba	2014	2014
FPSO Cid. Itaguaí	2015	2015
FPSO Cid. Maricá	2016	2016
FPSO Cid. Saquarema	2016	2016
FPSO P-66	2017	2017
FPSO P-67	2018	2017
FPSO P-68	2018	2018
FPSO P-69	2019	2020

Figure 20. *FPSO delivery schedule*

The model assumes that each well takes two to three years to reach its production peak, and it holds that production for one or two years in average. Afterwards, the production flow declines at the designated depletion rate. The platforms, on the other hand, take two to three years to reach their production capacity and they are able to hold that production flow for roughly seven years through new production and injection wells. Moreover, they decrease the production until it is not economic viable any longer; the production's revenue is smaller than its operational cost. The model assumes that for two production wells, there is one injection well is drilled.

The model's estimated production curve reaches its peak at 2021 with an annual production of 484 mmboe and an average of 1,327 kbd. It is estimated a total of 34 years to produce the 8,373 mmboe of the field and a total of 84 production wells and 42 injection wells.

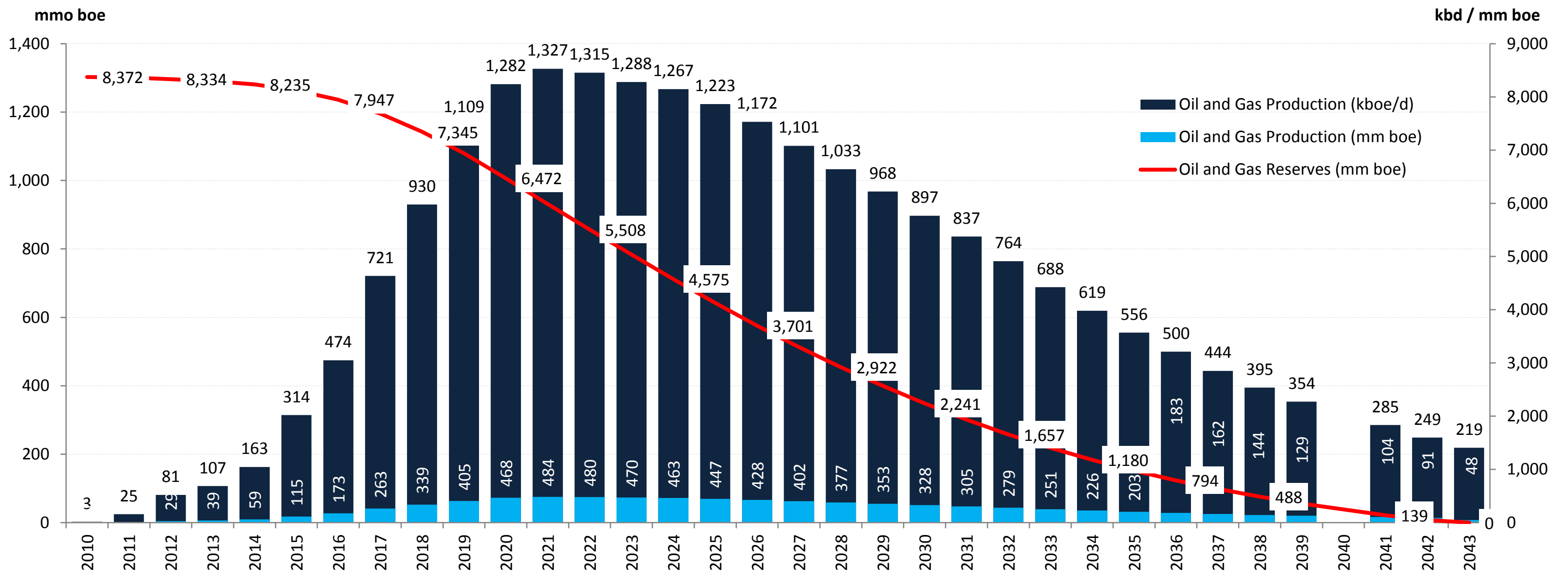

Figure 21. *Lula production curve*

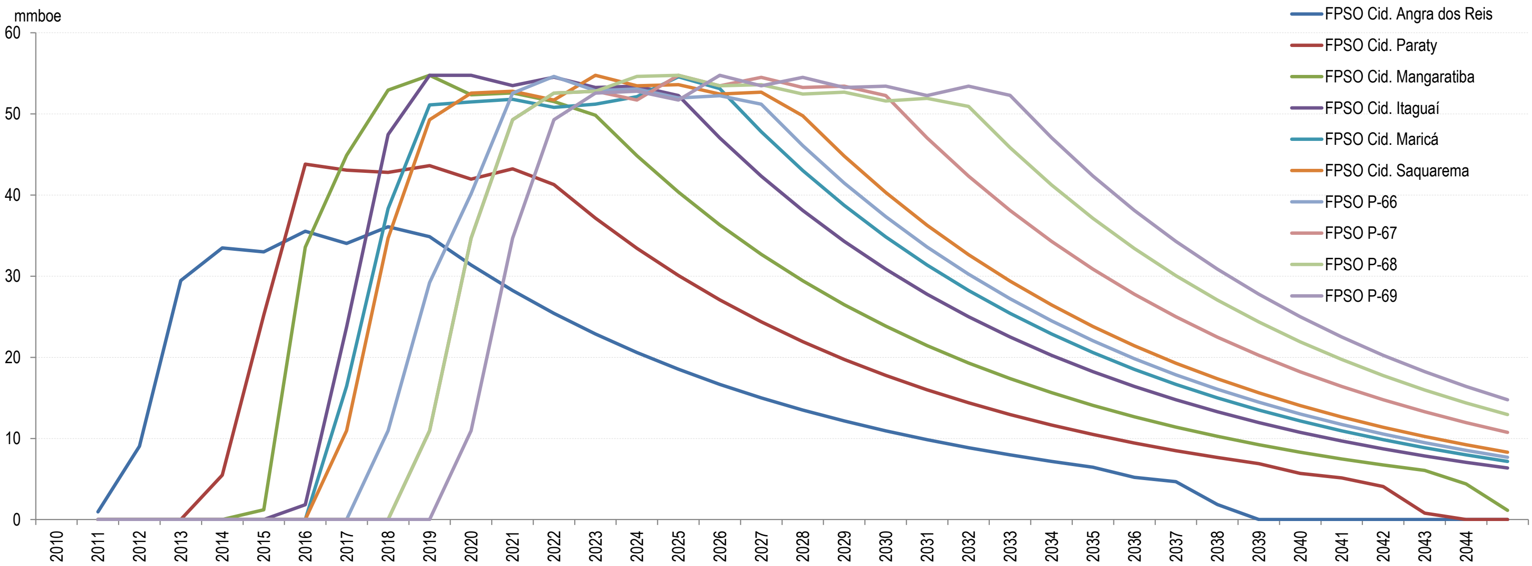

Figure 22. *FPSO production curve*

3.2.3 Capital Expenditures & Operational Expenditures

The first capital expense in Lula's model is the signature bonus, an upfront payment to the government in order to win the concession contract auction. Lula field concession contract was signed in 2000 and it was required roughly $15m as signature bonus. This signature fee might seem immaterial in relation to the signature fee of the latest bid rounds, however, it reflects the uncertainty and risk of the enterprise, given that Lula field was the first reservoir in the pre-salt area to be explored.

The winner consortium had to draft an exploratory and development plan for the reservoirs and submit them to ANP's approval. The exploration phase has the objective of finding, delineating and gathering information of the discoveries in the exploratory acreage. The commitment usually consists in the acquisition of seismic and other exploratory data of the area, and a defined schedule to drill exploratory wells. The exploration phase of Lula's field was divided in three phases. The first phase is mandatory to acquire seismic data, 5km of 2D or 1km² of 3D seismic, the exploratory wells were optional. The second phase required 2 exploratory wells to be drilled, and the third phase requires additional three wells. The last part of the exploratory phase is to implement an extended well test (EWT). EWTs consist in small capacity platforms used to confirm long-term productivity and deliverability, and to design future production facilities. The model does not consider Lula's ETW as part of its production curve nor of its expenses. If hydrocarbons are found, and economically viable, a commerciality declaration is issued along with a development plan.

Furthermore, the development phase of the fields requires many infrastructure expenses. The model considers the construction of the FPSO's and its engineering, well drilling, the subsea equipment, the gas pipelines and other costs. The Lula's field platform portfolio consists of a mix of leased and owned platforms. The first six are leased, namely FPSO Cidade de Angra dos Reis (owned by Modec), FPSO Cidade de Paraty (owned by SBM offshore, Mitsubishi, QGOG, Nippon Yusen Kabushiki and Itochu), FPSO Cidade de Mangaratiba (owned by Modec), FPSO Cidade de Itaguaí (owned by Modec), FPSO Cidade de Maricá (owned by owned by SBM offshore, Mitsubishi, QGOG, Nippon Yusen Kabushiki and Itochu) and FPSO Cidade de Saquarema (owned by owned by SBM offshore, Mitsubishi, QGOG, Nippon Yusen Kabushiki and Itochu). On the other hand, Petrobras owns P-66, P-67, P-68 and P-69.

FPSO	Capacity (kbd)	Lease/ Owned	Total Capex($m)	Capex/boe	Opex/boe
FPSO Cid. Angra dos Reis	100	Lease	3,244	3.2	7.7
FPSO Cid. Paraty	120	Lease	4,761	3.6	6.4
FPSO Cid. Mangaratiba	150	Lease	5,356	3.2	5.1
FPSO Cid. Itaguaí	150	Lease	5,566	3.4	5.1
FPSO Cid. Maricá	150	Lease	5,356	3.4	5.1
FPSO Cid. Saquarema	150	Lease	5,356	3.4	5.1
FPSO P-66	150	Owned	5,356	3.5	1.0
FPSO P-67	150	Owned	5,356	3.6	1.0
FPSO P-68	150	Owned	5,356	3.6	1.0
FPSO P-69	150	Owned	5,356	3.8	1.0

*In case the platform was bought by Petrobras

Figure 23. *FPSOs cost profile*

The model assumes a capital expense of $63m for the engineering services, mainly the Front End Engineering Design (FEED), which determines the technical requirements as well as rough investment costs for the project. A 150kbd FPSO, including the hull conversion, topside integration and anchoring system is assumed to cost around $1,750m. The leased platforms require no capital expenses to build them, however, there are operational expenses related to these platforms, as well as capital expenses related to drilling and subsea infrastructure.

Development Expenses	Capex	Comments
Engeneering	$63m	FEED, others
FPSO	$1750m	150kboed FPSO with topside and anchoring
Drilling	$450k + $500k	rig daily rate + for services
		100 days for drilling
Subsea equip	$6m	Christmas tree (more expensive given Water depth)
	$6m	Manifold (more expensive given Water depth)
	$2m	Umbilicals
	$6m	Control and others
Subsea (inst. and lines)	$80m per well	Includes flowlines, risers, umbilicals and installation
Contingencies		10% of the project's total

Figure 24. *Development expenses*

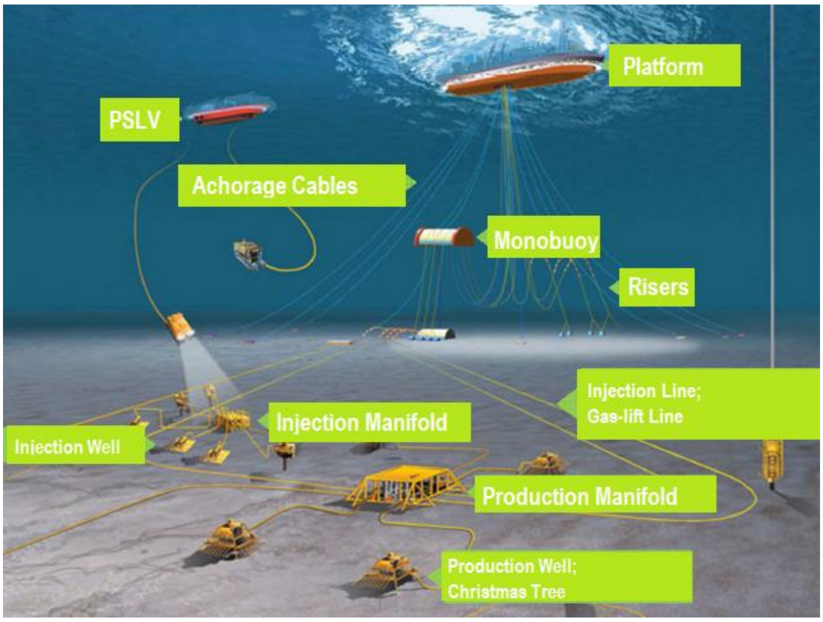

Figure 25. *Subsea infrastructure*

The main operational expense in the model is the day rates and operating services of the platforms, Production Support Vessels (PSV) and shuttle tankers. These expenses cover the production, offloading, transportation, maintenance and support of oil and gas production operations. While the FPSOs are responsible for extraction and the first treatment of the hydrocarbons, the PSVs provide transportation of workers and supplies to the platforms, the shuttle tankers transport the oil to the production and storage facilities on the shore. The choice of shuttle tankers to transport the oil production from the pre-salt area to the production and distribution facilities onshore is due to the lack of great upfront capital expenses required in pipelines and more delivery flexibility. The gas, on the other hand, will be transported by pipelines. The day rate is the daily cost to rent the equipment, namely FPSOs, PSV and shuttle tankers. The operating services generally involve the operation, management and maintenance of the FPSO, including process plant and offtake system, and subsea and associated equipment, among other tasks. It is assumed an operational expense of $770k per day in total for FPSOs, 150k per day for service cost and 620k per day for day rate. As to PSVs and Offtake tankers, 40k per day for both vessels. It is important to highlight the assumption of two PSV and shuttle tanker per platform.

In order to develop the reservoir, in addition to the platform itself, it is required to install the production subsea infrastructure. Firstly, the platform has to be connected to production and injection wells, in order to extract the hydrocarbons from the ground. The model assumes an average drilling period of 100 days to each well and a total of $950k of day rate and service for the rigs. In addition to the aforementioned, subsea equipment, such as Christmas trees, manifolds, umbilical, flow lines, risers and its installation are required to connect the drilled well to the platform. The model's assumption cost sums to roughly $191m per well, which corresponds to the drilling and the subsea equipment. The cost, on the contrary, to abandon a well is estimated to be around $10m per well. The wells are abandoned in the model by the end of the exploration and production time frame, or when the lifting cost of the way becomes greater than its revenue. It is also considered the drilling cost of exploratory wells. During the exploratory phase of Lula were drilling 26 exploratory wells, an estimated cost of $4,966m. The Lula field has incurred in a total of $30,232m in drilling expenses, taking in new exploratory, production and injection wells, as well as abandoning them.

Drilling Expenses	# of Wells	$m
Exploratory Wells	26	4,966
Production Wells	84	16,044
Injection Wells	42	8,022
Total	**152**	**29,032**
Abandonment Cost		1,200
Total Cost		**30,232**

Figure 25. *Drilling expenses*

Finally, the vast production of natural gas of Lula field has to have a special treatment according to Brazilian environmental laws. The gas production cannot be burned or released back to the environment, unless it is injected in the reservoirs. The model assumes the sale of its gas production, thus Petrobras has to transport it to the shore. There are three gas pipelines planned to transport the production of the pre-salt area, Rota 1, Rota 2 and Rota 3. Rota 1 connects Lula field to Caraguatatuba gas processing plant, has a total extension of 435km and a capacity of 20Mm³ per day. This pipeline is the main route to transport the gas production of Lula field. The pipeline system can be broken down in smaller divisions: Lula-Mexilhão pipeline (216km, 18’’, FPSO Angra dos Reis to PMXL-001), Sapinhoá-Lula (52km, 18’’, FPSO Cid. São Paulo to FPSO Angra dos Reis), Lula NE-Lula (22km,18’’, FPSO Paraty to FPSO Angra dos Reis), Lula NE-Cernambi (19km, 18’’, connects Rota 1 to Rota 2). Rota 2, on the other hand, connects Lula field, along with other fields, to Cabiúnas gas processing plant. It has 380km of extension and 16 Mm³ per day of capacity. Finally, Rota 3 connects Lula Norte to Comperj gas processing plant. It has 356km of extension and 20Mm³ per day of capacity.

Pipelines	Km	Pol	$m
Sapinhoá-Lula (Rota 1)	51	18"	288
Lula-Lula NE (Rota 1)	22	18"	124
Lula-PMXL (Rota 1)	216	18"	1,219
Lula NE- Cernambi (Rota 2)	19	18"	107
Total	**308**	**18"**	**1,738**
Rota 1 System	**435**	**18" and 24"**	**2,455**

Figure 26. *Pipelines segments*

The model’s base case scenario only takes in consideration the Rota 1 pipeline capital expenses, since most of the transported gas is produced in Lula field. In addition, Rota 1 and Rota 2 transports the production of many different fields, thus it is hard to measure the capital expenditure that should be allocated to Lula field. Our base scenario estimates a capital expenditure of $1,738 for the Rota 1 pipeline branches aforementioned. A bear case scenario would be to consider the total cost of the Rota 1 pipeline system, roughly $2,455m.

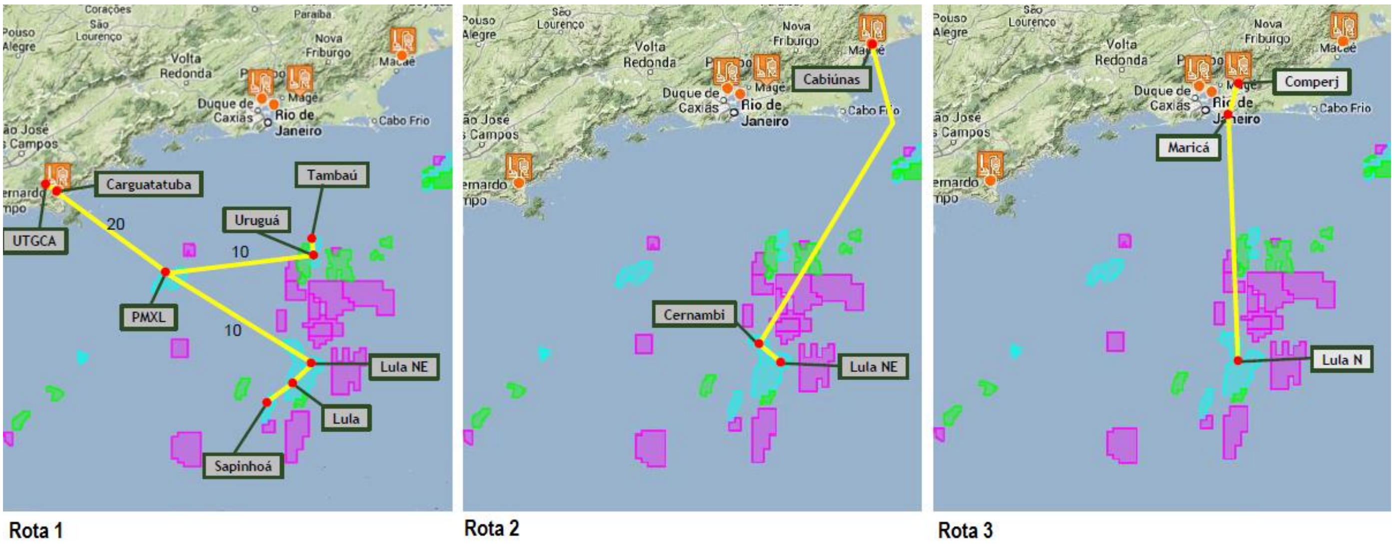

Figure 27. *Rota 1, Rota 2 and Rota 3*

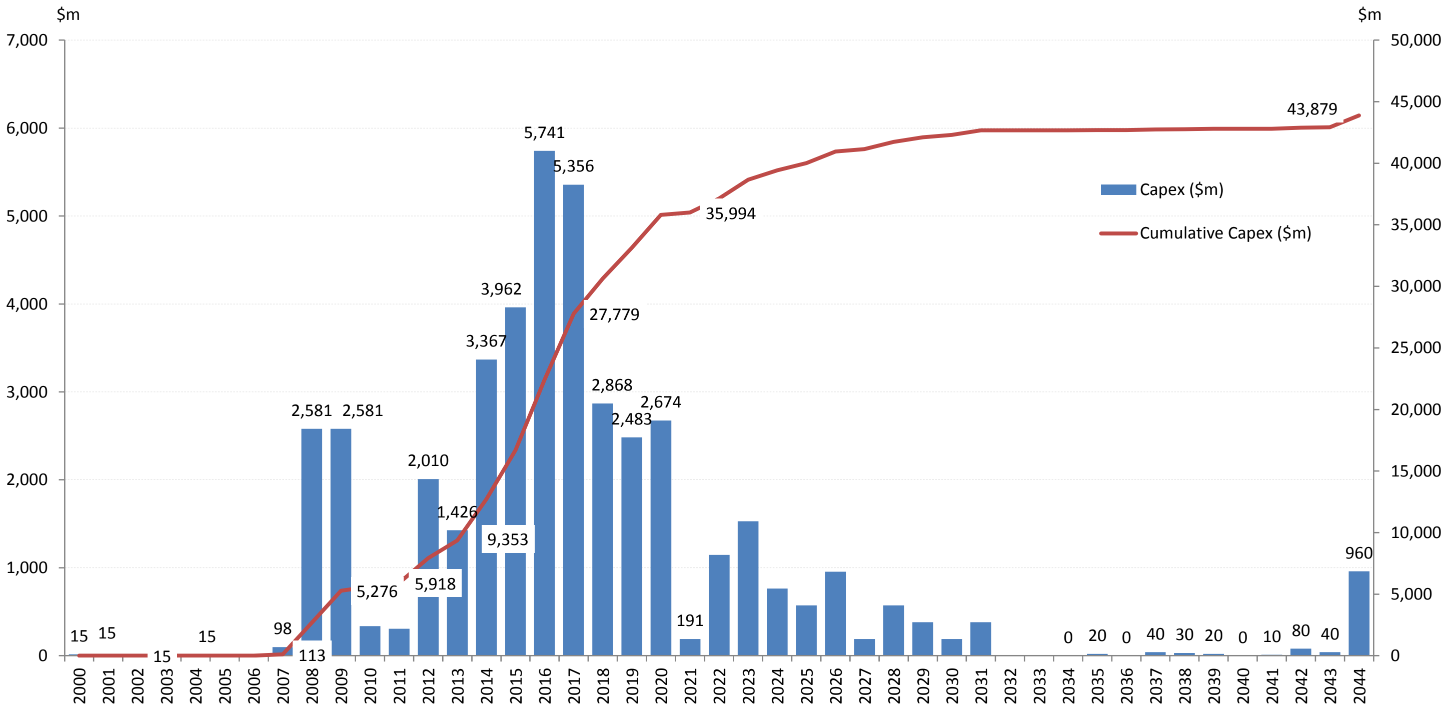

Figure 28. *Capex curve*

3.2.4 Free Cash Flow Calculation

Lula's revenue is its production volumes times the average realization price. The following step is to subtract the production cost off the field revenue. The government royalties incur directly to the fields revenue at a rate of 10%, which is stated in the concession contract of the field. Another expense subtracted is the lifting cost, which is the sum of all expenses to "lift" the hydrocarbons from the reservoirs to the platform, in other words, the operational expenses. The operational expense, in 35 years of production, totals to $72,303m, approximately 8.6 $/boe. Finally, the depreciation of the operational assets is discounted. The Oil and Gas industry has its specific set of accounting rules to treat depreciation. The model utilizes the unit-of-production method, the most common used to deplete upstream oil and gas assets, which depletes the asset base in the same proportion of the annual production in relation to the estimate of reserves within that field. The subtraction of all these expenses of the revenue results in the Oil Profit.

In accordance to the concession contract, the government is entitled to a share of the field's revenue called "Special Participation". The amount of the government take varies in relation to the location of the field, the production volume and the year of production. Lula field is located in ultra-deep water, which falls into the category "Offshore with depth greater than 400m". Given the same volume of production, the government take of this category is smaller compared to others categories, mainly due to the exploration and development difficulties. The government take also varies with the year of development; the three first years have smaller government take. Finally, the base which the government take is calculated is the revenue of the field discounted by the signature bonus and development capital expenditures (discounted through the depreciation in the model), and taxes related to Exploration and Production activities, such as royalties for instance.

Production Years and Volume	**1**	**2**	**3**	**4**	**5 and +**
0% Tax Rate (mm boe)	34	26	19	11	11
10% Tax Rate (mm boe)	45	38	30	23	23
20% Tax Rate (mm boe)	57	49	42	34	34
30% Tax Rate (mm boe)	68	60	53	45	45
35% Tax Rate (mm boe)	79	72	64	57	57
40% Tax Rate (mm boe)	91	83	75	68	68

Figure 29. *Production years and volume*

The amount left after the government take is called the pre-tax income, which is the base that the income tax is deducted. Lastly, after the income tax (34%) is deducted, the net income is reached. The next calculation is to find the free cash flow, which it the addition of depreciation and the subtraction of capital expenditure to the net income. The final step of the model is to bring the stream of cash flow generated by production to its Present Value for each year. It is chosen a discount rate of 12.5%, which it is believed to be an acceptable rate of return for this type of asset.

3.3 Sensitivity Tables

IRR						Brent ($/b)
		50	60	70	80	90
Reserves Volume (mboe)	-30%	10.7%	12.8%	14.5%	16.1%	17.5%
	-20%	12.8%	14.9%	16.6%	18.2%	19.5%
	-10%	14.7%	16.8%	18.6%	20.1%	21.5%
	0%	16.5%	18.6%	20.3%	21.9%	23.2%
	10%	18.2%	20.2%	22.0%	23.5%	24.8%
	15%	19.0%	21.0%	22.8%	24.3%	25.6%
	30%	21.3%	23.3%	25.0%	26.5%	27.8%

IRR						Brent ($/b)
		50	60	70	80	90
Reserves (% of Oil)	40%	11.8%	13.8%	15.6%	17.1%	18.5%
	50%	12.8%	14.9%	16.6%	18.2%	19.5%
	60%	13.8%	15.9%	17.6%	19.2%	20.6%
	70%	14.8%	16.9%	18.6%	20.2%	21.5%
	80%	15.8%	17.8%	19.6%	21.1%	22.5%
	90%	16.7%	18.8%	20.5%	22.0%	23.4%
	100%	17.6%	19.7%	21.4%	22.9%	24.3%

Figure 30. *Lula sensitivity table 1*

IRR						Brent ($/b)
		50	60	70	80	90
Depletion per year (%)	4%	18.4%	20.4%	22.2%	23.7%	25.0%
	6%	17.8%	19.9%	21.6%	23.1%	24.5%
	8%	17.2%	19.3%	21.0%	22.5%	23.9%
	10%	16.5%	18.6%	20.3%	21.9%	23.2%
	12%	15.6%	17.7%	19.5%	21.1%	22.5%
	14%	14.7%	16.9%	18.7%	20.3%	21.8%
	16%	13.8%	16.1%	18.0%	19.6%	21.1%

IRR						Brent ($/b)
		50	60	70	80	90
Capex Variation (%)	-30%	21.8%	23.9%	25.6%	27.1%	28.5%
	-20%	19.8%	21.8%	23.6%	25.1%	26.5%
	-10%	18.0%	20.1%	21.8%	23.4%	24.7%
	0%	16.5%	18.6%	20.3%	21.9%	23.2%
	10%	15.2%	17.3%	19.0%	20.5%	21.9%
	15%	14.6%	16.6%	18.4%	19.9%	21.2%
	30%	13.1%	15.0%	16.7%	18.2%	19.6%

Figure 31. *Lula sensitivity table 2*

IRR						Brent ($/b)
		50	60	70	80	90
Opex Variation (%)	-30%	17.6%	19.5%	21.2%	22.7%	24.0%
	-20%	17.2%	19.2%	20.9%	22.4%	23.7%
	-10%	16.9%	18.9%	20.6%	22.1%	23.5%
	0%	16.5%	18.6%	20.3%	21.9%	23.2%
	10%	16.2%	18.3%	20.0%	21.6%	22.9%
	15%	16.0%	18.1%	19.9%	21.4%	22.8%
	30%	15.5%	17.6%	19.4%	21.0%	22.4%

Figure 32. *Lula sensitivity table 3*

PV						Brent ($/b)
		50	60	70	80	90
Reserves Volume (mboe)	-30%	12,436	17,836	23,301	28,786	34,263
	-20%	17,120	23,253	29,455	35,674	41,885
	-10%	21,770	28,636	35,574	42,528	49,473
	0%	26,397	33,997	41,669	49,359	57,037
	10%	31,007	39,340	47,746	56,171	64,583
	15%	33,307	42,007	50,780	59,571	68,351
	30%	40,190	49,991	59,866	69,757	79,637

PV						Brent ($/b)
		50	60	70	80	90
Reserves (% of Oil)	40%	14,832	20,640	26,397	32,220	38,050
	50%	17,233	23,435	29,574	35,791	41,993
	60%	19,641	26,175	32,759	39,364	45,953
	70%	22,052	28,970	35,943	42,921	49,914
	80%	24,461	31,759	39,130	46,500	53,873
	90%	26,864	34,559	42,308	50,067	57,831
	100%	29,234	37,354	45,493	53,650	61,798

Figure 33. *Lula sensitivity table 4*

PV						Brent ($/b)
		50	60	70	80	90
Depletion per year (%)	4%	52,058	52,058	52,058	52,058	52,058
	6%	49,446	49,446	49,446	49,446	49,446
	8%	46,220	46,220	46,220	46,220	46,220
	10%	42,407	42,407	42,407	42,407	42,407
	12%	37,871	37,871	37,871	37,871	37,871
	14%	33,833	33,833	33,833	33,833	33,833
	16%	30,492	30,492	30,492	30,492	30,492

PV						Brent ($/b)
		50	60	70	80	90
Capex Variation (%)	-30%	30,520	38,129	45,801	53,491	61,169
	-20%	29,146	36,752	44,423	52,114	59,792
	-10%	27,771	35,374	43,046	50,737	58,414
	0%	26,397	33,997	41,669	49,359	57,037
	10%	25,023	32,619	40,291	47,982	55,660
	15%	24,335	31,930	39,603	47,293	54,971
	30%	22,274	29,864	37,537	45,227	52,905

Figure 34. *Lula sensitivity table 5*

PV		50	60	70	80	90
						Brent ($/b)
Opex Variation (%)	-30%	28,787	36,469	44,160	51,860	59,558
	-20%	27,960	35,642	43,329	51,018	58,716
	-10%	27,153	34,820	42,498	50,188	57,875
	0%	26,397	33,997	41,669	49,359	57,037
	10%	25,578	33,186	40,852	48,522	56,211
	15%	25,173	32,784	40,444	48,108	55,797
	30%	23,971	31,622	39,219	46,891	54,572

PV		50	60	70	80	90
						Brent ($/b)
Discount Rate (%)	4%	64,673	80,344	96,432	112,702	128,871
	6%	51,531	64,510	77,753	91,103	104,391
	8%	41,526	52,402	63,453	74,565	85,639
	10%	33,785	43,002	52,334	61,703	71,049
	13%	26,397	33,997	41,669	49,359	57,037
	15%	20,825	27,180	33,582	39,993	46,397
	17%	17,316	22,874	28,465	34,062	39,654

Figure 35. *Lula sensitivity table 6*

NPV		50	60	70	80	90
						Brent ($/b)
Reserves Volume (mboe)	-30%	-793	129	1,063	2,001	2,937
	-20%	146	1,194	2,254	3,317	4,378
	-10%	1,076	2,250	3,435	4,624	5,810
	0%	1,998	3,297	4,608	5,922	7,234
	10%	2,911	4,335	5,772	7,212	8,649
	15%	3,367	4,853	6,352	7,855	9,355
	30%	4,725	6,400	8,088	9,778	11,466

NPV		50	60	70	80	90
						Brent ($/b)
Reserves (% of Oil)	40%	-333	659	1,643	2,638	3,634
	50%	151	1,211	2,260	3,322	4,382
	60%	636	1,753	2,878	4,007	5,133
	70%	1,122	2,304	3,496	4,688	5,884
	80%	1,608	2,855	4,115	5,374	6,634
	90%	2,092	3,407	4,732	6,058	7,384
	100%	2,571	3,959	5,350	6,744	8,136

Figure 36. *Lula sensitivity table 7*

NPV		50	60	70	80	90
						Brent ($/b)
Depletion per year (%)	4%	2,908	4,404	5,900	7,396	8,892
	6%	2,629	4,072	5,514	6,957	8,400
	8%	2,332	3,711	5,091	6,474	7,859
	10%	1,998	3,297	4,608	5,922	7,234
	12%	1,411	2,626	3,846	5,060	6,282
	14%	949	2,054	3,180	4,313	5,455
	16%	536	1,583	2,627	3,693	4,752

NPV		50	60	70	80	90
						Brent ($/b)
Capex Variation (%)	-30%	3,656	4,956	6,267	7,581	8,893
	-20%	3,103	4,403	5,714	7,028	8,340
	-10%	2,550	3,850	5,161	6,475	7,787
	0%	1,998	3,297	4,608	5,922	7,234
	10%	1,445	2,743	4,054	5,369	6,681
	15%	1,169	2,467	3,778	5,092	6,404
	30%	340	1,637	2,948	4,262	5,575

Figure 37. *Lula sensitivity table 8*

NPV		50	60	70	80	90
						Brent ($/b)
Opex Variation (%)	-30%	2,528	3,841	5,155	6,471	7,787
	-20%	2,346	3,659	4,973	6,287	7,602
	-10%	2,168	3,478	4,790	6,104	7,418
	0%	1,998	3,297	4,608	5,922	7,234
	10%	1,817	3,117	4,427	5,738	7,052
	15%	1,728	3,028	4,337	5,647	6,961
	30%	1,461	2,769	4,067	5,378	6,691

NPV		50	60	70	80	90
						Brent ($/b)
Discount Rate (%)	4%	30,659	39,361	48,294	57,328	66,306
	6%	17,121	22,536	28,062	33,633	39,177
	8%	9,417	12,846	16,329	19,832	23,323
	10%	4,993	7,199	9,434	11,676	13,914
	13%	1,998	3,297	4,608	5,922	7,234
	15%	505	1,286	2,073	2,861	3,648
	17%	-112	415	945	1,476	2,007

Figure 38. *Lula sensitivity table 9*

4. Libra Field Valuation Model

4.1 Field Description

Libra field was discovered in 2010. It is one of the largest offshore oil accumulations in the world, with estimated reserves from 8 to 15bn boe according to ANP. It lies on BM-S-11 block, in the Santos Basin, approximately 230km of the coast of Rio de Janeiro, nearby Búzios field. It is situated 2,000m below the water and roughly 5,000 below sand, rock and a salt layer. Libra's oil is considered intermediate or medium quality (28º API). It was auctioned in the first bidding round of the Production Sharing Contract (PSC) format, in 2013, and its signature bonus was around 7 billion dollars. Petrobras, the operator (40%), leads the consortium with Shell (20%), Total (20%), CNOOC (10%) and CNPC (10%). In this PSC, the consortium bid the minimum 41% government share of profit oil, 50% of cost of recovery and a 15% royalty rate. At first, the PSC results in a higher government take than other concessions. The PSC structure, however, determines the government take based on productivity per well and Brent prices, which decreases the share of production given to the government in light of challenging circumstances for the industry, such as nowadays.

4.2 Libra Field Model

4.2.1 Inputs

Libra model assumes a total amount of 8,000 mmboe, in line with ANP's independent consultant Gaffney, Cline & Associates[4] estimates, and 15,000 mmboe as a bull case scenario. As to the reserves breakdown, the model determines 88% of the reserves are made of oil, and 12% of gas, in line with Citigroup[5] estimates. It is a consensus through independent analysts that Libra field presents unique characteristics in relation to oil and gas reservoirs around the world. It proven reserves are among the largest of the world, especially accounting its great upside risk potential. The model uses a standard depletion rate of 10%, same as Lula field, given the reservoir characteristic similarities. Libra's oil quality (28º API) is very similar to Lula's oil type; therefore, we assume the same discounts to Brent (5% to oil and 50% to gas). The average long-term realization price of Libra's production is $62.6/boe, due to the compositions of its reserves. The discount rate used in the model is 12.5%.

The next section of inputs is intrinsic to the PSC of Libra's field. The first input is Capex Recovery per Year, it refers to how much of the capital expenditure can be

[4] Gaffney, Cline & Associates. 2010. *Review and Evaluation of Ten Selected Discoveries and Prospects in the Pre-Salt Play of Deepwater Santos Basin*
[5] Citigroup. 2015. *Global Oil Vision 2015 – Project Book*

used to calculate the annual Oil Cost, Libra field assumes 100%. The Oil Cost Cap is how much of the Oil Cost can be returned to the oil companies by the end of the year. Libra's contract states that the Oil Cost Cap is 50% for the first and second years of production, and 30% thereafter. The government's take and royalty rate were bided by the consortium in Libra's bidding round. The winning consortium proposed 41.65% of government take and 15% of royalty, the minimum rates allowed. Finally the model assumes 34% of income rate, in line with Gaffney, Cline & Associates[6] assumptions.

4.2.2 Production

Libra's PSC has a timeframe of 35 years and it is divided in two phases: The exploration phase and the production phase. The exploration phase will take 4 years, thus it will be finished in 2017. During this phase, the consortium is required to acquire 5km of 2D or 1km² of 3D seismic, two exploratory wells, an Extended Well Test, and finally the declaration of commerciality. The production phase englobes the remainder of the contract timeframe. Petrobras has already leased the FPSO responsible for Libra's EWT, which should start by the beginning of 2017. The model does not take in consideration neither the production nor the expenses of the ETW.

The development of Libra field is responsibility of Petrobras, the field's operator. The company, however, has not announced the number of FPSOs allocated to Libra field. Libra's project, in fact, has been postponed to the end of the decade due to the delicate financial situation of the company and the focus on assets able to provide cash flow to the company in the short term. The fist FPSO dedicated to Libra is called FPSO Libra, it has a capacity of 150 kbd and it start-up is expected to be in 2020. ANP estimates that a total of 12 to 18 FPSOs are required to develop Libra reserves during the contract life time. The model estimates a total of 11 FPSOs, including FPSO Libra, all with 150 kpd of capacity and all owned by the consortium, except FPSO Libra that has been leased by the consortium. The 11 FPSOs are the amount of units required in order to produce the estimated reserves in the contract timeframe.

FPSO	Total Production (mmboe)	Years of Production	Production Start-up (Year)
Libra Pilot	1,533	28	2020
Unit 1	1,478	27	2021
Unit 2	1,424	26	2022
Unit 3	1,424	26	2022
Unit 4	1,369	25	2023
Unit 5	1,369	25	2023
Unit 6	1,314	24	2024
Unit 7	1,314	24	2024
Unit 8	1,259	23	2025
Unit 9	1,259	23	2025
Unit 10	1,205	22	2025

Figure 39. *Libra's FPSO profile*

[6] Gaffney, Cline & Associates. 2010. *Review and Evaluation of Ten Selected Discoveries and Prospects in the Pre-Salt Play of Deepwater Santos Basin*

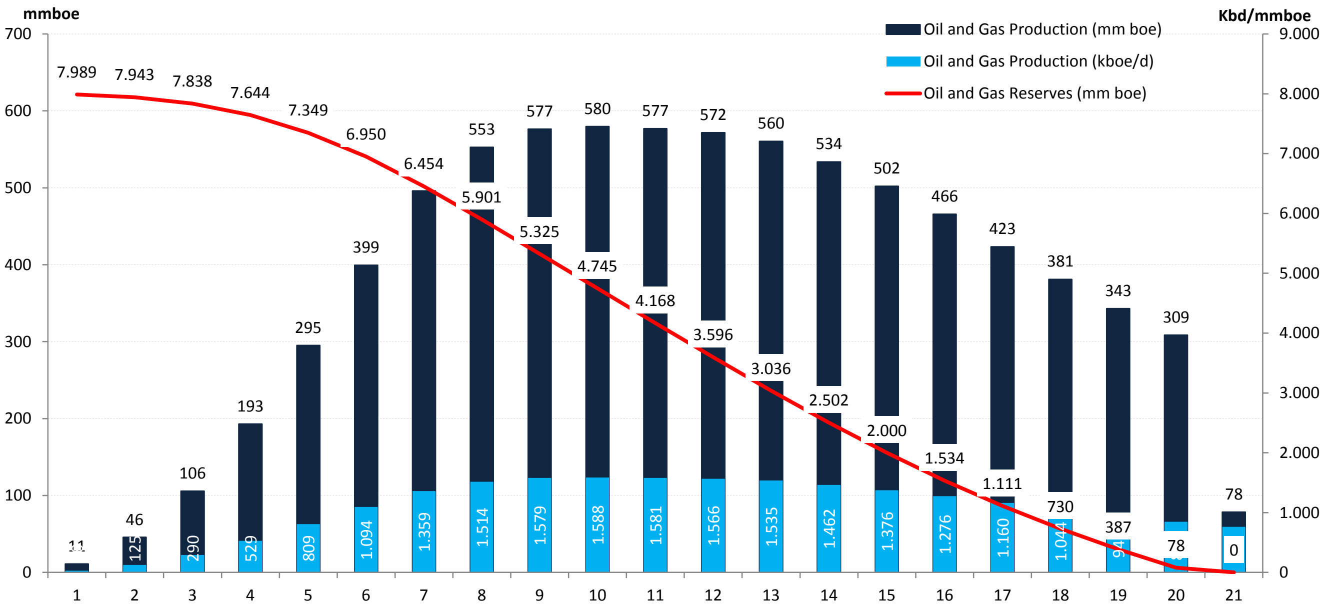

Figure 40. *Libra's production curve*

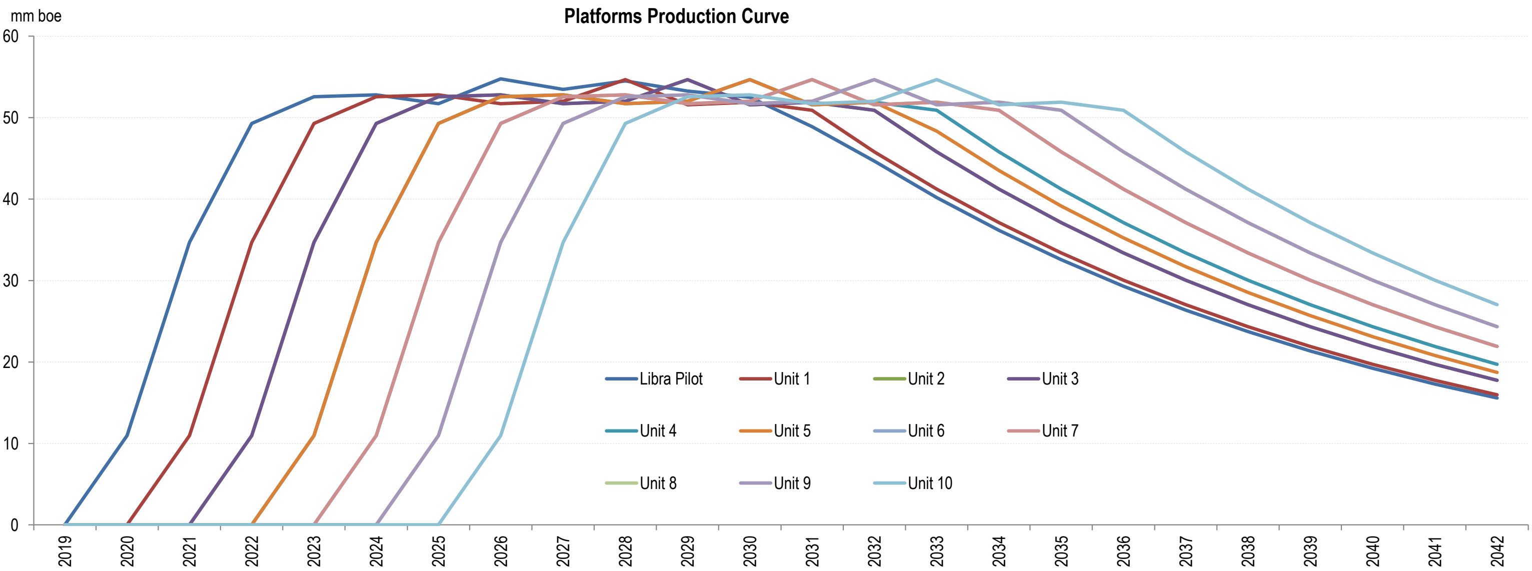

Figure 41. *Libra's FPSOs production curve*

Altogether, these eleven FPSO's at their full capacity are able to produce roughly1,650k per day. The model assumes that FPSO Libra will commence operations in 2020. Unit 1 starts up operations on the following year, and thereafter, two platforms start production each year. Each platform connects 9 production wells, the necessary number to reach the platform's full capacity. The well schedule starts with two wells in the first year of operations, three new production wells are added in the following year, on the firth year onwards, one well is built every other year. According to the well schedule, the platform takes roughly three years to reach full capacity and more approximately 7 years in the output plateau, before the production starts declining annually. Each well commences production at 15 kbd flow rate, elevating this rate to 25 kdp and 30 kdp, in the second and third year respectively. The wells start declining production on the fourth year onwards. The model assumes that for each two production wells, there is one injection well is drilled.

Libra's production curve reaches its peak on 2029 with an annual production of 580 mmboe, an average of 1,588 kbd. The production of the 8,000 mmboe takes 21 years to be completed, starting on 2020 and finishing 2040. The total number of wells required is 135, taking aside exploratory wells, being 90 production wells and 45 injection wells.

4.2.3 Capital Expenditures & Operational Expenditures

In order to produce its vast oil and gas reserves, Libra field requires a great investment program. The first significant capital expenditure was the upfront signature bonus of $7,000m attached to its PSC. This signature bonus, in contrast to Lula's, reflects the certainty of the great potential of the asset. Libra does not represent an exploration new frontier, full of technology challenges, as Lula did on date of its bidding round. The deep water production process was tested and approved previously in the development of other fields, as well as the techniques of data acquiring and reservoir modelling. The oil companies, therefore, knew Libra's potential reserves with a good degree of certainty before its bid, and also had the know-how to explore it.

Furthermore, our assumption that all production platforms, but Libra Pilot, are owned by the consortium generates a significant capital expenditure. Libra's platforms' cost assumptions are the same as in Lula's model, since we assume that similar type of FPSO will produce in Libra. The operational expenses, on the other hand, differ significantly in Libra's project. We incorporate a great increase in the platforms' day rate and operational services, in line with industry news[7]. This is a result of the restriction to the companies allowed to participate in the leasing bidding rounds due to the Car Wash investigation, therefore increasing substantially the prices. We estimate $1,000k per day for as day rate and $200k per day as operational services. Furthermore, we keep our previous assumption regarding day rate and operational services of PSVs and Shuttle tankers, $40k per day in total.

Development Expenses	Capex	Comments
Engeneering	$63m	FEED, others
FPSO	$1750m	150kboed FPSO with topside and anchoring
Drilling	$650k + $500k	rig daily rate + for services
		100 days for drilling
Subsea equip	$6m	Christmas tree (more expensive given Water depth)
	$6m	Manifold (more expensive given Water depth)
	$2m	Umbilicals
	$6m	Control and others
Subsea (inst. and lines)	$80m per well	Includes flowlines, risers, umbilicals and installation
Contingencies		10% of the project's total

Figure 42. *Libra's development expenses*

[7] http://brasilenergiaog.editorabrasilenergia.com/daily/bog-online/ep/2015/08/petrobras-volta-afretar-fpsos-465025.html

Libra's drilling cost, as well, has changed drastically. Libra's model incorporates higher rig day rates, a change from $450k per day to $650k per day, in line with Petrobras latest signed contracts. This change increases the drilling cost to $210m per well, from $190m previously. The model maintains its average drilling days and well abandonment cost, however, 100 day and $10m respectively. We estimate a total of 137 wells: 2 exploratory wells, 90 production wells and 45 injection wells. The aggregate capital expenditure with drilling and abandonment is $30,257m; $422m in exploratory wells, $28,485m in well drilling and $1,350m in well abandonment.

Drilling Expenses	# of Wells	$m
Exploratory Wells	2	422
Production Wells	90	18,990
Injection Wells	45	9,495
Total	**137**	**28,907**
Abandonment Cost		1,350
Total Cost		**30,257**

Figure 43. *Libra's drilling expenses*

FPSO	Capacity (kbd)	Lease/ Owned	Total Capex* ($m)	Capex/boe	Opex/boe
Libra Pilot	150	Lease	6,190	4.0	8.0
Unit 1	150	Owned	6,190	4.2	8.0
Unit 2	150	Owned	6,190	4.3	8.0
Unit 3	150	Owned	6,190	4.3	8.0
Unit 4	150	Owned	6,190	4.5	8.0
Unit 5	150	Owned	6,190	4.5	8.0
Unit 6	150	Owned	6,190	4.7	8.0
Unit 7	150	Owned	6,190	4.7	8.0
Unit 8	150	Owned	6,190	4.9	8.0
Unit 9	150	Owned	6,190	4.9	8.0
Unit 10	150	Owned	6,190	5.1	8.0

*In case the platform was bought by Petrobras

Figure 44. *Libra's FPSOs cost profile*

Finally, Libra's reservoir hold a great amount of natural gas. Libra's model assumes the sale of this gas, and therefore, it requires transportation to the shore. Rota 3 has 354km of extension, a capacity of 18Mm³ per day, and connects the production of Lula Norte, Iara, Iara surroundings, Búzios, Libra and others, to Comperj in Rio de Janeiro. Given the longevity of Libra's FPSOs delivery dates, there is no formal pipeline plans designed yet. The model estimates the capital expense to connect each Libra's FPSO to Rota 3 pipeline based on Lula's pipeline expenses. The estimation is reasonable given the diameter of the pipes, its depth and extension. The model assumes an average pipeline of 50km to each FPSO, with an average cost of $250m.

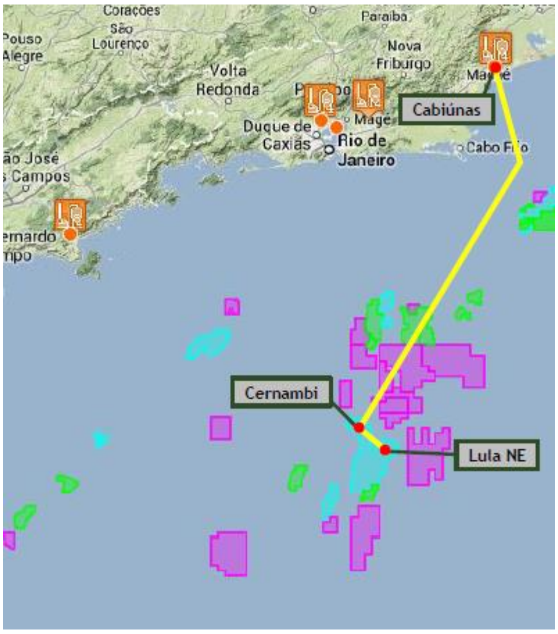

Figure 45. *Rota2 pipeline*

The total capital expenditure of Libra's field is $64,313m or 8.0 $/boe. The amount invested in Libra's field either in absolute number or in relative number are very large due to the industry's difficulties aforementioned. These expenses, however, can be diluted if the proven reserves of the field increase, as the field's upside risk suggests. This is due to the fact that most of this amount is fixed cost, thus an increase in reserves and production presents great opportunity of economics of scale. The operational cost, on the other hand, sums up to $126,465m or 15.8 $/boe.

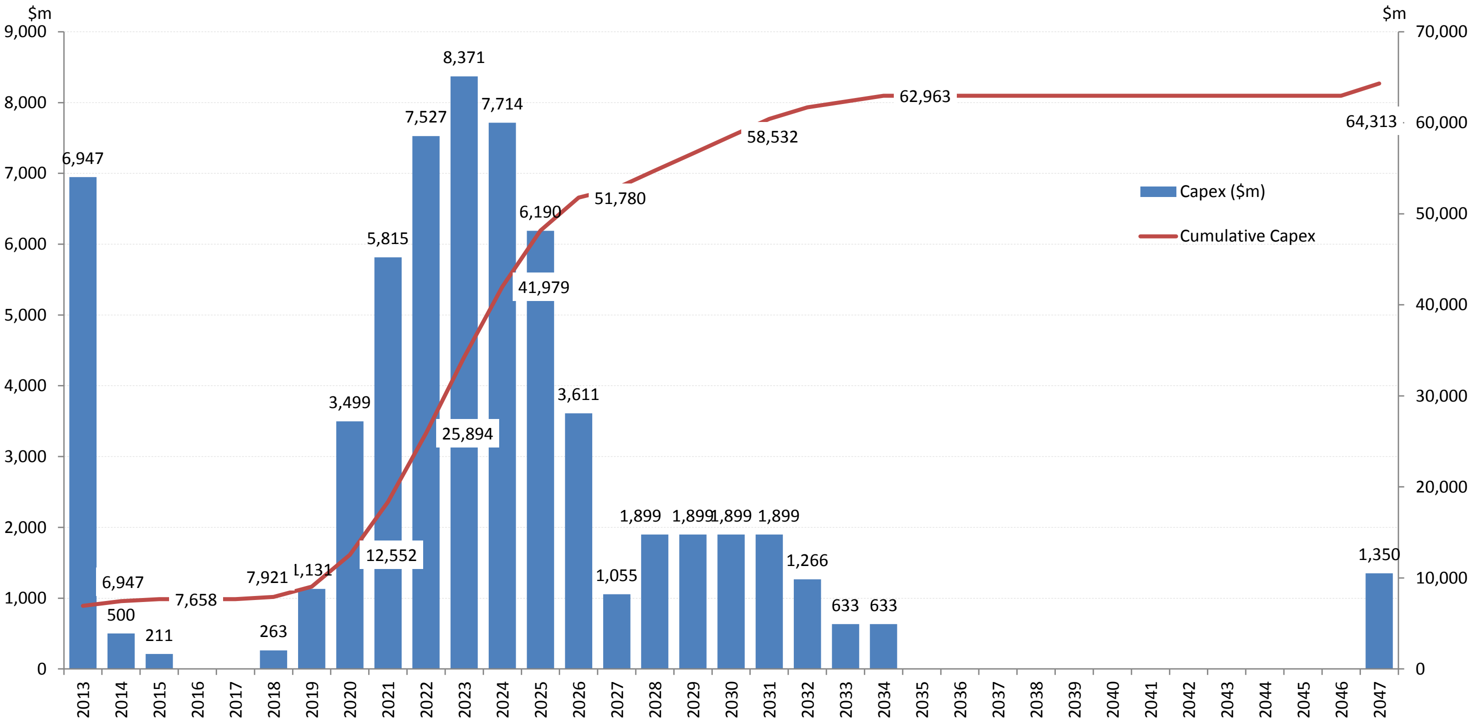

Figure 46. *Libra'sCapex curve*

Capex Breakdown	$m
FPSO	18,130
Drilling	30,257
Pipelines	2,750
Contingencies	5,940
Signature Bonus	7,000
Others	236
Total	**64,313**

Opex Breakdown	$m
FPSO	110,522
PSV + Shuttle Tanker	15,943
Total	**126,465**

Figure 47. *Libra'sCapex breakdown*

4.2.4 Free Cash Flow Calculation in PSC

Libra field, given its PSC, has a specific calculation of Free Cash Flow. The government take in the PSC contract is calculated based on the companies' Oil Profit. The Oil Profit is the profit after the royalties (15% of field revenue), R&D provision (1% of field revenue), and Recovered Oil Cost (ROC) are subtracted from the field's revenue (average realization price times production). The government take, on the other hand, is a function of two variables: the productivity per well, the average daily production per number of active production wells, and the Brent price. Given a combination of these two variables, a premium or a discount is given on the bided government take percentage of 41.65% according to the followingtable.

Brent oil prices (US$/bbl)												Average productivity per well (kb/d)
Less than	0.0	4.0	6.0	8.0	10.0	12.0	14.0	16.0	18.0	20.0	22.0	24.0
60	-31.72%	-15.85%	-9.62%	-6.33%	-4.26%	-2.56%	-1.48%	-0.86%	-0.29%	0.23%	0.69%	1.11%
80	-26.45%	-12.85%	-7.51%	-4.70%	-2.92%	-1.46%	-0.54%	**0.00%**	0.48%	0.92%	1.32%	1.68%
100	-19.44%	-8.86%	-4.71%	-2.52%	-1.14%	**0.00%**	0.71%	1.13%	1.51%	1.85%	2.16%	2.44%
120	-14.98%	-6.32%	-2.92%	-1.13%	**0.00%**	0.93%	1.51%	1.86%	2.17%	2.45%	2.70%	2.93%
140	-11.89%	-4.56%	-1.69%	-0.17%	0.79%	1.57%	1.86%	2.36%	2.62%	2.86%	3.07%	3.26%
160	-9.62%	-3.27%	-0.78%	0.53%	1.36%	2.04%	2.36%	2.72%	2.95%	3.16%	3.34%	3.51%
800	-5.94%	-1.18%	-0.69%	1.68%	2.30%	2.81%	2.72%	3.32%	3.49%	3.65%	3.73%	3.91%

Figure 48. *Libra's government take*

The calculation of the Recovered Oil Cost is also very peculiar to the PSC. In addition to being subtracted from the field revenue in order to calculate the Oil profit, it is the amount that the oil companies will receive back from the government. The ROC is the minimum between the Cost Oil Cap (gross) and the Net Cumulative Oil Cost plus the Annual Oil Cost (the sum of Lifting cost, R&D provision and Capex of the year). The Cost Oil Cap (Gross) is the Cost Oil Cap (50% for the first and second year of production, and 30% thereafter) times the result of field revenue minus royalties. The Net cumulative Oil, on the other hand, is the Cumulative Oil Cost plus the Cumulative ROC and the Annual Cost Oil of the present year.

Sequentially, the Oil Company Profit is the Oil profit subtracted the Government take and the Lifting cost, whereas the Net Income is the Oil profit subtracted the Income

Tax (34% rate). Finally, the Free Cash Flow is the Net Income added back the ROC sub and subtracted the Capex.

4.3 Sensitivity Tables

IRR						Brent ($/b)
		50	60	70	80	90
Reserves Volume (mboe)	-30%	n.m.	n.m.	4.9%	8.9%	11.2%
	-20%	n.m.	4.1%	8.7%	11.7%	13.7%
	-10%	n.m.	7.8%	11.2%	13.8%	15.8%
	0%	5.3%	10.2%	13.2%	15.7%	17.4%
	10%	8.1%	12.2%	14.9%	17.2%	18.8%
	15%	9.2%	13.0%	15.7%	17.8%	19.4%
	30%	11.8%	15.2%	17.6%	19.6%	21.1%

IRR						Brent ($/b)
		50	60	70	80	90
Reserves (% of Oil)	40%	n.m.	n.m.	7.1%	10.4%	12.6%
	50%	n.m.	4.1%	8.7%	11.7%	13.8%
	60%	n.m.	6.3%	10.2%	12.9%	14.9%
	70%	n.m.	8.0%	11.4%	14.0%	15.9%
	80%	3.6%	9.3%	12.4%	14.9%	16.8%
	90%	5.7%	10.4%	13.4%	15.8%	17.6%
	100%	7.2%	11.5%	14.3%	16.7%	18.3%

Figure 49. *Libra's sensitivity table 1*

IRR						Brent ($/b)
		50	60	70	80	90
Depletion per year (%)	4%	5.6%	11.2%	14.3%	16.6%	18.2%
	6%	5.4%	10.9%	14.0%	16.3%	18.0%
	8%	5.3%	10.6%	13.6%	16.1%	17.7%
	10%	5.3%	10.2%	13.2%	15.7%	17.4%
	12%	5.6%	9.9%	12.8%	15.2%	17.1%
	14%	4.3%	8.9%	12.0%	14.5%	16.4%
	16%	2.5%	7.6%	10.9%	13.6%	15.6%

IRR						Brent ($/b)
		50	60	70	80	90
Capex Variation (%)	-30%	9.4%	13.2%	15.8%	17.9%	19.4%
	-20%	8.1%	12.2%	15.0%	17.2%	18.7%
	-10%	6.8%	11.2%	14.1%	16.4%	18.1%
	0%	5.3%	10.2%	13.2%	15.7%	17.4%
	10%	3.7%	9.2%	12.4%	14.9%	16.8%
	15%	-2.9%	8.7%	11.9%	14.5%	16.4%
	30%	n.m.	7.1%	10.6%	13.3%	15.4%

Figure 50. *Libra's sensitivity table 2*

IRR						Brent ($/b)
		50	60	70	80	90
Opex Variation (%)	-30%	8.7%	12.1%	14.7%	16.6%	18.1%
	-20%	7.8%	11.5%	14.2%	16.3%	17.9%
	-10%	6.7%	10.9%	13.7%	16.0%	17.7%
	0%	5.3%	10.2%	13.2%	15.7%	17.4%
	10%	3.1%	9.5%	12.7%	15.2%	17.2%
	15%	n.m.	9.0%	12.4%	15.0%	17.0%
	30%	n.m.	7.5%	11.5%	14.4%	16.4%

Figure 51. *Libra's sensitivity table 3*

PV						Brent ($/b)
		50	60	70	80	90
Reserves Volume (mboe)	-30%	-11,263	-5,030	643	6,557	11,867
	-20%	-7,037	-168	6,250	12,961	19,073
	-10%	-2,937	4,652	11,864	19,375	26,274
	0%	1,111	9,462	17,476	25,773	32,791
	10%	5,149	14,306	23,111	31,823	38,506
	15%	7,198	16,765	25,965	34,488	41,314
	30%	13,323	24,102	33,660	42,106	49,466

PV						Brent ($/b)
		50	60	70	80	90
Reserves (% of Oil)	40%	-9,088	-2,654	3,447	9,756	15,609
	50%	-6,882	-112	6,368	13,095	19,336
	60%	-4,827	2,408	9,292	16,436	23,056
	70%	-2,701	4,927	12,214	19,773	26,776
	80%	-584	7,446	15,137	23,107	30,320
	90%	1,521	9,967	18,060	26,440	33,395
	100%	3,620	12,486	20,977	29,773	36,381

Figure 52. *Libra's sensitivity table 4*

PV						Brent ($/b)
		50	60	70	80	90
Depletion per year (%)	4%	10,375	29,761	48,480	64,505	77,270
	6%	7,362	21,974	36,049	49,232	59,227
	8%	4,068	15,130	25,758	36,701	44,716
	10%	1,111	9,462	17,476	25,773	32,791
	12%	-1,252	5,089	11,127	17,414	23,199
	14%	-3,584	1,224	5,820	10,577	14,925
	16%	-4,857	-1,215	2,270	5,890	9,192

PV						Brent ($/b)
		50	60	70	80	90
Capex Variation (%)	-30%	7,920	16,273	24,287	32,001	37,909
	-20%	5,650	14,003	22,016	30,176	36,263
	-10%	3,381	11,733	19,746	28,044	34,558
	0%	1,111	9,462	17,476	25,773	32,791
	10%	-1,158	7,192	15,205	23,503	30,953
	15%	-2,293	6,057	14,070	22,368	30,004
	30%	-5,697	2,652	10,665	18,962	26,661

Figure 53. *Libra's sensitivity table 5*

PV					Brent ($/b)
		50	60	70	80	90
Opex Variation (%)	-30%	6,079	14,425	22,422	29,362	35,248
	-20%	4,419	12,776	20,774	28,453	34,485
	-10%	2,761	11,123	19,125	27,421	33,671
	0%	1,111	9,462	17,476	25,773	32,791
	10%	-584	7,803	15,814	24,125	31,799
	15%	-1,432	6,973	14,984	23,298	31,000
	30%	-3,992	4,451	12,494	20,807	28,520

PV						Brent ($/b)
		50	60	70	80	90
Discount Rate (%)	4%	11,072	29,901	47,969	66,748	81,762
	6%	6,934	21,122	34,733	48,861	60,396
	8%	3,616	14,439	24,821	35,584	44,538
	10%	1,111	9,462	17,476	25,773	32,791
	13%	-1,060	5,073	10,960	17,048	22,288
	15%	-2,422	2,154	6,548	11,087	15,053
	17%	-3,091	567	4,082	7,709	10,911

Figure 54. *Libra's sensitivity table 6*

NPV						Brent ($/b)
		50	60	70	80	90
Reserves Volume (mboe)	-30%	-15,421	-11,800	-8,505	-5,076	-1,989
	-20%	-12,961	-8,974	-5,247	-1,356	2,195
	-10%	-10,580	-6,176	-1,989	2,366	6,373
	0%	-8,229	-3,383	1,268	6,078	10,219
	10%	-5,884	-570	4,539	9,629	13,643
	15%	-4,693	858	6,197	11,227	15,321
	30%	-1,135	5,120	10,743	15,785	20,180

NPV						Brent ($/b)
		50	60	70	80	90
Reserves (% of Oil)	40%	-14,174	-10,414	-6,868	-3,209	192
	50%	-12,893	-8,939	-5,174	-1,272	2,354
	60%	-11,680	-7,475	-3,478	665	4,511
	70%	-10,442	-6,014	-1,783	2,600	6,667
	80%	-9,213	-4,553	-88	4,533	8,741
	90%	-7,989	-3,091	1,607	6,465	10,581
	100%	-6,771	-1,630	3,298	8,397	12,366

Figure 55. *Libra's sensitivity table 7*

NPV						Brent ($/b)
		50	60	70	80	90
Depletion per year (%)	4%	-7,023	-1,850	3,145	7,733	11,560
	6%	-7,401	-2,327	2,564	7,292	11,104
	8%	-7,803	-2,830	1,953	6,874	10,719
	10%	-8,229	-3,383	1,268	6,078	10,219
	12%	-8,666	-3,951	540	5,214	9,518
	14%	-9,733	-5,198	-865	3,626	7,716
	16%	-10,730	-6,469	-2,390	1,869	5,712

NPV						Brent ($/b)
		50	60	70	80	90
Capex Variation (%)	-30%	-3,792	1,055	5,707	10,235	13,779
	-20%	-5,271	-424	4,227	8,974	12,631
	-10%	-6,750	-1,904	2,748	7,558	11,445
	0%	-8,229	-3,383	1,268	6,078	10,219
	10%	-9,708	-4,863	-211	4,599	8,952
	15%	-10,448	-5,602	-951	3,859	8,300
	30%	-12,666	-7,822	-3,170	1,640	6,111

Figure 56. *Libra's sensitivity table 8*

NPV						Brent ($/b)
		50	60	70	80	90
Opex Variation (%)	-30%	-5,456	-618	4,022	8,165	11,695
	-20%	-6,381	-1,536	3,104	7,617	11,239
	-10%	-7,306	-2,457	2,187	6,996	10,751
	0%	-8,229	-3,383	1,268	6,078	10,219
	10%	-9,178	-4,309	341	5,161	9,621
	15%	-9,657	-4,772	-121	4,700	9,173
	30%	-11,117	-6,184	-1,511	3,311	7,792

NPV						Brent ($/b)
		50	60	70	80	90
Discount Rate (%)	4%	2,809	20,218	36,922	54,285	68,166
	6%	-1,247	11,380	23,494	36,068	46,334
	8%	-4,310	4,969	13,870	23,098	30,774
	10%	-6,483	419	7,041	13,899	19,698
	13%	-8,229	-3,383	1,268	6,078	10,219
	15%	-9,213	-5,753	-2,430	1,002	4,001
	17%	-9,632	-6,960	-4,392	-1,743	596

Figure 57. *Libra's sensitivity table 9*

NPV						Brent ($/b)
		50	60	70	80	90
Government Take (%)	42%	-8,229	-3,383	1,268	6,078	10,219
	50%	-9,901	-5,326	-998	3,500	7,293
	55%	-10,948	-6,507	-2,355	1,950	5,536
	60%	-12,074	-7,727	-3,725	399	3,773
	65%	-13,291	-9,033	-5,144	-1,165	2,011
	70%	-14,726	-10,453	-6,677	-2,795	213
	75%	-16,182	-12,145	-8,399	-4,592	-1,711

Figure 58. *Libra's sensitivity table 10*

5. Búzios Field Valuation Model

5.1 Field Description

Búzios, previously known as Franco, is part of a broader area called Transfer of Rights (ToR). Transfer of Rights is an area of pre-salt that comprises other fields, such as Florim, Northeast of Tupi, South of Tupi, South of Guará and Iara surroundings. The exploration and production rights of the area, up to 5,000 mm boe, were value at roughly $42,000m and awarded to Petrobras as a payment for PBR stocks by the Government, in its follow-on of 2010. Búzios field is located in water depth of approximately 2,000m, about 200km south of Rio de Janeiro. It was discovered in 2010, and its recoverable reserves are estimated to have from 6,500 mmboe to 10,000 mmboe, according to Petrobras[8]. The Transfer of Rights contract, however, limits the exploration and production rights to 3,058 mmboe. Búzios' oil is considered intermediate or medium quality (28º API). Petrobras operates and detains the monopoly of exploration and production of the field. ToR contract stipulates 10% Royalty rate, 34% of corporate taxes, as well as a Minimum Work Program (MWP), but it excludes Signature Bonus, Special Participation Tax and Research Contribution. A second contract, Surplus of Transfer of Rights, is being sought between the government and Petrobras, in order to cover the remainder of the recoverable reserves. This contract should be in line with PSC, nevertheless, it will not be taken in consideration in the project due to the lack of concrete information.

5.2 Búzios Field Model

5.2.1 Inputs

Búzios model assumes 3,058 mmboe as recoverable reserves, the number stipulated in the ToR contract, and no bull case scenario applies in this model. We assume an oil percentage of 88% relative to its reserves, as well as the 10% depletion rate, due to the field's similarities and proximity to Libra and Lula field. Libra's oil and gas discount rate in relation to Brent is also assumed in Búzios model, 5% for oil and 50% for gas, given the same oil quality (28º API). The average long-term realization price of Búzios' production is $62.6/boe, due to the compositions of its reserves. The discount rate used in the model is 12.5%. Due to the simplicity of ToR contract the two remainder inputs are the royalty rate (15%) and corporate income tax (34%).

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[8] Petrobras. 2014. *Surplus Transfer of Rights (presentation)*

5.2.2 Production

Búzios' ToR contract is valid for 40 years with the extension possibility of 5 more years. The exploration phase started in 2010 and takes up to four years and requires 3D seismc, 2 exploratory wells and an EWT. The model does not take in consideration the EWT. The remainder of the timeframe is considered production phase.

Petrobras has a defined plan of development for Búzios field. In its latest strategic plan, the company dedicates 5 FPSOs (all owned by the company) to produce in the field, two of them (Búzios 1 and Búzios 3) starting in 2017 and three in 2019 (Búzios 2, Búzios 4 and Búzios 5). The strategy to own the FPSOs reflects the company's perspective to re-utilize the platforms and production facilities to produce under the Surplus Transfer of Rights contract, otherwise, the choice to lease the necessary platforms would make more economic sense due to the lack of upfront capital investment.

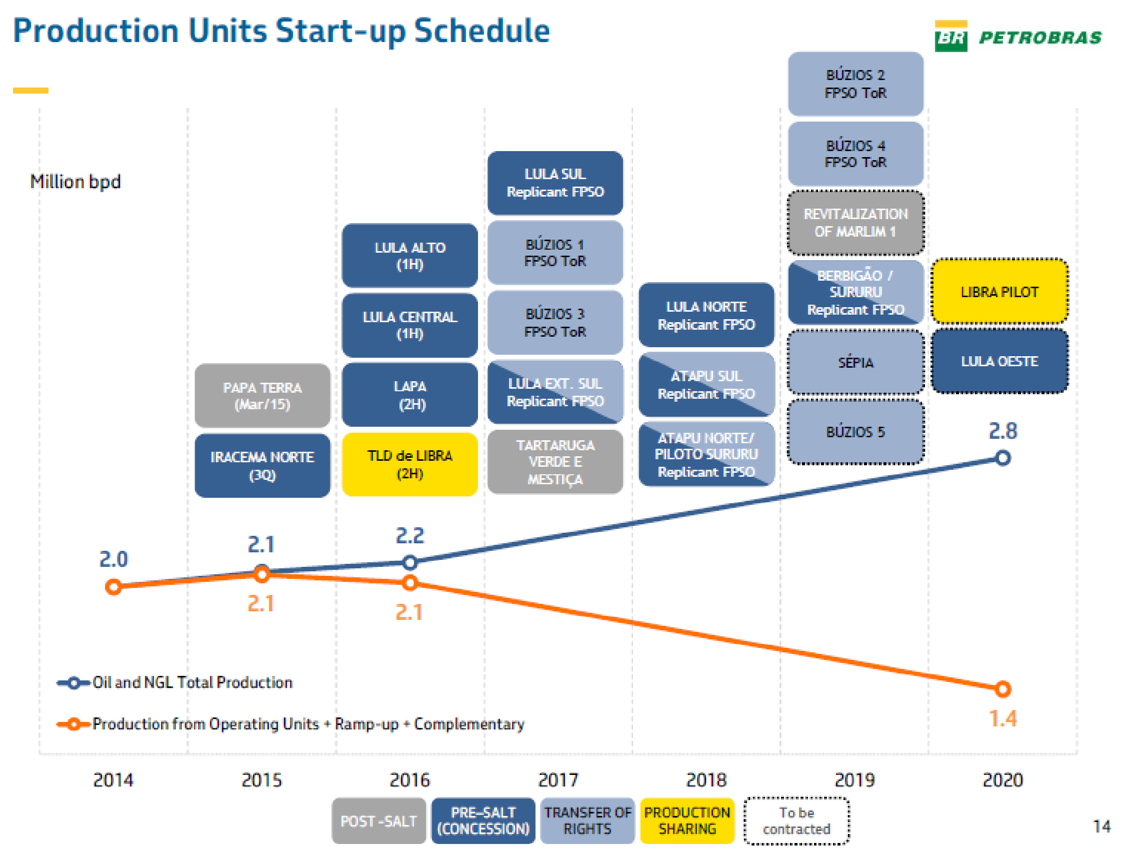

Figure 58. Petrobras (2015) *Petrobras Update, Outubro 2015* p. 20

Búzios' model assumes five standard FPSOs, with 150 kpd capacity, and estimates that they will produce the recoverable reserves in roughly 16 years, starting in 2017 and being finished in 2031. Altogether, the platforms at their full capacity can produce up to 750 kpd, however, Búzios model estimates a production peak of 733 kpd and a total of 268 mmboe in 2026.

FPSO	Total Production (mmboe)	Years of Production	Production Start-up (Year)
Búzios 1	1,916	35	2017
Búzios 2	1,807	33	2019
Búzios 3	1,916	35	2017
Búzios 4	1,807	33	2019
Búzios 5	1,807	33	2019

Figure 59. *Búzios' FPSO profile*

We use the same assumption of production of Libra model given the same characteristics. Each platform connects 9 production wells, the necessary number to reach the platform's full capacity. The well schedule starts with two wells in the first year of operations, three new production wells are added in the following year, on the firth year onwards, one well is built every other year. According to the well schedule, the platform takes roughly three years to reach full capacity and more approximately 7 years in the output plateau, before the production starts declining annually. Each well commences production at 15 kbd flow rate, elevating this rate to 25 kdp and 30 kdp, in the second and third year respectively. The wells start declining production on the fourth year onwards. The model assumes that for each two production wells, there is one injection well is drilled. The total number of wells required is 67, not counting with exploratory wells, being 45 production wells and 22 injection wells

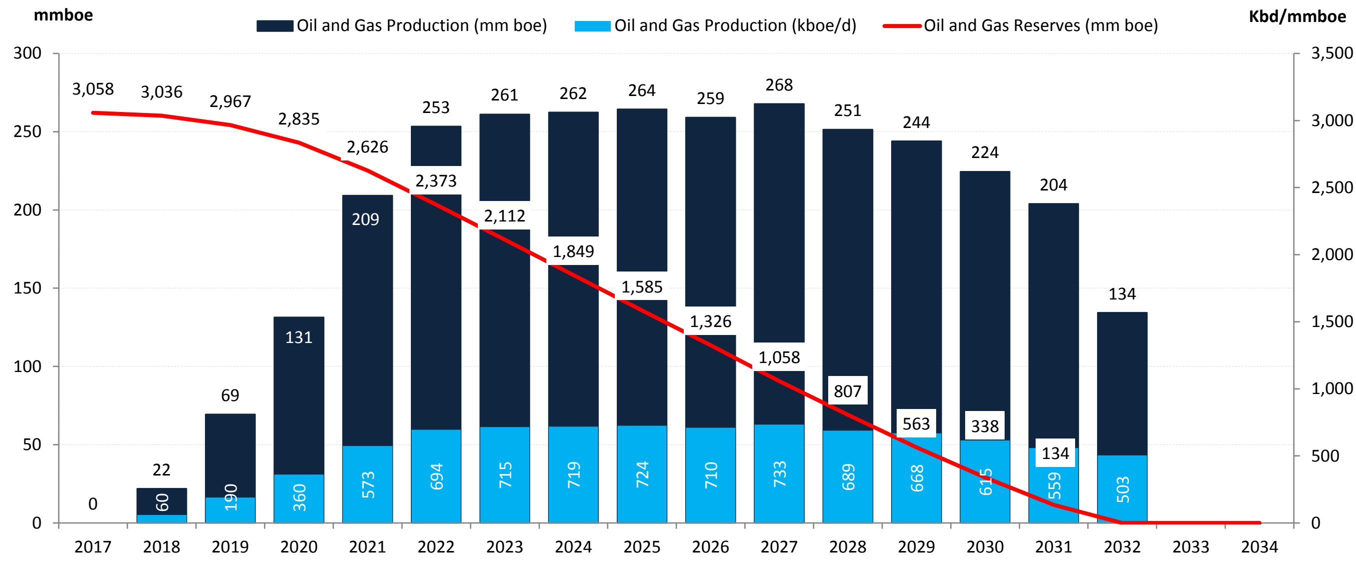

Figure 60. *Búzios' production curve*

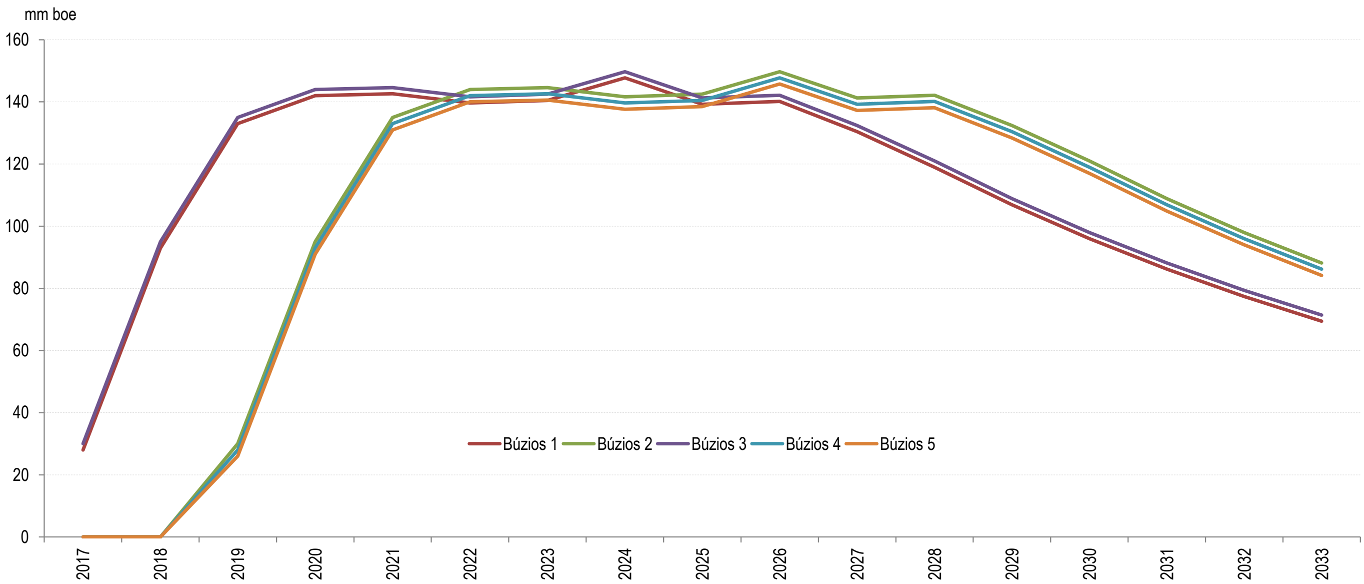

Figure 61. *Búzios' FPSOs production curve*

5.2.3 Capital Expenditures & Operational Expenditures

Búzios, in terms of platforms and production facilities, has a development program relatively smaller than the previous fields due to the volume of reserves Petrobras is allowed to produce. In terms of capital expenditure, however, Búzios has invested more capital than Lula field for instance ($55,736m vs. $43,879m), even though Lula has almost the triple of reserves to explore. This capital expenditure is explained mainly by Búzios signature bonus of $27,644m or 9.04 $/boe, an extraordinary amount if compared to the projected cash flow of the field nowadays. The disparity of numbers is explain by the time the contract was signed (2010) and the significant different future projections (Brent price for instance) and moment of the industry. The ToR is to be reviewed by Petrobras and the government until the beginning of 2016 given the new reality of the oil industry. We forecast that the price per barrel of Búzios is to decrease from its current 9.04 $/boe. The signature bonus of Búzios, as well as Libra's signature bonus, reflected the certainty of great investment opportunity.

Development Expenses	Capex	Comments
Engeneering	$63m	FEED, others
FPSO	$1750m	150kboed FPSO with topside and anchoring
Drilling	$450k + $500k	rig daily rate + for services
		100 days for drilling
Subsea equip	$6m	Christmas tree (more expensive given Water depth)
	$6m	Manifold (more expensive given Water depth)
	$2m	Umbilicals
	$6m	Control and others
Subsea (inst. and lines)	$80m per well	Includes flowlines, risers, umbilicals and installation
Contingencies		10% of the project's total

Figure 62. *Búzios' development cost*

The model assumes that all five platforms are standard 150 kpd capacity and owned by Petrobras, therefore, the capital expenditure assumptions are the similar to Lula's. We estimate that the five FPSOs will cost a total of $11,595m. The drilling costs assumptions are also similar to Lula's. Our base cases forecasts a total of 77 wells: 10 exploratory wells, 45 production wells and 22 injection wells. The total capital expenditure with drilling and abandonment is $15,197m; $1,190m in exploratory wells, $12,797m in well drilling and $490m in well abandonment.

Capex Breakdown	$m
FPSO	9,065
Drilling	15,197
Pipelines	1,250
Contingencies	2,530
Signature Bonus	27,644
Total	**55,686**

Opex Breakdown	$m
FPSO	19,392
PSV + Shuttle Tanker	4,029
Total	**23,421**

Figure 63. *Búzios' capex breakdown*

Drilling Expenses	# of Wells	$m
Exploratory Wells	10	1,910
Production Wells	45	8,595
Injection Wells	22	4,202
Total	**77**	**14,707**
Abandonment Cost		490
Total Cost		**15,197**

Figure 64. *Búzios' drilling expenses*

Búzios also produces a significant volume of natural gas. As previously, we also assume that the natural gas produced in the field is processed and sold to the Brazilian domestic market. The two pipeline routes that serve Búzios are Rota 2 and Rota 3. As Rota 3 details we presented previously, we will briefly introduce Rota 2. Rota 2 has

380km of extension, a capacity of 16Mm³ per day, and connects Búzios fields and others, to natural gas processing plant of Cabiúnas in Rio de Janeiro. Given the same problem faced in Libra field, the location of the platforms is not clear yet; the same strategy used in Libra's model to estimate the pipelines is adopted here. We model assume an average pipeline of 50km to each FPSO, with an average cost of $250m.

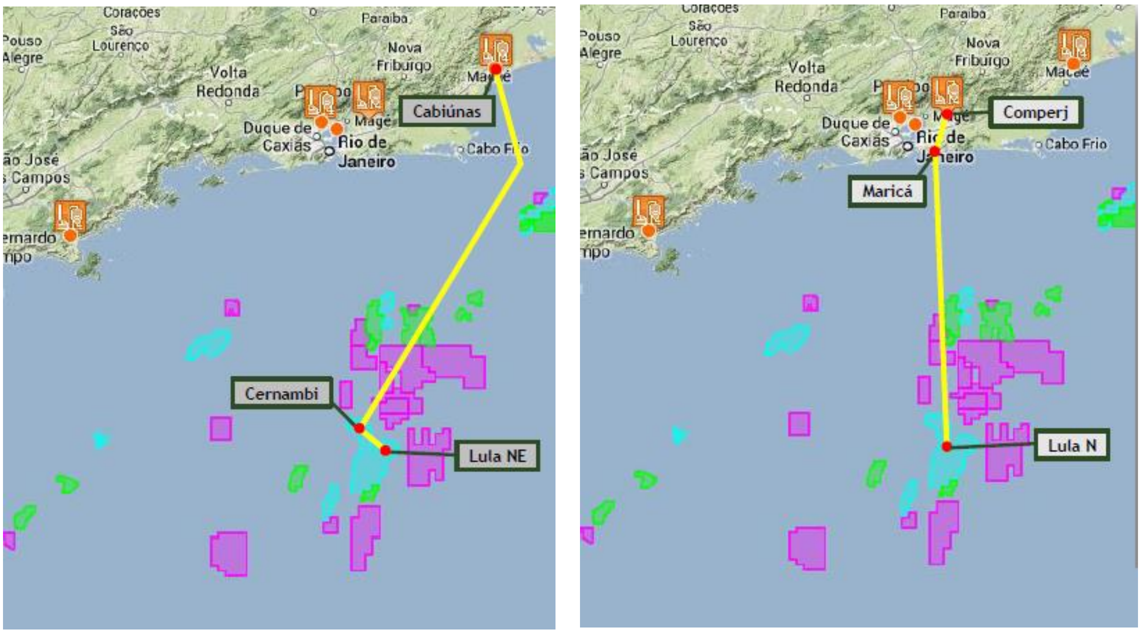

Figure 65. *Rota 2 and Rota 3*

Búzios total capital expenditure is $55,686m or 18.2 $/boe. It is useful, however, to look at an adjusted figure, without the signature bonus, since the amount is to be modified soon. Furthermore, the figure of 18.2 $/boe, given the small volume of reserves in ToF contract, might give an idea of a significant development plan and intense investments in equipments and facilites. The adjusted capital expenditure is $28,042m or 9.2 $/boe, a much more reasonable figure. The operational cost , on the other hand, sums up to $23,422 or 7.6 $/boe.

5.3 Sensitivity Tables

IRR	Signature Bonus Included					Brent ($/b)
		50	60	70	80	90
	-30%	0.4%	2.7%	4.3%	5.7%	6.8%
	-20%	1.9%	3.9%	5.4%	6.8%	7.9%
Reserves	-10%	2.7%	4.6%	6.2%	7.6%	8.8%
Volume	0%	3.2%	5.2%	6.8%	8.2%	9.4%
(mboe)	10%	3.5%	5.6%	7.2%	8.7%	9.9%
	15%	3.8%	5.8%	7.5%	8.9%	10.2%
	30%	4.1%	6.3%	8.0%	9.5%	10.8%

IRR	Signature Bonus Excluded					Brent ($/b)
		50	60	70	80	90
	-30%	15.1%	20.0%	24.1%	27.6%	30.6%
	-20%	19.0%	23.8%	27.8%	31.2%	34.1%
Reserves	-10%	22.2%	27.0%	30.9%	34.3%	37.1%
Volume	0%	25.0%	29.7%	33.6%	36.9%	39.7%
(mboe)	10%	27.4%	32.1%	36.0%	39.2%	42.0%
	15%	28.5%	33.2%	37.0%	40.3%	43.1%
	30%	31.5%	36.1%	39.9%	43.1%	45.9%

Figure 66. *Búzios' sensitivity table 1*

IRR	Signature Bonus Included					Brent ($/b)
		50	60	70	80	90
	40%	0.0%	2.1%	3.8%	5.3%	6.5%
	50%	0.7%	2.8%	4.5%	5.9%	7.2%
Reserves	60%	1.5%	3.5%	5.2%	6.6%	7.8%
(% of Oil)	70%	2.1%	4.1%	5.8%	7.2%	8.4%
	80%	2.7%	4.7%	6.4%	7.8%	9.0%
	90%	3.3%	5.3%	6.9%	8.3%	9.5%
	100%	3.8%	5.8%	7.4%	8.8%	10.0%

IRR	Signature Bonus Excluded					Brent ($/b)
		50	60	70	80	90
	40%	17.2%	22.2%	26.3%	29.8%	32.8%
	50%	19.1%	24.0%	28.1%	31.5%	34.4%
Reserves	60%	20.8%	25.6%	29.7%	33.0%	35.9%
(% of Oil)	70%	22.4%	27.2%	31.1%	34.5%	37.4%
	80%	23.8%	28.6%	32.5%	35.9%	38.7%
	90%	25.3%	30.0%	33.9%	37.1%	40.0%
	100%	26.6%	31.3%	35.1%	38.4%	41.2%

Figure 67. *Búzios' sensitivity table 2*

IRR	Signature Bonus Included					Brent ($/b)
		50	60	70	80	90
	4%	3.7%	5.7%	7.3%	8.7%	10.0%
	6%	3.4%	5.4%	7.1%	8.5%	9.8%
Depletion	8%	3.4%	5.4%	7.0%	8.4%	9.6%
per year	10%	3.2%	5.2%	6.8%	8.2%	9.4%
(%)	12%	2.8%	4.8%	6.5%	7.9%	9.1%
	14%	2.4%	4.5%	6.2%	7.6%	8.8%
	16%	1.5%	3.7%	5.5%	7.0%	8.3%

IRR	Signature Bonus Excluded					Brent ($/b)
		50	60	70	80	90
	4%	26.8%	31.4%	35.2%	38.3%	41.1%
	6%	26.2%	30.9%	34.7%	37.9%	40.7%
Depletion	8%	25.7%	30.3%	34.2%	37.4%	40.2%
per year	10%	25.0%	29.7%	33.6%	36.9%	39.7%
(%)	12%	24.2%	29.0%	33.0%	36.3%	39.2%
	14%	23.3%	28.3%	32.3%	35.7%	38.7%
	16%	22.2%	27.4%	31.6%	35.1%	38.1%

Figure 68. *Búzios' sensitivity table 3*

IRR	Signature Bonus Included					Brent ($/b)
		50	60	70	80	90
	-30%	4.1%	6.0%	7.5%	8.9%	10.1%
	-20%	3.8%	5.7%	7.3%	8.6%	9.8%
Capex	-10%	3.5%	5.4%	7.0%	8.4%	9.6%
Variation	0%	3.2%	5.2%	6.8%	8.2%	9.4%
(%)	10%	2.9%	4.9%	6.5%	8.0%	9.2%
	15%	2.7%	4.8%	6.4%	7.8%	9.1%
	30%	2.3%	4.4%	6.1%	7.5%	8.8%

IRR	Signature Bonus Excluded					Brent ($/b)
		50	60	70	80	90
	-30%	32.5%	37.3%	41.2%	44.4%	47.3%
	-20%	29.7%	34.5%	38.3%	41.6%	44.5%
Capex	-10%	27.2%	32.0%	35.8%	39.1%	42.0%
Variation	0%	25.0%	29.7%	33.6%	36.9%	39.7%
(%)	10%	23.0%	27.7%	31.6%	34.9%	37.7%
	15%	22.0%	26.8%	30.6%	33.9%	36.8%
	30%	19.5%	24.2%	28.0%	31.3%	34.2%

Figure 69. *Búzios' sensitivity table 4*

IRR	Signature Bonus Included					Brent ($/b)
		50	60	70	80	90
	-30%	3.8%	5.7%	7.2%	8.6%	9.7%
	-20%	3.6%	5.5%	7.1%	8.4%	9.6%
Opex	-10%	3.4%	5.3%	6.9%	8.3%	9.5%
Variation	0%	3.2%	5.2%	6.8%	8.2%	9.4%
(%)	10%	3.0%	5.0%	6.6%	8.1%	9.3%
	15%	2.8%	4.9%	6.6%	8.0%	9.2%
	30%	2.5%	4.6%	6.3%	7.8%	9.1%

IRR	Signature Bonus Excluded					Brent ($/b)
		50	60	70	80	90
	-30%	26.7%	31.1%	34.8%	38.0%	40.7%
	-20%	26.1%	30.7%	34.4%	37.6%	40.4%
Opex	-10%	25.6%	30.2%	34.0%	37.3%	40.1%
Variation	0%	25.0%	29.7%	33.6%	36.9%	39.7%
(%)	10%	24.4%	29.2%	33.2%	36.5%	39.4%
	15%	24.1%	29.0%	33.0%	36.3%	39.2%
	30%	23.2%	28.2%	32.3%	35.8%	38.7%

Figure 70. *Búzios' sensitivity table 5*

PV						Brent ($/b)
		50	60	70	80	90
Reserves Volume (mboe)	-30%	4,642	8,992	13,322	17,645	21,964
	-20%	7,885	12,711	17,533	22,353	27,169
	-10%	10,624	15,852	21,075	26,296	31,518
	0%	12,857	18,427	23,991	29,554	35,118
	10%	14,700	20,568	26,426	32,282	38,139
	15%	15,654	21,649	27,639	33,627	39,616
	30%	17,830	24,175	30,514	36,852	43,190

PV						Brent ($/b)
		50	60	70	80	90
Reserves (% of Oil)	40%	6,000	10,227	14,452	18,680	22,903
	50%	7,429	11,934	16,443	20,944	25,448
	60%	8,857	13,643	18,430	23,212	27,992
	70%	10,286	15,350	20,414	25,477	30,537
	80%	11,714	17,061	22,401	27,741	33,082
	90%	13,143	18,768	24,388	30,007	35,627
	100%	14,570	20,474	26,375	32,272	38,172

Figure 71. *Búzios' sensitivity table 6*

PV						Brent ($/b)
		50	60	70	80	90
Depletion per year (%)	4%	14,753	20,587	26,421	32,254	38,088
	6%	14,035	19,795	25,555	31,315	37,075
	8%	13,598	19,262	24,926	30,590	36,255
	10%	12,857	18,427	23,991	29,554	35,118
	12%	11,865	17,324	22,784	28,242	33,700
	14%	10,897	16,228	21,558	26,888	32,212
	16%	9,477	14,631	19,774	24,927	30,083

PV						Brent ($/b)
		50	60	70	80	90
Capex Variation (%)	-30%	15,702	21,270	26,835	32,398	37,962
	-20%	14,754	20,322	25,887	31,450	37,014
	-10%	13,805	19,375	24,939	30,502	36,066
	0%	12,857	18,427	23,991	29,554	35,118
	10%	11,909	17,479	23,043	28,606	34,170
	15%	11,434	17,005	22,569	28,132	33,696
	30%	10,012	15,583	21,148	26,710	32,274

Figure 72. *Búzios' sensitivity table 7*

PV						Brent ($/b)
		50	60	70	80	90
Opex Variation (%)	-30%	14,542	20,105	25,669	31,234	36,798
	-20%	13,981	19,547	25,109	30,674	36,238
	-10%	13,423	18,985	24,550	30,113	35,678
	0%	12,857	18,427	23,991	29,554	35,118
	10%	12,295	17,862	23,430	28,996	34,559
	15%	12,014	17,582	23,149	28,716	34,278
	30%	11,171	16,740	22,306	27,874	33,440

PV						Brent ($/b)
		50	60	70	80	90
Discount Rate (%)	4%	31,411	42,602	53,705	64,795	75,899
	6%	25,281	34,656	43,987	53,309	62,638
	8%	20,439	28,360	36,257	44,150	52,046
	10%	16,594	23,338	30,069	36,797	43,528
	13%	12,857	18,427	23,991	29,554	35,118
	15%	10,012	14,659	19,304	23,948	28,592
	17%	8,221	12,268	16,314	20,360	24,406

Figure 73. *Búzios' sensitivity table 8*

NPV	Signature Bonus Included					Brent ($/b)
		50	60	70	80	90
Reserves Volume (mboe)	-30%	-26,585	-24,171	-21,767	-19,369	-16,972
	-20%	-24,785	-22,106	-19,431	-16,756	-14,084
	-10%	-23,265	-20,364	-17,465	-14,568	-11,670
	0%	-22,026	-18,935	-15,847	-12,760	-9,673
	10%	-21,003	-17,746	-14,496	-11,246	-7,996
	15%	-20,474	-17,147	-13,823	-10,500	-7,177
	30%	-19,266	-15,745	-12,227	-8,710	-5,193

NPV	Signature Bonus Excluded					Brent ($/b)
		50	60	70	80	90
Reserves Volume (mboe)	-30%	1,192	3,908	6,611	9,310	12,007
	-20%	3,217	6,230	9,240	12,249	15,256
	-10%	4,927	8,191	11,451	14,711	17,971
	0%	6,321	9,798	13,272	16,745	20,218
	10%	7,471	11,135	14,792	18,448	22,104
	15%	8,067	11,810	15,549	19,287	23,026
	30%	9,426	13,387	17,344	21,301	25,258

Figure 74. *Búzios' sensitivity table 9*

NPV	Signature Bonus Included					Brent ($/b)
		50	60	70	80	90
Reserves (% of Oil)	40%	-25,831	-23,485	-21,140	-18,794	-16,451
	50%	-25,038	-22,538	-20,036	-17,538	-15,039
	60%	-24,245	-21,590	-18,933	-16,280	-13,627
	70%	-23,452	-20,642	-17,832	-15,022	-12,214
	80%	-22,660	-19,693	-16,730	-13,766	-10,803
	90%	-21,867	-18,745	-15,627	-12,509	-9,390
	100%	-21,075	-17,799	-14,524	-11,252	-7,978

NPV	Signature Bonus Excluded					Brent ($/b)
		50	60	70	80	90
Reserves (% of Oil)	40%	2,040	4,679	7,317	9,956	12,593
	50%	2,933	5,745	8,560	11,370	14,182
	60%	3,824	6,812	9,800	12,785	15,770
	70%	4,716	7,877	11,039	14,200	17,359
	80%	5,607	8,946	12,279	15,613	18,947
	90%	6,500	10,011	13,520	17,028	20,536
	100%	7,391	11,076	14,760	18,442	22,125

Figure 75. *Búzios' sensitivity table 10*

NPV	Signature Bonus Included				Brent ($/b)
	50	60	70	80	90
Depletion per year (%) 4%	-20,974	-17,736	-14,499	-11,262	-8,024
6%	-21,372	-18,176	-14,979	-11,783	-8,586
8%	-21,615	-18,471	-15,328	-12,185	-9,042
10%	-22,026	-18,935	-15,847	-12,760	-9,673
12%	-22,576	-19,547	-16,517	-13,488	-10,459
14%	-23,114	-20,155	-17,197	-14,240	-11,285
16%	-23,902	-21,041	-18,187	-15,327	-12,466

NPV	Signature Bonus Excluded				Brent ($/b)
	50	60	70	80	90
Depletion per year (%) 4%	7,505	11,147	14,789	18,431	22,073
6%	7,056	10,652	14,248	17,844	21,440
8%	6,783	10,319	13,856	17,392	20,928
10%	6,321	9,798	13,272	16,745	20,218
12%	5,702	9,110	12,518	15,926	19,333
14%	5,097	8,425	11,753	15,080	18,404
16%	4,211	7,428	10,639	13,856	17,075

Figure 76. *Búzios' sensitivity table 11*

NPV	Signature Bonus Included				Brent ($/b)
	50	60	70	80	90
Capex Variation (%) -30%	-19,992	-16,902	-13,814	-10,727	-7,639
-20%	-20,670	-17,580	-14,492	-11,405	-8,317
-10%	-21,348	-18,257	-15,169	-12,082	-8,995
0%	-22,026	-18,935	-15,847	-12,760	-9,673
10%	-22,704	-19,612	-16,525	-13,438	-10,350
15%	-23,043	-19,951	-16,863	-13,777	-10,689
30%	-24,059	-20,968	-17,880	-14,793	-11,706

NPV	Signature Bonus Excluded				Brent ($/b)
	50	60	70	80	90
Capex Variation (%) -30%	8,609	12,085	15,559	19,032	22,506
-20%	7,846	11,323	14,797	18,270	21,743
-10%	7,083	10,560	14,034	17,507	20,981
0%	6,321	9,798	13,272	16,745	20,218
10%	5,558	9,036	12,510	15,982	19,456
15%	5,177	8,655	12,128	15,601	19,075
30%	4,033	7,511	10,985	14,458	17,931

Figure 77. *Búzios' sensitivity table 12*

NPV	Signature Bonus Included				Brent ($/b)
	50	60	70	80	90
Opex Variation (%) -30%	-21,090	-18,004	-14,916	-11,828	-8,740
-20%	-21,402	-18,313	-15,227	-12,139	-9,051
-10%	-21,712	-18,625	-15,537	-12,450	-9,362
0%	-22,026	-18,935	-15,847	-12,760	-9,673
10%	-22,337	-19,248	-16,159	-13,070	-9,983
15%	-22,494	-19,404	-16,314	-13,225	-10,138
30%	-22,961	-19,871	-16,782	-13,693	-10,603

NPV	Signature Bonus Excluded				Brent ($/b)
	50	60	70	80	90
Opex Variation (%) -30%	7,373	10,846	14,319	17,793	21,267
-20%	7,023	10,497	13,970	17,444	20,918
-10%	6,674	10,147	13,621	17,094	20,568
0%	6,321	9,798	13,272	16,745	20,218
10%	5,970	9,446	12,921	16,396	19,869
15%	5,794	9,271	12,746	16,221	19,694
30%	5,269	8,745	12,220	15,696	19,171

Figure 78. *Búzios' sensitivity table 13*

NPV	Signature Bonus Included				Brent ($/b)
	50	60	70	80	90
Discount Rate (%) 4%	-3,594	5,605	14,730	23,846	32,972
6%	-10,455	-3,449	3,523	10,489	17,461
8%	-15,375	-9,984	-4,609	762	6,136
10%	-18,924	-14,737	-10,557	-6,379	-2,200
13%	-22,026	-18,935	-15,847	-12,760	-9,673
15%	-24,120	-21,810	-19,500	-17,192	-14,883
17%	-25,301	-23,455	-21,610	-19,765	-17,919

NPV	Signature Bonus Excluded				Brent ($/b)
	50	60	70	80	90
Discount Rate (%) 4%	25,013	34,579	44,070	53,549	63,041
6%	18,221	25,647	33,038	40,422	47,811
8%	13,251	19,073	24,878	30,679	36,483
10%	9,592	14,198	18,796	23,391	27,988
13%	6,321	9,798	13,272	16,745	20,218
15%	4,053	6,710	9,365	12,021	14,676
17%	2,741	4,901	7,060	9,219	11,378

Figure 79. *Búzios' sensitivity table 14*

6. Conclusion

6.1 Lula's results

In our base case scenario, the Lula field yields a Present Value of $41,591m in 2015, which represents 5.1 $/boe. It is the highest PV among the analyzed fields in 2015, Libra's PV is $10,960 and Búzios' PV is $23,991. The reason why Lula has a higher PV in 2015 than Libra is that it has passed its most intensive investment phase and it has started delivering production (314 kbd), whereas Libra still have a significant investment schedule. Búzios, on the hand, has neither started its production nor does it have the significant amount of reserves to produce relative to Lula project.

The Net Present Value of investment is $4,593m, or 0.5 $/boe. Lula has the highest NPV among the three fields, Libra's NPV is $1,268m and Búzios' NPV is $-15,847m. Even though Lula and Libra have similar reservoir characteristics, such as oil quality, well productivity and reserve volume, the economics of Lula field are stronger. Lula's capital expenses ($43,879m vs. $64,313) and operational expenses ($72,303 vs. $126,465) are smaller due to 1) Lula's significantly smaller signature bonus, which reflected the exploratory risks at its time 2) A FPSO portfolio mixed with owned and mostly leased platforms 3) Significantly lower drilling costs and operational expenses, a reflects of the better situation of the oil and gas industry in Brazil. Búzios, on the contrary, presents a negative NPV given the tremendous signature bonus paid to the government. If the NPV is adjusted to exclude the signature bonus, the field delivers a NPV of $13,272, which reflects the strong economics of the field.

The model estimates an IRR of 20.3% for the field, also the highest among the field. Libra has an IRR of 13.2% and an adjusted IRR (ex-sig. bonus) of 21.8%, whereas Búzios delivers an IRR of 7% and IRR (ex-sig. bonus) of 33.6%. It is important to note that all these figures are in real terms. Finally, we estimate a breakeven of 49.5 $/boe; 8.6 $/boe of lifting cost, 30.5 $/boe of taxes, 5.2 $/boe of exploration and 5.1 $/boe of DD&A. The breakeven is the aggregate cost to produce one barrel of hydrocarbons, it takes into account the development cost, the operational cost, taxes and depreciation. As a comparison with the other analyzed fields, Libra has a breakeven of 59.1 $/boe (58.2 $/boe adjested to signature bonus) and Búzios has a breakeven of 54.7 $/boe (and an adjusted breakeven of 45.6 $/boe). The drivers behind this result are the same explained in the NPV section. In our base case scenario, Lula field presents strong economics even under very challenging macroeconomic circumstances, such as historical low Brent prices, and it is able to deliver higher return than its analyzed peers.

In face of many uncertainties in the commodity fundamentals and in the domestic industry, it is very important to analyze how the economics of the field behaves given different scenarios. First, we study Lula's IRR given the change of important value variables, such as reserve volumes, mix of reserves, depletion per year, capex variation and opex variation, always against Brent prices. The chosen ranges are the most realistic scenarios that the field might face in the feasible future, in our view.

The field is most sensitive to changes in the reserves volume, the IRR in its best case scenario and worst case scenario is 27.8% and 10.7% respectively. The reason behind this result is out assumption that the productivity of the well varies on the exact same proportion of the reserves volume. The rational is that, everything else constant, more volume in the reservoir results in more production flow. Another variable worth mentioning is the mix of the reserves, which results in an IRR in its best case scenario and worst case scenario of 24.3% and 11.8%. This result is driven by the significant difference of realization price of oil and gas, the higher percentage of oil in the reserve volumes, the higher the average realization price of the field, and thus, its return. The present value and net present value sensitivities present the same result given share the same drivers with the IRR. Lula field is a strong asset in every scenario analyzed. Its privileged reservoir characteristics along with strong economics provide sound and attractive return and intrinsic value.

6.2 Libra's results

In our base case scenario, the Libra field yields a Present Value of $10,960m in 2015, which represents 1.4 $/boe, whereas Lula has $41,591m and Búzios $23,991. The reason is its expensive development program, capital expenditure and operational expenditure wise, and its production start-up still a while from 2015. The Net Present Value of investment is $1,268m, or 0.2 $/boe, higher than Búzios only, if taken the signature bonus in consideration. Libra deliveries an IRR of 13.25% and an IRR (ex-signature bonus) of 21.8%. Lula and Búzios have an IRR of 20.3%and 7% respectively (33.6% ex-sig. bonus). As mentioned beforehand, all these figures are in real terms.

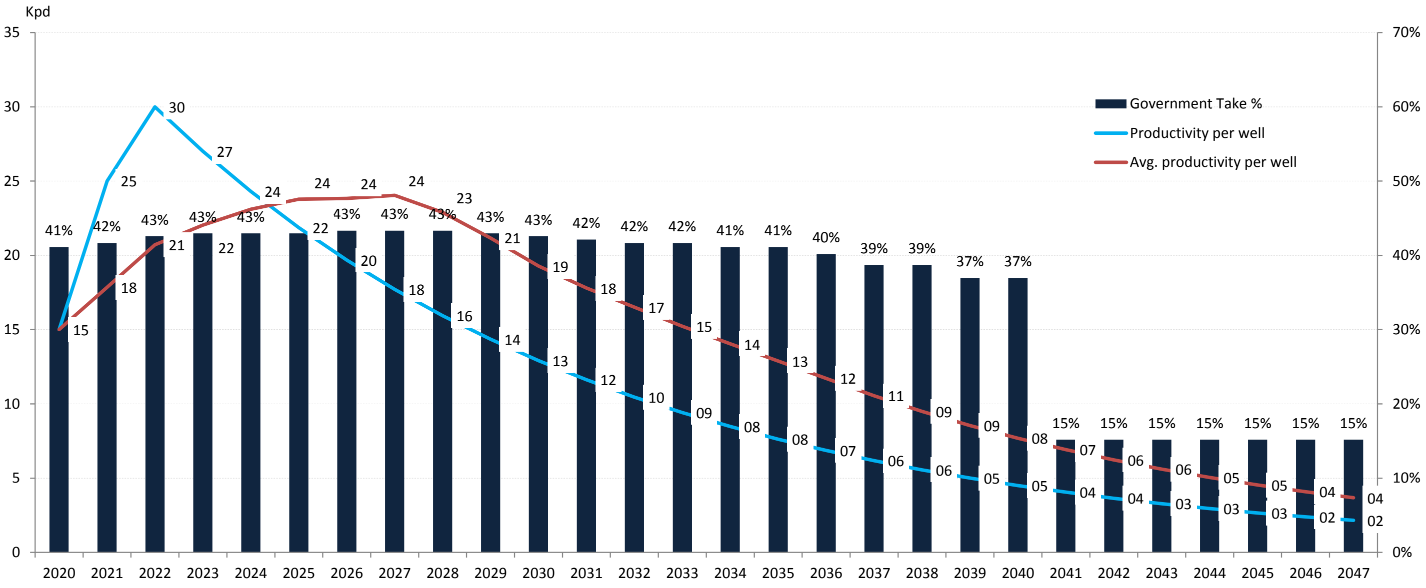

Figure 80. *Libra's government take vs. well produtivity*

Libra's breakeven is 59.1 $/boe, which includes the lifting cost 15.8 $/boe, capex 8.0 $/boe, taxes 28.2 and DD&A 7.0 $/boe. It is the highest breakeven among the three fields. It reflects the higher prices of drilling (Day rate + Op. services $1,150m vs. $950m other fields), larger owned FPSO portfolio and operating cost (Day rate + Op. services $1,200m vs. $770m other fields).

We estimate that 45% of Libra's revenue goes to the government in terms of taxes; 15% in royalties, 24% in government take and 6% in income taxes. This is an interesting conclusion, as intuitively the PSC would yield a much higher taxes percentage of revenue. The reason behind this result is that the government take in the PSC varies according to two main variables: the Brent price and the productivity per well. In our model, we assume a relatively high productivity per well if compared to non-pre-salt reservoirs, with a peak of 30 kpd in the third year, which makes possible to sustain the productivity higher than 15 kpd for roughly 10 years in an average well. The Brent price, however, remains persistently low (70 $/bbl) during all production years. The government take, thus, can only reach the lowest values.

Brent oil prices (US$/bbl)												**Average productivity per well (kb/d)**
Less than	**0.0**	**4.0**	**6.0**	**8.0**	**10.0**	**12.0**	**14.0**	**16.0**	**18.0**	**20.0**	**22.0**	**24.0**
60	-31.72%	-15.85%	-9.62%	-6.33%	-4.26%	-2.56%	-1.48%	-0.86%	-0.29%	0.23%	0.69%	1.11%
80	-26.45%	-12.85%	-7.51%	-4.70%	-2.92%	-1.46%	-0.54%	**0.00%**	0.48%	0.92%	1.32%	1.68%
100	-19.44%	-8.86%	-4.71%	-2.52%	-1.14%	**0.00%**	0.71%	1.13%	1.51%	1.85%	2.16%	2.44%
120	-14.98%	-6.32%	-2.92%	-1.13%	**0.00%**	0.93%	1.51%	1.86%	2.17%	2.45%	2.70%	2.93%
140	-11.89%	-4.56%	-1.69%	-0.17%	0.79%	1.57%	1.86%	2.36%	2.62%	2.86%	3.07%	3.26%
160	-9.62%	-3.27%	-0.78%	0.53%	1.36%	2.04%	2.36%	2.72%	2.95%	3.16%	3.34%	3.51%
800	-5.94%	-1.18%	-0.69%	1.68%	2.30%	2.81%	2.72%	3.32%	3.49%	3.65%	3.73%	3.91%

Figure 81. *Libra's government take table*

We conclude that, in our base case scenario, is Libra field is a good asset. It does not fare as well as Lula in present challenging industry conditions due to the timming that the development plan started being implemented, but it has strong drivers, such as oil reserves (with a great upside risk), great reserve mix and well productivity. How does Libra do in different scenarios though? As aforementioned, the most sensitive value drivers of the field are reserves volumes and reserve mix. Opposed to Lula field, the worst case scenarios truly deteriorate the economics of the asset, delivering low or very negative returns, NPV and PV. We highlight that lower than expected recoverable reserves (-10%, -20% and -30%), more than expected percentage of gas in the reserves volumes (70%, 60%, 50%,40%), higher than expected capex and opex (30% and 15%, 30% respectively) combines with low Brent prices (50 and 60 $/bbl) will destroy return and the value of the asset. Even though we assign very low probability of a long term Brent price at 50 or 60 $/boe, we enphasize the relatively high risk of capex and opex overrun given the historical operational perfomance of Petrobras in implementing its projects and harsher domestic industry circumstances. Finally, we see Libra as a good asset but with very margin of safety in light of tough market environment.

6.3 Búzios' results

Búzios has a Present Value of $23,991m or 7.8 $/boe in 2015. The Net Present Value of investment, if considered the signature bonus is $-15,847m or -5.2 $/boe. If we adjust the NPV to exclude the signature bonus, however, it becomes $13,272 or 4.3 $/boe. The field has an IRR of 7.0% (IRR ex-signature bonus of 33.6%). Regardless of which breakeven is considered, the one including signature bonus or excluding it, Búzios has the lowest figure among the analyzed fields, 54.7 $/boe and 45.6 $/boe respectively. It is interesting to see that even relative to the reserve volumes, Búzios has a small development plan, in terms of capex, opex, taxes and DD&A. We estimate that 32% of Búzios' revenue goes to the government in terms of taxes; 10% in royalties and 22% in income taxes, or 19.8 $/boe, the lowest among the three fields once again .This result is intuitive since the ToR contract does not include any government take or special participation, in addition to a relatively low royalty rate.

Búzios field is an asset with great potential. Its reservoirs characteristics (reserve volumes with a great upside risk, reserve mix, well productivity) are among the best oil and gas assets of the world, the Transfer of Rights contract sets very favorable (no government take and low royalty rate), and its development plan incorporates favorable market conditions (drilling cost, day rates, operational services). The economics of the field, however, are destroyed by the significant signature bonus agreed in 2010 based in totally different market conditions. The ToR contract is to be negotiated again by the beginning of 2016 and our view is that the charged price per barrel should be lowered in light of the current economic environment. We estimate a signature bonus of approximately $7,000 in order to set the IRR in 16%, the reasonable IRR alleged by the government. We assign very low probability to such signature bonus reduction given the current tough fiscal situation of the government. It is also important to highlight that a second contract, transfer of rights surplus, is to be sought between Petrobras and the government, which can change significantly the economics of the field.

In our sensitivity table exercise, we apply different variables scenarios to study the field's IRR, PV and NPV, including and excluding the signature bonus. Our metrics are most sensitive to reserves volume and reserve mix, which can bring the IRR of the field close to zero. We highlight, however, that there is no scenario that turns the return or the PV negative, which shows the resilience of the field's economics. We conclude that Búzios is a very good asset, with a great upside risk, which has its economics destroy by the signature bonus agreed between Petrobras and the government.

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