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Professional Study

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Probabilistic volumetric and economic evaluation of potential turbidite prospects from offshore Uruguay.

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ABSTRACT

This project presents a probabilistic techno-economic evaluation of several turbidite prospects recognized, through 3D seismic, in deep to ultra-deep waters of the Punta del Este and Pelotas sedimentary basins, offshore of Uruguay. The production potential of many prospective turbidite reservoirs on the Atlantic margin has been recognized before, and new turbidite prospects were identified after analyzing data from the world's deepest water-depth well (Raya-X1) drilled in 2016 in Uruguay's maritime zone.

The estimated ultimate recovery of oil and gas was determined, for each prospect, through the interpretation of 3D seismic and by carrying out probabilistic resource analyses using key parameters from analog turbidite fields located in sedimentary basins from offshore Brazil, Ghana and Falkland Islands.

A black oil fluid was assumed and the production concept involves Floating, Production, Storage and Offloading (FPSO) vessels. The produced oil would be exported via tankers and the associated gas would be either sent to shore through a gas pipeline, or re-injected into the formation. For the economic evaluation, the latest fiscal terms of the applicable production-sharing contract (PSC), for offshore assets in Uruguay, were considered.

The outcomes of the probabilistic economic analyses include, for each prospect, several key performance indicators such as: net present value, internal rate of return, maximum negative cash flow, breakeven oil price, government take and entitlement percentage of hydrocarbons. These indicators were determined after running Monte Carlo simulations, which considered probability distribution functions for fixed and variable capital and operational expenditures, along with well productivities and decline rates. Regarding the economics of the project, several scenarios of incremental profit oil for the government and maximum association percentage for ANCAP, the National Oil Company of Uruguay, were evaluated. The cases considered show how key negotiables and variables, featuring in the tender process offered to oil companies interested in Uruguay's offshore hydrocarbon assets, may affect the economics and development solutions of a typical field development project.

This study sheds light on the exploration potential of turbidites, offshore of Uruguay, and analyzed resource volumes, production profiles and economic returns of a hypothetic development in the case of a commercial discovery. The analyses provide useful templates for international oil companies, which, under the new and more flexible open-round licensing regime, may be interested in the exploration and imminent development of the Uruguayan offshore sedimentary basins.

Acknowledgement

I would like to thank ANCAP, for the permission to use the seismic and well data that was required for this Final Report, as well as to all my colleagues at the company that supported me all the time while I was focused on this project.

Finally, I would specially like to thank Dr. Ruud Weijermars, the chair of my committee, for his supervision during this project and his permanent guidance over the time it took me to fulfill this degree.

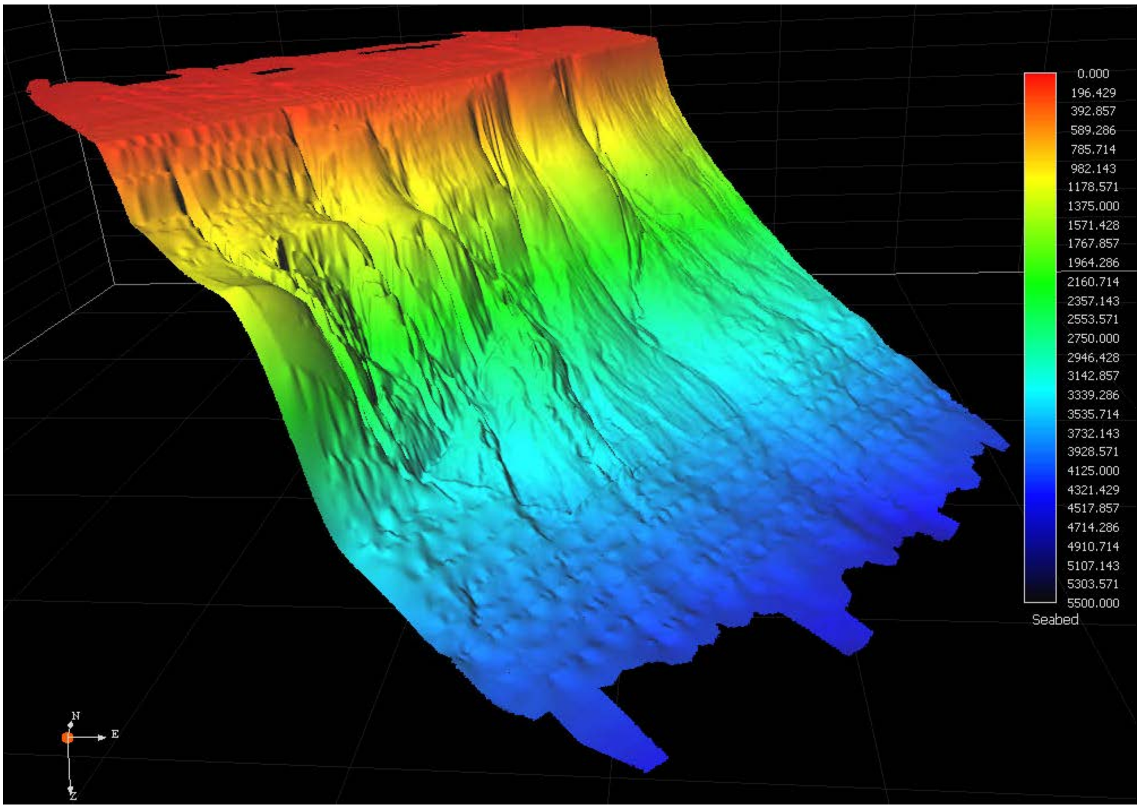

Fig. 1 – Offshore Uruguay seismic interpreted seafloor

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1. Objective

This report presents a probabilistic techno-economic evaluation of several turbidite prospects recognized, through 3D seismic, in deep to ultra-deep waters of the Punta del Este and Pelotas sedimentary basins, offshore of Uruguay. This study is motivated by the importance of turbidite reservoirs in this region of the Atlantic margin.

2. Introduction

Turbidite reservoirs have been drilled in the offshore of Brazil since the 70s. They became an objective of great interest for exploration and an important source for Brazil's current hydrocarbon production (Bacoccoli and Toffoli 1998). Turbidites have also been a popular exploration target in places like West Africa and the southern region of North Falkland Basin, amongst others.

In the last 10 years of exploration in the offshore of Uruguay, nearly 41,000 km^2 of 3D seismic data were acquired, several prospects were recognized and one of them was drilled by Total in 2016 (RAYA well, see **Fig. 2**). The objective of that well was to collect detailed data from a Cenozoic turbidite reservoir mapped with 3D seismic. The well confirmed that the prospect was a good quality turbidite reservoir, but it did not contain hydrocarbons. It was also the first ever-drilled turbidite in the offshore of Uruguay and it is a current world record in matters of water depth (Wood Group Mustang 2018).

The geological and geophysical database used in this project comprises three 3D seismic surveys: UR13_3D, BG12_3D and TO12_3D, and well log data from three offshore wells: LOBO and GAVIOTIN, drilled by Chevron in 1976, and RAYA, drilled by Total in 2016. The geographical location of these datasets is shown in Fig. 2.

The probabilistic volumetric resource evaluation of the prospects was carried out for PETE685 report and a summary of it is included in chapter 3 of this report. The performed volumetric analysis required a detailed interpretation of the five potential turbidite prospects that were selected for this study. The analyzed prospects, in order of appearance in this report, are: Chafalote, Maspoli, Jasper, Emerald-Deep and Emerald. Their locations within the 3D seismic surveys used in this project are shown in **Fig. 3.**

After completing the probabilistic volumetric resource evaluation of each prospect, a probabilistic economic analysis was performed considering the most updated fiscal terms of the applicable production-sharing contract, for offshore assets in Uruguay.

For all the prospects a black oil fluid was assumed and the proposed production concept involves production through FPSO vessels. The produced oil would be exported via tankers and the associated gas would be either sent to shore through a gas pipeline, or re-injected into the formation.

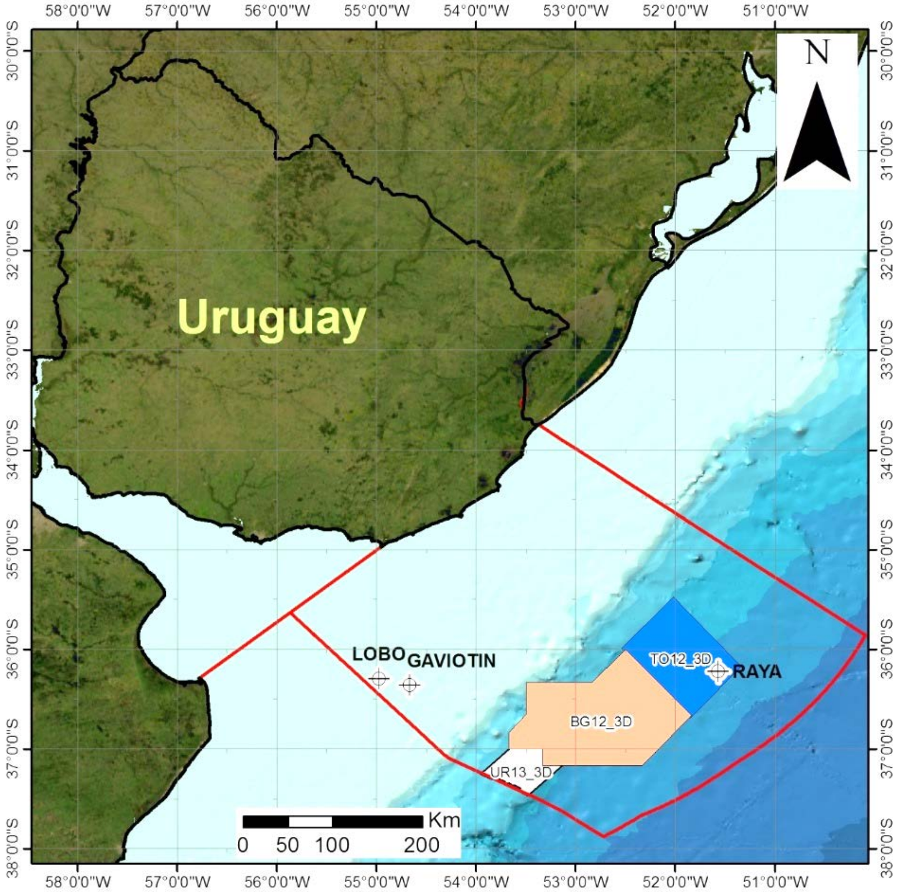


Fig. 2 – Offshore Uruguay 3D seismic and well data used in this project

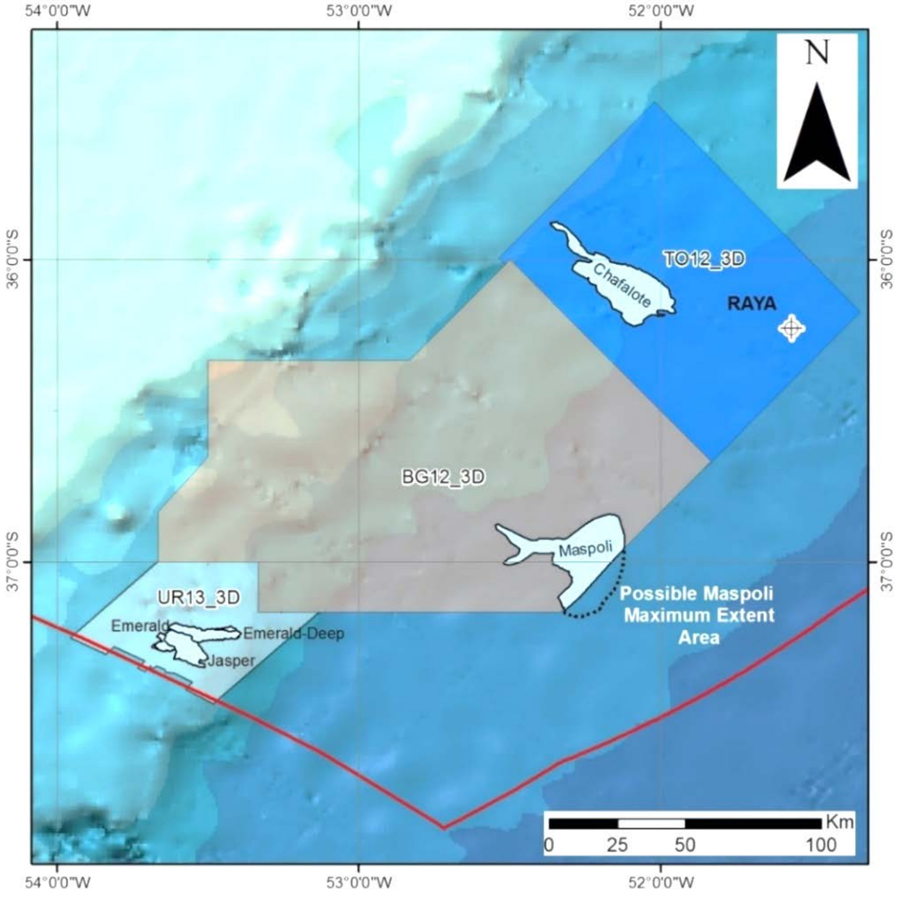


Fig. 3 – Map of the analyzed turbidite prospects

3. Volumetric Analysis (PETE685 report summary)

The hydrocarbon prospective resource assessment of turbidite prospects, recognized within the Uruguayan Exclusive Economic Zone (EEZ), started with the creation of a database of turbidite reservoir and fluid parameters. This information was then used in the resource evaluation to support analogous parameters for the volumetric calculations. The mentioned database includes information of turbidite fields from offshore Brazil (Albacora, Albacora Leste, Marlim, Marlim Sul, Barracuda, Espadarte, Namorado, Frade and Roncador, all located in Campos basin), offshore Ghana (Jubilee) and offshore Falkland Islands (Sea Lion Complex). The locations of the studied turbidite fields are shown in **Fig. 4.**

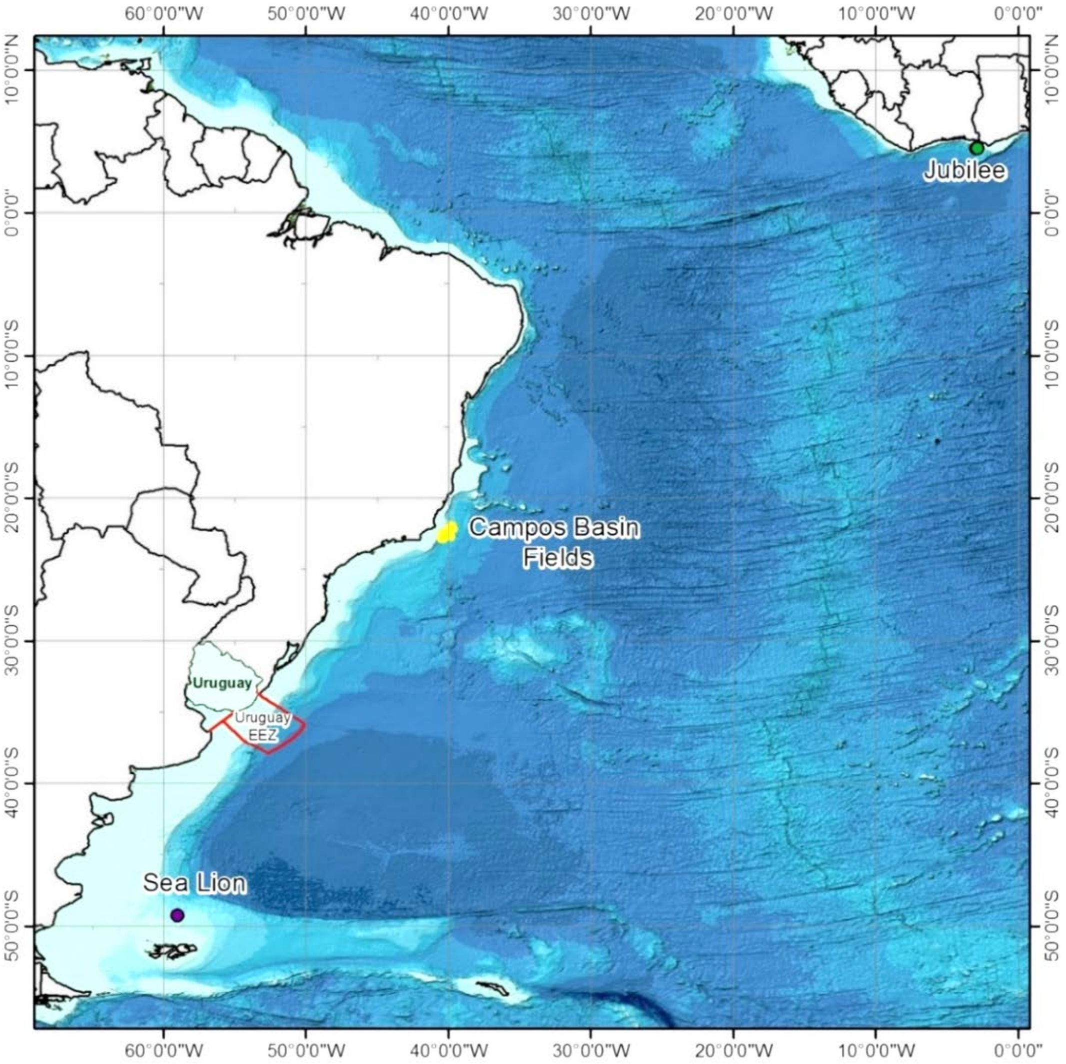


Fig. 4 – Location of turbidite fields analyzed for this report

The inputs of the created database were used, as analogous, to support the parameters for probability distribution functions (PDF) of key reservoir variables used in the volumetric formula (Wright 2015; Cronquist 2001) for Estimated Ultimate Recovery (EUR):

$$EUR_{oil} = \frac{7{,}758 * A * h * \frac{N}{G} * \varphi * (1 - S_w)}{B_{oi}} * RF = \frac{6.29 * GRV * \frac{N}{G} * \varphi * (1 - S_w)}{1{,}000{,}000 * B_{oi}} * RF \ldots (1)$$

Where:

- Gross Rock Volume (*GRV*) is expressed in m^3 leading to an EUR_{oil} in MMbbls.
- The parameters required to define *GRV* PDF are obtained from the 3D seismic interpretation of the prospects. *GRV* was automatically computed, with the IHS® Markit® Kingdom® software package, using the seismic interpreted surfaces that correspond to the top and base of the turbidite bodies.
- Net to Gross $\left(\frac{N}{G}\right)$ PDF is constructed with values obtained from the previously analyzed turbidite reservoirs.
- Porosity (φ) PDF is constructed with values that result from applying the relationships between porosity and sedimentary overburden published by Ehrenberg and Nadeau (2005) for sandstones. This distribution is truncated at 48% because porosities higher than this value are not possible for clastic rocks because the theoretical maximum porosity for a cubic packed rock is 47.64% (Graton and Fraser 1935).
- Water Saturation (S_w) PDF is constructed with values obtained from the previously analyzed turbidite reservoirs.
- Recovery Factor (RF) PDF is constructed with values obtained from the previously analyzed turbidite reservoirs. This distribution is truncated at 50% because recovery factors higher than this value are not expected.
- Initial formation volume factor (B_{oi}) PDF parameters are estimated using the Levitan and Murtha (1999) correlation for formation volume factor at the bubble point pressure with some assumed properties of the fluid within the reservoir (gas oil ratio values and an estimation of reservoir temperature).

Since a black oil reservoir fluid is assumed, the EUR for associated gas is calculated as:

$$EUR_{associated\_gas} = \frac{EUR_{oil} * GOR}{1{,}000{,}000} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots (2)$$

Where:

- Gas Oil Ratio (*GOR*) is expressed in scf/STB leading to a gas EUR in trillion cubic feet (TCF).
- *GOR* PDF is constructed with values obtained from the previously analyzed turbidite reservoirs. It is truncated at 2000 scf/STB because a black oil fluid was assumed.

The probabilistic volumetric resource evaluation of the turbidite prospects studied in this project led to volumes that, according to the Petroleum Resources Management System guidelines (SPE 2018), must be classified as "Prospective Resources". A summary of the calculated resources for each prospect is shown in **Table 1:**

	Oil (MMbbls)			Associated Gas (TCF)		
Prospect	**1U - Low Estimate**	**2U - Best Estimate**	**3U - High Estimate**	**1U - Low Estimate**	**2U - Best Estimate**	**3U - High Estimate**
Chafalote	759.82	1,828.47	4,020.55	0.299	0.932	2.532
Maspoli	905.06	2,224.96	4,680.26	0.355	1.146	3.020
Jasper	103.61	257.24	566.84	0.041	0.132	0.358
Emerald-Deep	54.55	140.12	330.99	0.022	0.072	0.206
Emerald	60.25	175.59	468.88	0.024	0.090	0.294

Table 1 – Prospective Resources per prospect

4. History of Exploration in Offshore Uruguay

Offshore Uruguay oil and gas exploration started in 1970 with the acquisition of the first 2D marine seismic survey. As a result of this first approach, as well as several posterior 2D seismic surveys, the wells LOBO and GAVIOTIN (Fig. 2) were drilled by Chevron in 1976. These were the first exploratory wells drilled in the offshore of Uruguay, but despite of some gas indications in the wireline logs of GAVIOTIN, both were declared dry. In this period of extended exploration, two additional seismic surveys were accomplished, the last one in 1982. After this last exploratory activity there was a 20 years halt in the acquisition of new marine data.

Offshore exploration restarted in 2002 with the acquisition of a new 2D seismic survey, and continued with two additional 2D seismic surveys on years 2007 and 2008. Based on the prospectivity shown in this better quality seismic information, an offshore bidding round was launched in 2009 and eleven areas were offered for that occasion. It was named Uruguay Round 2009 and had as outcome the qualification of six oil companies, the reception of two offers, and the award of two areas (Ferro et al. 2017). After this milestone, in 2011 a new 2D seismic survey was acquired. It was contracted by ANCAP and was particularly designed to cover the most promising areas in order to better define some leads and prospects. Its results were used to promote offshore Uruguay exploration during the following years.

The next offshore bidding round was held in 2012 and it was named Uruguay Round II. It was very successful, fifteen areas were offered, eleven oil companies qualified, nineteen offers were received, there was competition for five areas, and it resulted in the signature of eight new contracts with important exploratory work commitments (Ferro et al. 2017).

From 2012 to 2017 there was an intense exploratory activity, which was mostly in response to the work commitments of the Uruguay Round II. Some of the most remarkable exploration activities during this period were:

- The acquisition of four 2D seismic surveys, totaling nearly 11,000 km of new 2D seismic data.
- The acquisition of five 3D seismic surveys, totaling a coverage of nearly 41,000 km^2 of 3D seismic data.
- The acquisition of a large 3D Controlled Source Electromagnetics (CSEM) survey, with an approximately coverage of 13,000 km^2.
- Several piston core seabed samples were taken for geochemical analyses.
- RAYA well was drilled.

The following offshore bidding round, which was also the last one, was named Uruguay Round 3. It was held in 2018 and resulted in the qualification of two oil companies, but no offers were received (ANCAP 2018b). The reason behind this outcome was the long lasting low oil price scenario which made the exploration in frontier basins poorly attractive for international oil companies (ANCAP 2018b).

5. Characteristics of the Uruguayan oil and gas Fiscal Regime

ANCAP, which in Spanish stands for "Administración Nacional de Combustibles, Alcohol y Portland" (National Administration of Fuels, Alcohol and Portland), besides of being the national oil company of Uruguay, it is also, by law, the state entity that signs, with the previous approval of the Executive Branch, the Exploration and Production contracts with private parties. These contracts, due to the current hydrocarbon legislation in Uruguay, are typical PSCs.

The relevant characteristics of the Uruguayan PSC for offshore areas, as explained in Ferro et al. (2017) and in ANCAP (2018a), are the following:

- The title of the hydrocarbons is kept by the Uruguayan State.
- Total duration of the contract is 30 years. It could be extended, in the production phase, with the approval of the Executive Branch, for 10 additional years.
- Contractors do not pay royalties, bonuses or surface rentals of any kind.
- Contractors bear with all the exploration and exploitation risks, costs and responsibilities, and receive no compensation if no commercial discovery is made.
- The committed exploratory program for the initial exploratory phase is biddable and used for comparison of offers.
- ANCAP has a back-in option. It has the right to take up a working interest in the project development if commerciality of a discovery is declared. ANCAP's maximum percentage of association, which varies between 20% and 40%, is also biddable and used for comparison of offers. In the case ANCAP decides to associate, it would bear its prorated share of development and exploitation costs and would receive its prorated share of revenues.
- The production income is divided into three portions: Cost Oil, Profit Oil for the Contractor and Profit Oil for the Uruguayan State.
- The Contractor is allowed to recover operating expenditures (OPEX) and capital expenditures (CAPEX). While OPEX is recovered quarterly, CAPEX is recovered in 20 quarterly installments.
- Cost Oil is deduced from gross income, before sharing production profits, and there is a cost recovery limit. For the case of oil production, cost recovery is limited to 60% of the gross income, while for the case of natural gas production, it is limited to 80%. If Cost Oil, for any quarter, is greater than the cost recovery limit, the remaining unrecovered amount is carried forward to the following quarter.
- Profit Oil is the portion of production remaining after Cost Oil has been deducted. It is split by the State and the Contractor according to a recovery factor (R factor, see **Table 2**), which is defined as the relationship between accumulated gross income and accumulated Cost Oil. The incremental Profit Oil for the State (X for oils with ºAPI>25, X' for oils with ºAPI<25 and Xg for natural gas) is biddable and is used for comparison of offers.

R Factor	% Profit Oil State
<1	8 + X
1-1,5	15 + X
1,5-2	20 + X
>2	30 + X

Table 2 – Profit Oil for the Uruguayan State vs. R factor (ANCAP 2018a)

The offered incremental Profit Oil for the State: X, X' and Xg, have to be values between 0% and 70%.

- There is a domestic market obligation. For the case of oil, local sales price is the same as the international price of a basket of oils with similar characteristics. Natural gas price is an average of four terms: Henry Hub natural gas price (from US); National Balancing Point natural gas price (from UK); a regional gas price to be agreed (it could be the cost to import gas for Argentina); and a parity formula relating natural gas price to oil price.
- The Contractor pays Income Tax on its share of Profit Oil, and according to local legislation the Economic Activities Income Tax is 25%.
- Since all the hydrocarbon activities are declared of national interest, all taxes, except for Income Tax and Social Security Taxes for workers, are exempted by Hydrocarbons' Law.

Oil companies interested in participating in the bidding process for offshore areas have to offer: a work program for the first exploration period, incremental Profit Oil values (X for oils with ºAPI>25, X' for oils with ºAPI<25 and Xg for natural gas) and ANCAP's maximum association percentage. In the case of competition for the same area, offers are compared using the formula shown in Eq. 3, and the area will be awarded to the company that presented the offer with the highest score.

$$Total\ Score = 60 * \left(\frac{A}{A_{max}}\right) + 120 * \left(\frac{WU}{WU_{max}}\right) + 40 * \left(\left(\frac{X}{X_{max}}\right) + \left(\frac{X'}{X'_{max}}\right) + \left(\frac{Xg}{Xg_{max}}\right)\right) \ldots (3)$$

Where:

- A: is the offered ANCAP association percentage.
- A_{max}: is the maximum ANCAP association percentage offered for the area.
- WU: are the offered total Work Units (committed exploratory work).
- WU_{max}: is the maximum total Work Units offered for the area.
- X: is the offered Uruguayan State Profit Oil increase for light oils.
- X_{max}: is the Uruguayan State maximum Profit Oil increase for light oils offered for the area.
- X': is the offered Uruguayan State Profit Oil increase for heavy oils.
- X'_{max}: is the Uruguayan State maximum Profit Oil increase for heavy oils offered for the area.
- X_G: is the offered Uruguayan State Profit Oil increase for natural gas.
- X_{Gmax}: is the Uruguayan State maximum Profit Oil increase for natural gas offered for the area.

In the near future, Uruguay Open Round is going to be launched and blocks are planned to be awarded every six months to oil companies that have qualified and presented offers (ANCAP 2018c).

The exploratory phase will have a first exploration sub-period of 4 years **(Fig. 5).** In this initial stage the required minimum work commitment is very low. After this first sub-period, the contractor could relinquish the area or choose between two supplementary exploration sub-periods (A or B).

The supplementary exploration sub-period A could last up to 3 years. During this sub-period there is no need for partial area relinquishment, but a well must be drilled. On the other hand, if the contractor chooses to go for the supplementary exploration sub-period B, which could last up to 2 years, it would be required to fulfill a minimum work commitment and it will also have to relinquish 50% of the area. However, during this sub-period the drilling of a well is not mandatory.

Additionally, there could be a final extension sub-period (3rd exploration period in Fig. 5), which is optional and could last up to 3 years. In order to accede to this extension, the contractor has to commit at least one well and relinquish 30% of its remaining area.

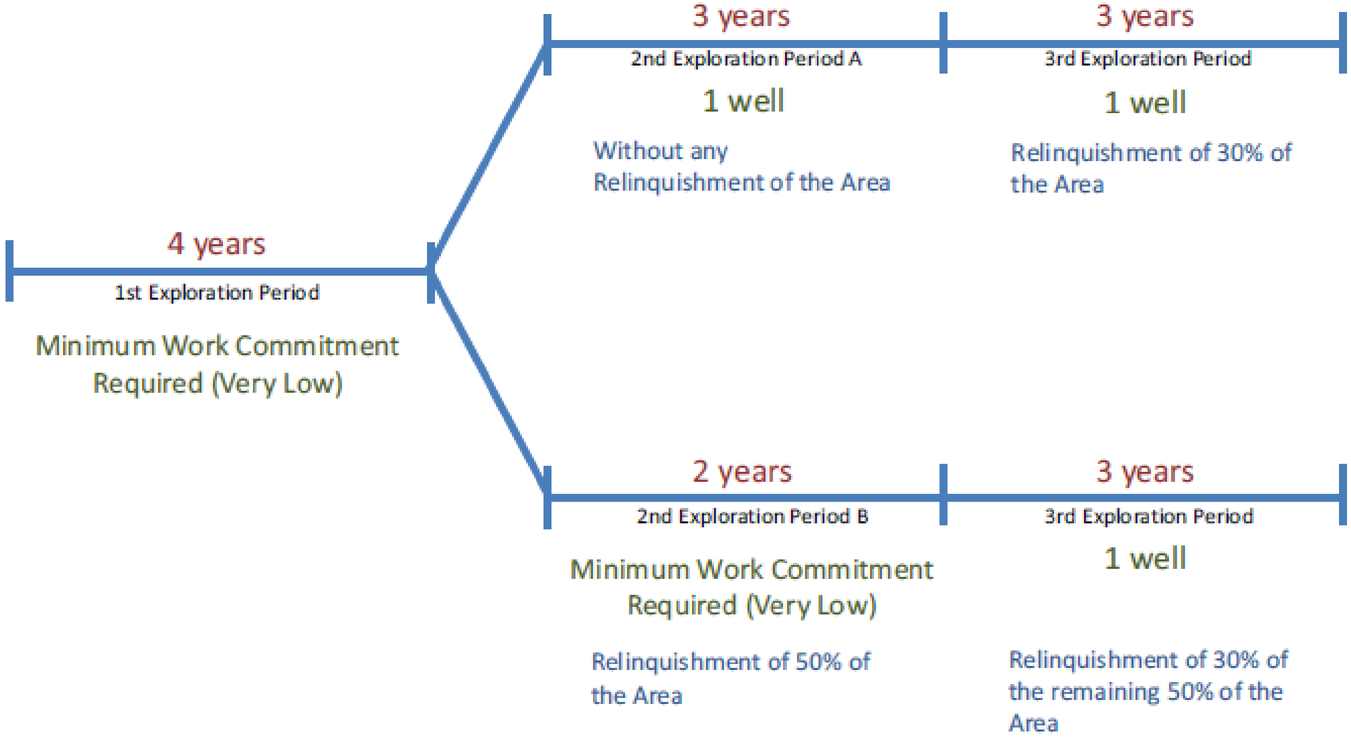


Fig. 5 – Main features of the exploration periods (ANCAP 2018c)

6. Methodology applied in the economic analyses

6.1. Probabilistic analysis

The probabilistic volumetric resource analyses as well as the probabilistic economic analyses were carried out in Microsoft® Excel® spreadsheets running Palisade® @Risk® add-in. In this report the economic spreadsheets are referred as ECO-Spreadsheets. All the probabilistic analyses were performed through the application of Monte Carlo simulations, which consisted of 10,000 iterations using Latin Hypercube sampling.

For the probabilistic volumetric analyses, some key parameters were obtained from published data about turbidite fields located in sedimentary basins from offshore Brazil, Ghana and Falkland Islands, others were estimated from published correlations. The values from the created database were used, as analogous, to support the parameters for the probability distribution functions of key reservoir variables used in the volumetric formula for Estimated Ultimate Recovery (Eqs. 1 and 2).

The selected production concept for the economic evaluation involves production through FPSO vessels. The produced oil would be exported via tankers and the associated gas would be either sent to shore through a gas pipeline, or re-injected into the reservoir. For the economic evaluation, the latest fiscal terms of the applicable production-sharing contract, for offshore assets in Uruguay, were considered.

The probabilistic economic analysis results includes, for each prospect, several key performance indicators such as: net present value, internal rate of return, maximum negative cash flow, breakeven oil price, government take and entitlement percentage of hydrocarbons. These indicators were determined after running the economic simulations, which considered probability distribution functions for fixed and variable capital and operational expenditures along with well productivities and decline rates.

Regarding the economics of the project, several scenarios of incremental profit oil for the government and maximum association percentage for ANCAP, were evaluated. The cases considered show how key negotiables and variables, featuring in the tender process offered to oil companies interested in Uruguay’s offshore hydrocarbon assets, may affect the economics and development solutions of a typical field development project.

6.2. Assumed reservoir fluid

All the prospects analyzed in this project are assumed to contain a black oil fluid with the following properties:

$$30° \text{ API}$$

$$\gamma_g = 0.8 \;\; (\text{air} = 1)$$

$$0 \le GOR \le 2{,}000 \text{ scf/STB}$$

This choice is supported by the fact that two independent fluid inclusions studies, which analyzed unwashed cuttings from LOBO and GAVIOTIN wells (Fig. 2), encountered light oil inclusions of approximately 32° API (Tavella and Wright 1996; Soto et al. 2016).

Oil generation offshore Uruguay is also supported by source rock maturation models presented in Morales (2013).

6.3. Oil Price

Local oil sales price is stipulated in the Production Sharing Contract to be equal to the international price of a basket of oils with similar characteristics.

In the analyses performed in this project the following oil price scenarios were considered:

- Fixed price, user defined, for the entire project.
- Fixed initial price and a variable annual escalation percentage, taken at the start of each year, from a symmetrical triangular distribution defined between -10% and 10%. Moreover, to avoid unrealistic low prices, a minimum oil price value can be entered by the user, which by default is set equal to $30/bbl.
- EIA Low, Reference and High Brent oil price forecasts up to year 2050, extended with a straight line trend up to year 2060 **(Fig. 7).**

EIA Brent price forecasts are taken from the 2019 EIA's Annual Energy Outlook and were developed using the National Energy Modeling System, which is an "integrated model that captures interactions of economic changes and energy supply, demand and prices" (EIA 2019). The EIA Reference case "represents EIA's best assessment of how U.S. and world energy markets will operate through 2050, based on many key assumptions" (EIA 2019), while the EIA High and Low oil price cases "represent international conditions outside the United States that could collectively drive prices to extreme, sustained deviations from the Reference case price path" (EIA 2019).

Since EIA forecasts cover up to year 2050, and the project could last up to a maximum of 40 years, the forecasted oil prices were extended up to year 2060 with straight line trends using, for that purpose, the last 20 years of EIA forecasted data **(Fig. 6).**

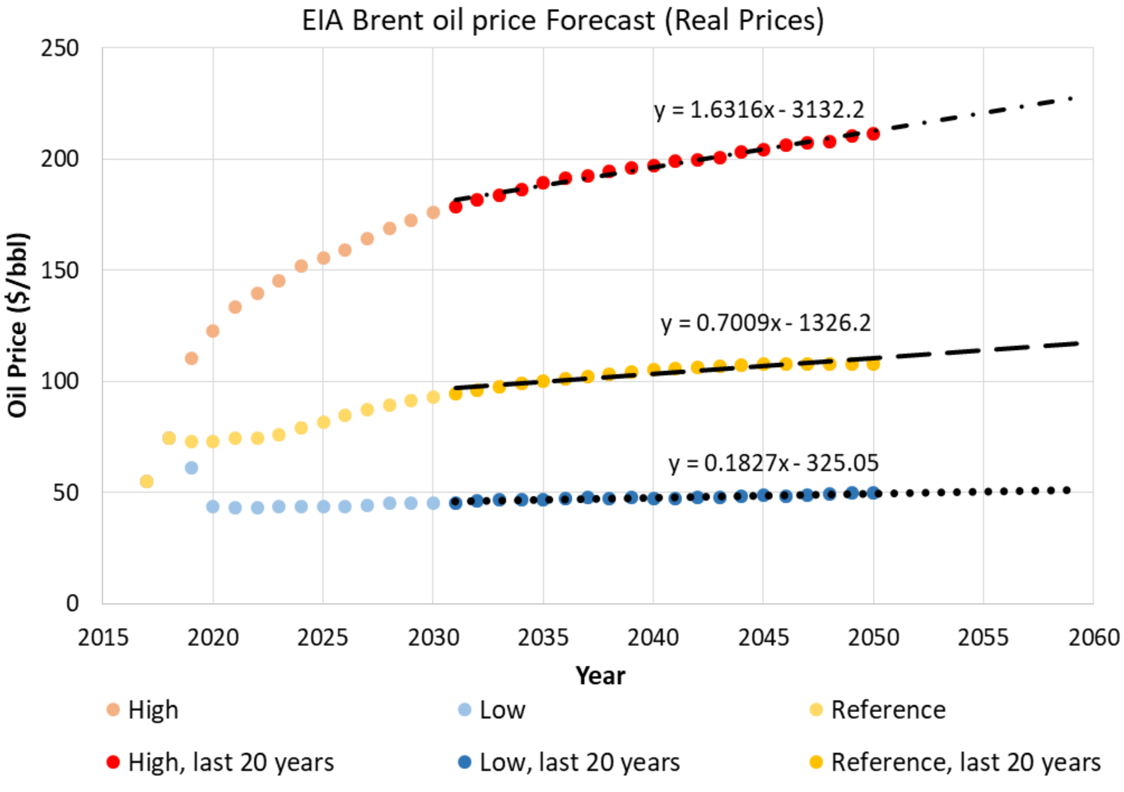


Fig. 6 – EIA Brent Oil price forecast

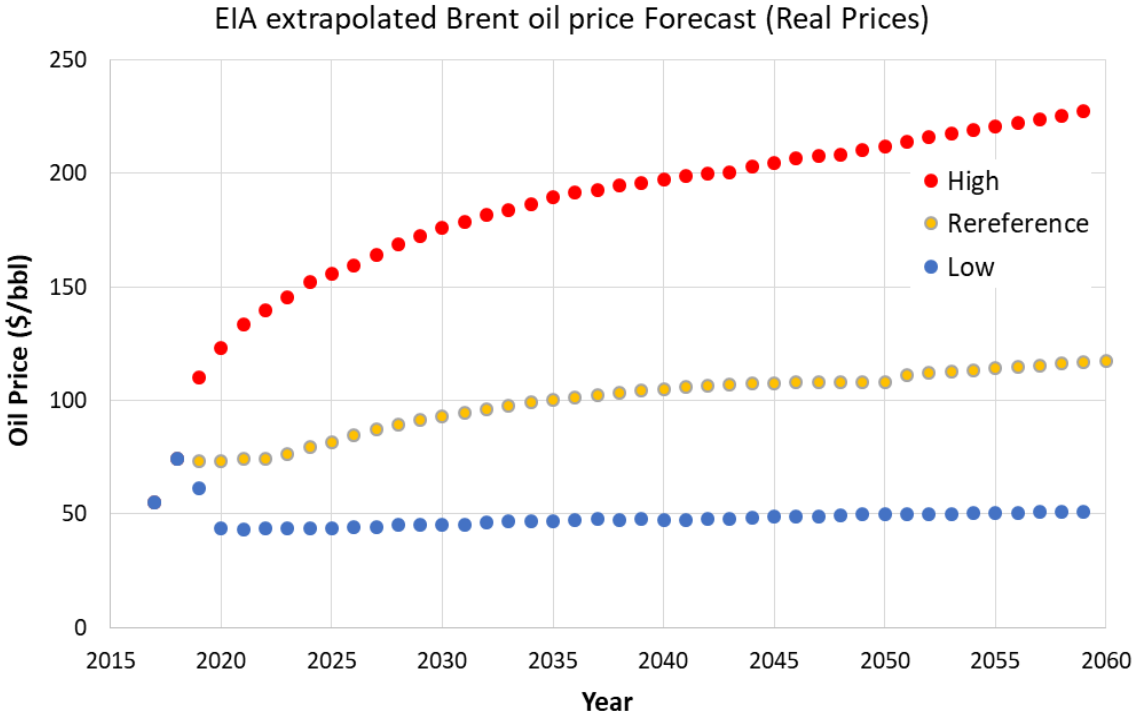


Fig. 7 – EIA Brent Oil price forecast extrapolated up to year 2060

All the above-mentioned forecasts as well as the historical Brent oil price are shown in **Fig. 8**. In this figure the user defined forecast starts with an initial $70/bbl oil price and a yearly variable escalation is taken from a symmetric triangular distribution defined between -10% and 10%. At the start of each year a new escalation is taken from a PDF, identical to the one previously mentioned, and kept for that particular year. This process is repeated until January 1st 2060.

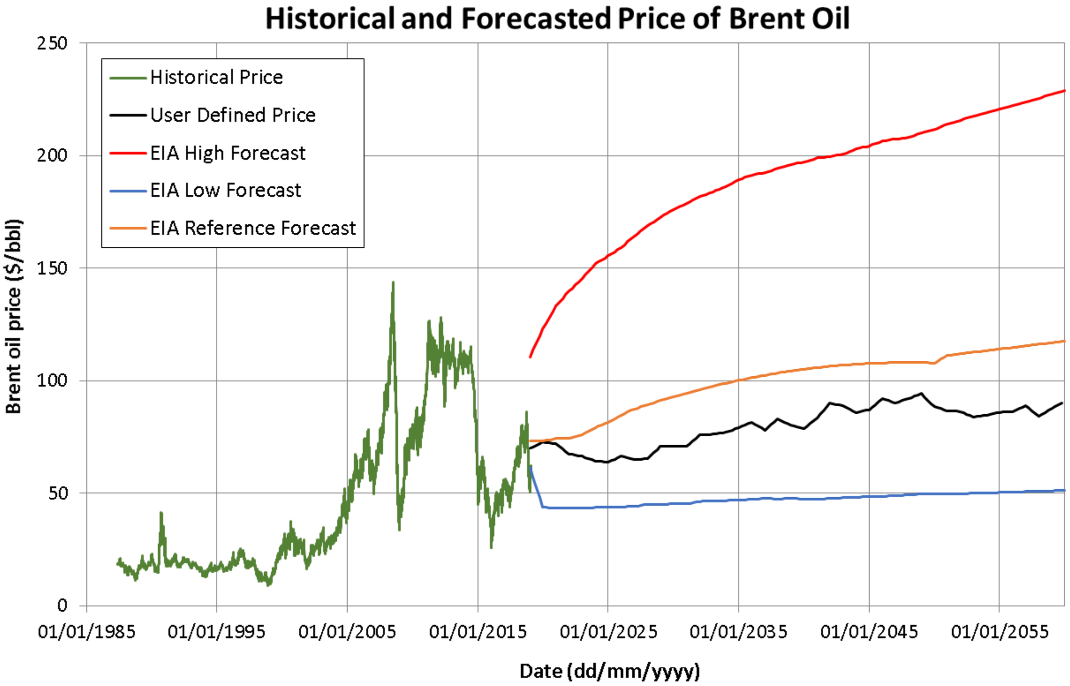


Fig. 8 – Oil price forecast example

6.4. Natural Gas Price

Natural gas price is stipulated in the Production Sharing Contract as the average of these four factors: Henry Hub (HH) Natural Gas (NG) price, UK National Balancing Point (NBP) NG price, an agreed Regional Gas price, which could be the cost to import gas from Argentina, and a parity formula relating natural gas price to oil price. In this project the following assumptions were made for gas price computation:

- Regional gas price is set equal to $17.5/MMBTU, which corresponds to an approximate average gas importation cost form Argentina.
- UK NBP gas price is set equal to $5.5/MMBTU, which corresponds to the average NBP NG price between 1996 and 2017 **(Fig. 9).**

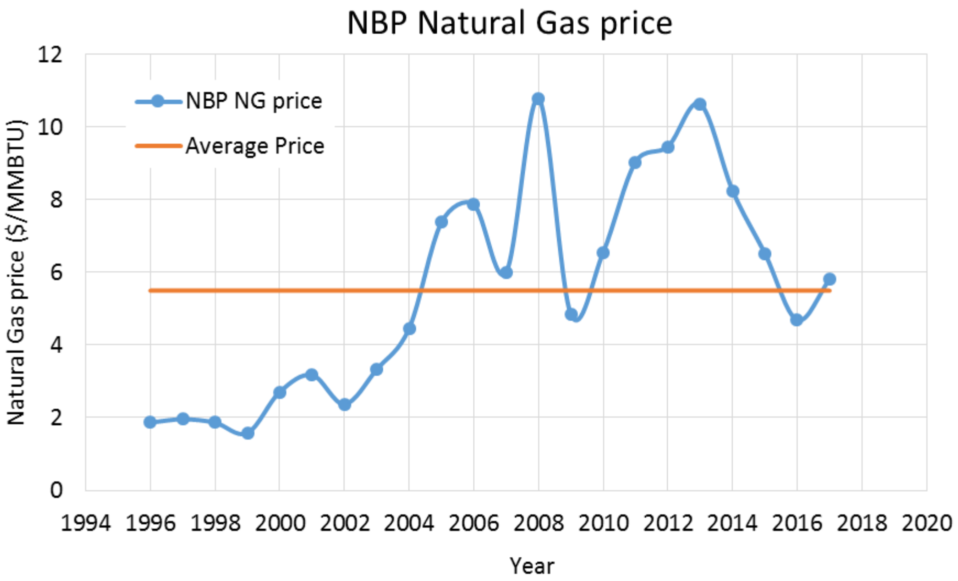


Fig. 9 – Historical NBP Natural Gas price (Ycharts 2019)

- HH gas price is set to \$3/MMBTU unless an EIA price forecast is selected, in that case, as happened with oil price, the EIA forecasts were extended until year 2060. For that purpose the last 10 years of the EIA forecasts were used for a straight line extrapolation **(Fig. 10).**
- The oil price dependent term in the formula used for natural gas price calculations is: $0.1 * (Oil\ Price) - \$3$, and for its computation it uses the oil price settings entered by the user.

As defined in the PSC, the Natural Gas price formula is:

$$NG\ Price\left(\frac{\$}{\text{MMBTU}}\right) = \frac{HH\ NG\ price + NBP\ NG\ price + Regional\ NG\ price + (0.1 * (Oil\ price) - 3)}{4} \ldots.(4)$$

Applying the above-mentioned assumptions it is simplified to:

$$NG\ Price\left(\frac{\$}{\text{MMBTU}}\right) = \frac{HH\ NG\ price + 5.5 + 17.5 + (0.1 * (Oil\ price) - 3)}{4} = \frac{HH\ NG\ price + 20 + 0.1 * (Oil\ price)}{4} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (5)$$

Finally, NG price is calculated as:

$$NG\ Price\left(\frac{\$}{\text{MMBTU}}\right) = \frac{HH\ NG\ price + 20 + 0.1 * (Oil\ price)}{4} \ldots\ldots\ldots\ldots\ldots\ldots (6)$$

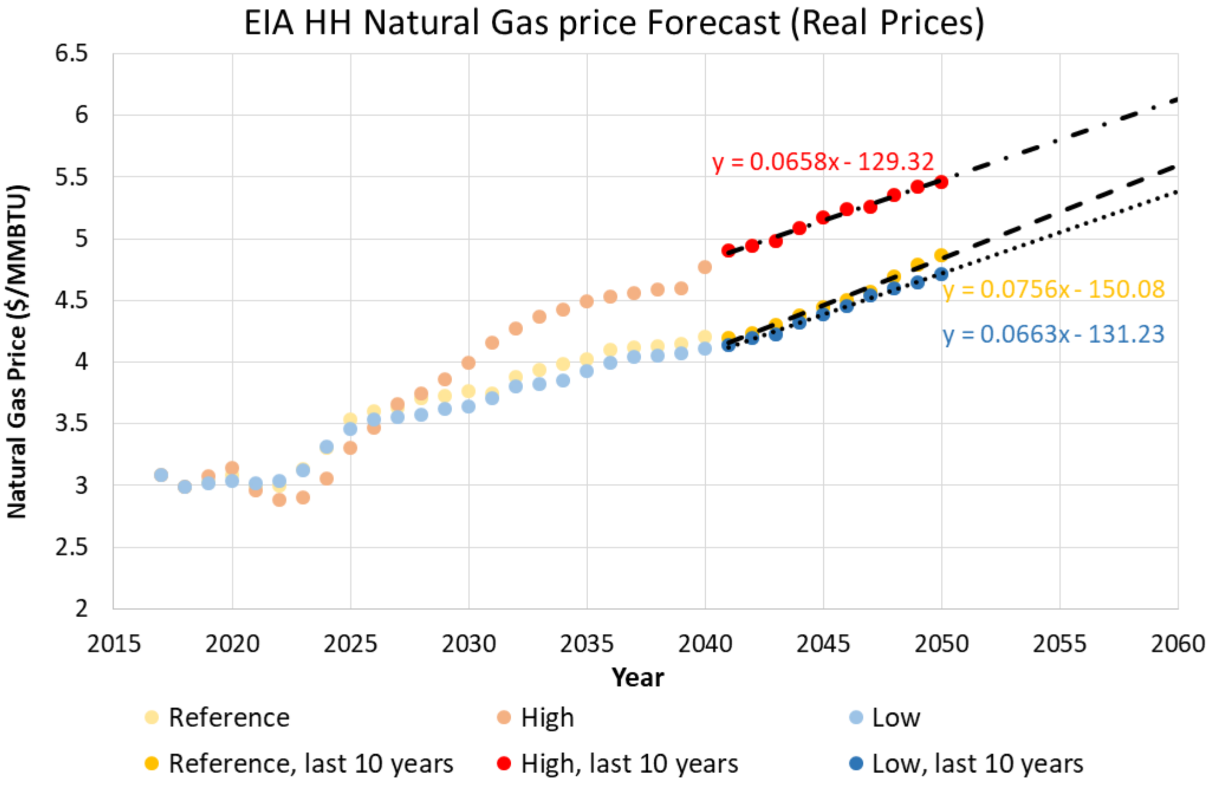


Fig. 10 – EIA HH Natural Gas price forecast

6.5. Operating Expenditures

Operating expenditures are divided into two categories: fixed and variable. Fixed OPEX is defined as a triangular distribution with a minimum value of 4 MM$/quarter, a most probable value of 5 MM$/quarter and a maximum value of 6 MM$/quarter. These values are based on what oil companies that operated in Uruguay reported as operating expenditures.

Variable OPEX is based on a published image, created in 2015, using a Rystad Energy® database as a reference for the cost to produce one barrel of oil in different countries **(Fig. 11).** For this parameter, minimum, average and maximum values are obtained from what was reported for a list of countries that have a long tradition of offshore oil and gas production. The selected countries are: UK, Brazil, USA, Norway, Angola and Mexico **(Table 3).**

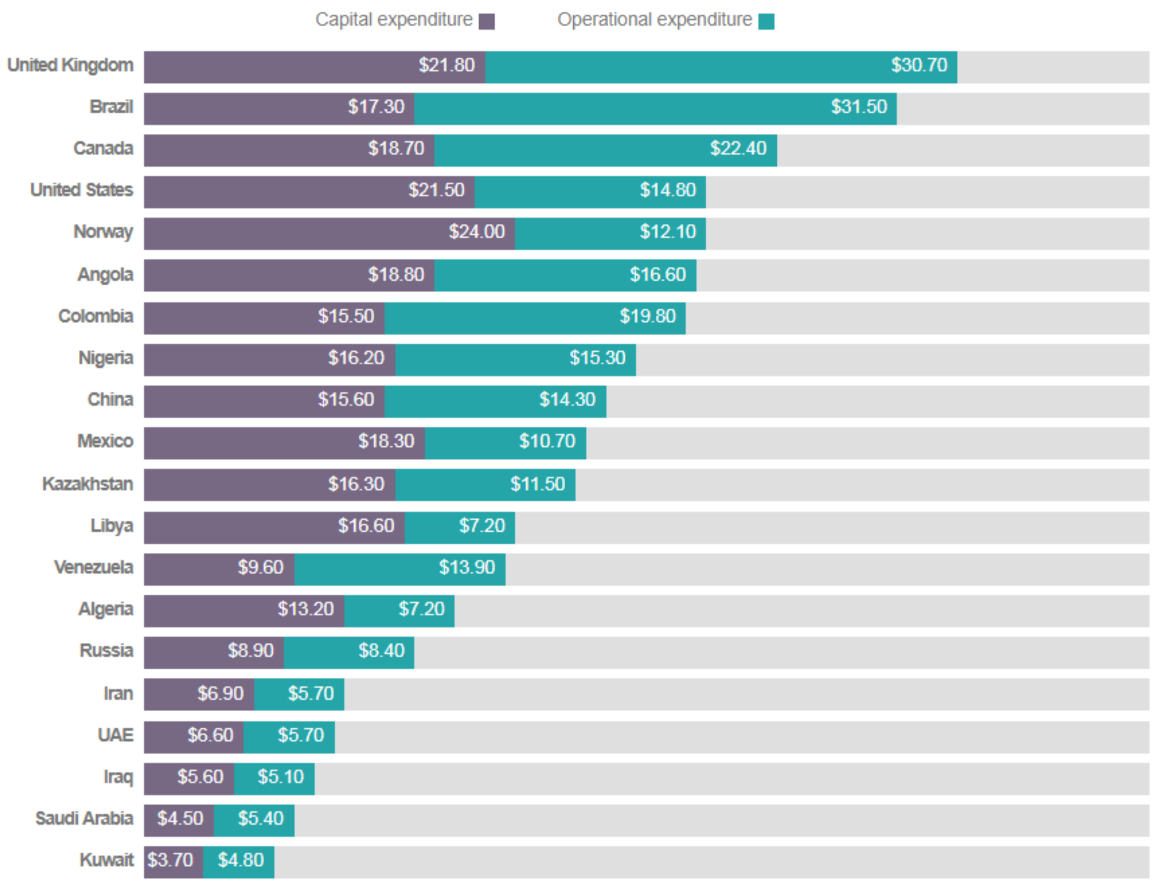


Fig. 11 – Cost to produce one oil barrel in different countries (Rystad Energy 2015)

	CAPEX ($/bbl)	OPEX ($/bbl)
UK	21.8	30.7
Brazil	17.3	31.5
USA	21.5	14.8
Norway	24	12.1
Angola	18.8	16.6
Mexico	18.3	10.7
MIN:	17.3	10.7
AVG:	20.3	19.4
MAX:	24	31.5

Table 3 – Cost to produce one oil barrel in selected countries

Using the statistics from Table 3, variable OPEX is defined as a triangular distribution with a minimum value of 10.7 \$/bbl, a most probable value of 19.4 \$/bbl and a maximum value of 31.5 \$/bbl.

Finally, an additional variable OPEX cost of \$1 per barrel of produced water (cost taken from Botechia et al. 2016) is assumed for produced water treatment and disposal to the sea.

6.6. Capital Expenditures

Capital Expenditures for the development of the analyzed prospects are divided into the following costs:

- Cost of drilling the exploratory, appraisal, production and injection wells required to develop the field.
- Cost of all the required subsea infrastructure: Subsea Umbilicals, Risers and Flowlines, also known as SURF costs.
- Cost to process produced oil and gas (FPSO cost).
- Cost to transport produced gas if it is sold (gas pipeline construction cost).
- Field abandonment cost.

6.6.1. Drilling Expenditures

The proposed field development projects for the analyzed prospects include both vertical and horizontal wells. The exploratory, appraisal and injection wells are defined to be vertical, while production wells are defined to have a horizontal section. In order to estimate well costs, a simplified 'L' shaped well is considered, taking this into account, the cost to drill a well can be estimated as:

$$Well\ cost = Rig.cost * \left(\frac{(vert.sec. + horiz.sec.)}{average.drilling.rate} * (1 + A) * B + mob.demob.days\right) \ldots\ldots\ldots (7)$$

Where:

- ***Rig.cost*** is the average drillship cost per day. It is defined as a triangular distribution with a minimum of \$200,000 per day, a most probable value of \$250,000 per day and a maximum of \$350,000 per day. The reference for these values is **Fig. 12,** which is taken from an IHS Markit report.
- ***vert.sec.*** is the vertical section drilled by the well and it is assumed equal to the average sedimentary overburden on the prospect. It is calculated as:
  $vert.section = Average\ Reservoir\ TVD - Average\ Water\ Depth$……………(8)
- ***horiz.sec.*** is the total horizontal section length. According to Martins et al. (2011), typical horizontal sections for production wells in Campos basin, range from 500 m to 700 m for light oil production, while for heavy oil production this distance could be larger than 1200 m, therefore, a horizontal section of 1000 m is assumed for the production wells.

- ***average.drilling.rate*** is an average value for: total amount of meters drilled by a well divided by the total number of days required for the well to be drilled. A value of 50 m/day was used, this reference was taken from Barcelos et al. (1994) and correspond to a value achieved in 1985, which makes it a conservative reference.
- ***A*** is a contingency factor for total drilling days. For this project it was set equal to 50%.
- ***B*** is the ratio of the total cost of "Services, Consumables and Logistics" to "Rig Cost". This ratio is based on costs reported for the recently drilled RAYA well and was set equal to 3.
- ***mob.demob.days*** is the mobilization and demobilization time (in days) that a drillship may require to trip to Uruguay and then leave for another area. For the analysis done in this report it was assumed equal to 40 days, but in the ECO-spreadsheet it is a user defined variable.

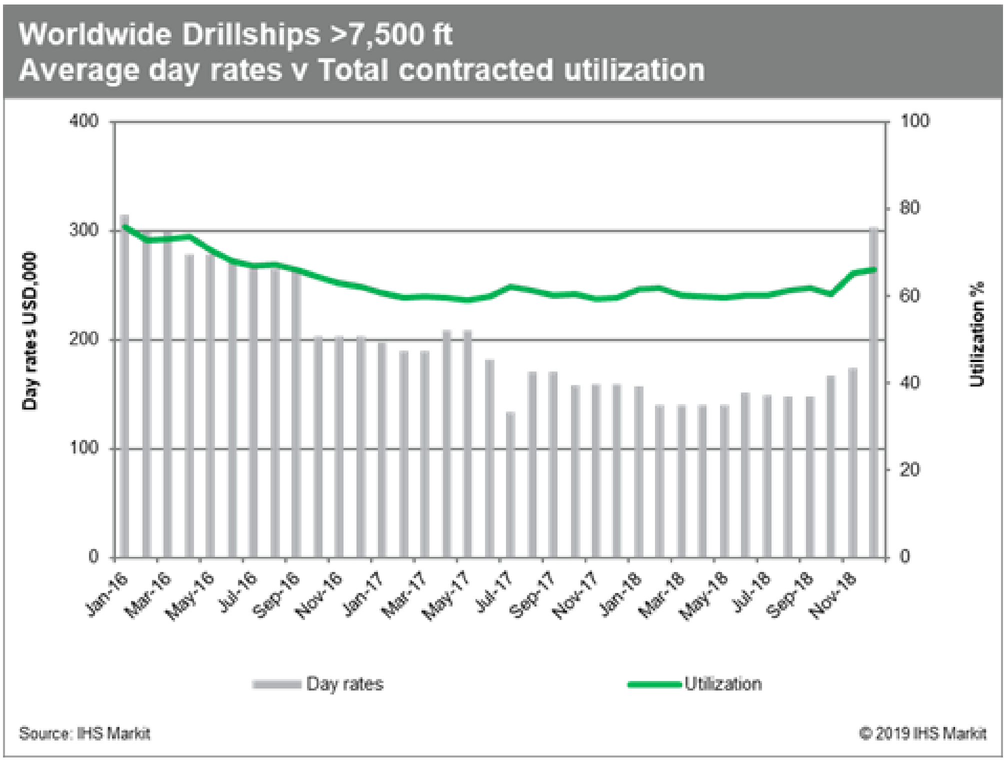


Fig. 12 – Drillship cost per day (IHS Markit 2019)

Once the exploratory well is successfully drilled and logged, good estimates of formation pore and fracture pressures are obtained. As a result of this new information, well design can be optimized and thus well drilling costs can be reduced. For this reason, a user defined well cost reduction percentage (20% by default) was set for the appraisal wells.

Production wells are defined to have an additional horizontal section and therefore will require more drilling days, which is translated in an additional cost. However, for those wells a user defined well cost reduction percentage was set (40% by default), which is justified by these two reasons: improvement on well design due to a better knowledge of the rock physics, and reduction in prices due the fact that better prices can be negotiated for long term drilling contracts.

Along the life of a well it will require a certain amount of interventions such as workovers, re-completions, stimulations, etc. This adds up to total CAPEX, and for a more realistic scenario they must be considered. In order to account for that, a number of interventions per well and per quarter was defined in the ECO-Spreadsheet and was set equal to 0.0450 (0.18 interventions per year). This reference value is based on an analysis performed by Hauge and Horn (2005) for the case of production wells from the Troll field (located in the Norwegian sector of the North Sea). These authors reported between 0.16 and 0.19 interventions per well, per year, between 1999 and 2004. On the other hand, the cost associated to each intervention was assumed equal to 5 MM$, which is a conservative average of what was reported by Small et al. (2015) for a case study in the Gulf of Mexico.

6.6.2. SURF, Production Processing and Gas Transportation Expenditures

SURF costs, as well as production processing and gas transportation expenditures, were defined as triangular distributions. The parameters used to define them are based on price estimations obtained from consulted service companies as well as from oil companies that operated in the offshore of Uruguay.

The total cost for Subsea Umbilicals, Risers and Flowlines was defined as a triangular distribution with a minimum of $4/boe, a most probable value of $5/boe and a maximum of $6/boe.

The cost of production processing (FPSO cost) was defined as a triangular distribution with a minimum of $4/boe, a most probable value of $5/boe and a maximum of $6/boe.

If produced gas is sold, a deepwater gas pipeline has to be constructed, therefore a fixed CAPEX is required for gas transportation. With the aim of having a realistic estimate of this cost, a short research on recent deepwater gas pipelines was conducted. The results of this study are summarized in **Table 4.**

Pipeline	Location	Deepest Point (m)	Cost in local currency		Exchange Rate		Cost (MM$)	Capacity (MMm^3/d)
Medgaz	Mediterranean Sea	2,155	900,000,000	€	1.13	USD/€	1,017.0	21.90
Route 2	Brazil (Santos Basin)	2,233	8,609,792,000	R$	0.25817	USD/R$	2,222.8	13.00
Route 3	Brazil (Santos Basin)	2,296	5,910,721,000	R$	0.25817	USD/R$	1,526.0	17.80

Pipeline	Capacity (MMscf/d)	Diameter	Length (km)	Offshore Section (km)	Cost MM$/km	Sources
Medgaz	773.29	24'' ID	210	210	4.843	Medgaz 2019
Route 2	459.03	24'' OD	402	398	5.529	de Lemos et al. 2015; PAC 2018a; d'Huart 2018
Route 3	628.52	24'' OD	355	307	4.299	de Lemos et al. 2015; PAC 2018b; Figueira 2018

Table 4 – Costs of deepwater gas pipelines

With these references the cost per kilometer for a 24'' gas pipeline from the prospect area to shore is defined as a triangular distribution with a minimum value of 4.299 MM$/km, a most probable value of 4.843 MM$/km and a maximum value of 5.529 MM$/km. The total cost of the pipeline required is therefore estimated as the product of the previous distribution and the total length of the required gas pipeline.

6.6.3. Abandonment

When a contract for an area in the offshore Uruguay enters in the Production phase, the contractor has an obligation to quarterly deposit a predefined amount of US dollars ($) in a Uruguayan bank account. The total deposited amount will be growing over the life of the field and it will serve as an "Abandonment Fund".

From the start of production a fixed amount of $250,000 must be deposited per quarter in the Abandonment Fund, and this will regularly occur until the moment in which the field has produced half of its expected reserves. After the accumulated production surpasses that threshold, the amount to be deposited in the "i" quarter will follow this formula:

$$FA_i = CA * \frac{NP_i - EUR * 0.5}{EUR * 0.5} - FAA_i \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots.. (9)$$

Where:

- FA_i: is the amount, in $, to be deposited in the Abandonment Fund in the "i" quarter.
- CA: is the total updated estimated abandonment cost, in $.
- NP_i: is the cumulative production, in barrels of oil equivalent, until the beginning of the "i" quarter.
- EUR: is the total estimated ultimate recovery in barrels of oil equivalent.
- FAA_i: is the total amount deposited in the Abandonment Fund, in $, before the "i" quarter.

For this project the estimated abandonment cost is set equal to 5% of the capital expenditures.

6.7. Exploratory approach

The exploratory approach assumed for the economic evaluation of the prospects addressed within this report, is divided into the following sub-periods and activities:

- An initial basic exploratory sub-period of four years (Fig. 5). Since there is a great amount of 3D seismic data already acquired, during this time a potential contractor may offer to reprocess a portion of it, at least in the areas where the most promising prospects are located. In this sub-period, which has no mandatory drilling commitment, no exploratory wells are expected to be drilled.
- After the basic exploratory sub-period, the supplementary sub-period A is chosen. An Exploratory well would be drilled during the first year of this sub-period and if it results in a discovery, one appraisal well will be drilled at each following year, totaling two appraisal wells. With the results of these three wells, the contractor may declare the commerciality of the discovery at the end of the seventh year **(Table 5).** After this moment the contract enters in the Field Development Planning (FDP) phase.

Year:	1	2	3	4	5	6	7
Phase:	Exploration (basic sub-period)				Exp.	Appraisal	

Table 5 – Proposed schedule for the Exploration and Appraisal phases

6.8. Field Development

The Field Development Plan is addressed on the eighth year **(Table 6).** During this time all the engineering design work takes place as well as the selection of suppliers.

During the next two years (9 and 10) the Development phase of the project occurs, this implies the construction and installation of the required infrastructure (FPSOs, pipelines, etc.). Additionally, at the beginning of year 10, the drilling of production wells starts.

Year:	8	9	10	11	12	…	39	40
Phase:	FDP	Development		Production				

Table 6 – Proposed schedule for the development phases

Production phase begins at the start of year 11. The successful appraisal wells (a user defined variable, set by default to be one out of two) would be put in production in addition to production wells drilled during the previous year. Drilling activities will continue in the following years to keep field production at a plateau **(Fig. 13).** In order to achieve this production plateau, well drilling activities are phased according to the following drilling schedule:

- 20% of the required production wells are drilled during the last year of the development phase (year 10). Those wells are put in production at the start of the first year of the production phase (year 11).
- 20% of the required production wells are drilled during year 11 and are put in production at the start of year 12.
- 10% of the required production wells are drilled during year 12 and are put in production at the start of year 13.
- 10% of the required production wells are drilled during year 13 and are put in production at the start of year 14.
- From year 14 to year 21, 5% of the required production wells are drilled per year and are put in production at the start of the following year.

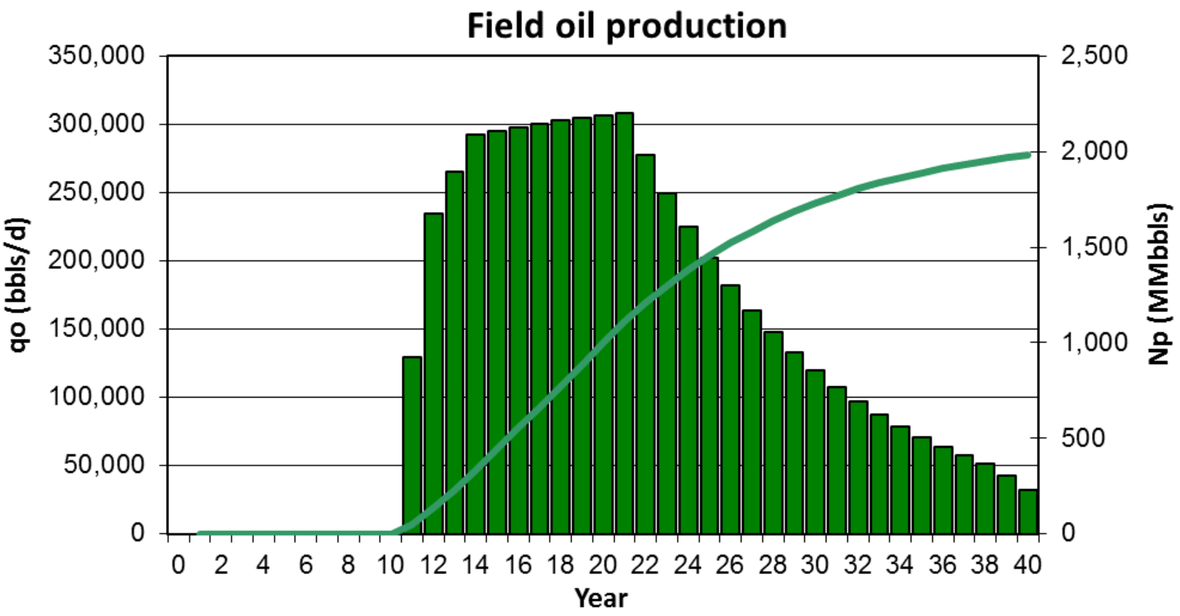


Fig. 13 – Example of a field oil production profile

6.8.1. Type Well

Since there is no hydrocarbon production history in Uruguay, published data from Campos basin fields was used in order to create analogous production profiles for its use in the ECO-Spreadsheet.

Oil production is assumed to present an exponential decline, therefore the oil production rate can be calculated as (Wright 2015):

$$q_o(t) = q_{oi} * \mathrm{e}^{-D*t} \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots ..\dots \dots \dots (10)$$

With this assumption, only two parameters are required to describe oil production: initial oil production rate (q_{oi}) and nominal decline rate (D). For both of them a probabilistic distribution function was defined based on published data of analogous producing fields.

According to Bruhn et al. (2003) production wells from Campos basin, which produce from Aptian to Miocene reservoirs, have initial production rates ranging from 3,000 bopd to 40,000 bopd, while in deepwater projects wells are typically designed to produce in the range of 10,000 bopd to 20,000 bopd. Taking into account these considerations, q_{oi} was defined as a triangular distribution with a minimum value of 5,000 bopd, a most probable value of 10,000 bopd and a maximum value of 20,000 bopd.

Regarding declines rates, Dumas et al. (2018) showed that the Marlim field (which is located in Campos basin) presented an annual decline rate, from 2002 up to 2014, of approximately 10%. In 2014 a proactive field management project started in order to slow down the decline rate of the field. It involved infill drilling, which was aided by 4D seismic, and resulted in the reduction of the field's decline rate to 3.8% per year. Furthermore, Nascimento and Shiozer (2017) performed an analysis on production wells from the Santos basin and showed that the average annual decline rate of a typical well in the pre-salt is 10.2%. Taking these considerations into account, the effective annual decline rate (D_e) was defined as a triangular distribution, which presents a minimum value of 5%, a most probable value of 10% and a maximum value of 15%. Since this distribution is for the effective annual decline, the nominal annual decline is then found using the formula shown in Eq. 11 (Wright 2015):

$$D = -\mathrm{Ln}(1 - D_e) \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots ..(11)$$

In this project a well is kept on producing only if oil production rate is greater than 100 bbls/d and water cut is less than 95%. To check this last condition water production is calculated by assuming that the well produces at a constant rate throughout the project duration ($q(t) = q_{oi}$), therefore a reduction in oil production rate coincides with an incremental increase in water production rate:

$$q_w(t) = q_{oi} - q_o(t) \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots .\dots \dots \dots \dots (12)$$

Associated gas production rate is calculated by multiplying oil production rate by gas oil ratio:

$$q_g(t) = q_o(t) * GOR \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots \dots .(13)$$

Fig. 14 shows production profiles from a hypothetical type well. In this example the initial oil production rate is 10,976 bbls/d and the effective decline is 7.7% (nominal decline = 8.0%). Gas production rate is depicted in barrels of oil equivalent per day (boe/d).

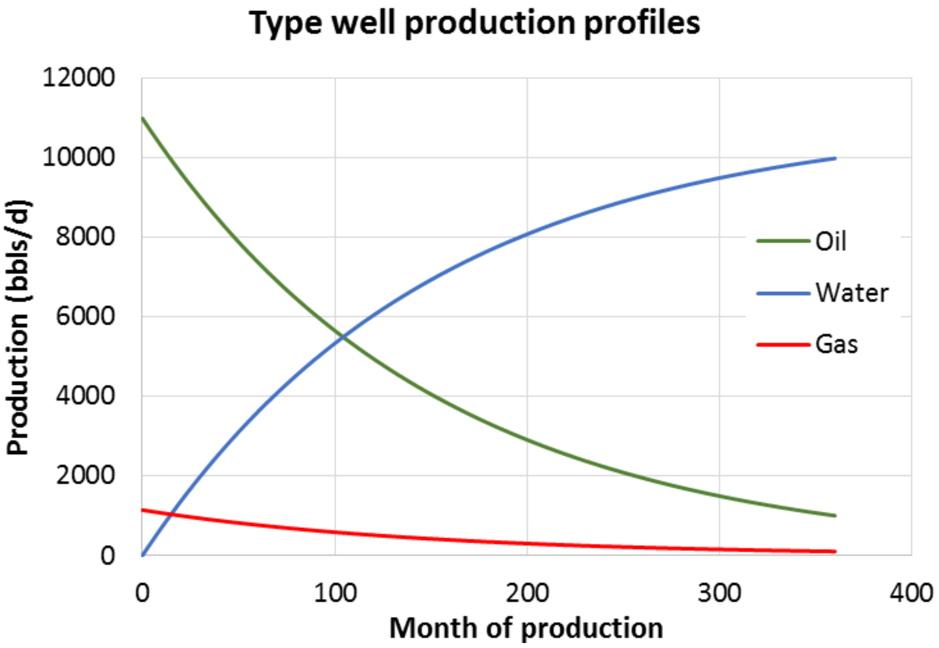


Fig. 14 – Example production profiles for a type well

The required amount of production wells is estimated using the oil EUR of the prospect and the cumulative production of the type well in 30 years of continuous production ($Np_{30yr\_type\_well}$), which according to the proposed field development schedule, 30 years would be the longest a well may produce under the same contract, therefore:

$$\#Wells = \frac{Oil\ EUR\ of\ the\ prospect}{Np_{30yr\_type\_well}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (14)$$

$Np_{30yr\_type\_well}$ is calculated from the initial oil production rate, the nominal decline rate and considering that the well is shut-in if the production rate falls below $q_{min} = 100$ bbls/d or if water cut is greater than 95%.

6.8.2. Produced water

Produced water would be treated and disposed to the sea as commonly done in Campos fields (Souza et al. 2005; Nunes et al. 2011). Injection wells would be costly in an early stage, therefore they are not addressed in this report. However, the ECO-Spreadsheet was designed to allow the user to select if water injection is required. In that case, the number of necessary water injection wells, is determined by dividing water production by a hypothetical water injection rate per well. The PDF defined for water injection rate (per injection well) is defined as a triangular distribution with a minimum value of 10,000 bwpd, a most probable value of 25,000 bwpd and a maximum value of 50,000 bwpd. The parameters for this distribution were obtained from water injection values reported in the literature (Reid et al. 2009; Silva et al. 2007; Weathon and Manu 2012; Martinez and Ascencio 2018; García Ruiz et al. 2017; Botechia et al. 2016).

6.8.3. Produced gas

The produced gas in Campos basin fields has four applications: gas flaring, use in gas lift, re-injection into the reservoir and flow to the shore through existing pipelines (Bruhn et al. 2017). In a country with a developed gas infrastructure like Brazil, this last option is cheaper than drilling injection wells and it additionally generates revenues from gas sales. Gas flaring is not a valid option in Uruguay (ANCAP 2018a), therefore for this project only the following two alternatives are addressed: gas transportation through a gas pipeline to the city of Montevideo and re-injection of the produced gas into the reservoir.

Montevideo is the capital city of Uruguay and concentrates almost 40% of its population, approximately 1.3 million inhabitants out of 3.3 million (INE 2011), therefore it is a potential market for natural gas sales. It also has the advantage of an existing gas pipeline connecting to Argentina **(Fig. 15),** which has a maximum design capacity of 174 MMscf/d (Wikipedia 2019). The location map of the gas pipeline is shown in Fig. 15, the pipeline is depicted as orange line segments and Montevideo city is shaded in red.

Fig. 15 – Location map of Cruz del Sur gas pipeline (Gasoducto Cruz del Sur 2019)

The ECO-Spreadsheet was designed to allow the user to select if gas is re-injected or sold. In the case of re-injection, the number of required gas injection wells, is determined by dividing gas production by a hypothetical gas injection rate. The defined PDF for gas injection rate (per well) is a triangular distribution with a minimum value of 10,000 Mscf/d, a most probable value of 50,000 Mscf/d and a maximum value of 100,000 Mscf/d. The parameters for this distribution were obtained from gas injection values reported in the literature (Weathon and Manu 2012; Agrawal et al. 2016; Etuhoko and Proctor 2004; Silva et al. 2007). On the other hand, a user defined fixed amount of the produced gas (5% by default) will be used for internal consumption at the FPSO regardless of the fact that produced gas is re-injected or sold.

6.8.4. Field production

Field production is computed by aggregating single well productions. An example of this is shown in **Fig. 16:**

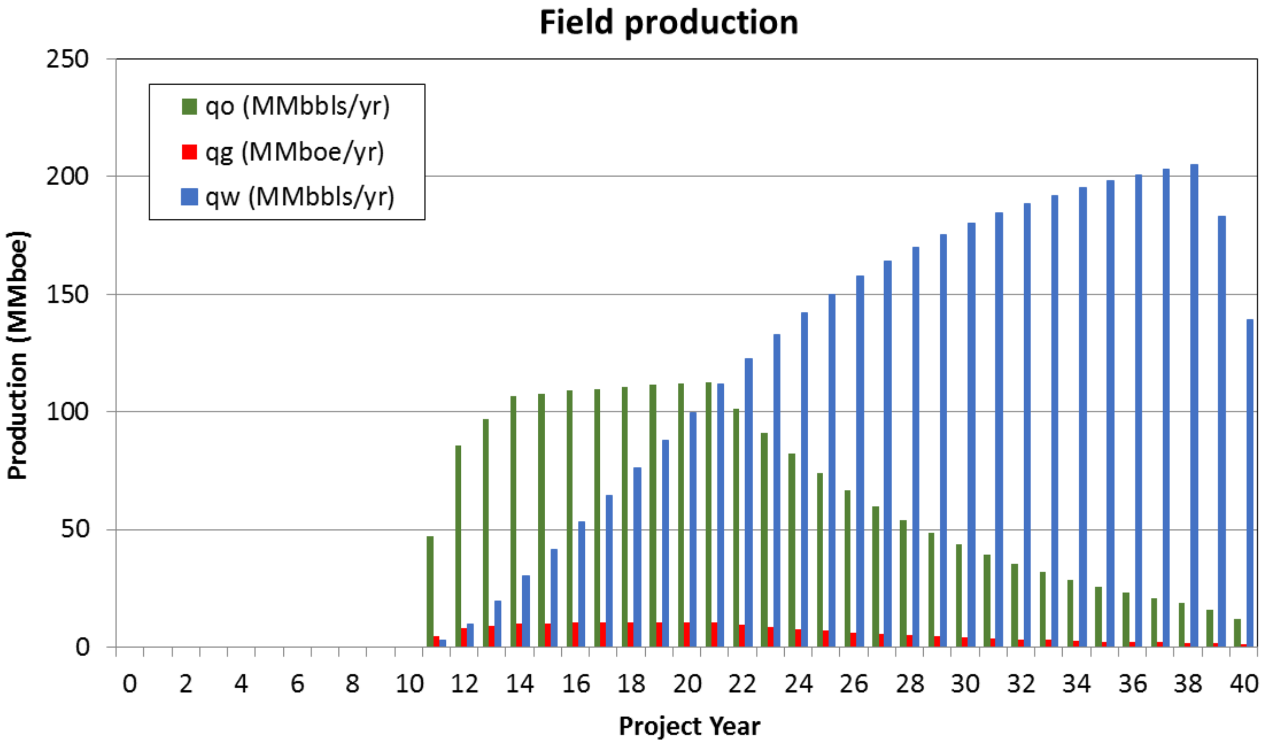


Fig. 16 – Annual field production example

6.9. Economic Scenarios

For the economic evaluation of the prospects two economic offer scenarios for a PSC were considered. The first one, named Scenario 1, is an optimistic case for an interested oil company (a potential contractor), and the other, named Scenario 2, is a conservative case. Both scenarios are further described in this report.

To correctly understand these scenarios it is important to know what an oil company interested in submitting a bid for an offshore area in Uruguay has to propose. As shown in chapter 5, the economic proposal is composed of:

1. An exploration program, which must be equivalent to an amount of Work Units (WU) greater than the minimum WU stipulated for the area in which the oil company is interested in.
2. A maximum participation of ANCAP (A) in the event of association, this value must be between 20% and 40%.
3. Incremental Profit Oil values for the Uruguayan State (X, X’ and Xg), these variables must be between 0% and 70%.

6.9.1. Scenario 1 – Low economic offer case

The first scenario represents the lowest economic proposal for the Uruguayan government, and therefore is an optimistic case for a potential contractor because it maximizes its profit. ANCAP's association percentage is set to the minimum stipulated value, equal to 20% (A=20%), incremental profit oil, which is based on a predefined recovery factor (see Table 2), for the case of oil and natural gas is set equal to 0% (X=X'=Xg=0%).

This scenario is considered quite probable and it is justified by these two reasons:

- The current long lasting low oil prices.
- The industry interest in the offshore of Uruguay, where currently there is only one contract in force, while in 2014 there were ten (Ferro et al. 2017).

6.9.2. Scenario 2 – High economic offer case

The second scenario can be considered as an extreme case because the offered variables for the economic proposal are similar to the average economic variables offered in 2012 for the contracts signed after Uruguay Round II. This scenario is defined as follows:

- Maximum ANCAP association percentage = 30%.
- Incremental profit oil for the case of oil production = 25%.
- Incremental profit oil for the case of natural gas production = 25%.

6.10. Performance Indicators

Several key performance indicators were calculated in the economic simulations, some of them are: Net Present Value for the International Oil Company (IOC) with a 10% discount rate (NPV10_IOC), Internal Rate of Return for the IOC (IRR_IOC), Maximum Negative Cash Flow the IOC will face (MNCF_IOC), Lifting Entitlement for the IOC (IOC_Entitlement), Government Take and the project's Net Present Value with a 10% discount rate (NPV10_Project).

NPV10_IOC is calculated from the IOC's quarterly after tax cash flows discounted with a 2.5% quarterly (10% annual) discount rate. IRR_IOC is the discount rate that would make NPV10_IOC equal to zero, therefore it corresponds to the maximum expected hurdle rate.

MNCF_IOC gives an idea of the maximum accumulated negative cash flow that the IOC may have to bear. Based on this indicator the IOC may decide to ask for external financing to develop the project, for instance it may consider to sell part of its participation in the area.

According to Johnston (2008), Lifting Entitlement "often corresponds to the reserves a company can book". IOC_Entitlement, for the case of a PSC, is composed of the company's share of recovered cost oil and profit oil.

Government Take represents the portion of the total profit that goes for the Uruguayan State, it is composed of the Profit Oil for the State, income taxes paid by the Contractor and ANCAP's cash flow, which, according the Uruguayan Fiscal Regime, are the only means that the Uruguayan State has to capture an economic rent.

Finally, NPV10_Project is an indicator that measures the profitability of the Project, which is very useful because it is independent of the economic scenario established in the PSC.

6.11. Economic simulations

Several economic simulations were run, considering the previously defined economic offer scenarios, for various oil price forecasts and scenarios. Moreover, a sensitivity analysis was performed to the offered economic variables in order to analyze their impact in the project profitability for an IOC.

6.11.1. Sensitivity to EIA oil price forecasts

To assess the project sensitivity to the EIA oil price forecasts, two sets of simulations were run for both economic offer scenarios 1 and 2, and for the following oil price forecasts:

- <u>Forecast 1 (base case):</u> assumes a $70/bbl oil price with a variable escalation taken at the start of each year from a symmetrical triangular distribution defined between -10% and 10%.
- <u>Forecast 2 (high oil price case):</u> corresponds to the EIA High oil price forecast case, extrapolated with a straight line trend up to year 2060.
- <u>Forecast 3 (low oil price case):</u> corresponds to the EIA Low oil price forecast case, extrapolated with a straight line trend up to year 2060.
- <u>Forecast 4 (reference oil price case):</u> corresponds to the EIA Reference oil price forecast case, extrapolated with a straight line trend up to year 2060.

6.11.2. Sensitivity to fixed oil price scenarios

In order to analyze the project sensitivity to fixed oil price scenarios, a set of simulations were run for fixed oil price scenarios without escalation. The oil price scenarios that were considered are the following: $50/bbl, $60/bbl, $70/bbl, $80/bbl, $90/bbl, $100/bbl and $140/bbl. From the resultant NPV10_IOC distributions, the breakeven oil price percentiles P90, P50 and P10 were determined by finding the oil price that makes the IOC's discounted net present value equal to zero.

6.11.3. Sensitivity to A, X and Xg

Sensitivity analyses were performed to the offered economic variables: maximum ANCAP's percentage in the case of association and incremental profit oil percentage for the Uruguayan State.

These sensitivity analyses were only performed for Chafalote, and they are intended to show how the offered economic variables affect the economics of a project.

For these analyses oil price was fixed at $70/bbl and one variable was varied at a time while the rest were kept constant.

These analyses provide useful templates for IOCs, which, under the new and more flexible open-round licensing regime, may be interested in the exploration and development of the Uruguayan offshore sedimentary basins.

7. Results of Probabilistic Economic Analysis

This chapter presents the results of the detailed economic analyses of the five turbidite prospects studied in this project. The prospects are, in order of appearance in the following sections: Chafalote, Maspoli, Jasper, Emerald-Deep and Emerald.

The economic probabilistic analyses were carried out in Microsoft Excel spreadsheets running Palisade @Risk add-in. All the analyses consisted of Monte Carlo simulations, each one with 10,000 iterations and using Latin Hypercube sampling.

Prior to the economic analyses, and with the purpose of assessing the geologic risk of these prospects, the chance of geologic success (P_g) was determined for each prospect and calculated as follows (Murtha 1996):

$$P_g = \left(P_{HCgeneration}\right) * \left(P_{Migration\&Timing}\right) * \left(P_{Reservoir}\right) * \left(P_{Seal}\right) * \left(P_{Trap}\right) \dots\dots\dots..(15)$$

Where:

- $P_{HCgeneration}$ is the probability that hydrocarbons have been generated.
- $P_{Migration\&Timing}$ is the probability that hydrocarbons have migrated from the source rock after the trap was formed.
- $P_{Reservoir}$ is the probability that the reservoir is present.
- P_{Seal} is the probability that the seal is present.
- P_{Trap} is the probability that the trap is present.

The Pg is used (later in this study) to estimate the Expected Monetary Value (EMV) of each prospect based on the probabilistic NPV estimates (see Section 7.1.6).

7.1. Prospect 1 - Chafalote

7.1.1. Prospect description

Chafalote was recognized in the TO12_3D seismic survey (location shown in Fig. 2). This prospect is composed by a set of Upper Albian turbidite lobes with Cenomanian-Turonian shales on top which are interpreted as seal. The trap is a combined stratigraphic-structural one with an updip sealing fault. The proposed source rocks are marine Aptian shales, which are widespread recognized in seismic sections of the South Atlantic margins. Migration of hydrocarbons is assisted by fault systems connecting the source rock with the reservoir **(Fig. 17).**

This speculative petroleum system corresponds to the “Cretaceous post-rift marine petroleum system: Aptian–Late Cretaceous (?)” proposed by Morales et al. (2017) and Morales (2013).

The probabilistic volumetric analysis performed to Chafalote led to the prospective resources results shown in **Table 7:**

Oil (MMbbls)			Associated Gas (TCF)		
1U	2U	3U	1U	2U	3U
759.82	1,828.47	4,020.55	0.299	0.932	2.532

Table 7 – Chafalote Prospective Resources

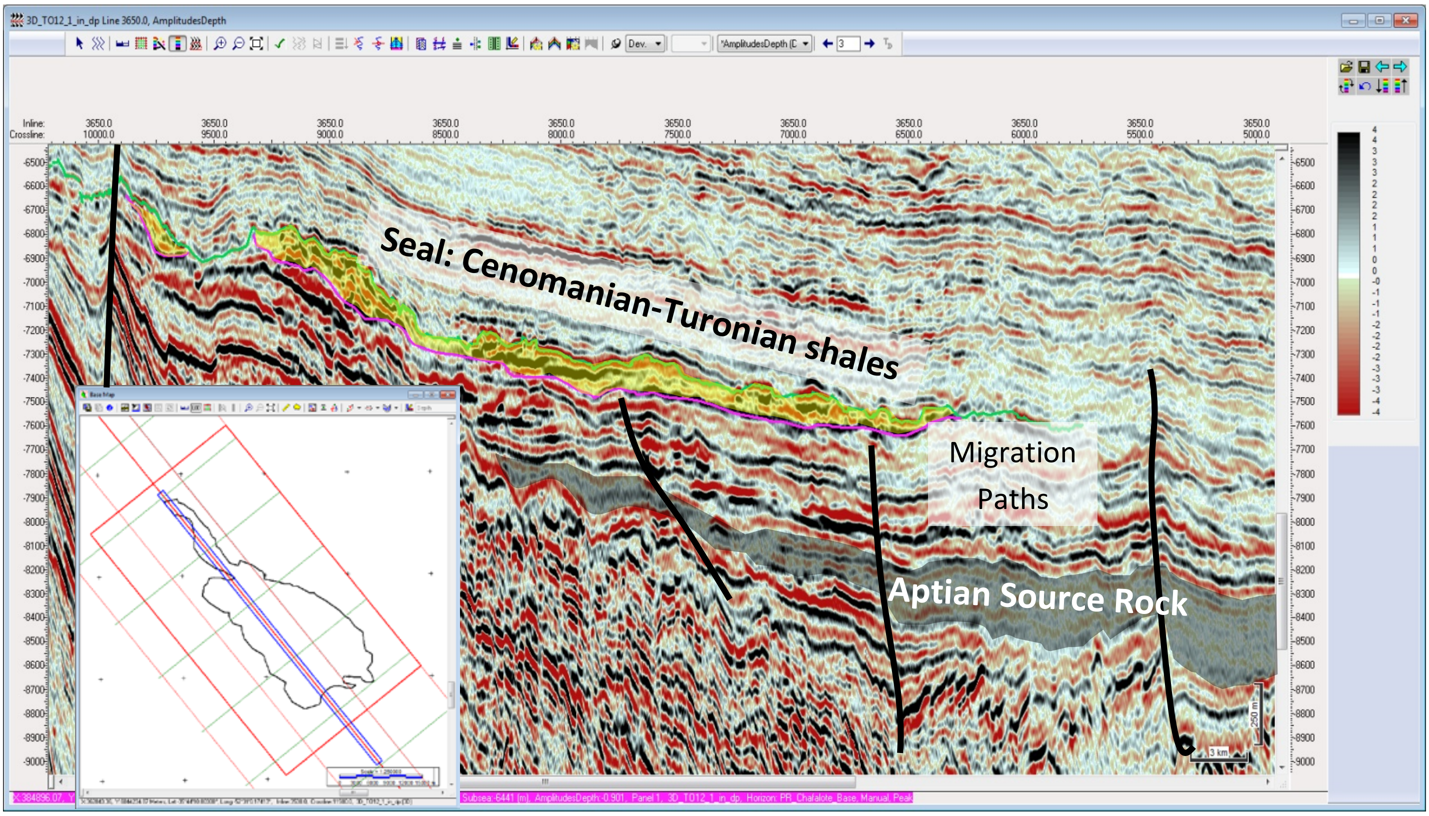


Fig. 17 – Seismic section along Chafalote with interpreted petroleum system elements (courtesy of ANCAP)

Some characteristics of this prospect are shown in **Table 8:**

Prospect Characteristics		
Name:	Chafalote	
Reservoir:	Upper Albian turbidites	
Trap:	Combined stratigraphic-structural trap with an updip sealing fault	
Geologic Province:	Pelotas	basin
Area/Round:	14/Round_II	
Distance to Montevideo:	375	Km
Average Water Depth:	2750	m
Average Reservoir TVD:	7200	m
Probable Fluid Type:	30° API oil	

Table 8 – Chafalote characteristics

As it is shown in **Table 9,** Chafalote presents a chance of geologic success of 17.64%**.** The probability of hydrocarbon generation is 80% due to the presence of Aptian source rock beneath the prospect; probability of migration and timing is 90% because Chafalote is a clastic reservoir with recognizable faults, probably interconnecting source rock and reservoir. Since the reservoir is Cretaceous and clastic, then the probability that the reservoir is present is 70%. Seal probability is only 50% because it is a Cretaceous seal. Finally, trap probability is 70% because it is a combined trap with a clear seismic amplitude anomaly that was mapped with 3D seismic.

Probability of Geologic Success	
Hydrocarbon generation	80%
Migration & timing	90%
Reservoir	70%
Seal	50%
Trap	70%
***Pg* =**	**17.64%**

Table 9 – Chafalote probability of geologic success

7.1.2. Chafalote economic simulations

This section presents the results of several economic simulations, for various oil price scenarios as well as for the previously defined economic offer scenarios. **Table 10** shows some simulation results that are independent of the oil price scenario and of the offered economic variables.

According to Table 10 the development of this prospect would require, in average, 47 production wells and due to its expected maximum oil production rate of almost 280,000 bopd, two FPSOs would be required.

Variable	P90	P50	P10
# Production Wells	18	47	117
Max. Field Oil production (bbls/d)	121,178.4	279,146.6	602,444.4
Max. Field Water production (bbls/d)	192,607.4	487,811.2	1,116,845.0
Max. Gas production (MMscf/d)	44.67	136.33	362.63
CAPEX (MM$)	12,762.09	27,617.97	58,426.46
OPEX (MM$)	14,878.83	36,673.67	83,599.82
CAPEX/BOE ($/boe)	13.05	14.56	16.82
OPEX/BOE ($/boe)	14.80	19.47	25.10
TOTAL_COST/BOE ($/boe)	29.06	34.24	40.54
Exp. Well Cost (MM$)	100.16	116.02	137.11
Prod. Well Cost (MM$)	66.92	77.52	91.60

Table 10 – Chafalote field development statistics

7.1.3. Chafalote sensitivity to EIA oil price forecasts

To assess the project sensitivity to the EIA oil price forecasts, two sets of simulations were run for both economic offer scenarios 1 and 2, and for the following oil price forecasts:

- Base case: a $70/bbl initial oil price with a variable escalation at the start of each year taken from a symmetric triangular distribution defined between -10% and 10%.
- EIA High oil price forecast.
- EIA Low oil price forecast.
- EIA Reference oil price forecast.

The results of these simulations, are summarized in **Table 11.** Regarding IOC_Entitlement, it corresponds to the percentage of the reserves that the IOC can book, it is composed of the company's share of recovered cost oil and profit oil and therefore it is different to the Contractor's take, which is calculated as: $Contractor's\ Take = 1 - Government\ Take$.

Economic and Oil Price scenario	NPV10_IOC (MM$) P90	NPV10_IOC (MM$) P50	NPV10_IOC (MM$) P10	NPV10_Project (MM$) P90	NPV10_Project (MM$) P50	NPV10_Project (MM$) P10	MNCF_IOC (MM$) P90	MNCF_IOC (MM$) P50	MNCF_IOC (MM$) P10
Scen. 1: $70 var. esc.	-1,224.5	878.3	4,937.8	27.4	4,194.0	14,153.1	-28,051.7	-13,875.1	-6,839.0
Scen. 1: EIA High	6,121.8	15,639.2	34,610.0	15,575.7	38,870.7	85,507.8	-27,692.6	-13,745.5	-6,810.1
Scen. 1: EIA Low	-5,337.8	-2,399.0	-1,161.7	-3,584.0	-1,338.7	437.3	-29,231.3	-14,428.0	-7,067.3
Scen. 1: EIA Ref.	1,707.1	5,168.8	12,139.6	5,043.2	13,604.2	31,147.0	-27,706.2	-13,745.5	-6,810.1
Scen. 2: $70 var. esc.	-2,052.1	-258.5	1,716.2	1.1	4,238.3	14,030.9	-24,975.5	-12,145.6	-5,997.3
Scen. 2: EIA High	3,132.4	8,195.5	18,500.1	15,714.0	38,716.8	85,973.7	-24,448.1	-11,958.2	-5,935.4
Scen. 2: EIA Low	-6,201.6	-2,846.3	-1,416.3	-3,687.7	-1,335.9	418.5	-26,274.7	-12,734.6	-6,216.9
Scen. 2: EIA Ref.	569.5	2,288.1	5,825.8	5,044.9	13,567.0	31,350.5	-24,539.4	-11,966.1	-5,935.4

Economic and Oil Price scenario	IRR_IOC P90	IRR_IOC P50	IRR_IOC P10	IOC_Entitlement P90	IOC_Entitlement P50	IOC_Entitlement P10	Government Take P90	Government Take P50	Government Take P10
Scen. 1: $70 var. esc.	6.80%	11.83%	16.53%	68.07%	73.17%	75.72%	48.08%	50.51%	54.70%
Scen. 1: EIA High	26.41%	30.81%	35.06%	60.13%	60.83%	61.66%	57.44%	57.61%	57.72%
Scen. 1: EIA Low	0.62%	4.61%	7.40%	75.42%	76.15%	76.59%	46.58%	47.30%	48.45%
Scen. 1: EIA Ref.	15.43%	18.62%	21.76%	64.61%	66.16%	68.14%	54.80%	55.74%	56.33%
Scen. 2: $70 var. esc.	4.71%	9.34%	13.11%	48.94%	55.41%	59.32%	67.66%	69.83%	73.46%
Scen. 2: EIA High	21.55%	25.15%	28.58%	37.85%	38.93%	40.22%	75.88%	76.03%	76.13%
Scen. 2: EIA Low	-2.56%	2.47%	5.49%	58.81%	59.68%	60.22%	66.38%	67.01%	68.02%
Scen. 2: EIA Ref.	12.36%	15.05%	17.61%	44.13%	46.37%	49.16%	73.56%	74.40%	74.92%

Table 11 – Chafalote simulation results for various EIA oil price forecasts

Fig. 18 graphically shows the sensitivity to various EIA oil price forecasts.

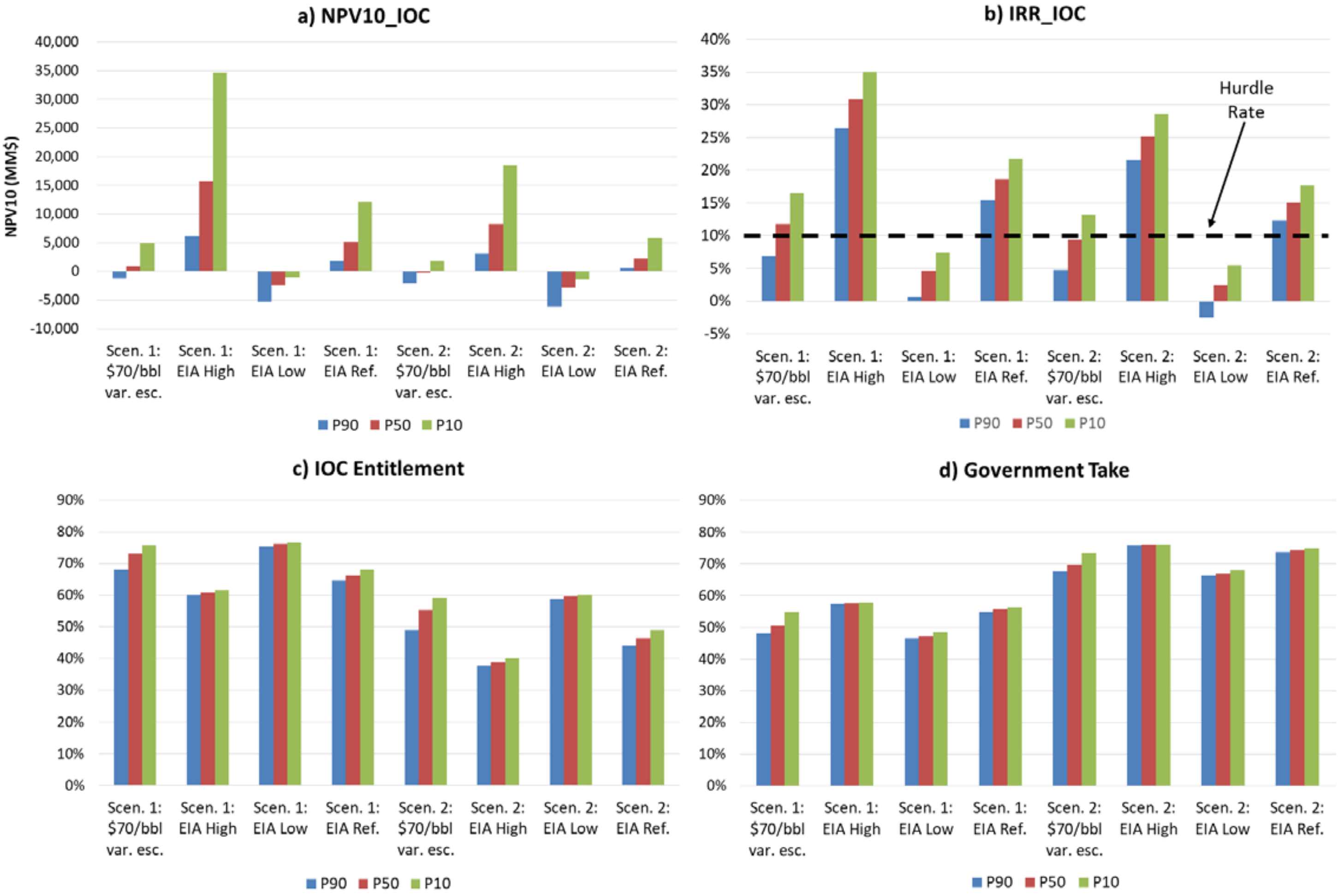


Fig. 18 – Chafalote sensitivity to various EIA oil price forecasts

It is concluded that, for an IOC, the project meets and exceeds a 10% hurdle rate for both the EIA High and EIA Reference oil price forecasts and for both economic offer scenarios. For the case of the EIA Low oil price forecast, even the project as a whole is not profitable because its discounted net present value P50 percentile is negative (Table 11). On the other hand, average IOC Entitlement and Government Take, in the most optimistic case for the IOC, are 69.1% and 52.8% respectively, while for the extreme case they are 50.1% and 71.8% respectively. Regarding the MNCF for the IOC, it varies between $11.9 billion and $14.5 billion.

7.1.4. Chafalote sensitivity to fixed oil price scenarios

In order to analyze the project sensitivity to fixed oil price scenarios, a set of simulations were run for fixed oil price scenarios without escalation. The oil price scenarios that were considered are the following: $50/bbl, $60/bbl, $70/bbl, $80/bbl, $90/bbl, $100/bbl and $140/bbl. From the resultant NPV10_IOC distributions, the breakeven oil price percentiles P90, P50 and P10 were determined by finding the oil price that makes the NPV10_IOC = $0.

The results for Scenario 1 simulations are shown in **Table 12** and in **Fig. 19,** from them it is found that for this scenario: the breakeven oil price for the P90 case (BE_P90) is equal to $73.2/bbl, the breakeven oil price for the P50 case (BE_P50) is equal to $62.6/bbl and the breakeven oil price for the P10 case (BE_P10) is equal to $53.8/bbl. It is then concluded that an oil price greater than $73.2/bbl will make this prospect profitable in at least 90% of the cases.

	Scenario 1 - Low economic offer case					
	NPV10_IOC (MM$)			**IRR_IOC**		
Oil price ($/bbl)	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
50	-4,528.38	-1,920.88	-794.68	1.87%	5.60%	8.42%
60	-1,656.71	-383.27	1,297.58	6.16%	9.18%	11.86%
70	-244.51	1,073.58	3,960.64	9.29%	12.06%	14.78%
80	528.65	2,459.23	6,685.12	11.66%	14.53%	17.42%
90	1,106.83	3,768.11	9,268.23	13.66%	16.72%	19.78%
100	1,638.70	4,991.06	11,866.16	15.44%	18.71%	21.94%
140	3,655.60	9,669.17	21,925.03	21.30%	25.19%	28.92%

Table 12 – Chafalote sensitivity to non-escalated oil price scenarios (Scenario 1)

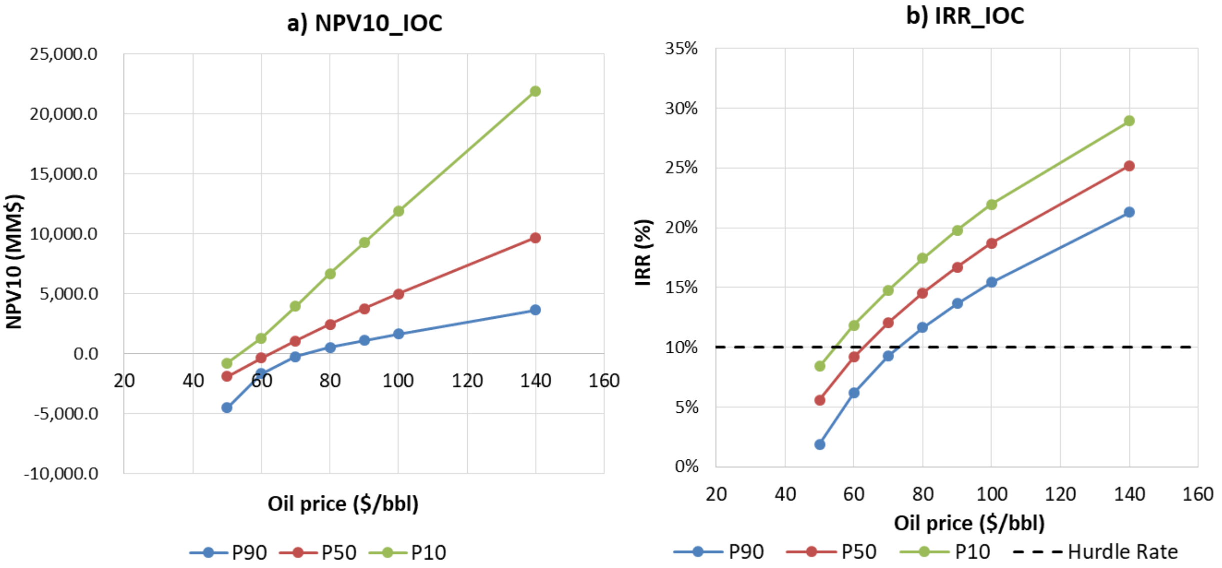


Fig. 19 – Chafalote sensitivity to oil price fluctuations (Scenario 1)

Regarding the economic offer Scenario 2, from **Table 13** and **Fig. 20** it is found that: BE_P90 is equal to \$85.5/bbl, BE_P50 is equal to \$72.2/bbl and BE_P10 is equal to \$62.3/bbl. It is then concluded that an oil price greater than \$85.5/bbl will make this prospect profitable, for an IOC, in at least 90% of the cases. These breakeven oil prices are shifted, around \$10/bbl, upwards with regard to the ones obtained for the low economic offer case (Scenario 1).

	Scenario 2 - High economic offer case					
	NPV10_IOC (MM\$)			**IRR_IOC**		
Oil price (\$/bbl)	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
50	-5,401.45	-2,449.23	-1,199.27	-1.43%	3.54%	6.38%
60	-2,747.90	-1,110.22	-320.33	4.01%	7.01%	9.33%
70	-981.29	-190.87	1,048.31	7.06%	9.51%	11.79%
80	-239.18	663.32	2,586.01	9.12%	11.59%	13.99%
90	198.72	1,454.49	4,155.85	10.79%	13.41%	15.95%
100	537.11	2,201.04	5,647.91	12.28%	15.07%	17.73%
140	1,697.78	4,873.51	11,312.18	17.16%	20.43%	23.41%

Table 13 – Chafalote sensitivity to non-escalated oil price scenarios (Scenario 2)

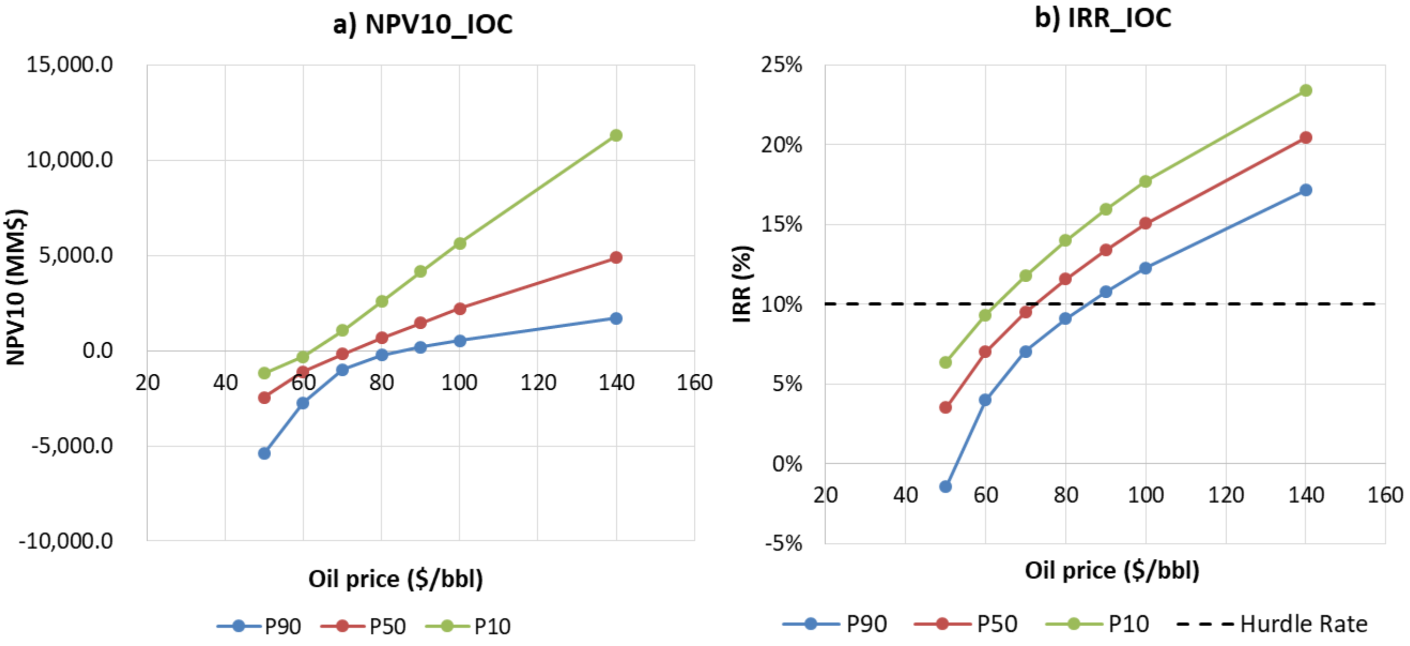


Fig. 20 – Chafalote sensitivity to oil price fluctuations (Scenario 2)

7.1.5. Chafalote sensitivity to the offered economic variables

In order to show how the offered economic variables, maximum ANCAP's percentage in the case of association (A) and incremental profit oil percentage for the State (both for oil and gas production, X and Xg respectively), affect the economics of this project, sensitivity analyses were performed for each one of these variables. In the analyses one variable was varied at a time while the rest were kept constant.

The results of these analyses could aid international oil companies that may be interested in bidding for a Uruguayan offshore area, in order to present an offer attractive for the Uruguayan State and for themselves.

7.1.5.1. Sensitivity to A

A sensitivity analysis was performed to quantify the impact on project profits of the ANCAP's percentage offered by the IOC in the bid offer (in the case of an actual association were to be taken up by ANCAP).

The assumptions made for this analysis were: zero incremental profit oil percentage for the State and oil price was fixed at $70/bbl without escalation.

The results for NPV10_IOC and IRR_IOC are shown in **Table 14** and in **Fig. 21:**

	NPV10_IOC, MM$ (X=Xg=0%)			IRR_IOC (X=Xg=0%)		
	P90	**P50**	**P10**	**P90**	**P50**	**P10**
A=20%	-244.51	1,073.58	3,960.64	9.29%	12.06%	14.78%
A=25%	-229.23	1,006.48	3,713.10	9.29%	12.06%	14.78%
A=30%	-213.95	939.38	3,465.56	9.29%	12.06%	14.78%
A=35%	-198.67	872.29	3,218.02	9.29%	12.06%	14.78%
A=40%	-183.39	805.19	2,970.48	9.29%	12.06%	14.78%

Table 14 – Chafalote sensitivity to ANCAP's association percentage

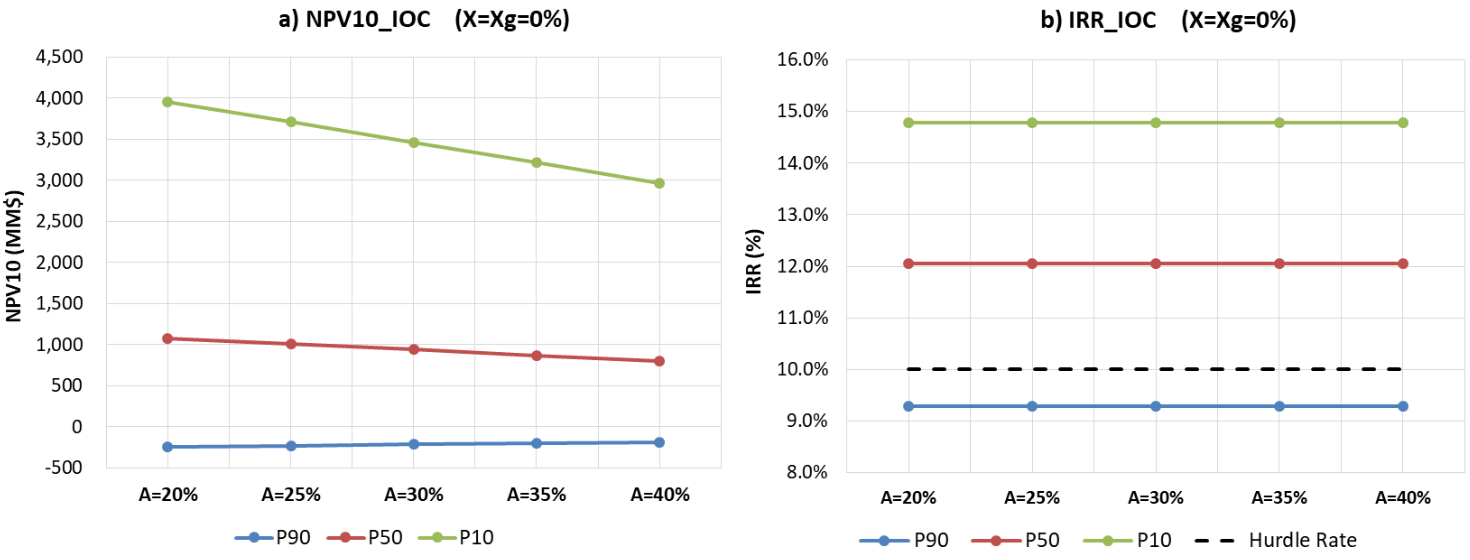


Fig. 21 – Chafalote sensitivity to ANCAP's association percentage

Fig. 21a shows that NPV10_IOC for the P90 and P50 percentile cases are only moderately affected by ANCAP's maximum association percentage. The P10 percentile, which corresponds to an optimistic case, with a small chance of occurrence, is the one that is mostly affected. On the other hand, the internal rate of return for the IOC remains constant because the incremental profit oil for the Uruguayan State was set equal to zero.

The analysis reveals that offering a high association percentage for ANCAP, such as 40%, would increasingly suppress the NPV10_IOC. However, in case of high competition for winning the lease area, IOCs can significantly increase their total bid score (see Eq. 3) by offering the largest possible ANCAP share (40%, see p. 15 of Section 5 in this study). An interesting observation is what happens with the P90 percentile curve, the NPV10_IOC for that curve is negative for all the studied range of association percentages. However, it improves with increasing association percentages, therefore for a project that is as not profitable as originally expected it would be convenient for an IOC to have a significant participation of ANCAP in the area, because it will act as a shock absorber due to development cost sharing, which shields the IOC from further losses in the project.

7.1.5.2. Sensitivity to X

A sensitivity analysis was performed to the offered incremental profit oil for the State for the case of light oil production.

The assumptions made for this analysis were: zero incremental profit oil for the State for produced gas, ANCAP's maximum association percentage was set equal to the minimum bid threshold of 20% and oil price was fixed at $70/bbl without escalation.

The results for NPV10_IOC and IRR_IOC are shown in **Table 15** and in **Fig. 22:**

	NPV10_IOC, MM$ (A=20%, Xg=0%)			**IRR_IOC (A=20%, Xg=0%)**		
	P90	**P50**	**P10**	**P90**	**P50**	**P10**
X=0%	-244.51	1,073.58	3,960.64	9.29%	12.06%	14.78%
X=10%	-539.64	560.69	2,880.05	8.46%	11.13%	13.70%
X=20%	-865.66	58.39	1,820.09	7.59%	10.14%	12.54%
X=30%	-1,335.67	-406.98	821.94	6.65%	9.06%	11.28%
X=40%	-1,973.83	-843.78	-53.31	5.65%	7.89%	9.91%
X=50%	-2,819.27	-1,311.71	-694.78	4.53%	6.60%	8.35%
X=60%	-3,799.97	-1,862.66	-1,077.23	3.31%	5.14%	6.59%
X=70%	-4,835.85	-2,414.74	-1,364.02	1.60%	3.40%	4.53%

Table 15 – Chafalote sensitivity to X

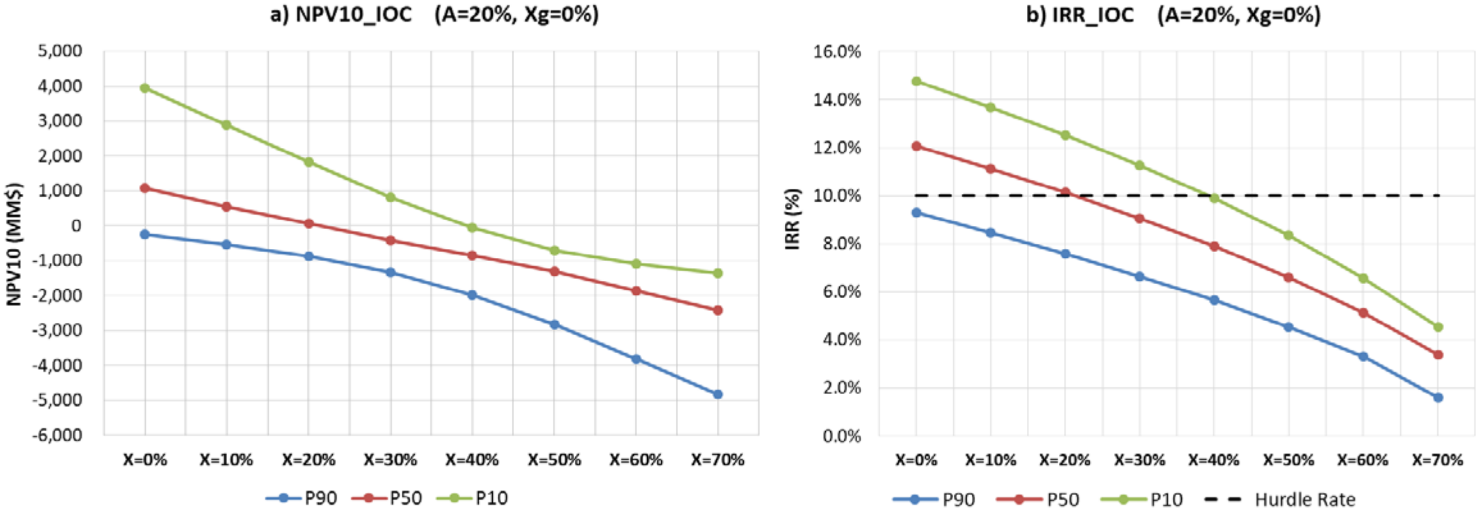


Fig. 22 – Chafalote sensitivity to X

In Fig. 22 it is observed that both NPV10_IOC and IRR_IOC are strongly affected by the offered incremental profit oil for the Uruguayan State, as X increases the NPV10_IOC and IRR_IOC significantly decrease.

It is concluded that for the case of an oil price scenario fixed at $70/bbl, it is highly risky for the IOC to offer an X greater than 20% for the area, because that would lead to negative NPV10_IOC for the P50 case when developing this field. For a case with an offered X=20%, the NPV_IOC P50 percentile is pretty close to zero and thus the desired 10% hurdle rate may not be achieved for this prospect.

7.1.5.3. Sensitivity to Xg

A sensitivity analysis was performed to the offered incremental profit oil for the State for the case of gas production.

The assumptions for this case were: zero incremental profit oil for the State for oil production, ANCAP's maximum association percentage was set equal to 20% and oil price was fixed at $70/bbl without escalation.

The results for NPV10_IOC and IRR_IOC are shown in **Table 16** and in **Fig. 23:**

	NPV10_IOC, MM$ (A=X=0%)			**IRR_IOC (A=X=0%)**		
	P90	**P50**	**P10**	**P90**	**P50**	**P10**
Xg=0%	-244.51	1,073.58	3,960.64	9.29%	12.06%	14.78%
Xg=10%	-252.92	1,055.71	3,917.08	9.26%	12.03%	14.74%
Xg=20%	-263.16	1,039.17	3,866.58	9.23%	12.00%	14.70%
Xg=30%	-272.03	1,019.19	3,811.28	9.21%	11.97%	14.65%
Xg=40%	-282.17	1,002.75	3,767.90	9.19%	11.94%	14.62%
Xg=50%	-289.57	983.23	3,714.33	9.16%	11.91%	14.58%
Xg=60%	-300.48	964.34	3,662.37	9.13%	11.88%	14.54%
Xg=70%	-307.18	944.37	3,612.23	9.11%	11.85%	14.50%

Table 16 – Chafalote sensitivity to Xg

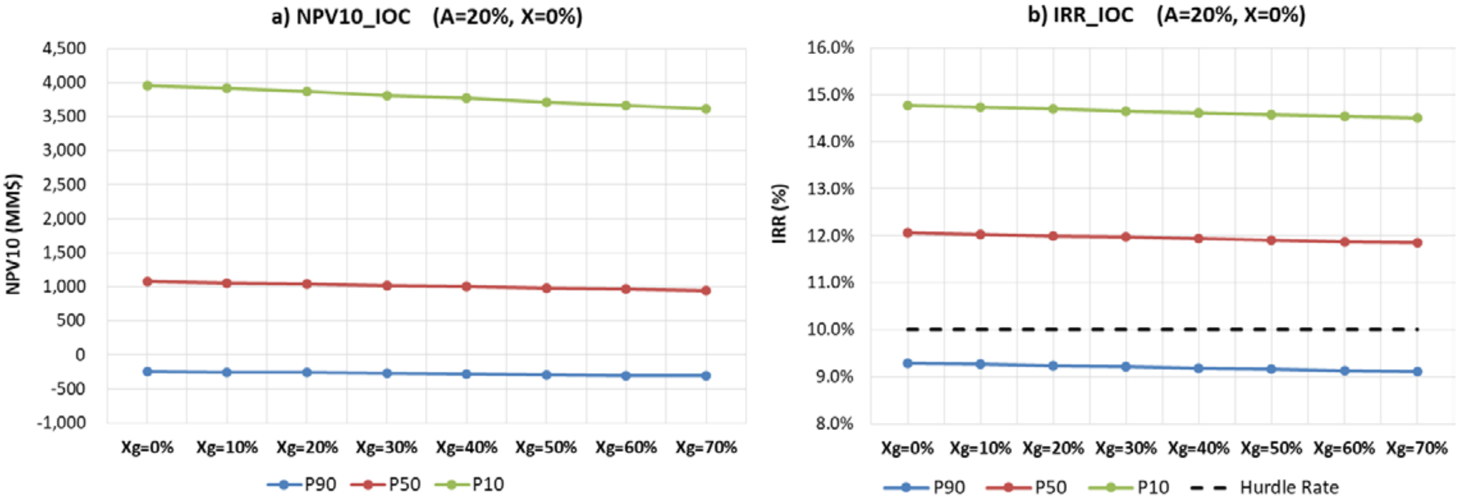


Fig. 23 – Chafalote sensitivity to Xg

In Fig. 23 it is observed that both NPV10_IOC and IRR_IOC are almost unaffected by the offered Xg. This is something reasonable for a black oil prospect because the revenues due to produced gas sales are insignificant compared to oil production revenues. On the other hand, for the case of a dry gas prospect, Xg would have the same effect as X for the case of a light oil prospect, Xg would be the most sensitive variable.

It is concluded that for the case of a black oil prospect, an offer with a high Xg for the area, such as 70%, would not affect too much the economics of the project, and in the case of competition for the area, a high Xg will help an IOC to increase the total bid score of their offer (see Eq. 3).

7.1.5.4. Impact of bid offer on NPV10_IOC and IRR

Regarding the offered economic variables, it is clear that as the economic proposal for the Uruguayan State improves (the offered economic variables increase), the NPV10 and IRR for the IOC decrease. In the case of a light oil discovery, both ANCAP share (A) and profit gas share (Xg) have minor effect on the economics of the project. However, the profit oil share (X) is a most sensitive bid parameter. For example, for an oil price of $70/bbl, offering a profit oil share in excess of 20% would compromise the IOC's profit margins when developing this field, because for that case the P50 percentile of the IOC’s net present value may become zero or even a negative value.

In a similar way it can be shown that for the case of a dry gas discovery, Xg is the most sensitive variable, while for the case of a heavy oil discovery, X’ is the most sensitive one.

A likely IOC strategy to increase the total score of their bid, which may be useful in the case of numerous bidders competing for a lease area, is for them to offer a high association percentage to ANCAP, as well as, a high Xg for the case of a black oil prospect. This is further illustrated with an example using the EIA Reference oil price case and various economic proposal scenarios. Results are shown in **Table 17** and graphically in **Fig. 24.** The recommended economic proposal for this prospect would be the one depicted in blue (A=40%, X=0% and Xg=70%):

	NPV10_IOC (MM$)			IRR_IOC		
Economic Proposal	P90	P50	P10	P90	P50	P10
A=20%, X=0%, Xg=0%	1,707.06	5,168.77	12,139.59	15.43%	18.62%	21.76%
A=40%, X=0%, Xg=70%	1,223.70	3,737.19	8,818.91	15.28%	18.42%	21.51%
A=30%, X=25%, Xg=25%	569.53	2,288.10	5,825.84	12.36%	15.05%	17.61%
A=20%, X=70%, Xg=0%,	-3,110.30	-1,709.05	-1,067.10	2.06%	4.03%	5.28%

Table 17 – Chafalote NPV10_IOC and IRR_IOC results for several scenarios

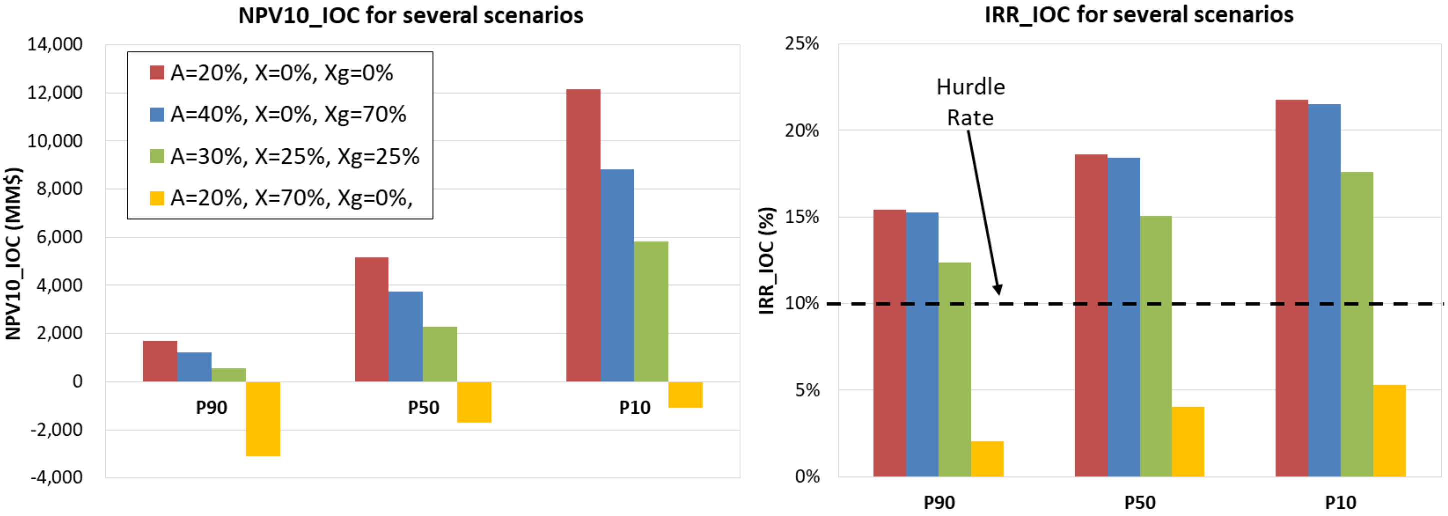


Fig. 24 – Chafalote NPV10_IOC and IRR_IOC results for several scenarios

In Fig. 24 it is clear that the economic proposals depicted in red (Scenario 1) and in blue yield similar IRRs for this prospect, while an increase of the offered X drastically decreases the IRR for the IOC, which is what happens for the cases shown in green (Scenario 2) and in orange.

Finally, in the case of a dry gas prospect, the recommendation to increase the total score of the bid would be to offer high values for A, X and X’ while keeping Xg as low as possible.

7.1.6. Expected Monetary Value

In order to rank all the studied prospects based on their EMVs, the following assumptions were made:

- Oil and gas prices are assumed to be equal to the EIA Reference forecasts.
- Economic offer Scenario 1 was selected.

To estimate the EMV of drilling an exploratory well in this prospect, two probabilities are required, one is the previously determined probability of geologic success ($Pg = 17.64\%$) and the other one is the probability of economic success (Pe). This last probability is found after all the simulations are run, and it is determined as the probability that the NPV10_IOC is greater or equal to zero:

$$Pe = \frac{\text{Amount of simulations with NPV10\_IOC} \geq 0}{\text{Total number of simulations run}} * 100 \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots.\dots\dots (16)$$

After all the economic simulations are completed, the *Pe* is found to be equal to 99.26% **(Fig. 25):**

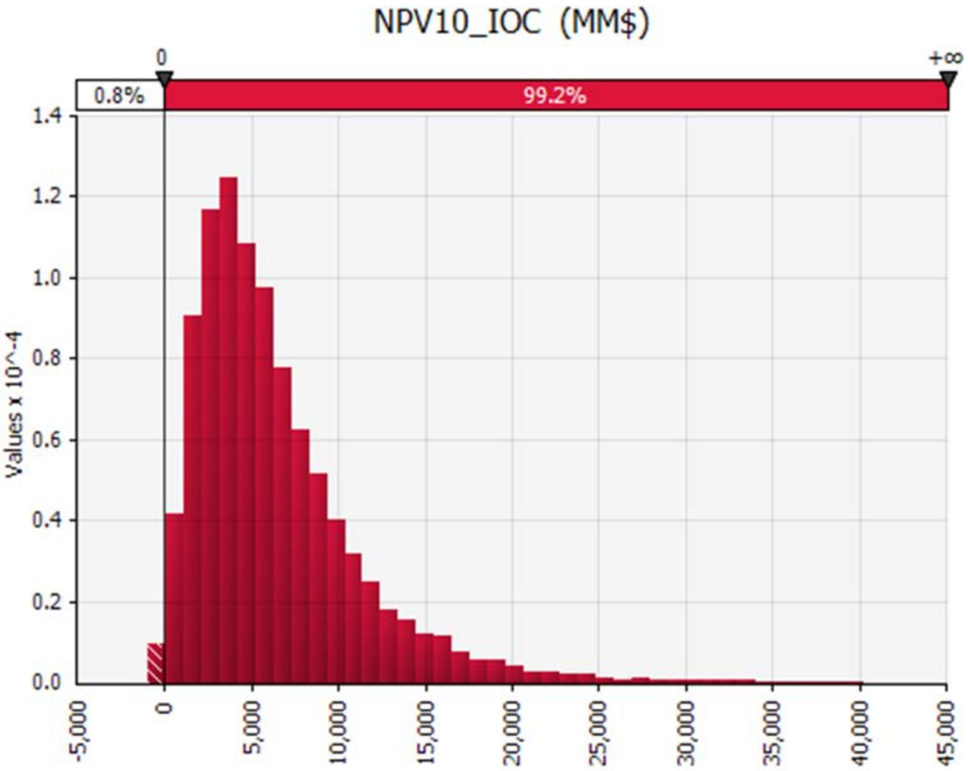


Fig. 25 – Chafalote NPV10_IOC

Fig. 26 shows the decision tree used to calculate the EMV for drilling an exploratory well in Chafalote. The first chance node is related to the Pg, which corresponds to the probability of finding mobile hydrocarbons in the prospect. If there is a geological success, the second chance node considers the probability of finding an accumulation with enough hydrocarbons to justify the development the field ($NPV10\_IOC \geq 0$).

The probability that the project results in both a geologic and an economic success is equal to: $Pg * Pe = 17.64\% * 99.20\% = 17.50\%$. It has an associated economic benefit that can be estimated as the P50 percentile of the NPV10_IOC distribution, which in this case is 5,164.83 MM$.

The chance that the exploratory well results in a geologic success but without commerciality is: $Pg * (1 - Pe) = 17.64\% * (100 - 99.20) = 0.14\%$, and it has an associated cost that is equal to the cost of the appraisal wells: -174.05 MM$.

In the case that the exploratory well does not result in a discovery, it has an associated cost that is equal to the cost of the well, which is: -116.03 MM$. This outcome has an associated probability equal to: $(1 - Pg) = 1 - 17.64\% = 82.36\%$.

The EMV of drilling an exploratory well in this prospect is then calculated as:

$$EMV\_IOC = (1 - Pg) * exploratory.well.cost + Pg * (Pe * NPV10\_IOC + (1 - Pe) * appraisal.wells.cost) \ldots\ldots\ldots\ldots\ldots.(17)$$

Substituting with the values that are obtained from the simulations:

$$EMV\_IOC = 82.36\% * (-116.02) + 17.64\% * [99.20\% * 5{,}164.83 + 0.80\% \times (-174.05)] = 807.96\ MM\$$$

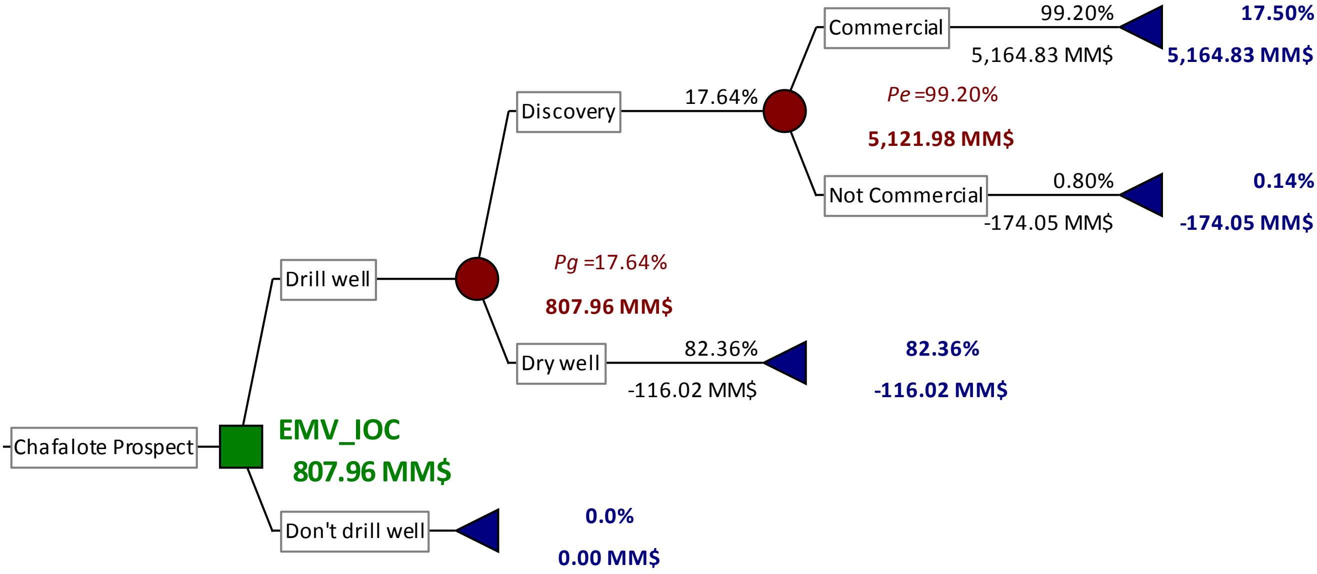


Fig. 26 – Chafalote decision tree for drilling an exploratory well

It is concluded that, based on the previous assumptions, Chafalote presents an EMV_IOC that is equal to 807.96 MM$.

7.2. Prospect 2 – Maspoli

7.2.1. Prospect description

Maspoli was recognized in the BG12_3D seismic survey (location shown in Fig. 2). This prospect is comprised of two Oligocene turbidite lobes with Miocene shales on top which are interpreted as seal. The trap is stratigraphic and presents an updip reservoir pinching out into its feeder canyons. The proposed source rocks are marine Aptian shales, which are widespread recognized in seismic sections of the South Atlantic margins. Migration of hydrocarbons is assisted by fault systems connecting the source rock with the reservoir **(Fig. 27).** This speculative petroleum system corresponds to the "Cenozoic post-rift marine petroleum system" proposed by Morales et al. (2017) and Morales (2013).

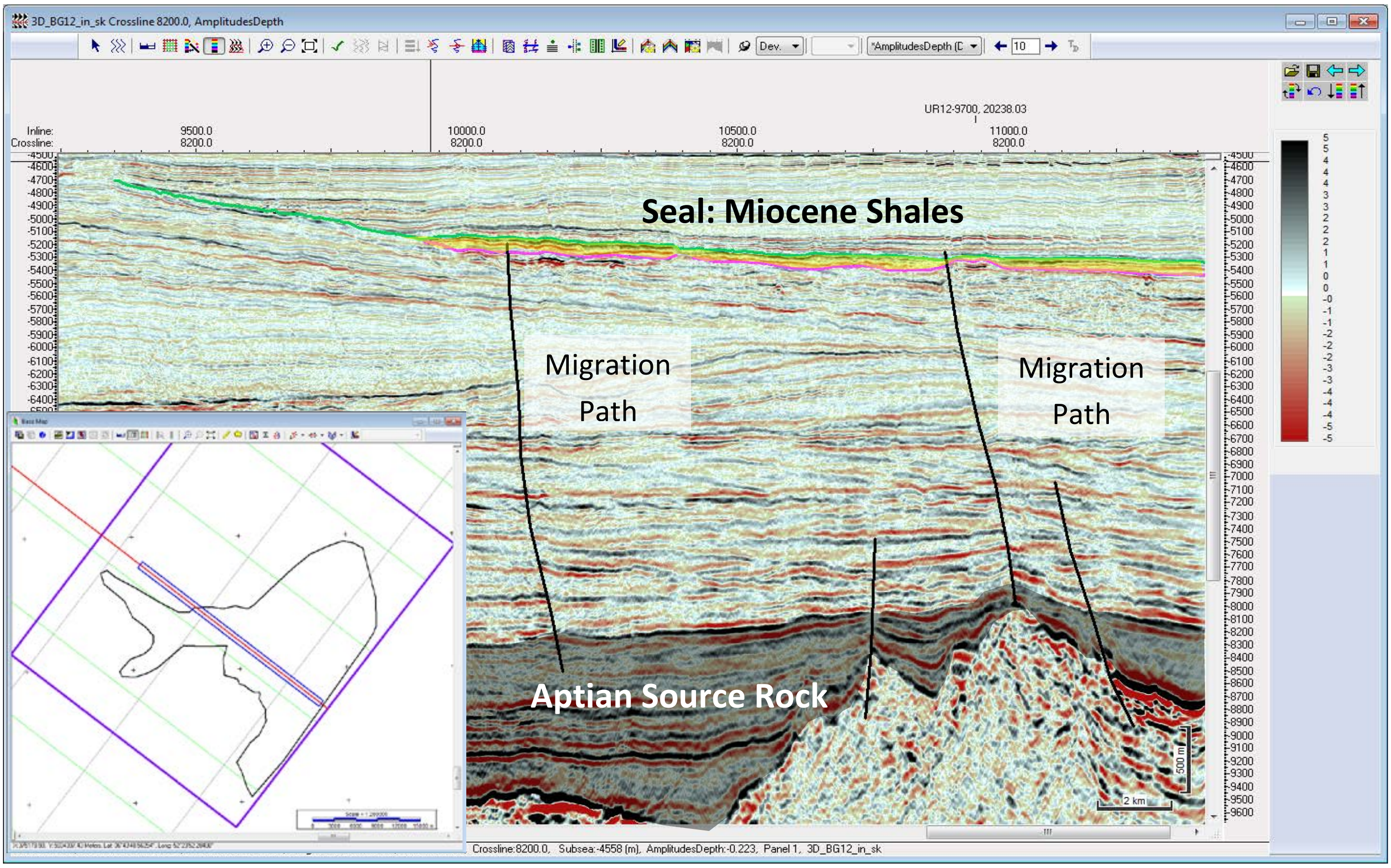


Fig. 27 – Seismic section along Maspoli with interpreted petroleum system elements (courtesy of ANCAP)

Some characteristics of this prospect are shown in **Table 18.**

Prospect Characteristics		
Name:	Maspoli	
Reservoir:	Oligocene turbidites	
Trap:	Stratigraphic, with updip reservoir pinch out into feeder canyons	
Geologic Province:	Punta del Este	basin
Area/Round:	13/Round_II	
Distance to Montevideo:	400	Km
Average Water Depth:	3325	m
Average Reservoir TVD:	5162	m
Probable Fluid Type:	30° API oil	

Table 18 – Maspoli characteristics

As it is shown in **Table 19,** Maspoli presents a chance of geologic success of 23.33%. The probability of hydrocarbon generation is 80% due to the presence of Aptian source rock beneath the prospect; probability of migration and timing is 60% because Maspoli is a clastic Cenozoic reservoir with recognizable faults, which probably interconnect source rock and reservoir. Since the reservoir is Cenozoic and clastic, the probability that the reservoir is present is 90%. Seal probability is 90% because there are clear Miocene shales on top acting as seal. Finally, trap probability is only 60% because it is a pure stratigraphic trap and it has a clear seismic amplitude anomaly that was mapped with 3D seismic.

Pg: Probability of Geologic Success	
Hydrocarbon generation	80%
Migration & timing	60%
Reservoir	90%
Seal	90%
Trap	60%
Pg =	**23.33%**

Table 19 – Maspoli probability of geologic success

The Pg is used (later in this study) to estimate the EMV of the prospect based on the probabilistic NPV estimates (see Section 7.2.5).

The probabilistic volumetric analysis of Maspoli led to the prospective resources results shown in **Table 20:**

Oil (MMbbls)			**Associated Gas (TCF)**		
1U	**2U**	**3U**	**1U**	**2U**	**3U**
905.062	2,224.964	4,680.260	0.355	1.146	3.020

Table 20 – Maspoli Prospective Resources

7.2.2. Maspoli economic simulations

This section presents the results of several economic simulations, for various oil price scenarios as well as for the two defined economic offer scenarios. **Table 21** shows some simulation results that are independent of the oil price scenario and of the offered economic variables.

According to Table 21 the development of this prospect would require, in average, 58 production wells and due to its expected maximum oil production of almost 336,000 bopd, two FPSOs would be required.

Variable	P90	P50	P10
# Production Wells	21	58	141
Max. Field Oil production (bbls/d)	140,049.3	336,343.1	709,164.9
Max. Field Water production (bbls/d)	226,377.3	590,146.9	1,314,315.0
Max. Gas production (MMscf/d)	52.30	163.24	429.70
CAPEX (MM$)	13,621.11	30,623.39	63,384.17
OPEX (MM$)	17,566.77	44,689.02	99,050.45
CAPEX/BOE ($/boe)	12.04	13.27	15.02
OPEX/BOE ($/boe)	14.72	19.39	24.97
TOTAL_COST/BOE ($/boe)	27.84	32.81	38.92
Exp. Well Cost (MM$)	46.69	54.08	63.91
Prod. Well Cost (MM$)	34.83	40.35	47.68

Table 21 – Maspoli field development statistics

7.2.3. Maspoli sensitivity to EIA oil price forecasts

To assess the project sensitivity to the EIA oil price forecasts, two sets of simulations were run for both economic scenarios 1 and 2, and for the following oil price forecasts:

- Base case: a $70/bbl initial oil price with a variable escalation at the start of each year taken from a symmetric triangular distribution defined between -10% and 10%.
- EIA High oil price forecast.
- EIA Low oil price forecast.
- EIA Reference oil price forecast.

The results of this set of simulations, run for both economic scenarios 1 and 2, are summarized in **Table 22:**

	NPV10_IOC (MM$)			NPV10_Project (MM$)			MNCF_IOC (MM$)		
Economic and Oil Price scenario	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
Scen. 1: $70 var. esc.	-830.2	1,633.8	6,713.7	645.6	6,019.2	18,366.7	-32,143.2	-15,895.0	-7,463.3
Scen. 1: EIA High	7,476.6	19,414.6	41,837.8	18,867.2	48,001.7	102,837.1	-32,007.2	-15,872.3	-7,458.2
Scen. 1: EIA Low	-5,277.2	-2,184.4	-833.3	-3,113.4	-821.1	1,689.4	-32,968.3	-16,292.7	-7,609.7
Scen. 1: EIA Ref.	2,316.5	6,752.1	15,299.0	6,465.3	17,447.1	38,616.9	-32,007.2	-15,872.3	-7,458.2
Scen. 2: $70 var. esc.	-1,747.4	98.3	2,625.1	645.6	6,019.2	18,366.7	-28,148.8	-13,952.9	-6,550.4
Scen. 2: EIA High	3,839.3	10,294.7	22,382.2	18,867.2	48,001.7	102,837.1	-28,006.3	-13,888.2	-6,525.9
Scen. 2: EIA Low	-6,251.5	-2,803.4	-1,291.4	-3,113.4	-821.1	1,689.4	-29,192.5	-14,419.0	-6,724.5
Scen. 2: EIA Ref.	907.4	3,144.4	7,439.1	6,465.3	17,447.1	38,616.9	-28,006.3	-13,888.2	-6,525.9

	IRR_IOC			IOC_Entitlement			Government Take		
Economic and Oil Price scenario	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
Scen. 1: $70 var. esc.	7.89%	12.97%	17.55%	67.50%	71.97%	75.44%	48.61%	51.77%	55.07%
Scen. 1: EIA High	27.90%	32.38%	36.78%	59.93%	60.61%	61.41%	57.51%	57.65%	57.75%
Scen. 1: EIA Low	1.95%	5.63%	8.44%	75.01%	75.97%	76.43%	46.88%	47.55%	48.95%
Scen. 1: EIA Ref.	16.58%	19.82%	23.06%	64.15%	65.63%	67.51%	55.20%	56.02%	56.53%
Scen. 2: $70 var. esc.	5.71%	10.28%	14.13%	48.12%	54.03%	59.03%	68.16%	70.93%	73.81%
Scen. 2: EIA High	22.75%	26.50%	30.04%	37.56%	38.60%	39.84%	75.94%	76.07%	76.15%
Scen. 2: EIA Low	-1.08%	3.59%	6.43%	58.33%	59.47%	60.06%	66.64%	67.24%	68.46%
Scen. 2: EIA Ref.	13.34%	16.08%	18.73%	43.52%	45.66%	48.29%	73.92%	74.64%	75.09%

Table 22 – Maspoli simulation results for various EIA oil price forecasts

Fig. 28 graphically shows the sensitivity to various EIA oil price forecasts.

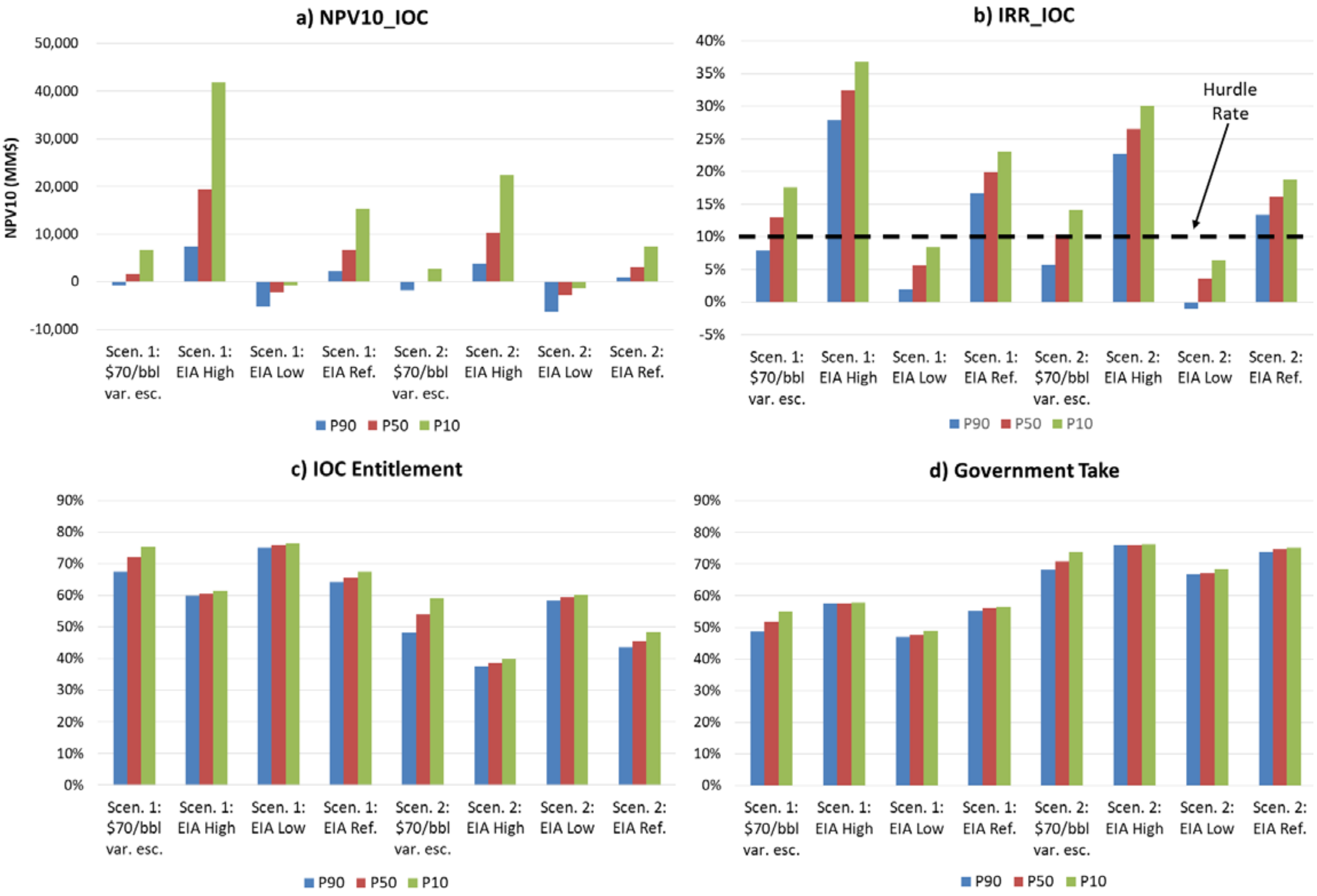


Fig. 28 – Maspoli sensitivity to various EIA oil price forecasts

It is concluded that, for an IOC, the project meets and exceeds the 10% hurdle rate for both the EIA High and EIA Reference oil price forecasts and for both economic offer scenarios. For the case of the EIA Low oil price forecast, even the project as a whole is not profitable because its discounted net present value P50 percentile is negative (Table 22). On the other hand, average IOC Entitlement and Government Take, in the most optimistic case for the IOC are 68.5% and 53.3% respectively, while for the extreme case they are 49.4% and 72.2% respectively. Regarding the MNCF for the IOC, it varies between $13.8 billion and $15.9 billion.

7.2.4. Maspoli sensitivity to fixed oil price scenarios

In order to analyze the project sensitivity to fixed oil price scenarios, a set of simulations were run for fixed oil price scenarios without escalation. The oil price scenarios that were considered are the following: $50/bbl, $60/bbl, $70/bbl, $80/bbl, $90/bbl, $100/bbl and $140/bbl. From the resultant NPV10_IOC distributions the breakeven oil price percentiles: P90, P50 and P10 were determined and then used to calculate the breakeven oil prices that make the project profitable for an IOC.

The results for Scenario 1 simulations are shown in **Table 23** and in **Fig. 29,** from them it is found that for this scenario: the BE_P90 is equal to $69.0/bbl, the BE_P50 is equal to $59.2/bbl and the BE_P10 is equal to $51.2/bbl. It is then concluded that an oil price greater than $69.0/bbl will make this prospect profitable, for an IOC, in at least 90% of the cases.

	Scenario 1 - Low economic offer case					
	NPV10_IOC (MM$)			IRR_IOC		
Oil price ($/bbl)	P90	P50	P10	P90	P50	P10
50	-4,229.82	-1,625.20	-322.68	3.11%	6.61%	9.49%
60	-1,185.83	141.64	2,458.76	7.30%	10.27%	12.98%
70	131.02	1,910.79	5,626.00	10.36%	13.18%	16.02%
80	940.70	3,546.51	8,749.46	12.74%	15.69%	18.70%
90	1,610.97	5,059.34	11,834.55	14.76%	17.93%	21.13%
100	2,228.37	6,534.87	14,846.05	16.56%	19.95%	23.33%
140	4,521.51	12,170.76	26,536.79	22.59%	26.61%	30.48%

Table 23 – Maspoli sensitivity to non-escalated oil price scenarios (Scenario 1)

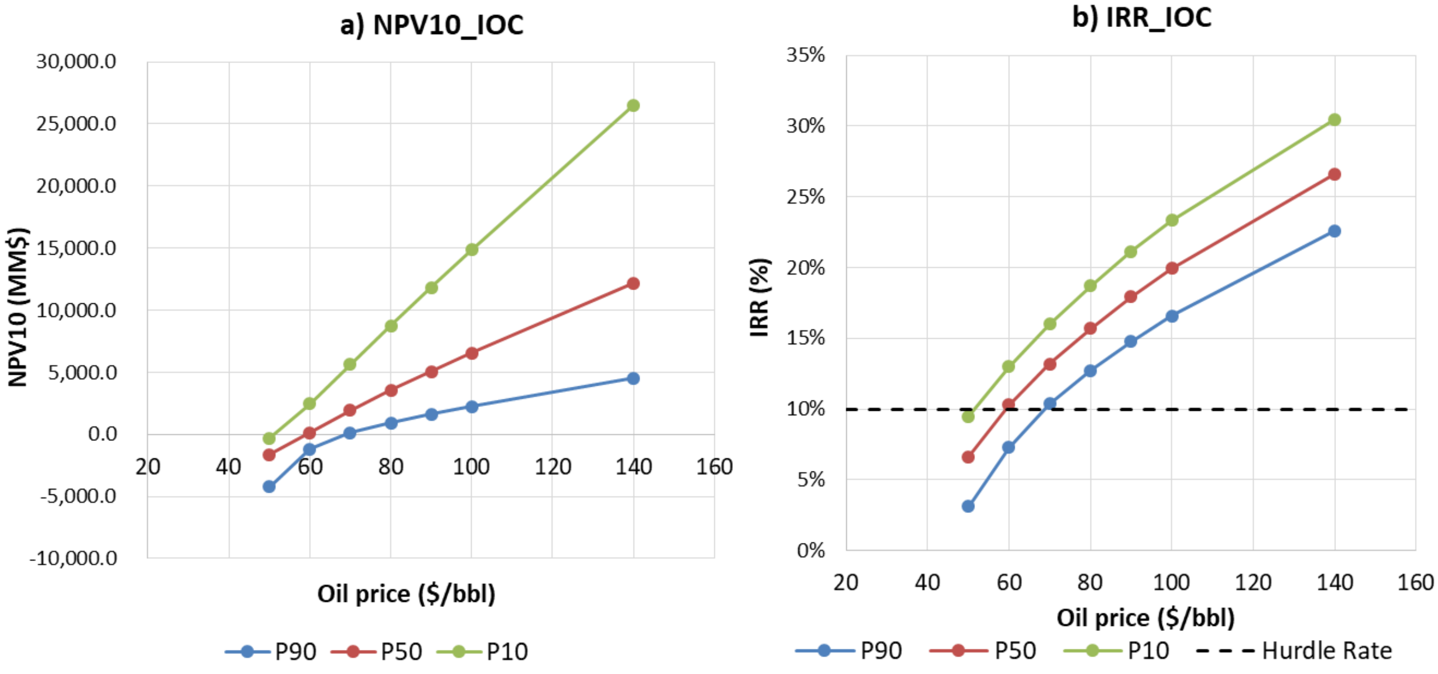


Fig. 29 – Maspoli sensitivity to oil price fluctuations (Scenario 1)

Regarding the economic offer Scenario 2, from **Table 24** and **Fig. 30** it is found that: BE_P90 is equal to $79.9/bbl, BE_P50 is equal to $68.0/bbl and BE_P10 is equal to $58.8/bbl. It is then concluded that an oil price greater than $79.9/bbl will make this prospect profitable, for an IOC, in at least 90% of the cases. These breakeven oil prices are shifted, around $9/bbl, upwards with regard to the ones obtained for the low economic offer case (Scenario 1).

	Scenario 2 - High economic offer case					
	NPV10_IOC (MM$)			**IRR_IOC**		
Oil price ($/bbl)	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
50	-5,351.58	-2,321.80	-1,032.72	0.22%	4.61%	7.32%
60	-2,414.30	-834.88	140.42	5.09%	7.95%	10.28%
70	-668.57	209.60	1,880.02	8.02%	10.46%	12.81%
80	10.14	1,224.42	3,687.93	10.04%	12.57%	15.05%
90	471.60	2,155.60	5,474.90	11.74%	14.43%	17.05%
100	861.95	3,025.84	7,230.03	13.27%	16.13%	18.86%
140	2,187.81	6,239.15	13,811.31	18.25%	21.62%	24.71%

Table 24 – Maspoli sensitivity to non-escalated oil price scenarios (Scenario 2)

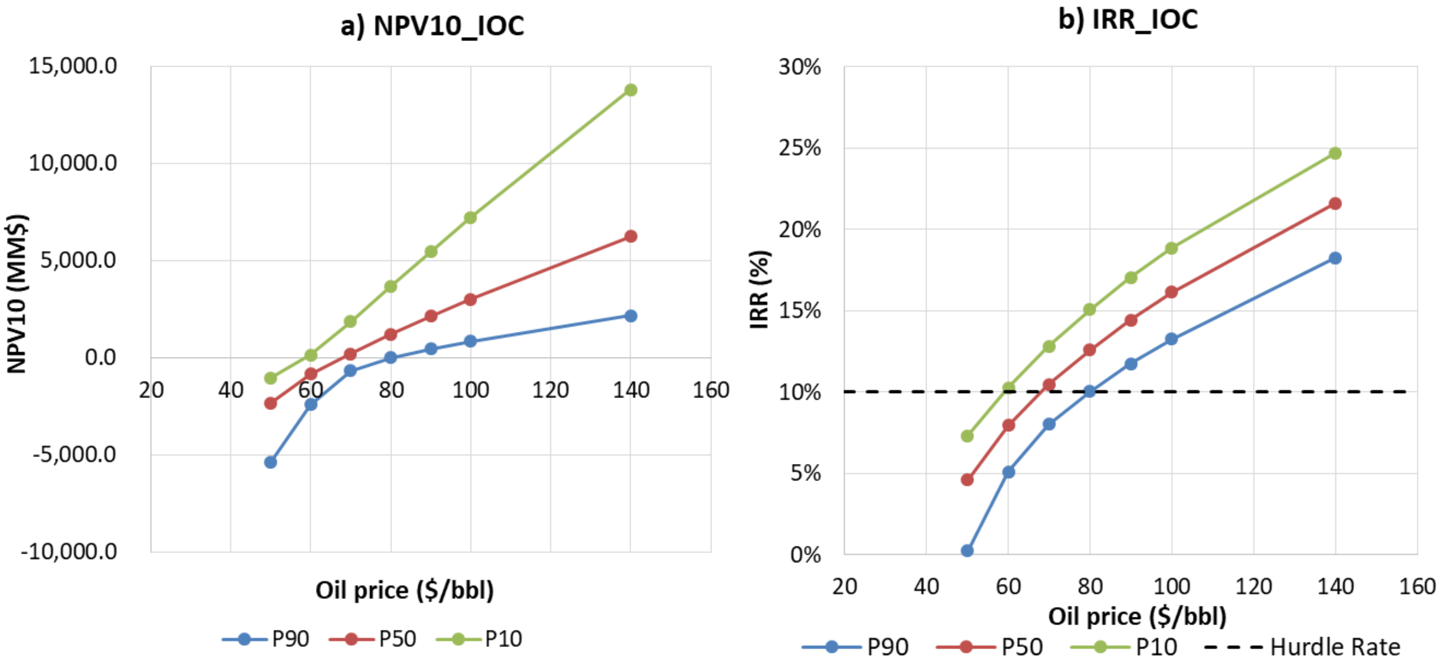


Fig. 30 – Maspoli sensitivity to oil price fluctuations (Scenario 2)

7.2.5. Maspoli Expected Monetary Value

To estimate the EMV of drilling an exploratory well in this prospect, the following assumptions were made:

- Oil and gas prices are assumed to be equal to the EIA Reference forecasts.
- Economic offer Scenario 1 was selected.

For the EMV calculations two probabilities are required, one is the previously determined probability of geologic success ($Pg = 23.33\%$) and the other one is the probability of economic success (Pe).

The Pe is found after all the simulations are run, and is determined as the probability that NPV10_IOC is greater or equal to zero. For the case of Maspoli, after the simulations were completed, the *Pe* is found to be equal to 99.5%.

Fig. 31 shows Maspoli decision tree, where the possibility of drilling an exploratory well is analyzed. It is concluded that, based on the previously mentioned assumptions, the EMV_IOC of drilling an exploratory well in this prospect is equal to: 1,520.45 MM$.

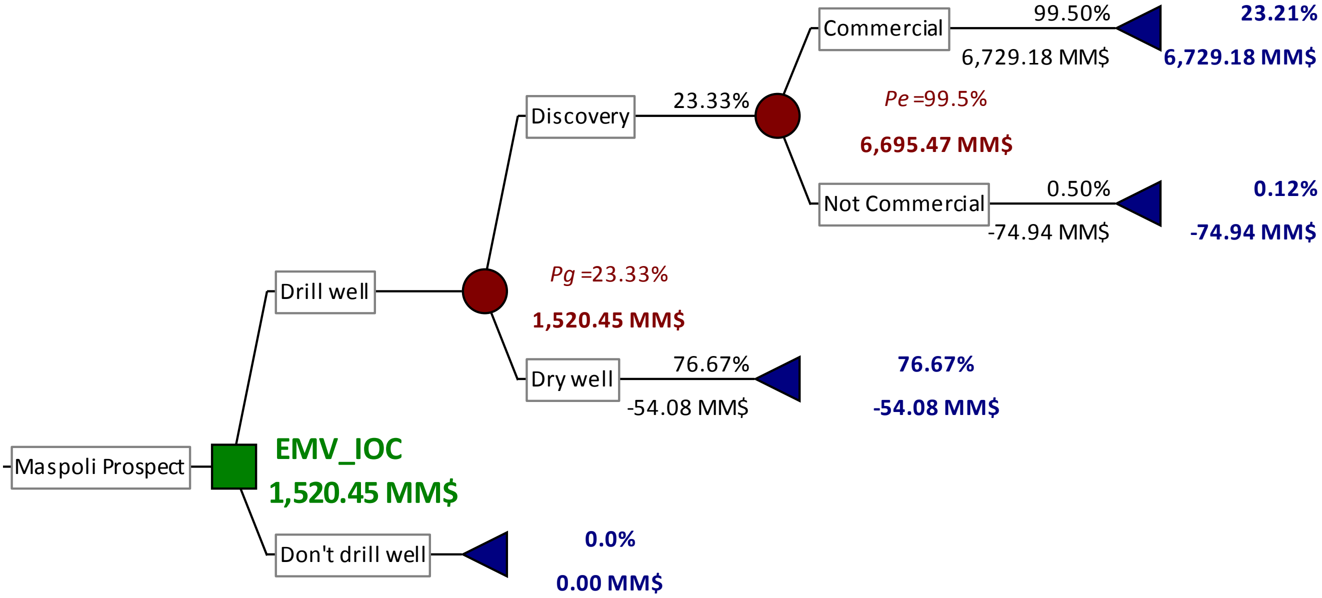


Fig. 31 – Maspoli decision tree for drilling an exploratory well

7.3. Prospect 3 – Jasper

7.3.1. Prospect description

Jasper was recognized in the UR13_3D seismic survey (location shown in Fig. 2). This prospect is a confined Santonian-Campanian turbidite with Campanian-Maastrichtian shales on top which are interpreted as seal. The trap is a combined stratigraphic-structural trap with an updip sealing fault. The proposed source rocks are marine Aptian shales, which are widespread recognized in seismic sections of the South Atlantic margins. Migration of hydrocarbons is assisted through fault systems connecting the source rock with the reservoir **(Fig. 32).**

This speculative petroleum system corresponds to the "Cretaceous post-rift marine petroleum system: Aptian–Late Cretaceous (?)" proposed by Morales et al. (2017) and Morales (2013).

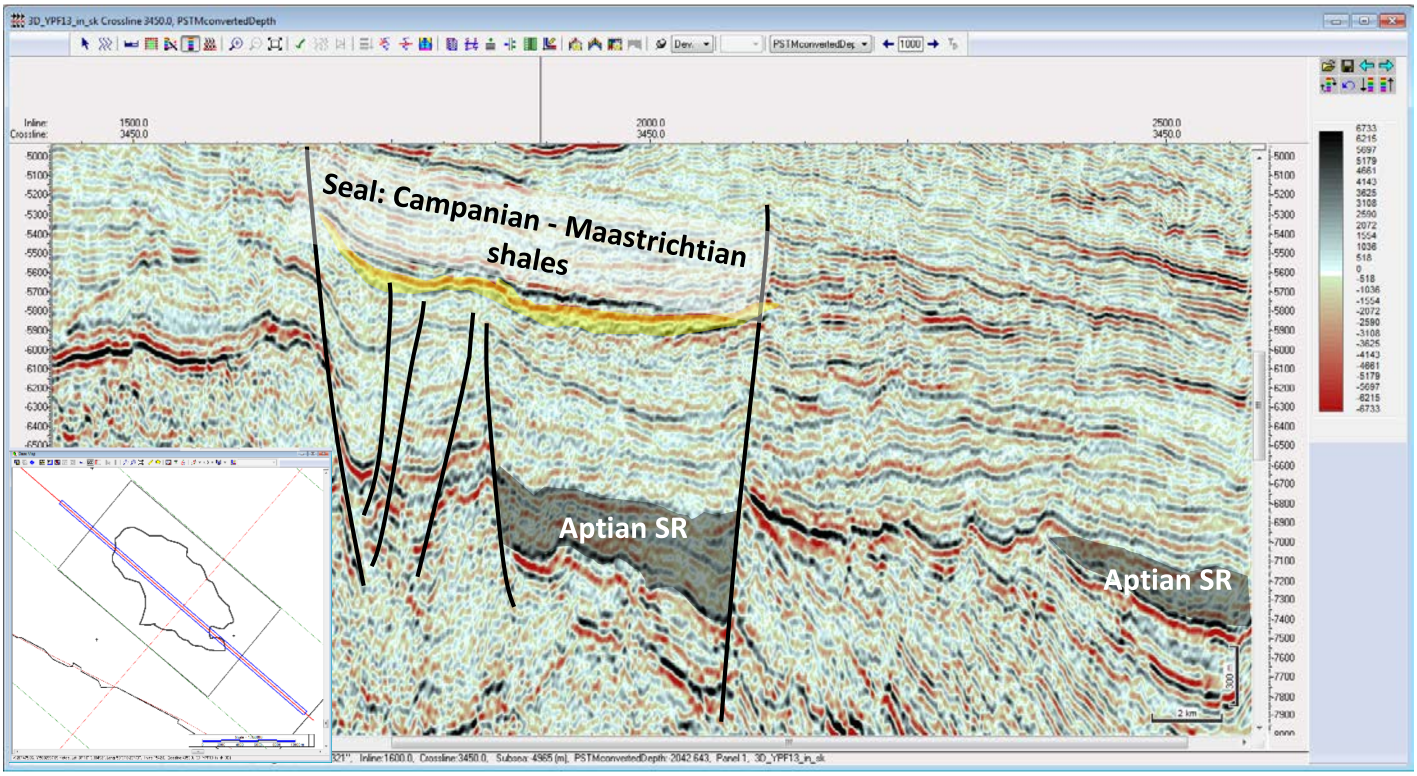


Fig. 32 – Seismic section along Jasper with interpreted petroleum system elements (courtesy of ANCAP)

Some characteristics of this prospect are shown in **Table 25.**

Prospect Characteristics		
Name:	Jasper	
Reservoir:	Confined Santonian-Campanian turbidites	
Trap:	Combined stratigraphic-structural trap with an updip sealing fault	
Geologic Province:	Punta del Este	basin
Area/Round:	3/Round_2009	
Distance to Montevideo:	345	Km
Average Water Depth:	1300	m
Average Reservoir TVD:	5597	m
Probable Fluid Type:	30° API oil	

Table 25 – Jasper characteristics

As it is shown in **Table 26**, Jasper presents a chance of geologic success equal to 17.64%. The probability of hydrocarbon generation is 80% due to the presence of Aptian source rock beneath the prospect; probability of migration and timing is 90% because Jasper is a clastic Cretaceous reservoir with recognizable faults, which probably interconnect source rock and reservoir. Since the reservoir is Cretaceous and clastic, the probability that the reservoir is present is 90%. Seal probability is 50% because it has Campanian-Maastrichtian shales on top acting as seal. Finally, trap probability is 70% because this prospect has a combined stratigraphic-structural trap with an updip sealing fault and it also has a clear seismic amplitude anomaly that was mapped with 3D seismic.

Pg: Probability of Geologic Success	
Hydrocarbon generation	80%
Migration & timing	90%
Reservoir	70%
Seal	50%
Trap	70%
***Pg* =**	**17.64%**

Table 26 – Jasper probability of geologic success

The Pg is used (later in this study) to estimate the EMV of the prospect based on the probabilistic NPV estimates (see Section 7.3.5).

The probabilistic volumetric analysis of Jasper led to the prospective resources results shown in **Table 27:**

Oil (MMbbls)			Associated Gas (TCF)		
1U	**2U**	**3U**	**1U**	**2U**	**3U**
103.612	257.236	566.839	0.041	0.132	0.358

Table 27 – Jasper Prospective Resources

7.3.2. Jasper economic simulations

This section presents the results of several economic simulations, for various oil price scenarios as well as for the two defined economic offer scenarios. **Table 28** shows some simulation results that are independent of the oil price scenario and of the offered economic variables.

According to Table 28 the development of this prospect would require, in average, 5 production wells and due to its expected maximum oil production of almost 49,000 bopd, only one FPSO would be required.

Variable	P90	P50	P10
# Prod. Wells	2	5	16
# Gas Inj. Wells	1	1	2
Max. Field Oil production (bbls/d)	17,565.8	48,597.9	97,462.0
Max. Field Water production (bbls/d)	17,097.3	57,707.1	155,389.8
Max. Gas production (MMscf/d)	6.95	23.65	59.64
CAPEX (MM$)	1,673.18	3,776.73	8,247.07
OPEX (MM$)	2,252.43	5,431.34	13,038.52
CAPEX/BOE ($/boe)	14.81	17.87	24.11
OPEX/BOE ($/boe)	20.63	26.98	35.82
TOTAL_COST/BOE ($/boe)	36.90	44.96	58.85
Exp. Well Cost (MM$)	97.03	112.40	132.82
Inj. Well Cost (MM$)	52.76	61.12	72.22
Prod. Well Cost (MM$)	65.04	75.34	89.03
Gas Pipeline Cost (MM$)	1,572.4	1,683.4	1,807.3

Table 28 – Jasper field development statistics

Since Jasper is located 345 km away from Montevideo, the construction of a gas pipeline to the shore would require an investment of around $1.7 billion (Table 28). However, due to the low gas volume of this prospect, the revenues from selling the gas would not pay for such gas pipeline. Therefore, for this particular case, produced gas is decided to be re-injected into the reservoir. As it is shown in Table 28, this solution would only require of one gas injection well.

7.3.3. Jasper sensitivity to EIA oil price forecasts

To assess the project sensitivity to the EIA oil price forecasts, two sets of simulations were run for both economic offer scenarios 1 and 2, and for the following oil price forecasts:

- Base case: $70/bbl initial oil price with a variable escalation at the start of each year taken from a symmetric triangular distribution defined between -10% and 10%.
- EIA High oil price forecast.
- EIA Low oil price forecast.
- EIA Reference oil price forecast.

The results of this set of simulations, run for both economic scenarios 1 and 2, are summarized in **Table 29:**

	NPV10_IOC (MM$)			NPV10_Project (MM$)			MNCF_IOC (MM$)		
Economic and Oil Price scenario	P90	P50	P10	P90	P50	P10	P90	P50	P10
Scen. 1: $70 var. esc.	-504.0	-147.5	446.1	-410.7	156.9	1,462.9	-4,186.9	-2,071.9	-1,098.3
Scen. 1: EIA High	508.3	1,897.1	4,823.9	1,326.4	4,746.2	11,922.8	-4,101.3	-2,049.9	-1,090.0
Scen. 1: EIA Low	-1,238.0	-666.1	-414.7	-1,104.6	-608.0	-348.6	-4,448.7	-2,198.5	-1,185.6
Scen. 1: EIA Ref.	-12.9	495.4	1,502.9	177.5	1,369.8	3,917.5	-4,101.6	-2,051.0	-1,090.0
Scen. 2: $70 var. esc.	-590.6	-254.1	93.5	-410.7	156.9	1,462.9	-3,691.7	-1,826.2	-970.2
Scen. 2: EIA High	238.1	981.1	2,548.3	1,326.4	4,746.2	11,922.8	-3,588.7	-1,793.7	-953.8
Scen. 2: EIA Low	-1,283.8	-680.7	-411.8	-1,104.6	-608.0	-348.6	-4,032.6	-1,980.8	-1,087.4
Scen. 2: EIA Ref.	-95.4	183.5	676.3	177.5	1,369.8	3,917.5	-3,591.2	-1,795.4	-953.8

	IRR_IOC			IOC_Entitlement			Government Take		
Economic and Oil Price scenario	P90	P50	P10	P90	P50	P10	P90	P50	P10
Scen. 1: $70 var. esc.	-9.78%	8.69%	14.23%	71.96%	75.65%	76.82%	46.09%	48.20%	51.64%
Scen. 1: EIA High	20.66%	26.90%	31.17%	60.96%	62.17%	64.47%	56.62%	57.37%	57.63%
Scen. 1: EIA Low	-28.28%	-4.84%	4.04%	76.34%	76.97%	77.56%	44.80%	45.77%	46.91%
Scen. 1: EIA Ref.	10.47%	15.87%	19.43%	66.77%	69.79%	74.54%	49.53%	53.55%	55.42%
Scen. 2: $70 var. esc.	-15.93%	6.70%	11.49%	53.94%	59.19%	60.22%	65.96%	67.80%	70.81%
Scen. 2: EIA High	16.95%	22.30%	25.94%	39.13%	40.93%	44.17%	75.17%	75.83%	76.05%
Scen. 2: EIA Low	-29.23%	-12.57%	1.66%	59.80%	60.35%	60.87%	64.83%	65.67%	66.67%
Scen. 2: EIA Ref.	8.45%	12.88%	15.86%	47.16%	51.17%	57.65%	68.97%	72.48%	74.11%

Table 29 – Jasper simulation results for various EIA oil price forecasts

Fig. 33 graphically shows the sensitivity to various EIA oil price forecasts.

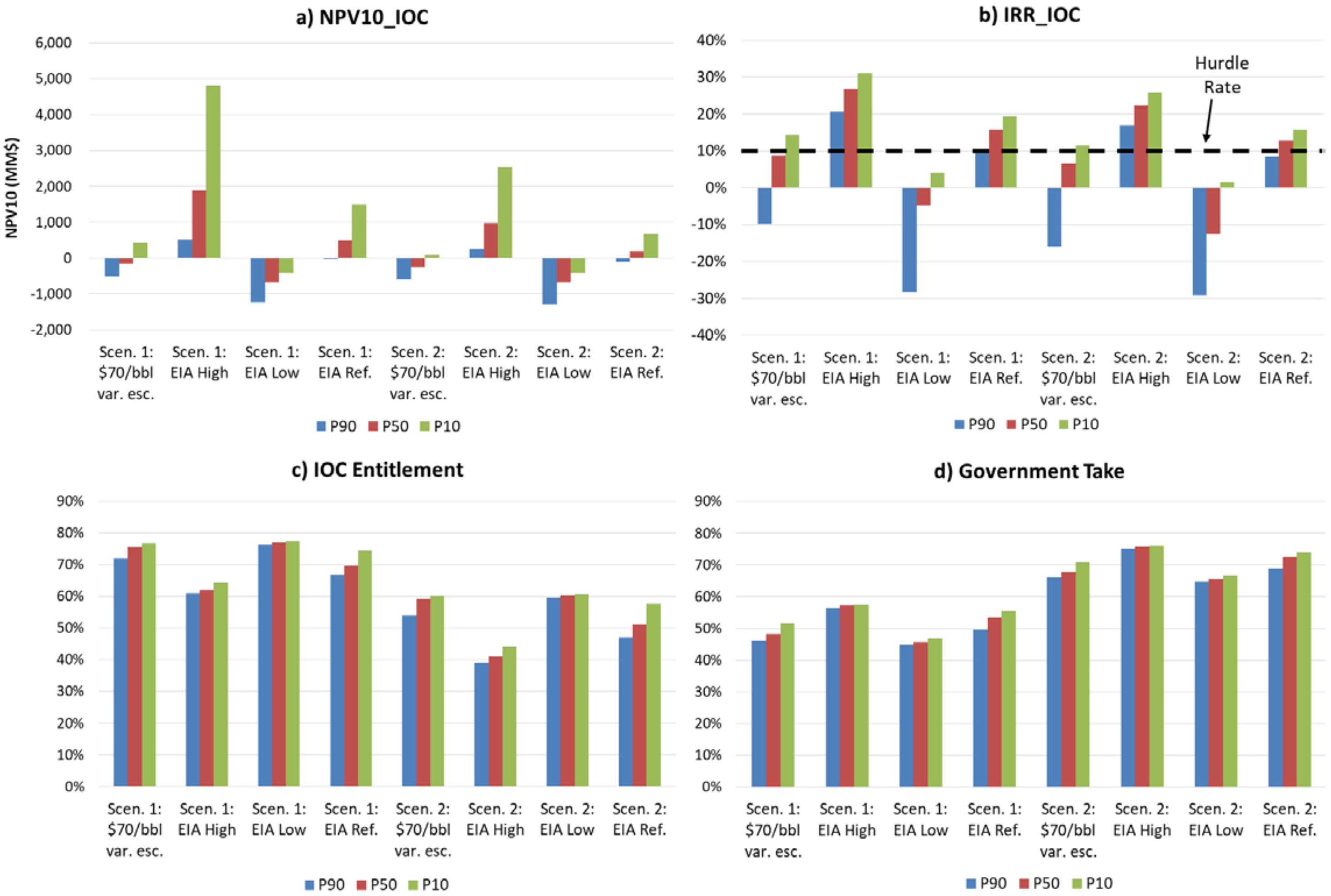


Fig. 33 – Jasper sensitivity to various EIA oil price forecasts

It is concluded that, for an IOC, the project meets and exceeds the 10% hurdle rate in the EIA High and EIA Reference oil price forecasts for both economic proposal scenarios. For the case of the EIA Low oil price forecast, even the project as a whole is not profitable because its discounted net present value P50 percentile is negative (Table 29). On the other hand, average IOC Entitlement and Government Take in the most optimistic case for the IOC are 71.2% and 51.2% respectively, while for the extreme case they are 52.9% and 70.4% respectively. Regarding the MNCF for the IOC, it varies between $1.79 billion and $2.20 billion.

7.3.4. Jasper sensitivity to fixed oil price scenarios

In order to analyze the project sensitivity to fixed oil price scenarios, a set of simulations were run for fixed oil price scenarios without escalation. The oil price scenarios that were considered are the following: $50/bbl, $60/bbl, $70/bbl, $80/bbl, $90/bbl, $100/bbl and $140/bbl. From the resultant NPV10_IOC distributions the breakeven oil price percentiles: P90, P50 and P10 were determined and then used to calculate the breakeven oil prices that make the project profitable for an IOC.

The results for Scenario 1 simulations are shown in **Table 30** and in **Fig. 34,** from them it is found that for this scenario: the BE_P90 is equal to $113.5/bbl, the BE_P50 is equal to $76.6/bbl and the BE_P10 is equal to $58.0/bbl. It is then concluded that an oil price greater than $113.5/bbl will make this prospect profitable, for an IOC, in at least 90% of the cases.

	Scenario 1 - Low economic offer case					
	NPV10_IOC (MM$)			**IRR_IOC**		
Oil price ($/bbl)	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
50	-1,203.74	-580.57	-271.25	-24.45%	0.70%	7.87%
60	-802.76	-362.61	68.08	-18.39%	5.59%	11.25%
70	-504.00	-147.45	446.14	-9.78%	8.69%	14.23%
80	-336.49	75.52	825.76	4.27%	11.38%	16.78%
90	-214.98	277.41	1,206.89	6.66%	13.70%	19.01%
100	-103.71	459.99	1,573.34	8.67%	15.68%	20.95%
140	203.31	1,100.12	3,063.54	14.91%	21.76%	27.10%

Table 30 – Jasper sensitivity to non-escalated oil price scenarios (Scenario 1)

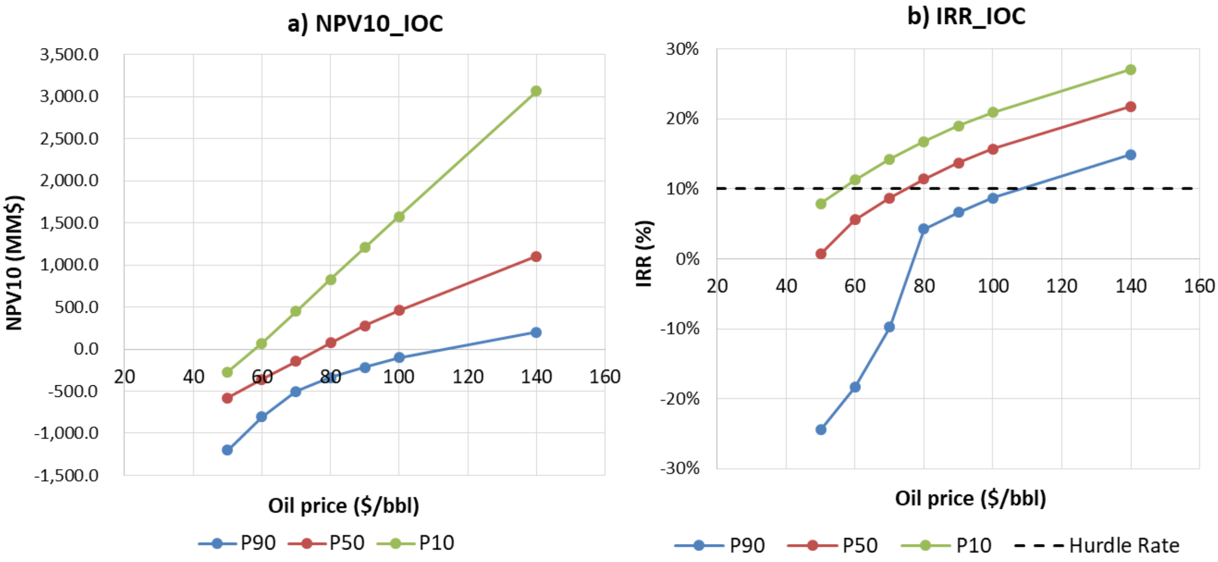


Fig. 34 – Jasper sensitivity to oil price fluctuations (Scenario 1)

Regarding the economic offer Scenario 2, from **Table 31** and **Fig. 35** it is found that: BE_P90 is equal to \$130.1, BE_P50 is equal to \$86.7 and BE_P10 is equal to \$65.8. It is then concluded that an oil price greater than \$130.1 will make this prospect profitable, for an IOC, in at least 90% of the cases. These breakeven oil prices are shifted, around \$12/bbl, upwards with regard to the ones obtained for the low economic offer case (Scenario 1).

	Scenario 2 - High economic offer case					
	NPV10_IOC (MM\$)			**IRR_IOC**		
Oil price (\$/bbl)	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
50	-1,231.58	-603.76	-329.70	-26.61%	-3.44%	6.10%
60	-874.44	-413.31	-127.40	-21.22%	3.86%	9.07%
70	-590.57	-254.08	93.54	-15.93%	6.70%	11.49%
80	-394.27	-91.57	307.39	0.56%	9.08%	13.65%
90	-272.32	45.64	525.90	4.76%	11.02%	15.50%
100	-180.46	161.72	737.47	6.81%	12.73%	17.14%
140	59.64	534.48	1,571.06	12.09%	17.83%	22.36%

Table 31 – Jasper sensitivity to non-escalated oil price scenarios (Scenario 2)

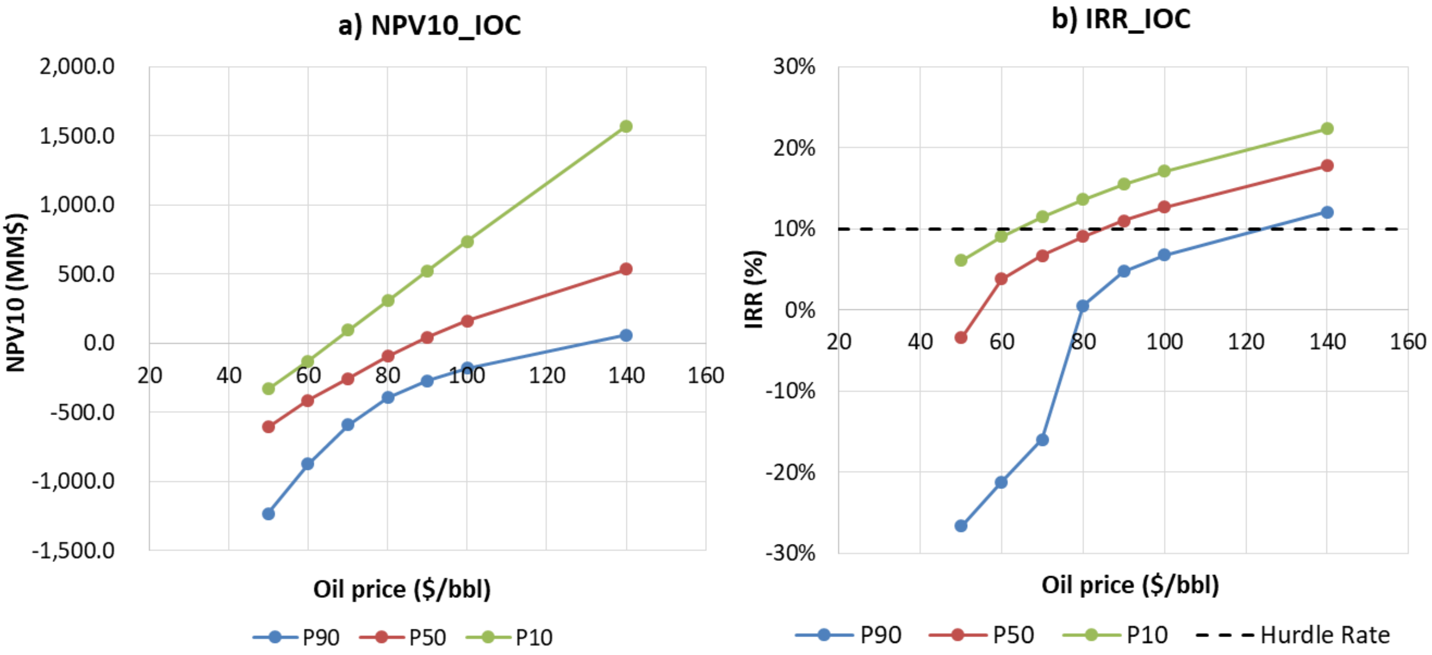


Fig. 35 – Jasper sensitivity to oil price fluctuations (Scenario 2)

7.3.5. Jasper Expected Monetary Value

To estimate the EMV of drilling an exploratory well in this prospect, the following assumptions were made:

- Oil and gas prices are assumed to be equal to the EIA Reference forecasts.
- Economic offer Scenario 1 was selected.

For the EMV calculations two probabilities are required, one is the previously determined probability of geologic success ($Pg = 17.64\%$) and the other one is the probability of economic success (Pe).

The Pe is found after all the simulations are run, and is determined as the probability that NPV10_IOC is greater or equal to zero. For the case of Jasper, after the simulations were completed, the *Pe* is found to be equal to 89.48%.

Fig. 36 shows Jasper decision tree, where the possibility of drilling an exploratory well is analyzed. It is concluded that, based on the previously mentioned assumptions, the EMV_IOC of drilling an exploratory well in this prospect is equal to: -16.76 MM$.

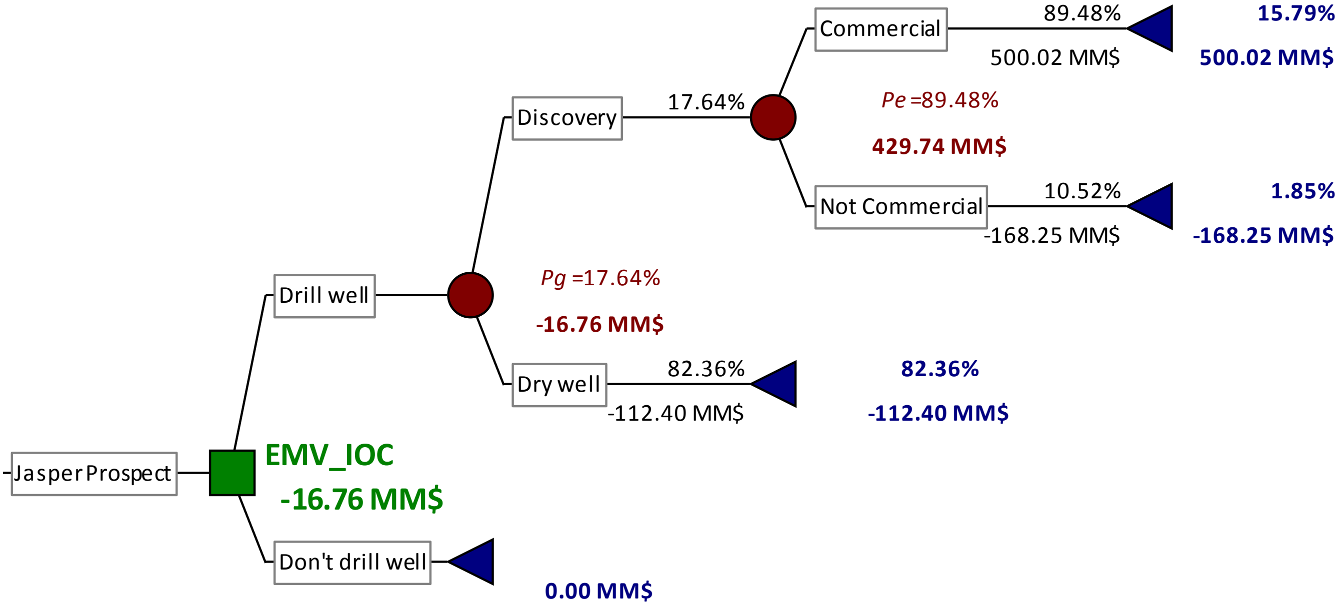


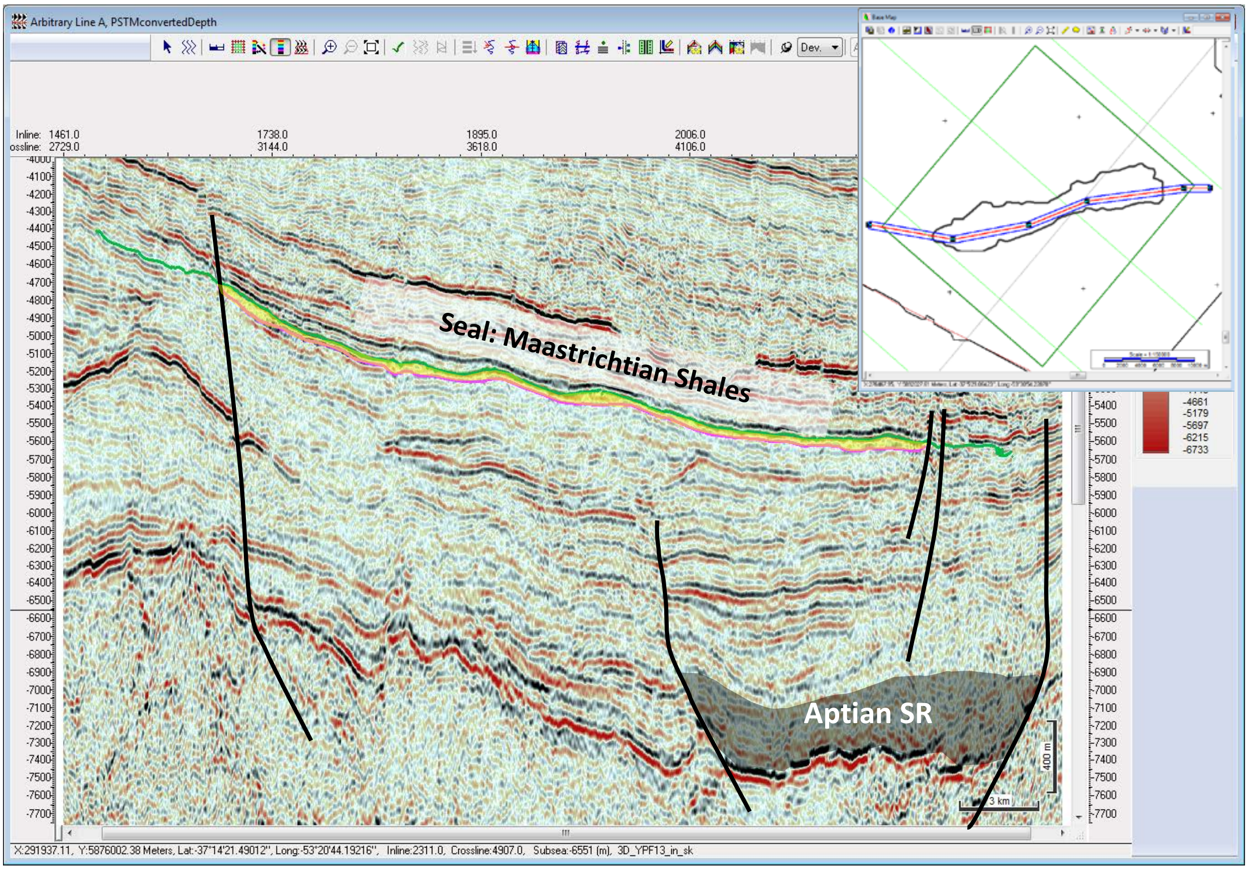
Fig. 36 – Jasper decision tree for drilling an exploratory well

7.4. Prospect 4 – Emerald-Deep

7.4.1. Prospect description

Emerald-Deep was recognized in the UR13_3D seismic survey (location shown in Fig. 2). This prospect is a confined Campanian-Maastrichtian turbidite with Maastrichtian shales on top which are interpreted as seal. The trap is a combined stratigraphic-structural trap with an updip sealing fault. The proposed source rocks are marine Aptian shales, which are widespread recognized in seismic sections of the South Atlantic margins. Migration of hydrocarbons is assisted through fault systems connecting the source rock with the reservoir **(Fig. 37).**

This speculative petroleum system corresponds to the "Cretaceous post-rift marine petroleum system: Aptian–Late Cretaceous (?)" proposed by Morales et al. (2017) and Morales (2013).



X:291937.11, Y:5876002.38 Meters, Lat:-37°14'21.49012", Long:-53°20'44.19216", Inline:2311.0, Crossline:4907.0, Subsea:-6551 (m), 3D_YPF13_in_sk

Fig. 37 – Seismic section along Emerald-Deep with interpreted petroleum system elements (courtesy of ANCAP)

Some characteristics of this prospect are shown in **Table 32.**

Prospect Characteristics		
Name:	Emerald-Deep	
Reservoir:	Confined Campanian-Maastrichtian turbidites	
Trap:	Combined stratigraphic-structural trap with an updip sealing fault	
Geologic Province:	Punta del Este	basin
Area/Round:	3/Round_2009	
Distance to Montevideo:	345	Km
Average Water Depth:	1350	m
Average Reservoir TVD:	5167.5	m
Probable Fluid Type:	30° API oil	

Table 32 – Emerald-Deep characteristics

As it is shown in **Table 33,** Emerald-Deep presents a chance of geologic success equal to 17.64%. The probability of hydrocarbon generation is 80% due to the presence of Aptian source rock beneath the prospect; probability of migration and timing is 90% because Emerald-Deep is a clastic Cretaceous reservoir with recognizable faults, which probably interconnect source rock and reservoir. Since the reservoir is Cretaceous and clastic, the probability that the reservoir is present is 90%. Seal probability is 50% because it has Maastrichtian shales on top acting as seal. Finally, trap probability is 70% because this prospect has a combined stratigraphic-structural trap with an updip sealing fault and it also has a clear seismic amplitude anomaly mapped with 3D seismic.

Pg: Probability of Geologic Success	
Hydrocarbon generation	80%
Migration & timing	90%
Reservoir	70%
Seal	50%
Trap	70%
Pg =	**17.64%**

Table 33 – Emerald-Deep probability of geologic success

The Pg is used (later in this study) to estimate the EMV of the prospect based on the probabilistic NPV estimates (see Section 7.4.5).

The probabilistic volumetric analysis of Emerald-Deep led to the prospective resources results shown in **Table 34:**

Oil (MMbbls)			**Associated Gas (TCF)**		
1U	**2U**	**3U**	**1U**	**2U**	**3U**
54.548	140.121	330.994	0.022	0.072	0.206

Table 34 – Emerald-Deep Prospective Resources

7.4.2. Emerald-Deep economic simulations

This section presents the results of several economic simulations, for various oil price scenarios as well as for the two defined economic offer scenarios. **Table 35** shows some simulation results that are independent of the oil price scenario and of the offered economic variables.

According to Table 35 the development of this prospect would require, in average, 3 production wells and due to its expected maximum oil production of almost 29,000 bopd, only one FPSO would be required.

Variable	P90	P50	P10
# Prod. Wells	1	3	7
# Gas Inj. Wells	1	1	1
Max. Field Oil production (bbls/d)	9,470.9	28,954.9	61,895.9
Max. Field Water production (bbls/d)	9,119.3	30,532.9	80,201.7
Max. Gas production (MMscf/d)	3.17	13.12	37.01
CAPEX (MM$)	962.43	2,136.60	4,715.83
OPEX (MM$)	1,482.56	3,180.07	7,179.00
CAPEX/BOE ($/boe)	15.59	19.90	30.91
OPEX/BOE ($/boe)	22.80	30.75	43.80
TOTAL_COST/BOE ($/boe)	39.89	50.25	73.60
Exp. Well Cost (MM$)	87.22	101.03	119.39
Inj. Well Cost (MM$)	46.87	54.30	64.16
Prod. Well Cost (MM$)	59.15	68.52	80.97
Gas Pipeline Cost (MM$)	1,572.4	1,683.4	1,807.3

Table 35 – Emerald-Deep field development statistics

Since Emerald-Deep is located 345 km away from Montevideo, the construction of a gas pipeline to the shore would require an investment of around $1.7 billion (Table 35). However, due to the low gas volume of this prospect, the revenues from selling the gas would not pay for such gas pipeline. Therefore, for this particular case, produced gas is decided to be re-injected into the reservoir. As it is shown in Table 35, this solution would only require of one gas injection well.

7.4.3. Emerald-Deep sensitivity to EIA oil price forecasts

To assess the project sensitivity to the EIA oil price forecasts, two sets of simulations were run for both economic offer scenarios 1 and 2, and for the following oil price forecasts:

- Base case: $70/bbl initial oil price with a variable escalation at the start of each year taken from a symmetric triangular distribution defined between -10% and 10%.
- EIA High oil price forecast.
- EIA Low oil price forecast.
- EIA Reference oil price forecast.

The results of this set of simulations, run for both economic scenarios 1 and 2, are summarized in **Table 36:**

	NPV10_IOC (MM$)			NPV10_Project (MM$)			MNCF_IOC (MM$)		
Economic and Oil Price scenario	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
Scen. 1: $70 var. esc.	-422.7	-213.6	175.0	-431.0	-87.8	693.3	-2,523.2	-1,296.9	-794.2
Scen. 1: EIA High	156.6	990.5	2,584.0	477.7	2,513.3	6,420.1	-2,495.1	-1,289.0	-781.1
Scen. 1: EIA Low	-817.7	-488.0	-345.6	-780.7	-497.9	-334.5	-2,670.5	-1,377.4	-911.1
Scen. 1: EIA Ref.	-193.3	193.9	770.1	-142.9	614.5	2,035.1	-2,495.1	-1,289.0	-781.1
Scen. 2: $70 var. esc.	-437.0	-252.9	-8.1	-431.0	-87.8	693.3	-2,224.2	-1,142.3	-708.9
Scen. 2: EIA High	45.2	498.5	1,357.3	477.7	2,513.3	6,420.1	-2,183.2	-1,127.9	-683.5
Scen. 2: EIA Low	-830.2	-477.3	-328.2	-780.7	-497.9	-334.5	-2,410.1	-1,259.8	-854.2
Scen. 2: EIA Ref.	-211.0	36.8	332.8	-142.9	614.5	2,035.1	-2,185.8	-1,128.0	-683.5

	IRR_IOC			IOC_Entitlement			Government Take		
Economic and Oil Price scenario	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
Scen. 1: $70 var. esc.	-13.24%	7.28%	13.37%	73.62%	76.11%	77.58%	44.80%	47.40%	50.16%
Scen. 1: EIA High	16.01%	24.60%	29.50%	61.41%	62.98%	67.38%	55.15%	57.19%	57.56%
Scen. 1: EIA Low	-27.46%	-12.73%	3.04%	76.53%	77.51%	77.67%	44.80%	44.80%	46.57%
Scen. 1: EIA Ref.	5.45%	13.97%	18.31%	67.84%	71.99%	76.18%	47.31%	51.72%	54.89%
Scen. 2: $70 var. esc.	-15.93%	6.70%	11.49%	56.09%	59.59%	60.88%	64.83%	67.10%	69.52%
Scen. 2: EIA High	16.95%	22.30%	25.94%	39.81%	42.10%	48.00%	73.88%	75.67%	75.99%
Scen. 2: EIA Low	-29.23%	-12.57%	1.66%	59.97%	60.82%	60.96%	64.83%	64.83%	66.38%
Scen. 2: EIA Ref.	8.45%	12.88%	15.86%	48.64%	53.99%	59.66%	67.02%	70.88%	73.66%

Table 36 – Emerald-Deep simulation results for various EIA oil price forecasts

Fig. 38 graphically shows the sensitivity to various EIA oil price forecasts.

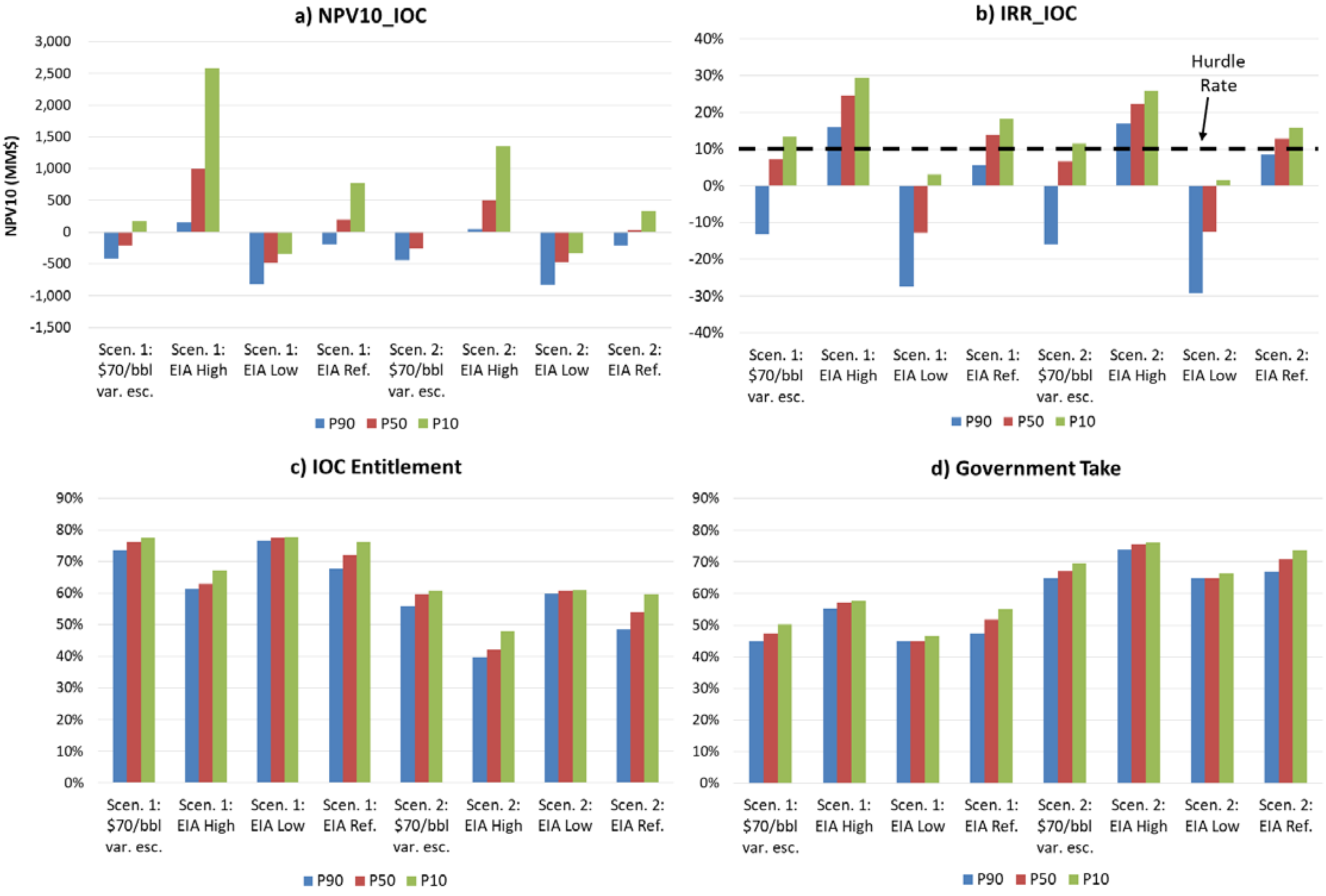


Fig. 38 – Emerald-Deep sensitivity to various EIA oil price forecasts

It is concluded that, for an IOC, the project meets and exceeds the 10% hurdle rate in the EIA High and EIA Reference oil price forecasts for both economic offer scenarios. For the case of the EIA Low oil price forecast, even the project as a whole is not profitable because its discounted net present value P50 percentile is negative (Table 36). On the other hand, average IOC Entitlement and Government Take in the most optimistic case for the IOC are 72.2% and 50.3% respectively, while for the extreme case they are 54.1% and 69.6% respectively. Regarding the MNCF for the IOC, it varies between $1.12 billion and $2.52 billion.

7.4.4. Emerald-Deep sensitivity to fixed oil price scenarios

In order to analyze the project sensitivity to fixed oil price scenarios, a set of simulations were run for fixed oil price scenarios without escalation. The oil price scenarios that were considered are the following: $50/bbl, $60/bbl, $70/bbl, $80/bbl, $90/bbl, $100/bbl and $140/bbl. From the resultant NPV10_IOC distributions the breakeven oil price percentiles: P90, P50 and P10 were determined and then used to calculate the breakeven oil prices that make the project profitable for an IOC.

The results for Scenario 1 simulations are shown in **Table 37** and in **Fig. 39,** from them it is found that for this scenario: the BE_P90 is equal to $139.4/bbl, the BE_P50 is equal to $83.6/bbl and the BE_P10 is equal to $66.4/bbl. It is then concluded that an oil price greater than $139.4/bbl will make this prospect profitable, for an IOC, in at least 90% of the cases.

	Scenario 1 - Low economic offer case					
	NPV10_IOC (MM$)			IRR_IOC		
Oil price ($/bbl)	P90	P50	P10	P90	P50	P10
50	-731.29	-444.74	-315.28	-26.28%	-11.93%	4.45%
60	-487.84	-322.42	-152.79	-19.87%	3.92%	8.37%
70	-361.64	-190.54	87.57	-11.64%	7.21%	11.66%
80	-296.25	-48.02	326.43	-0.15%	10.07%	14.35%
90	-243.42	85.89	556.44	3.79%	12.33%	16.66%
100	-188.34	202.53	768.89	5.42%	14.26%	18.66%
140	2.64	576.04	1,586.50	11.64%	20.14%	24.72%

Table 37 – Emerald-Deep sensitivity to non-escalated oil price scenarios (Scenario 1)

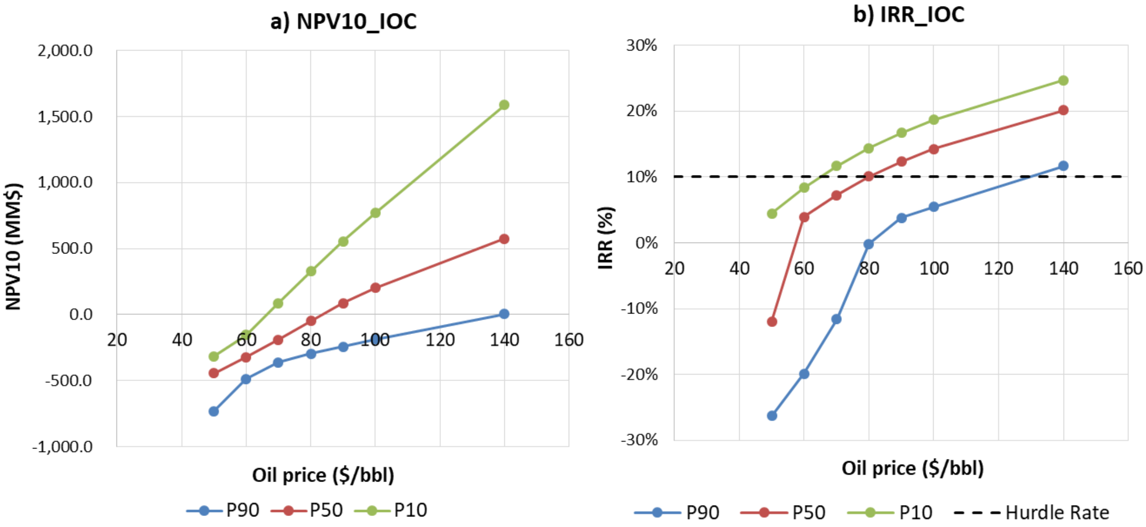


Fig. 39 – Emerald-Deep sensitivity to oil price fluctuations (Scenario 1)

Regarding the economic proposal Scenario 2, from **Table 38** and **Fig. 40** it is found that: BE_P90 is equal to $154.2/bbl, BE_P50 is equal to $94.5/bbl and BE_P10 is equal to $74.9/bbl. It is then concluded that an oil price greater than $154.2/bbl will make this prospect profitable, for an IOC, in at least 90% of the cases. These breakeven prices are shifted, around $12/bbl, upwards with regard to the ones obtained for the low economic offer case (Scenario 1).

	Scenario 2 - High economic offer case					
	NPV10_IOC (MM$)			**IRR_IOC**		
Oil price ($/bbl)	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
50	-753.87	-442.17	-310.90	-27.29%	-13.89%	2.07%
60	-528.11	-338.43	-224.14	-23.93%	-2.46%	6.27%
70	-373.70	-241.31	-72.27	-16.92%	5.17%	9.21%
80	-297.34	-134.39	73.76	-9.12%	7.92%	11.57%
90	-250.26	-36.75	207.89	1.66%	9.97%	13.52%
100	-207.76	44.13	334.01	3.91%	11.58%	15.19%
140	-54.52	268.48	798.16	9.26%	16.44%	20.31%

Table 38 – Emerald-Deep sensitivity to non-escalated oil price scenarios (Scenario 2)

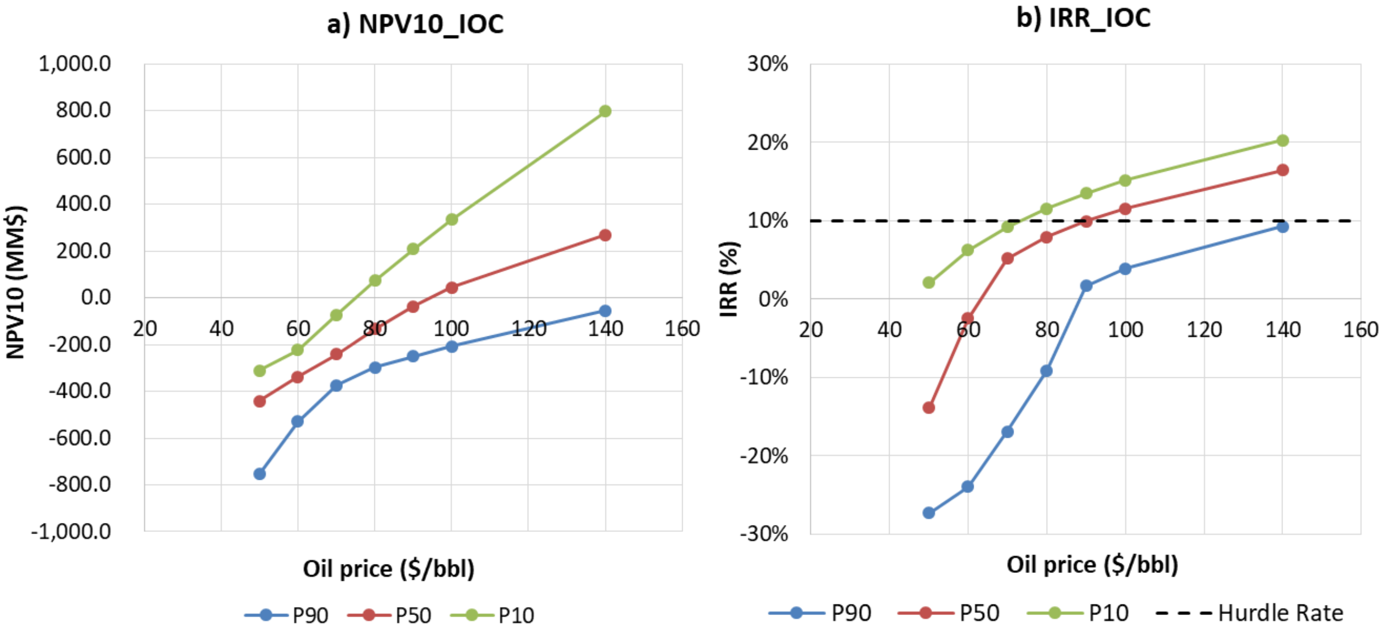


Fig. 40 – Emerald-Deep sensitivity to oil price fluctuations (Scenario 2)

7.4.5. Emerald-Deep Expected Monetary Value

To estimate the EMV of drilling an exploratory well in this prospect, the following assumptions were made:

- Oil and gas prices are assumed to be equal to the EIA Reference forecasts.
- Economic offer Scenario 1 was selected.

For the EMV calculations two probabilities are required, one is the previously determined probability of geologic success ($Pg = 17.64\%$) and the other one is the probability of economic success (Pe).

The Pe is found after all the simulations are run, and is determined as the probability that NPV10_IOC is greater or equal to zero. For the case of Emerald-Deep, after the simulations were completed, the *Pe* is found to be equal to 69.67%.

Fig. 44 shows Emerald-Deep decision tree, where the possibility of drilling an exploratory well is analyzed. It is concluded that, based on the previously mentioned assumptions, the EMV_IOC of drilling an exploratory well in this prospect is equal to: -67.21 MM$.

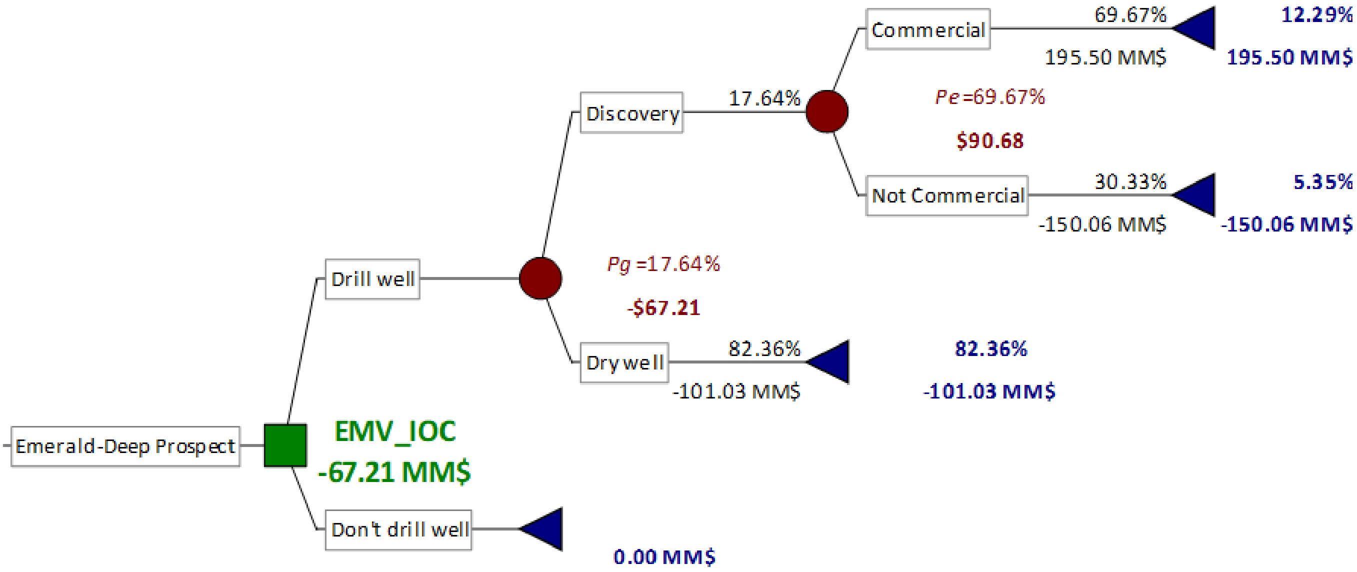


Fig. 41 – Emerald-Deep decision tree for drilling an exploratory well

7.5. Prospect 5 – Emerald

7.5.1. Prospect description

Emerald was recognized in the UR13_3D seismic survey (location shown in Fig. 2). This prospect is a confined Campanian-Maastrichtian turbidite with Maastrichtian shales on top which are interpreted as seal. The trap is a combined stratigraphic-structural trap with updip sealing faults. The proposed source rocks are marine Aptian shales, which are widespread recognized in seismic sections of the South Atlantic margins. Migration of hydrocarbons is assisted through fault systems connecting the source rock with the reservoir **(Fig. 42).**

This speculative petroleum system corresponds to the "Cretaceous post-rift marine petroleum system: Aptian–Late Cretaceous (?)" proposed by Morales et al. (2017) and Morales (2013).

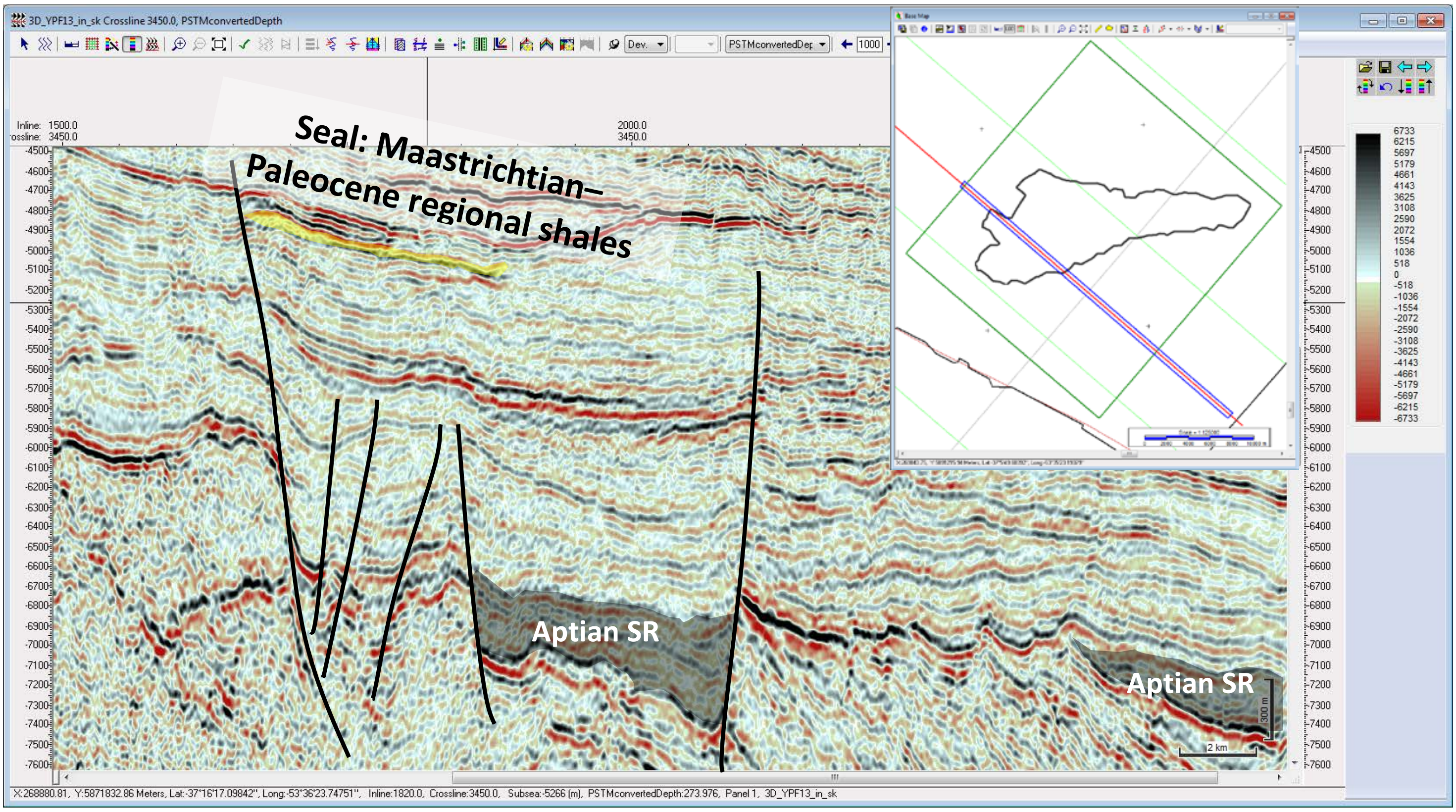


Fig. 42 – Seismic section along Emerald with interpreted petroleum system elements (courtesy of ANCAP)

Some characteristics of this prospect are shown in **Table 39.**

Prospect Characteristics		
Name:	Emerald	
Reservoir:	Confined Campanian-Maastrichtian turbidites	
Trap:	Combined stratigraphic-structural trap with updip sealing faults	
Geologic Province:	Punta del Este	basin
Area/Round:	3/Round_2009	
Distance to Montevideo:	345	Km
Average Water Depth:	1350	m
Average Reservoir TVD:	5099.5	m
Probable Fluid Type:	30° API oil	

Table 39 – Emerald characteristics

As it is shown in Table 40**,** Emerald presents a chance of geologic success equal to 24.7%. The probability of hydrocarbon generation is 80% due to the presence of Aptian source rock beneath the prospect; probability of migration and timing is 90% because Emerald is a clastic Cretaceous reservoir with recognizable faults, which probably interconnect source rock and reservoir. Since the reservoir is Cretaceous and clastic, the probability that the reservoir is present is 90%. Seal probability is 50% because it has Maastrichtian-Paleocene shales, a well-known regional seal, on top acting as seal. Finally, trap probability is 70% because this prospect has a combined stratigraphic-structural trap with updip sealing faults and it also has a clear seismic amplitude anomaly that was mapped with 3D seismic.

Pg: Probability of Geologic Success	
Hydrocarbon generation	80%
Migration & timing	90%
Reservoir	70%
Seal	70%
Trap	70%
***Pg* =**	**24.7%**

Table 40 – Emerald probability of geologic success

The Pg is used (later in this study) to estimate the EMV of the prospect based on the probabilistic NPV estimates (see Section 7.5.5).

The probabilistic volumetric analysis of Emerald led to the prospective resources results shown in **Table 41:**

Oil (MMbbls)			**Associated Gas (TCF)**		
1U	**2U**	**3U**	**1U**	**2U**	**3U**
60.253	175.587	468.880	0.024	0.090	0.294

Table 41 – Emerald Prospective Resources

7.5.2. Emerald economic simulations

This section presents the results of several economic simulations, for various oil price scenarios as well as for the two defined economic offer scenarios. **Table 42** shows some simulation results that are independent of the oil price scenario and of the offered economic variables.

According to Table 42 the development of this prospect would require, in average, 3 production wells and due to its expected maximum oil production of almost 36,000 bopd, only one FPSO would be required.

Variable	P90	P50	P10
# Prod. Wells	1	3	13
# Gas Inj. Wells	1	1	2
Max. Field Oil production (bbls/d)	10,188.1	35,883.5	83,184.8
Max. Field Water production (bbls/d)	9,888.7	39,469.2	124,247.6
Max. Gas production (MMscf/d)	3.85	16.75	49.06
CAPEX (MM$)	1,026.59	2,627.78	6,688.92
OPEX (MM$)	1,571.79	3,903.81	10,659.02
CAPEX/BOE ($/boe)	14.89	18.72	28.79
OPEX/BOE ($/boe)	21.67	29.05	41.87
TOTAL_COST/BOE ($/boe)	37.88	47.53	70.27
Exp. Well Cost (MM$)	85.83	99.42	117.48
Inj. Well Cost (MM$)	46.04	53.33	63.02
Prod. Well Cost (MM$)	58.32	67.55	79.83
Gas Pipeline Cost (MM$)	1,572.4	1,683.4	1,807.3

Table 42 – Emerald field development statistics

Since Emerald is located 345 km away from Montevideo, the construction of a gas pipeline to the shore would require an investment of around $1.7 billion (Table 42). However, due to the low gas volume of this prospect, the revenues from selling the gas would not pay for such gas pipeline. Therefore, for this particular case, produced gas is decided to be re-injected into the reservoir. As it is shown in Table 42, this solution would only require of one gas injection well.

7.5.3. Emerald sensitivity to EIA oil price forecasts

To assess the project sensitivity to the EIA oil price forecasts, two sets of simulations were run for both economic offer scenarios 1 and 2, and for the following oil price forecasts:

- Base case: $70/bbl initial oil price with a variable escalation at the start of each year taken from a symmetric triangular distribution defined between -10% and 10%.
- EIA High oil price forecast.
- EIA Low oil price forecast.
- EIA Reference oil price forecast.

The results of this set of simulations, run for both economic scenarios 1 and 2, are summarized in **Table 43:**

	NPV10_IOC (MM$)			NPV10_Project (MM$)			MNCF_IOC (MM$)		
Economic and Oil Price scenario	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
Scen. 1: $70 var. esc.	-443.8	-186.0	320.0	-421.8	1.9	1,124.9	-3,444.4	-1,526.3	-829.9
Scen. 1: EIA High	192.4	1,287.6	3,930.3	560.6	3,244.3	9,727.5	-3,396.9	-1,517.4	-815.4
Scen. 1: EIA Low	-1,017.0	-530.4	-348.2	-910.4	-516.5	-323.1	-3,646.1	-1,611.5	-949.4
Scen. 1: EIA Ref.	-169.2	300.7	1,225.7	-109.5	869.9	3,185.2	-3,398.4	-1,517.4	-815.4
Scen. 2: $70 var. esc.	-487.3	-244.9	48.7	-421.8	1.9	1,124.9	-3,042.5	-1,343.7	-738.7
Scen. 2: EIA High	67.0	657.6	2,076.9	560.6	3,244.3	9,727.5	-2,972.3	-1,327.7	-713.5
Scen. 2: EIA Low	-1,057.0	-530.2	-333.7	-910.4	-516.5	-323.1	-3,280.5	-1,459.7	-882.0
Scen. 2: EIA Ref.	-189.0	93.9	546.6	-109.5	869.9	3,185.2	-2,977.2	-1,327.7	-713.5

	IRR_IOC			IOC_Entitlement			Government Take		
Economic and Oil Price scenario	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
Scen. 1: $70 var. esc.	-11.55%	8.15%	14.08%	72.68%	75.94%	77.53%	44.80%	47.68%	50.92%
Scen. 1: EIA High	16.82%	25.92%	30.73%	61.10%	62.55%	66.72%	55.51%	57.31%	57.61%
Scen. 1: EIA Low	-27.44%	-9.41%	3.99%	76.39%	77.28%	77.65%	44.80%	45.22%	46.82%
Scen. 1: EIA Ref.	6.39%	15.07%	19.19%	67.11%	70.79%	76.00%	47.64%	52.82%	55.28%
Scen. 2: $70 var. esc.	-15.75%	6.32%	11.48%	54.74%	59.45%	60.84%	64.83%	67.35%	70.18%
Scen. 2: EIA High	13.69%	21.44%	25.61%	39.35%	41.49%	47.10%	74.19%	75.77%	76.03%
Scen. 2: EIA Low	-29.38%	-13.48%	1.77%	59.84%	60.62%	60.94%	64.83%	65.19%	66.59%
Scen. 2: EIA Ref.	5.03%	12.26%	15.67%	47.62%	52.49%	59.50%	67.31%	71.84%	74.00%

Table 43 – Emerald simulation results for various EIA oil price forecasts

Fig. 43 graphically shows the sensitivity to various EIA oil price forecasts.

Fig. 43 – Emerald sensitivity to various EIA oil price forecasts

It is concluded that, for an IOC, the project meets and exceeds the 10% hurdle rate in the EIA High and EIA Reference oil price forecasts for both economic offer scenarios. For the case of the EIA Low oil price forecast, even the project as a whole is not profitable because its discounted net present value P50 percentile is negative (Table 43). On the other hand average IOC Entitlement and Government Take in the most optimistic case for the IOC are 71.6% and 50.8% respectively, while for the extreme case they are 53.5% and 70.0% respectively. Regarding the MNCF for the IOC, it varies between $1.32 billion and $1.61 billion.

7.5.4. Emerald sensitivity to fixed oil price scenarios

In order to analyze the project sensitivity to fixed oil price scenarios, a set of simulations were run for fixed oil price scenarios without escalation. The oil price scenarios that were considered are the following: $50/bbl, $60/bbl, $70/bbl, $80/bbl, $90/bbl, $100/bbl and $140/bbl. From the resultant NPV10_IOC distributions the breakeven oil price percentiles: P90, P50 and P10 were determined and then used to calculate the breakeven oil prices that make the project profitable for an IOC.

The results for Scenario 1 simulations are shown in **Table 44** and in **Fig. 44,** from them it is found that for this scenario: the BE_P90 is equal to $133.8/bbl, the BE_P50 is equal to $78.7/bbl and the BE_P10 is equal to $63.6/bbl. It is then concluded that an oil price greater than $133.4/bbl will make this prospect profitable, for an IOC, in at least 90% of the cases.

	Scenario 1 - Low economic offer case					
	NPV10_IOC (MM$)			**IRR_IOC**		
Oil price ($/bbl)	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
50	-887.11	-476.04	-316.34	-26.12%	-8.77%	5.24%
60	-524.38	-319.95	-114.99	-18.89%	4.80%	9.13%
70	-352.94	-155.93	203.07	-7.20%	8.21%	12.44%
80	-276.68	23.38	546.53	3.98%	11.10%	15.17%
90	-217.33	176.23	893.92	4.98%	13.40%	17.45%
100	-164.07	308.20	1,211.17	6.54%	15.38%	19.50%
140	30.12	762.06	2,423.04	12.55%	21.34%	25.75%

Table 44 – Emerald sensitivity to non-escalated oil price scenarios (Scenario 1)

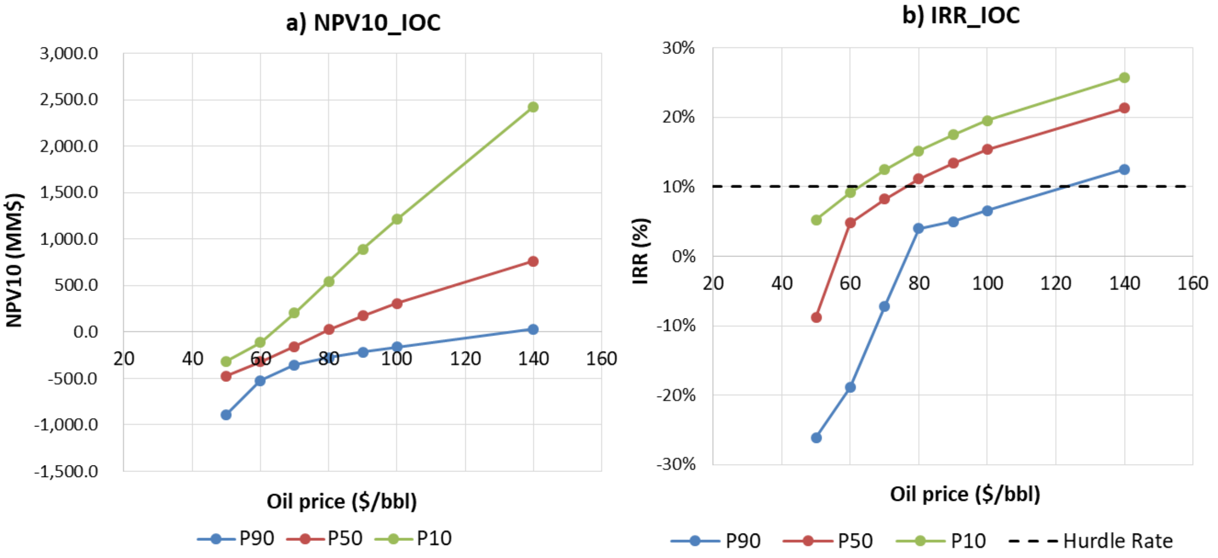

a) NPV10_IOC
b) IRR_IOC

Fig. 44 – Emerald sensitivity to oil price fluctuations (Scenario 1)

Regarding the economic offer Scenario 2, from **Table 45** and **Fig. 45** it is found that: BE_P90 is equal to $149.5/bbl, BE_P50 is equal to $88.9/bbl and BE_P10 is equal to $71.9/bbl. It is then concluded that an oil price greater than $154.2/bbl will make this prospect profitable, for an IOC, in at least 90% of the cases. These breakeven prices are shifted, around $12/bbl, upwards with regard to the ones obtained for the low economic offer case (Scenario 1).

	Scenario 2 - High economic offer case					
	NPV10_IOC (MM$)			**IRR_IOC**		
Oil price ($/bbl)	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
50	-947.47	-484.28	-314.49	-28.37%	-13.46%	3.32%
60	-617.26	-350.70	-219.24	-23.13%	2.02%	6.95%
70	-383.82	-231.61	-35.50	-14.59%	6.11%	9.86%
80	-286.18	-101.31	151.93	1.10%	8.77%	12.21%
90	-231.10	13.16	348.29	4.27%	10.83%	14.19%
100	-184.86	101.04	541.63	5.15%	12.49%	15.90%
140	-35.54	364.42	1,235.85	10.04%	17.45%	21.21%

Table 45 – Emerald sensitivity to non-escalated oil price scenarios (Scenario 2)

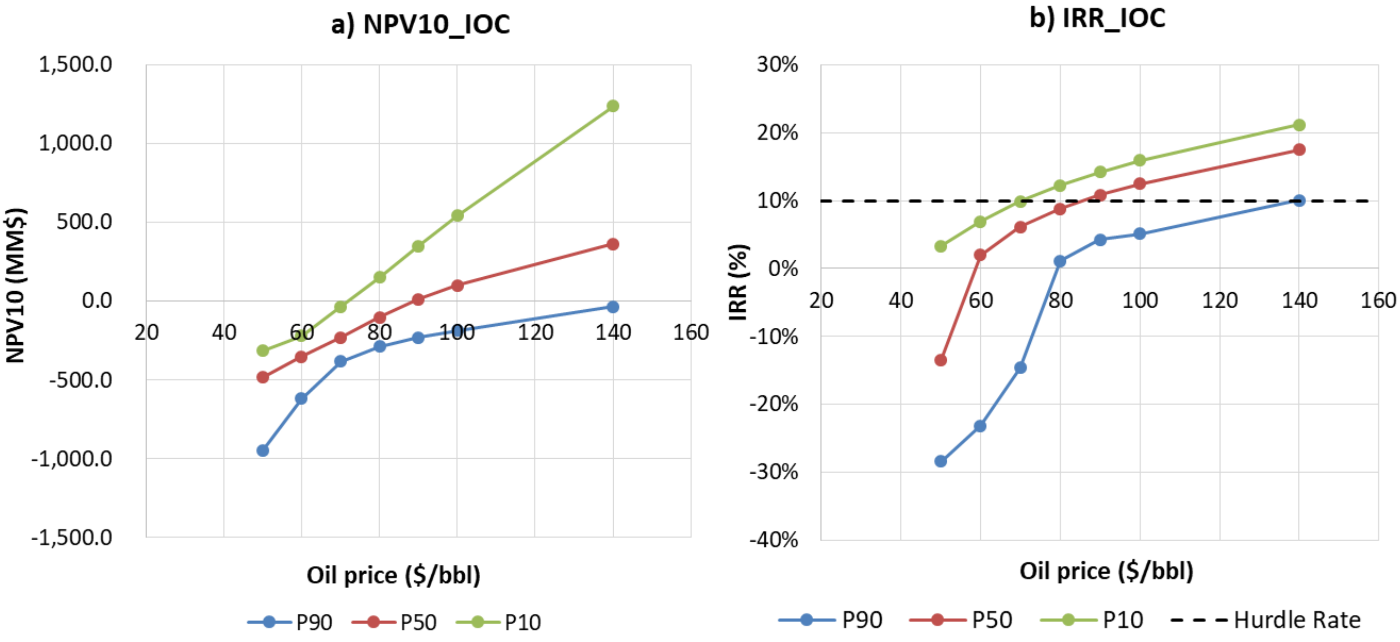


Fig. 45 – Emerald sensitivity to oil price fluctuations (Scenario 2)

7.5.5. Emerald Expected Monetary Value

To estimate the EMV of drilling an exploratory well in this prospect, the following assumptions were made:

- Oil and gas prices are assumed to be equal to the EIA Reference forecasts.
- Economic offer Scenario 1 was selected.

For the EMV calculations two probabilities are required, one is the previously determined probability of geologic success ($Pg = 24.70\%$) and the other one is the probability of economic success (Pe).

The Pe is found after all the simulations are run, and is determined as the probability that NPV10_IOC is greater or equal to zero. For the case of Emerald, after the simulations were completed, the *Pe* is found to be equal to 76.89%.

Fig. 46 shows Emerald decision tree, where the possibility of drilling an exploratory well is analyzed. It is concluded that, based on the previously mentioned assumptions, the EMV_IOC of drilling an exploratory well in this prospect is equal to: -25.68 MM$.

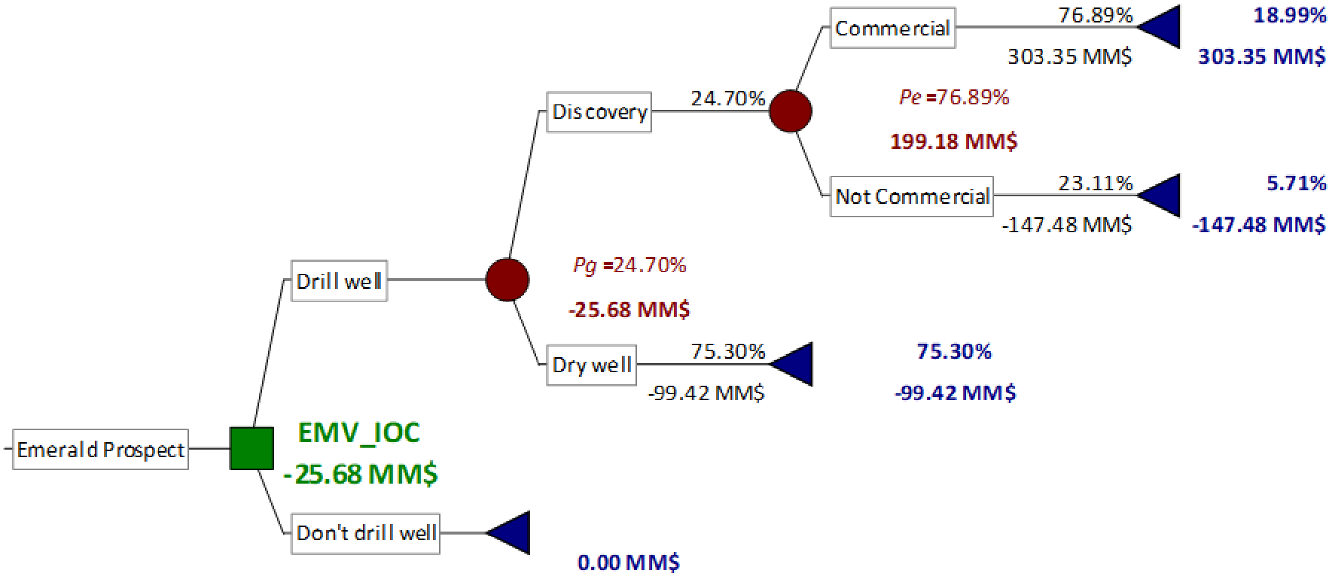


Fig. 46 – Emerald decision tree for drilling an exploratory well

8. Discussion

8.1. Extra study case: Emerald-Complex

After the completion of all the single prospect analyses and based on the prospects location, it is quite natural to wonder what would happen if the first well drilled through Jasper is a discovery and if it is drilled at a location that also tests Emerald-Deep and Emerald reservoirs and eventually finds hydrocarbons in those upper prospects **(Fig. 47).** This is an additional study case, which will be referenced as Emerald-Complex.

In this new case, and due to the increase in resource volumes because of the aggregation of single prospect resources, the construction of a gas pipeline to shore is justified and addressed.

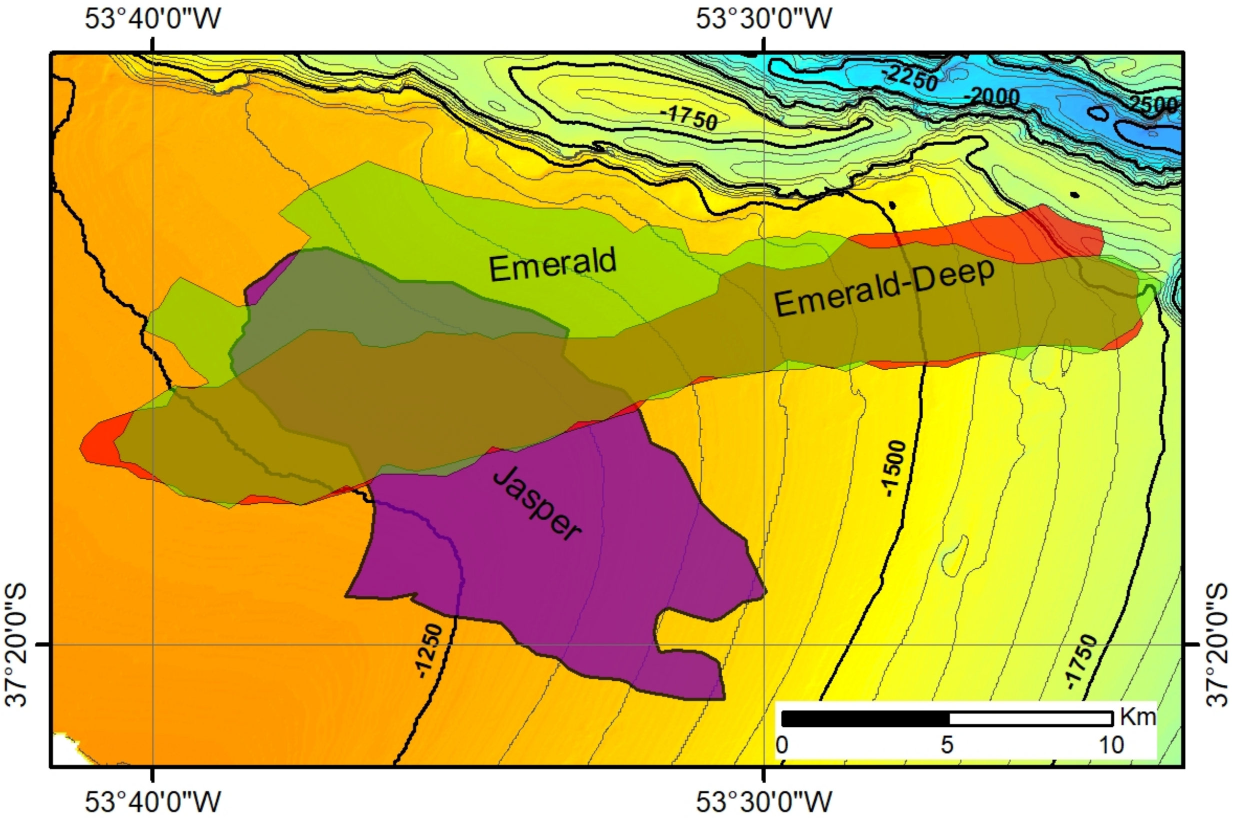


Fig. 47 – Emerald-Complex location on top of a seabed map

For this particular case, a probabilistic aggregation of resources was performed (SPE 2018) in order to determine the total prospective resources for the combined prospect. This probabilistic aggregation led to the prospective resources results shown in **Table 46:**

Oil (MMbbls)			Associated Gas (MMboe)		
1U	**2U**	**3U**	**1U**	**2U**	**3U**
378.26	652.24	1102.36	32.16	62.53	116.25

Table 46 – Emerald-Complex Prospective Resources

8.1.1. Emerald-Complex economic simulations

This section presents the results of several economic simulations, for various oil price scenarios as well as for the two defined economic offer scenarios. **Table 47** shows some simulation results that are independent of the oil price scenario and of the offered economic variables.

According to Table 47 the development of this prospect would require, in average, 17 production wells, and due to its expected maximum oil production of almost 108,000 bopd, only one FPSO would be required.

Variable	P90	P50	P10
# Prod. Wells	7	17	34
# Gas Inj. Wells	1	2	3
Max. Field Oil production (bbls/d)	66,247.4	107,516.4	174,734.1
Max. Field Water production (bbls/d)	81,383.2	173,145.2	313,838.6
Max. Gas production (MMscf/d)	30.61	57.07	102.74
CAPEX (MM$)	7,058.48	10,968.86	17,281.49
OPEX (MM$)	7,126.88	13,489.24	23,656.96
CAPEX/BOE ($/boe)	14.44	16.33	20.42
OPEX/BOE ($/boe)	15.65	20.33	25.65
TOTAL_COST/BOE ($/boe)	31.46	37.05	43.96
Exp. Well Cost (MM$)	90.19	104.48	123.47
Inj. Well Cost (MM$)	48.66	56.37	66.61
Prod. Well Cost (MM$)	60.94	70.59	83.42
Oil EUR (MMbbls)	378.26	652.24	1102.36
Gas EUR (MMboe)	32.16	62.53	116.25

Table 47 – Emerald-Complex field development statistics

8.1.2. Emerald-Complex sensitivity to EIA oil price forecasts

To assess the project sensitivity to the EIA oil price forecasts, two sets of simulations were run for both economic offer scenarios 1 and 2, and for the following oil price forecasts:

- Base case: $70/bbl initial oil price with a variable escalation at the start of each year taken from a symmetric triangular distribution defined between -10% and 10%.
- EIA High oil price forecast.
- EIA Low oil price forecast.
- EIA Reference oil price forecast.

The results of this set of simulations, run for both economic scenarios 1 and 2, are summarized in **Table 48**:

	NPV10_IOC (MM$)			NPV10_Project (MM$)			MNCF_IOC (MM$)		
Economic and Oil Price scenario	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
Scen. 1: $70 var. esc.	-876.4	-46.0	1,127.2	-432.0	1,057.7	3,702.8	-8,960.8	-5,975.6	-4,152.9
Scen. 1: EIA High	2,572.8	5,375.4	9,433.2	6,939.9	13,707.2	23,595.2	-8,911.7	-5,961.1	-4,148.9
Scen. 1: EIA Low	-2,071.4	-1,336.5	-887.5	-1,774.6	-1,076.4	-395.4	-9,250.5	-6,132.4	-4,225.1
Scen. 1: EIA Ref.	436.3	1,517.2	3,088.1	1,854.2	4,449.4	8,259.2	-8,911.7	-5,961.1	-4,148.9
Scen. 2: $70 var. esc.	-1,076.5	-424.0	232.0	-432.0	1,057.7	3,702.8	-7,879.4	-5,246.0	-3,637.5
Scen. 2: EIA High	1,187.0	2,729.7	4,929.3	6,939.9	13,707.2	23,595.2	-7,797.7	-5,216.0	-3,630.3
Scen. 2: EIA Low	-2,177.8	-1,419.5	-998.2	-1,774.6	-1,076.4	-395.4	-8,203.0	-5,429.1	-3,729.3
Scen. 2: EIA Ref.	-42.1	529.9	1,349.0	1,854.2	4,449.4	8,259.2	-7,799.9	-5,216.3	-3,630.3

	IRR_IOC			IOC_Entitlement			Government Take		
Economic and Oil Price scenario	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
Scen. 1: $70 var. esc.	4.86%	9.82%	14.26%	68.86%	73.77%	76.04%	47.68%	50.09%	54.34%
Scen. 1: EIA High	23.06%	27.38%	31.22%	60.49%	61.22%	62.11%	57.38%	57.55%	57.66%
Scen. 1: EIA Low	-21.69%	2.72%	5.82%	75.91%	76.41%	76.82%	46.25%	47.01%	47.94%
Scen. 1: EIA Ref.	12.77%	16.22%	19.21%	65.17%	66.82%	68.92%	54.39%	55.54%	56.22%
Scen. 2: $70 var. esc.	2.65%	7.50%	11.21%	50.07%	56.41%	59.73%	67.34%	69.45%	73.17%
Scen. 2: EIA High	18.33%	22.14%	25.40%	38.38%	39.53%	40.86%	75.83%	75.98%	76.08%
Scen. 2: EIA Low	-28.32%	0.30%	4.04%	59.66%	60.11%	60.49%	66.09%	66.76%	67.57%
Scen. 2: EIA Ref.	9.66%	12.85%	15.38%	45.01%	47.35%	50.18%	73.21%	74.22%	74.82%

Table 48 – Emerald-Complex simulation results for various EIA oil price forecasts

Fig. 48 graphically shows the sensitivity to various EIA oil price forecasts.

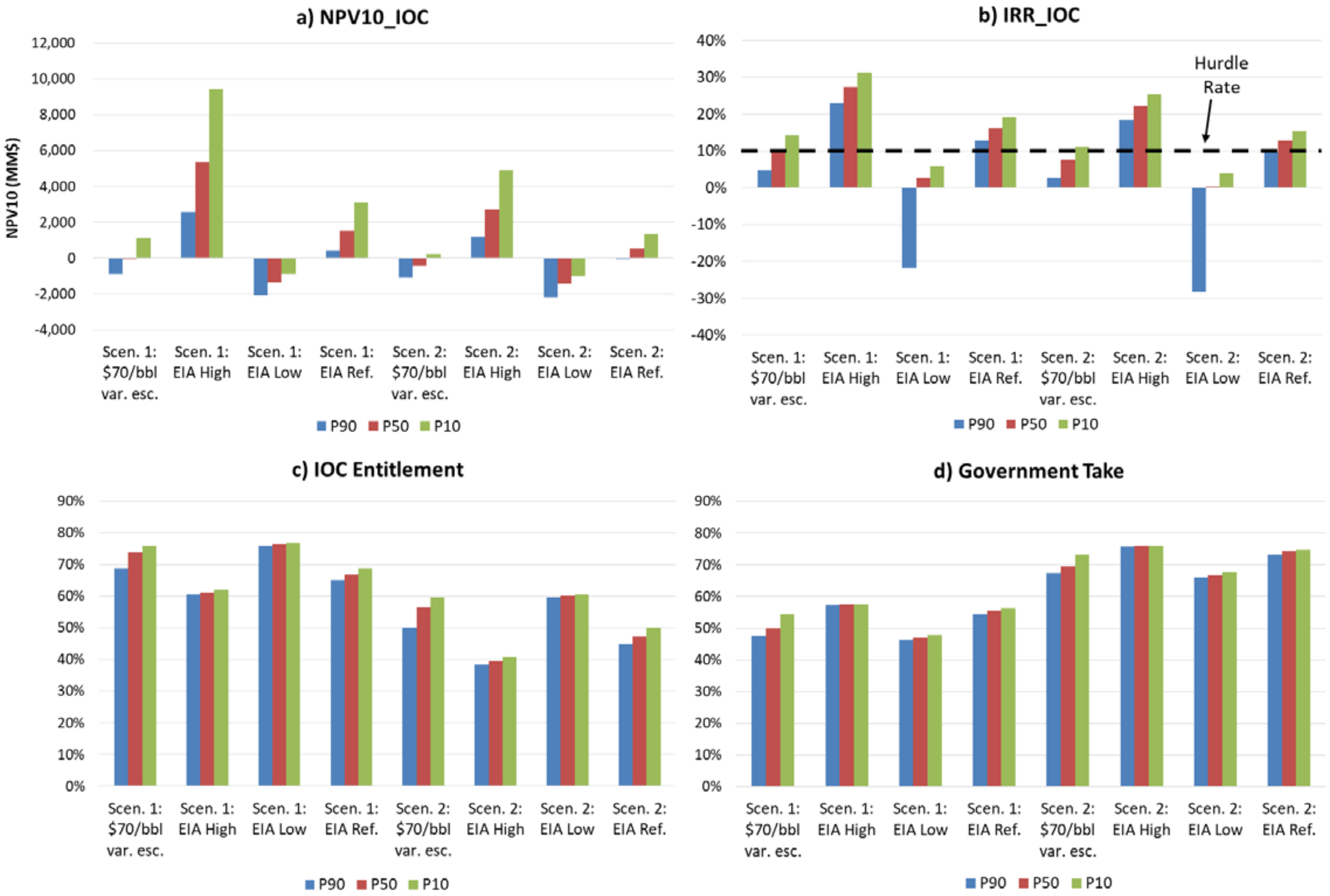


Fig. 48 – Emerald-Complex sensitivity to various EIA oil price forecasts

It is concluded that, for an IOC, the project meets and exceeds the 10% hurdle rate in the EIA High and EIA Reference oil price forecasts for both economic offer scenarios. For the case of the EIA Low oil price forecast, even the project as a whole is not profitable because its discounted net present value P50 percentile is negative (Table 48). On the other hand, average IOC Entitlement and Government Take in the most optimistic case for the IOC are 69.6% and 52.6% respectively, while for the extreme case they are 50.9% and 71.6% respectively. Regarding the MNCF for the IOC, it varies between $5.21 billion and $6.13 billion.

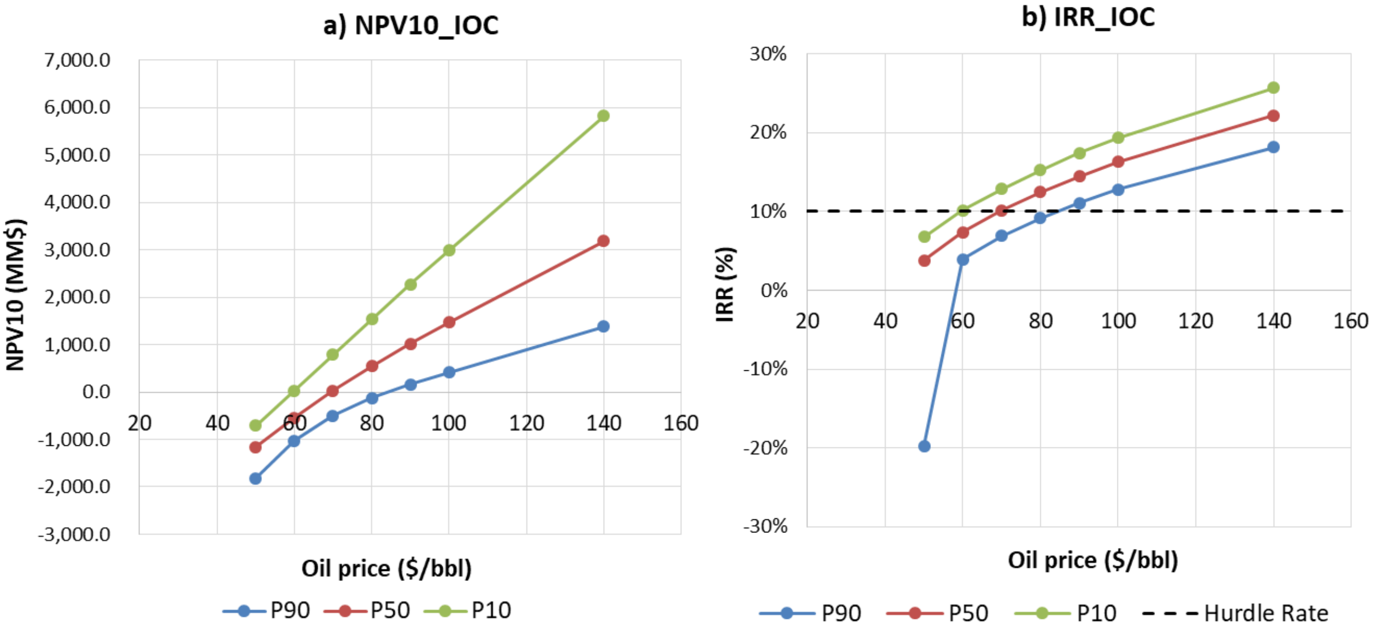
8.1.3. Emerald-Complex sensitivity to fixed oil price scenarios

In order to analyze the project sensitivity to fixed oil price scenarios, a set of simulations were run for fixed oil price scenarios without escalation. The oil price scenarios that were considered are the following: $50/bbl, $60/bbl, $70/bbl, $80/bbl, $90/bbl, $100/bbl and $140/bbl.

The results of these simulations are shown in **Table 49** and in **Fig. 49,** from them it is found that for Scenario 1: the BE_P90 is equal to $84.4/bbl, the BE_P50 is equal to $69.5/bbl and the BE_P10 is equal to $59.6/bbl. It is then concluded that an oil price greater than $84.4/bbl will make this prospect profitable, for an IOC, in at least 90% of the cases.

	Scenario 1 - Low economic offer case					
	NPV10_IOC (MM$)			IRR_IOC		
Oil price ($/bbl)	**P90**	**P50**	**P10**	**P90**	**P50**	**P10**
50	-1,821.61	-1,159.95	-705.73	-19.77%	3.78%	6.80%
60	-1,030.78	-541.87	26.07	3.92%	7.35%	10.12%
70	-498.42	30.45	786.55	6.88%	10.14%	12.85%
80	-126.65	542.06	1,538.54	9.17%	12.45%	15.24%
90	159.89	1,016.15	2,272.17	11.06%	14.46%	17.40%
100	416.45	1,463.57	2,989.34	12.76%	16.27%	19.37%
140	1,375.13	3,184.95	5,818.69	18.18%	22.20%	25.70%

Table 49 – Emerald-Complex sensitivity to non-escalated oil price scenarios (Scenario 1)


a) NPV10_IOC

b) IRR_IOC

Fig. 49 – Emerald-Complex sensitivity to oil price fluctuations (Scenario 1)

Regarding the economic offer Scenario 2, from **Table 50** and **Fig. 50** it is found that: BE_P90 is equal to $103.5/bbl, BE_P50 is equal to $82.1/bbl and BE_P10 is equal to $69.8/bbl. It is then concluded that an oil price greater than $103.5/bbl will make this prospect profitable, for an IOC, in at least 90% of the cases. These breakeven oil prices are shifted, around $14/bbl, upwards with regard to the ones obtained for the low economic offer case (Scenario 1).

	Scenario 2 - High economic offer case					
	NPV10_IOC (MM$)			IRR_IOC		
Oil price ($/bbl)	P90	P50	P10	P90	P50	P10
50	-1,967.33	-1,275.49	-881.71	-28.45%	1.33%	4.88%
60	-1,253.95	-784.03	-427.27	1.13%	5.34%	7.79%
70	-734.57	-387.18	8.68	4.80%	7.76%	10.05%
80	-422.36	-60.45	455.32	6.71%	9.65%	12.02%
90	-214.80	232.21	885.88	8.22%	11.31%	13.80%
100	-49.10	503.56	1,302.63	9.57%	12.81%	15.42%
140	512.14	1,491.77	2,904.32	14.11%	17.72%	20.65%

Table 50 – Emerald-Complex sensitivity to non-escalated oil price scenarios (Scenario 2)

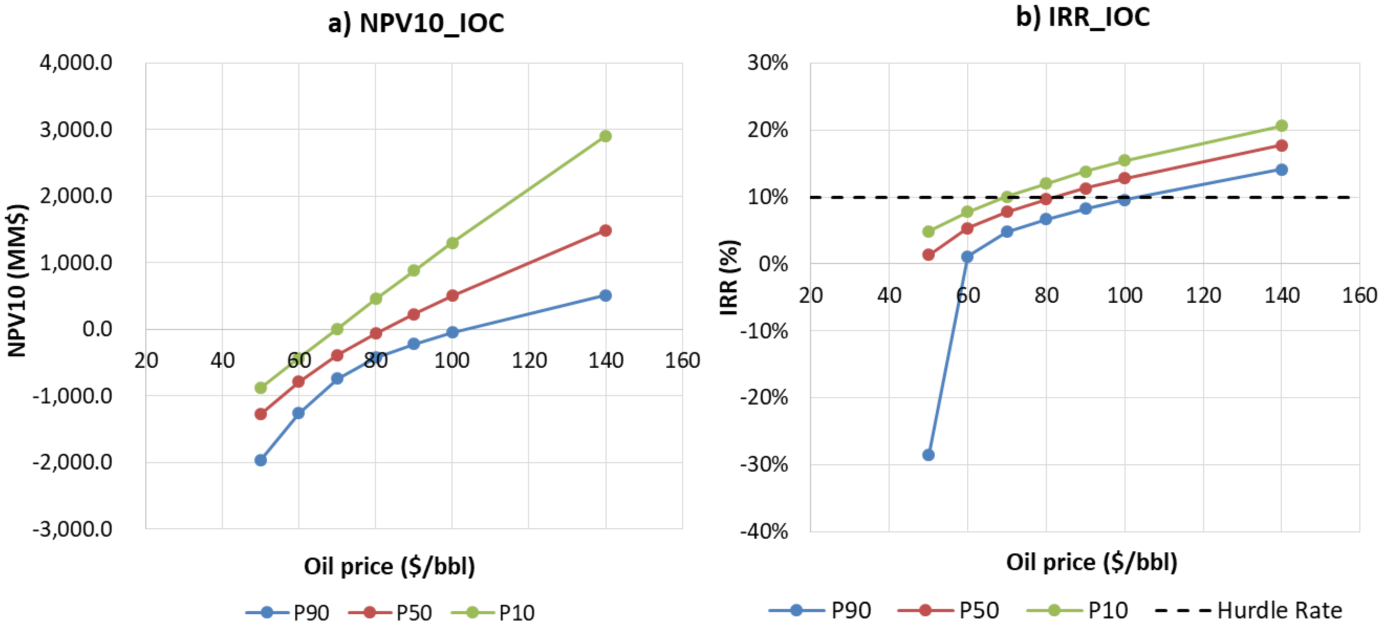


Fig. 50 – Emerald-Complex sensitivity to oil price fluctuations (Scenario 2)

8.2. Final ranking of prospects based on EMV and associated IRRs

To conclude this project a ranking of the studied prospects, based on their EMVs, is presented in **Table 51**. It is based on the results obtained for the economic simulations performed considering both the EIA Reference oil and gas price forecasts and the economic offer Scenario 1.

Prospect	Best Estimate EMV (MM$)	Best Estimate IRR
Maspoli	1,520.45	19.82%
Chafalote	800.19	18.62%
Jasper	-16.76	15.87%
Emerald	-25.68	15.07%
Emerald-Deep	-67.42	13.97%

Table 51 – Ranking of prospects based on EUR

Table 52 and **Table 53** show a brief summary of other key performance indicators obtained during the techno-economic evaluation of the studied prospects. In these tables the performance indicators are shown for the two economic scenarios considered within this project.

	Scenario 1		Scenario 2	
Prospect	**Government Take**	**IOC Entitlement**	**Government Take**	**IOC Entitlement**
Chafalote	52.8%	69.1%	71.8%	50.1%
Maspoli	53.3%	68.5%	72.2%	49.4%
Jasper	51.2%	71.2%	70.4%	52.9%
Emerald-Deep	50.3%	72.2%	69.6%	54.1%
Emerald	50.8%	71.6%	70.0%	53.5%
Emerald-Complex	52.6%	69.6%	71.6%	50.9%
Averages:	**51.8%**	**70.3%**	**71.0%**	**51.8%**

Table 52 – Government Take and IOC Entitlement for the analyzed prospects

	Scenario 1			Scenario 2		
Prospect	**BE_90 ($/bbl)**	**BE_50 ($/bbl)**	**BE_10 ($/bbl)**	**BE_90 ($/bbl)**	**BE_50 ($/bbl)**	**BE_10 ($/bbl)**
Chafalote	53.80	62.63	73.16	62.34	72.23	85.46
Maspoli	51.16	59.20	69.01	58.80	67.99	79.85
Jasper	57.99	76.61	113.51	65.77	86.67	130.06
Emerald-Deep	66.36	83.59	139.45	74.95	94.54	154.23
Emerald	63.62	78.70	133.80	71.89	88.85	149.52
Emerald-Complex	59.64	69.47	84.42	69.80	82.07	103.50

Table 53 – Breakeven oil price results for the analyzed prospects

8.3. Considerations about volumetric resource calculations using seismic data

Gross rock volumes, which are important inputs in EUR calculations, are obtained directly from the interpretation of 3D seismic data. This kind of data has certain limitations that were not considered in the volumetric calculations, but they may affect the quality of the interpretation and therefore add uncertainty to the computed volumes. Some of these limitations are:

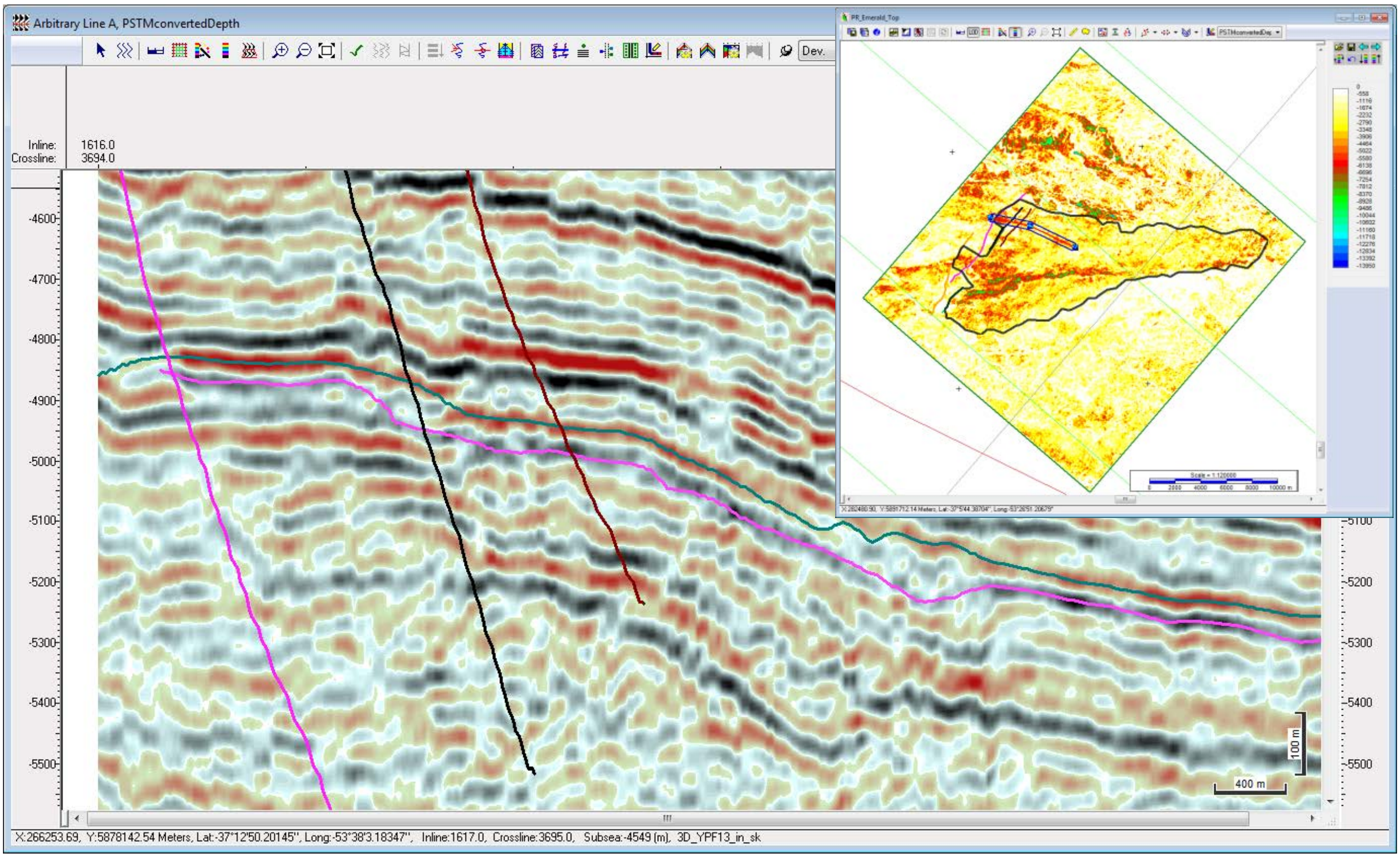
- The vertical resolution of the seismic data. The vertical seismic resolution is approximately 10 m for the Cenozoic prospect Maspoli and 20 m for the Cretaceous prospects: Chafalote, Jasper, Emerald-Deep and Emerald. The smallest prospects, Jasper, Emerald and Emerald-Deep are more affected by this issue because their thickness is in the same order of magnitude of the vertical resolution of the seismic data used for their recognition.
- Potential errors in the seismic velocities used to process the seismic data. Since the UR13_3D survey was processed in the time domain and was later converted to depth (stretched to depth), the prospects analyzed within it: Jasper, Emerald-Deep and Emerald, are more affected by this issue. On the other hand, the advanced processing sequences used to process the BG12_3D and TO12_3D surveys (anisotropic Pre-Stack Depth Migrations), minimize potential errors in the depth imaging of both Maspoli and Chafalote.

The areal extent definition of Maspoli may be larger; it is constrained by the seaward extension of the BG12_3D survey. For this prospect, only the most conservative area, lies completely within its seismic survey boundaries, Fig. 3 shows a sketch of a potential maximum extension for Maspoli.

8.4. Reservoir compartmentalization

The analyzed prospects may present reservoir compartmentalization. It can be due to faulting and/or internal shale facies that may act as barriers to fluid flow, which is something common with turbidite reservoirs. The direct implication of this issue is that some parts of the reservoir may remain disconnected and may not be drained, therefore special care must be taken when placing production wells in order to drain all possible compartments.

Regarding the prospects recognized in the UR13_3D survey (Jasper, Emerald-Deep and Emerald), their seismic response within the turbidite bodies is quite homogeneous. In those cases, there are some minor faults, but since they do not present significant displacements, they are not likely to compartmentalize the reservoir. Their main faults, which also conform their traps, act as seals, and this is supported by the fact that seismic amplitudes vanish after them. From those prospects Emerald is the one which is most affected by faulting. **Fig. 51** shows an arbitrary line through it with some interpreted faults. From the seismic response of Emerald, it seems quite probable that the different zones of the reservoir are interconnected.



X:266253.69, Y:5878142.54 Meters, Lat:-37°12'50.20145", Long:-53°38'3.18347", Inline:1617.0, Crossline:3695.0, Subsea:-4549 (m), 3D_YPF13_in_sk

Fig. 51 – Seismic profile through Emerald (courtesy of ANCAP)

Regarding the largest prospects, Maspoli and Chafalote, their seismic response shows internal stratification and faults. This is a signal of potential isolated production zones within the recognized turbidite bodies. In the case of Maspoli, the variability of facies is not very significant. It is composed only by two turbidite lobes, and according to the seismic data, it is highly probable that both lobes are interconnected. On the other hand, Chafalote presents a more complex case, it is a stack of turbidites and up to five turbidite lobes are recognized. However, since there are zones where the lobes are potentially in contact, it is highly probable that most of them are interconnected. This is a quite common situation with this kind of prospects, the Sea Lion complex, at the North Falkland Basin, is an example of a reservoir that is affected by faulting whose lobes are interconnected (Griffiths 2015; MacAulay 2015). On the other hand, Roncador field, from the Campos Basin, is an example of a reservoir that presents significant faulting, with some sealing faults. Its reservoir is highly compartmentalized and this is evidenced by the production of oils with different densities (Cysne and Mihaguti 2008).

9. Conclusions

The sensitivity analyses performed to the EIA forecasts of future oil and gas prices, show that all the studied prospects meet and exceed a 10% hurdle rate for both the EIA High and EIA Reference oil and gas price forecasts. This observation is valid for the two studied economic offer scenarios. Regarding the EIA Low oil price scenario, the simulations clearly show that for that case none of the prospects are profitable because, for all of them, the P50 percentile of the IOC's discounted net present value is negative and the IRR for the IOC never reaches the 10% hurdle rate.

Average IOC Entitlement and Government Take in the most optimistic case for the IOC (Scenario 1), are situated near 70% and 52% respectively, while for the extreme case (Scenario 2) are situated near 52% and 71% respectively (Table 52). Regarding these values, Scenario 1 offers a Government Take (52%) with is favorable to attract IOCs to invest in an undeveloped frontier play like Offshore Uruguay, while the Government Take in Scenario 2 (71%) is in the range of what oil producing countries offer (Johnston 2008).

Considering the plausible base case of 20% ANCAP association and no incremental profit oil for the State (Scenario 1), the results show that, for the biggest prospects, the average breakeven oil price is situated near $60/bbl, while for the smallest prospects, the average breakeven oil price is situated near $80/bbl (Table 53). The analysis also shows that the smaller prospects would need to be developed, as far as possible, in association with nearby prospects in order to become attractive for development. According to the analysis performed to the Emerald-Complex case, the grouped case presents a breakeven oil price of only $69.5/bbl, while the average breakeven oil price for its ungrouped prospects is $79.6/bbl. Furthermore, for a higher economic offer for the Uruguayan State, the average breakeven oil prices are shifted upwards. This shifting is around $11/bbl for the economic offer Scenario 2 case.

Regarding the economic offer for the Uruguayan State, it is clear that as it improves (the offered variables increase), the NPV10 and IRR for the IOC decrease. In the case of a light oil discovery both A and Xg do not affect very much the economics of the project, on the other hand, X is the most sensitive and significant variable. For the case of a dry gas discovery Xg would be the most sensitive variable and for the case of a heavy oil discovery X' would be the most sensitive one.

A strategy to increase the total score of the bid, which may be useful in the case of competition for an area, would be to offer a high association percentage for ANCAP. For the case of a light oil prospect in the area, it is also recommended to offer high values for Xg and X', trying to keep X (the most sensitive variable) as low as possible. On the other hand, for the case of a dry gas prospect, the recommendation would be to offer high values for X and X' trying to keep Xg as low as possible.

Finally, IOCs may offer an amount of working units greater than the predefined minimum for the area, which will help to increase their bid's probability of success. Furthermore, it creates a valuable opportunity in order to reduce uncertainty in the Pg estimate, which is a significant variable when it comes the time to decide whether the project's updated EMV outcome of the exploration effort will merit further appraisal investments.

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