TEXAS A&M UNIVERSITY
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Estimation of Prospective Resources and Economic Assessment of Selected Carbonate Prospects Offshore Uruguay

Professional Study

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1. Abstract

Estimation of petroleum resources plays a particularly important role for petroleum companies (public or private) and petroleum industry stakeholders, since they represent their most significant asset and it is critical for making rational business decisions. In the present work, a volumetric estimation and economic evaluation of selected prospects that have been identified offshore Uruguay will be performed.

Even though there have not been petroleum discoveries in Uruguay yet, several offshore prospects have been identified through 2D and 3D seismic. In particular, three carbonate prospects in Punta del Este and Pelotas Basins will be evaluated.

For the volumetric evaluation, it is assumed that a 32 °API oil is produced. OOIP and oil EUR will be determined, together with the associated gas volume produced. On the other hand, the current Uruguayan petroleum fiscal regime will be taken into account for the economic assessment and will include the determination of key parameters such as NPV, IRR, EMV, Payout Time and MNCF. Also, through the PSC cashflow, Contractor's and Government Take will be obtained.

The estimation of reservoir features, as well as production performance parameters, will be determined through analogy, and for this purpose carbonate reservoirs in Campos and Santos Basins in Brazil will be used as analogues. In projects that present low-maturity stages data is more restricted and consequently there is more uncertainty; the probabilistic approach is more adequate for handling those uncertainties more efficiently. Therefore, this assessment will be performed by means of stochastic simulations using Latin Hypercube sampling. Additionally, in the economic assessment four different oil prices will be considered (30, 60, 80 and 100 USD/bbl, respectively). Also, two different cases are studied; in one of them, the produced gas is sold, whereas in the other the gas is reinjected.

The main results include that with respect to EMV the Gas Sold case is always more favorable than the Gas Injection case. Also, for the lower oil price scenarios of 30 and 60 USD/bbl, none of the projects results feasible. For a higher oil price of 80 USD/bbl, the projects studied for Gas Injection are not feasible either; however, in the Gas Sold case, the development the largest prospects result viable. Finally, for the highest-price scenario of 100 USD/bbl, the development of the smallest prospect is still not feasible in the Gas Injection scenario, while the rest of the projects present a positive EMV value. For the Gas Sold scenario, all the studied projects are profitable considering the highest oil price.

This assessment provides useful insight to Government entities through the study of potential assets, including the application of the new fiscal regime comprised in the Open Uruguay Round terms. Additionally, it presents a valuable analysis procedure for companies interested in exploration in frontier basins, such as the ones existing offshore Uruguay.

2. Introduction

Estimation of petroleum resources plays a particularly important role for petroleum companies (public or private), since they represent their most significant asset and it is critical for making rational business decisions. Also, they are essential for other petroleum industry stakeholders such as financial institutions involved in financing activities in the petroleum industry and assets' purchasing, regulatory and governmental agencies responsible for the planning and development of national energy policies and investors in companies related to the exploration and production (E&P) sector (Cronquist 2001; Senturk 2011).

Petroleum accumulations have not been identified yet offshore Uruguay and the basins, still underexplored, can be considered to be in a "frontier" status, with a high exploratory risk. Only two offshore wells were drilled in Punta del Este Basin by Chevron in 1976 (Lobo X-1 and Gaviotín X-1) and both were declared dry. For the following 30 years, exploration activities were very limited in the country. Since 2007, however, there have been efforts from Uruguayan authorities to reactivate the upstream industry, through bidding rounds and multiclient agreements, for attracting investment from International Oil Companies (IOCs) and from service companies.

ANCAP, the National Oil Company of Uruguay, is the entity responsible for executing all upstream operations in the country, by itself or by third parties. A regional offshore 2D seismic survey contracted by ANCAP through a multiclient agreement was performed between 2007 and 2008 and was the trigger for a renewed interest in exploration in Uruguay, leading to the first offshore bidding round, Uruguay Round 2009. Two contracts were signed as a result of this process (operators: YPF and Petrobras). Afterwards, in 2012, Uruguay Round II took place, and its results were very significant, with a total of 8 contracts signed with world-leading oil companies (operators: BG, BP, Total and Tullow Oil). Several farm-ins and farm-outs also occurred afterwards, that allowed the entry of new top IOCs. Offered work included drilling one exploratory well, the acquisition of more than 33,000 Km^2 of 3D Seismic and 13,000 Km^2 of 3D CSEM (Controlled Source Electromagnetism). The committed exploratory well, Raya X-1, was drilled in 2016 in Pelotas Basin by a consortium operated by Total and was also declared dry (ANCAP 2017).

Uruguay Round 3 was launched in 2017, however, due to the recent negative results of Raya X-1 well and considering the low oil prices of that moment, no offers were submitted. In order to prevent a cessation in the upstream activities in the country, the Uruguayan Government, through ANCAP and the Ministry of Energy, decided to revise the general system that was being employed with the objective of making it more competitive with respect to other frontier basins, and in 2019 the Open Uruguay Round system was approved. Even though at this moment there are no contracts in force offshore Uruguay, two offers were submitted through the new Open Uruguay Round process, therefore the results are being very promising so far (ANCAP 2019b).

A significant amount of 2D and 3D seismic data has been acquired in the last years, which can be observed in Fig. 1.

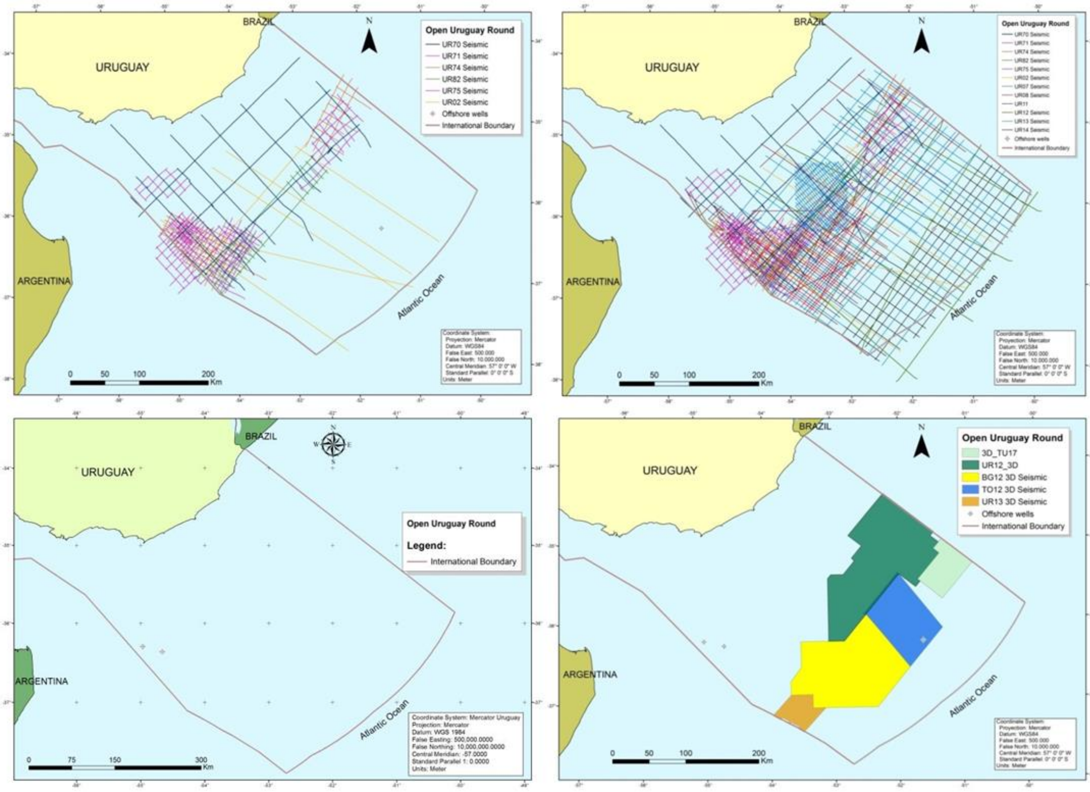


Fig. 1 – 2D Seismic before 2007: 13,000 Km (top left); Present 2D Seismic: 41,000 Km (top right); 3D Seismic before 2012: 0 Km^2 (bottom left); Present 3D Seismic: 42,000 Km^2 (bottom right) (ANCAP 2019a)

Lobo X-1 and Gaviotín X-1 wells were drilled in shallow waters (42 and 56 m of water depth, respectively), very close one from the other, and were located in basement highs, with total drilled thicknesses of 2,713 m and 3,631 m respectively (Morales 2013; Conti 2017). Both wells were declared dry, and neither of them found significant source rock levels, because they were placed in a proximal basin position. The presence of an active petroleum system was proved, however, through the determination of fluid inclusions of oil and gas that were found in both wells (ANCAP 2017).

Regarding Raya X-1 well, it was drilled in ultradeep waters (water depth of 3,404 m) and its main objective was a tertiary basin floor fan. Total sediment depth of this well was 2,452 m, reaching a sand body which presented a thickness of 135 m and high porosity. However, no oil accumulations were found (ANCAP 2017; Conti 2017).

The geological context will be presented, together with the prospects to be evaluated, which were identified through seismic geological and structural interpretation. The methodology for the volumetric resources' estimation will be described, and analogy will assist in the determination of reservoir parameters for this study. In the assessment of projects that present an early stage of development, which is our case, the probabilistic approach is more suitable, and for this purpose Monte Carlo modelling will be employed. On the other hand, the economic assessment will also be performed using probabilistic methods, which will be applied to a cashflow model.

3. Geological Context

Six sedimentary basins are recognized in Uruguay. Three of them are located onshore: Norte, Santa Lucía and Laguna Merín basins. The other three are located offshore: Punta del Este, Pelotas and Oriental del Plata in ultradeep waters. Punta del Este and Pelotas are separated by a basement high (Polonio High) in shallow waters. They are illustrated in Fig. 2 (ANCAP 2017).

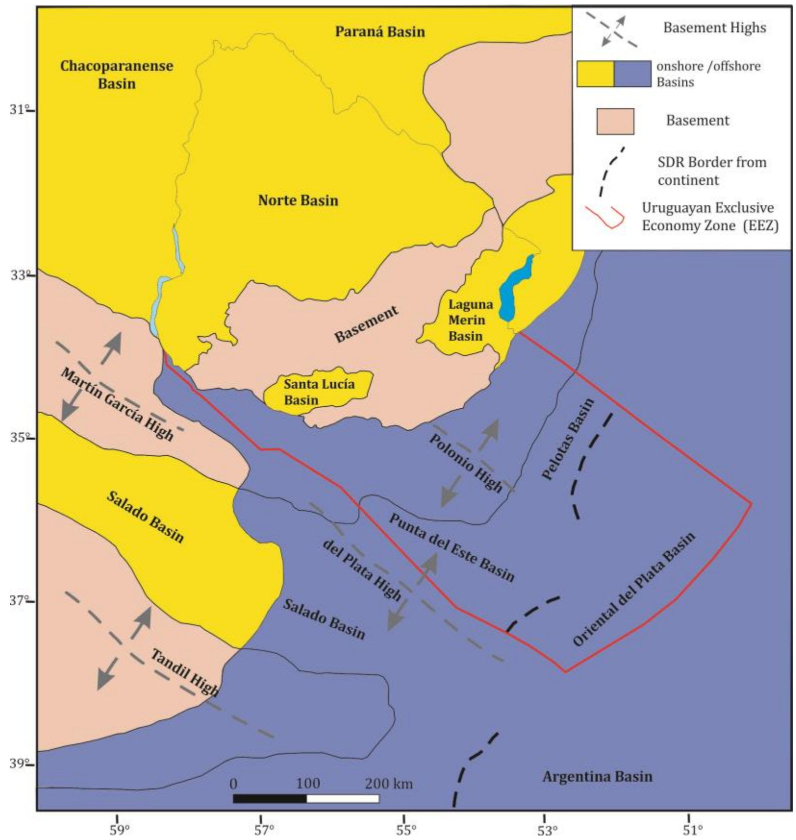


Fig. 2 – Uruguayan offshore and onshore basins and main structures (ANCAP 2017)

As observed in Fig. 3, two significant structural trends can be identified offshore Uruguay. The first one is located in the proximal segment of Punta del Este Basin and presents a NW trend. This is an indication of an extensional stress, which is normal to the continental margin, and is attributed to an initial rifting stage that started in the Upper Jurassic and was aborted. This is also a characteristic present in other Argentinian South Atlantic basins, such as Salado, Colorado, and Golfo de San Jorge basins. The second trend is NE and is located in the distal segment of Punta del Este and Pelotas basins and it shows similar orientation as most of the Brazilian South Atlantic basins. This represents a second rifting stage of the Early Cretaceous age (ANCAP 2017).

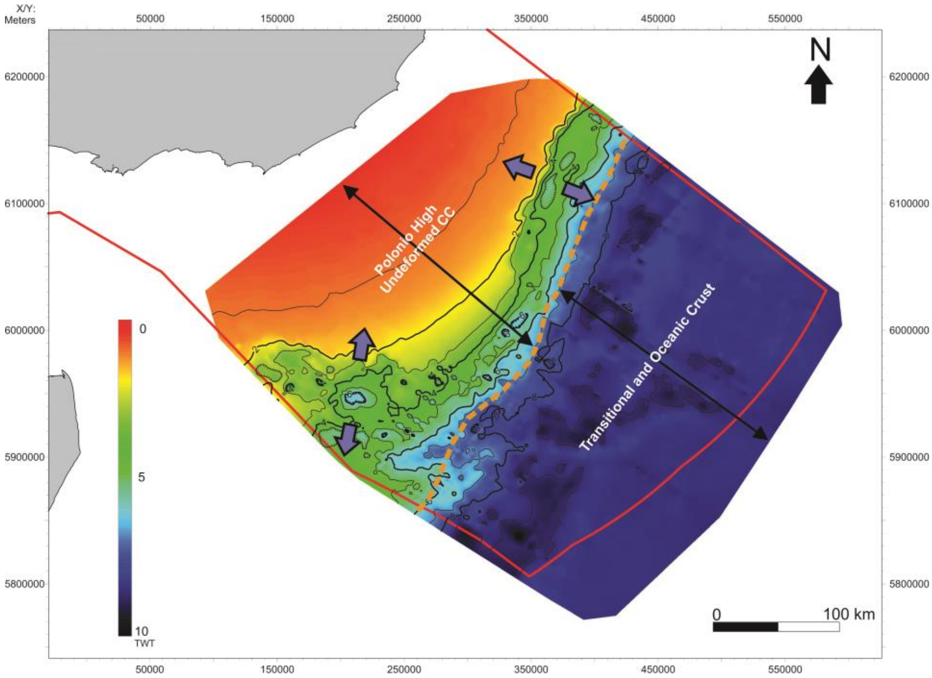


Fig. 3 – Top basement structural TWT map showing two main tectonic trends: NW – SE and NE – SW and the distribution of extensive efforts (blue arrows) that affected the Continental Crust (Polonio High). CC: Continental Crust (ANCAP 2017)

Because of the difference in basin styles, subsidence histories and sedimentary inputs and the dynamics of the Polonio High, Punta del Este and Pelotas basins present different evolution features until the Late Maastrichtian. The stratigraphy of both basins is represented by large depositional sequences (ANCAP 2017).

Offshore basins' generation is related to the breakup of Gondwana and the opening of the South Atlantic Ocean, which occurred later in the Late Jurassic – Early Cretaceous. They share this genesis with Orange and Walvis basins, which are located in the offshore margin of South Africa and Namibia. These aspects can be observed in Figs. 4 and 5 (ANCAP 2017).

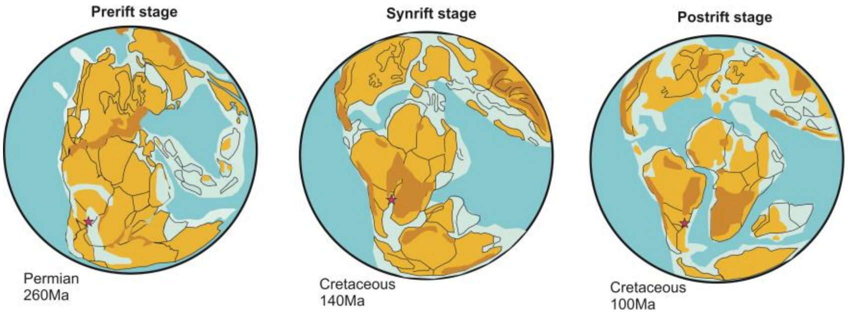


Fig. 4 – Gondwana evolution and generation of Atlantic basins. The red star shows location of Uruguay (ANCAP 2017)

Fig. 5 – Paleogeographic restoration for the Aptian showing South Atlantic basins (ANCAP 2017)

Taking into account the outer boundary of 200 nautical miles, offshore Uruguayan basins have a total area of more than 130,000 km^2. Additionally, based on seismic data, they present a sedimentary infill of more than 8,000 m. Water depth in the continental margin of Uruguay is very variable and ranges from less than 20 m to more than 4,000 m near the limit of 200 nautical miles (Morales 2013; ANCAP 2017).

Punta del Este is a rift basin, separated from the Salado Basin (Argentina) to the west by the Martín García/Plata High and from Pelotas Basin to the east by the Polonio High. In the evolution of this basin, three main tectonic-stratigraphic stages are recognized: prerift (Devonian – Permian), synrift (Late Jurassic – Early Cretaceous) and postrift (Aptian – Present) (Morales 2013; ANCAP 2017).

Pelotas Basin extends from the Polonio High up to the Florianópolis Fracture Zone (Brazil), where the Santos Basin begins. It corresponds to the flexural border of a precursor synrift structure and develops on continental, transitional and oceanic crust. The prerift megasequence has been drilled in the Brazilian portion of the basin, reaching Paleozoic and Mesozoic units of the Paraná Basin, including the high TOC marine shales of Iratí formation (ANCAP 2017).

Finally, the ultradeep water Oriental del Plata Basin is in part equivalent to the Argentina Basin of the Argentinian margin, also known as Patagonia Oriental Basin or Ameghino Basin. It presents a sedimentary fill that reaches 5,000 m, including Cretaceous and Cenozoic marine sequences. Its limit with Punta del Este Basin is given by the landward limit of the SDR sequence, which can be seen in Fig. 2. Therefore, while Punta del Este Basin develops over continental crust, the Oriental del Plata basin develops over both transitional and oceanic crusts (Soto et al. 2011).

A summary of the main features of the basins in study are shown in Table 1.

	Punta del Este Basin	Pelotas Basin
Gross area (Km^2)	50,000	80,000
Sequences	Prerift, synrift and postrift	Prerift, synrift and postrift
Geologic age	Late Jurassic – present	Late Jurassic – present
Depositional environment	Lacustrine (synrift phase) Transitional and Marine (postrift phase)	Lacustrine (synrift phase) Transitional and Marine (postrift phase)
Prospective area (Km^2)	33,000	50,000
Bathymetry (m)	50 to 4,000	50 to 4,000
Maximum thickness (m)	6,800	6,900
Drilled wells	2 (Lobo X-1 and Gaviotín X-1)	1 (Raya X-1)
Maximum drilled depth (m)	3,600	2,400

Table 1 – Summary of Punta del Este and Pelotas Basins' features

Lobo X-1 and Gaviotín X-1 wells presented fluid inclusions of 32°API oil and gas (Tavella and Wright 1996). Additionally, the reservoir encountered in Raya X-1 well presented a porosity of 24% (Conti et. al 2019).

3.1 Selected Prospects for Evaluation

The great amount of seismic acquired offshore Uruguay in the last years led to the identification of several structural, stratigraphic and combined leads and prospects at different water depths, from shallow to ultradeep waters (ANCAP 2017). In particular, isolated carbonate deposits associated with basement highs were identified, at the base of the postrift sequence (transition), for both Punta del Este and for Pelotas basins. Three of these carbonate prospects were selected for this study and will be presented as follows.

The carbonates in offshore Uruguay were deposited in a similar geological context than the carbonates of Brazil, at the beginning of the opening of the South Atlantic Ocean. These carbonates (Barra Velha Formation in Santos Basin) were deposited at the top of the synrift sequence in a transition stage between the continental rift phase and a shallow marine environment during the Aptian (Assine et. al 2008). The oil fields in these carbonate reservoirs are generally associated with structures in basement highs (Mohriak 2015).

They also were deposited in similar depositional environments and at the same age (Aptian). Additionally, taking several carbonate fields in Santos Basin (such as Tupi/Lula; Iara/Berbigâo, Sururu and Atapu; Franco/Buzios; Libra/Mero) it is possible to determine that they present bathymetries of around 2,000 m and overburden between 4,900 m and 5,200 m (Gaffney, Cline & Associates 2010). These features are similar to those encountered in the prospects offshore Uruguay to be evaluated. Finally, the prospects defined in this work are structural traps associated with basement highs, like many of the fields discovered in the presalt of Santos and Campos Basin in Brazil.

The carbonate structures are highly consolidated sediments, with much higher velocity and density with respect to the adjacent shales, and this causes a strong positive reflection, which is reduced by the presence of hydrocarbons (Temples 2009). This effect is also described by Roden et. al (2012), considering the "phase or character change at downdip edge of the anomaly" as one of the main direct hydrocarbon indicators. These features were identified in the carbonate prospects that will be assessed.

In Fig. 6, the exploratory model offshore Uruguay can be observed, whereas in Fig. 7, the three exploratory situations that will be studied are presented.

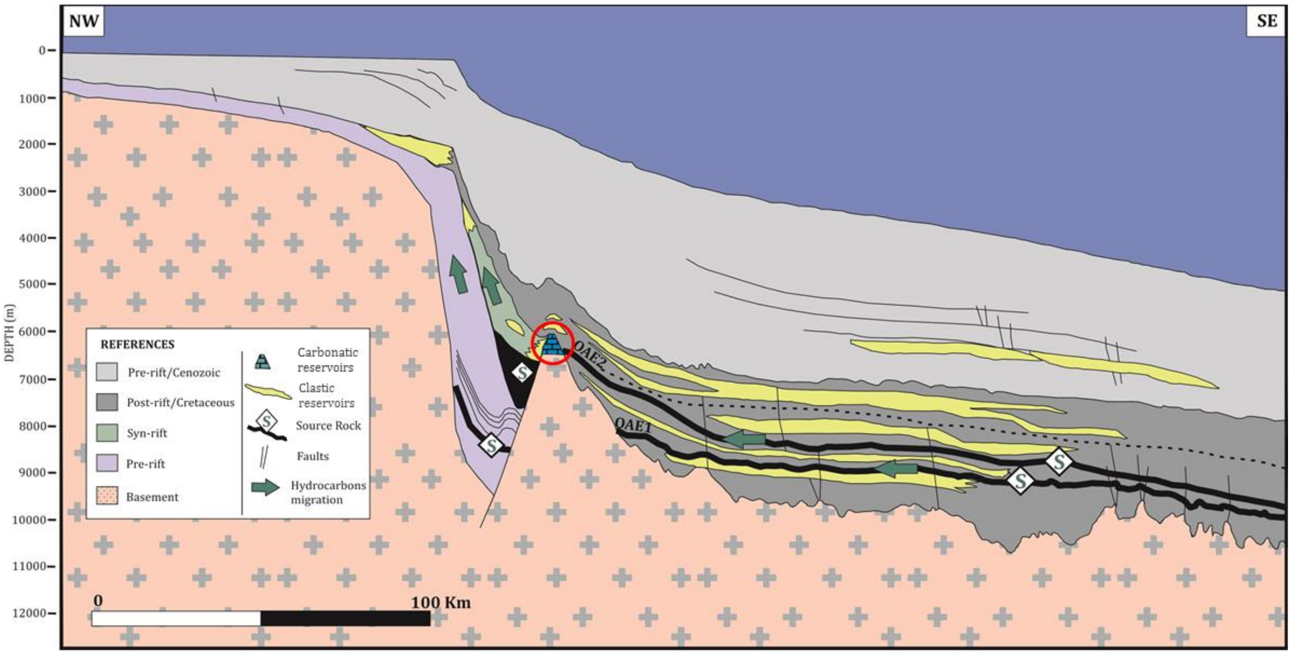


Fig. 6 – Exploratory model offshore Uruguay. The location of the carbonate is presented in the red circle (After Conti 2017)

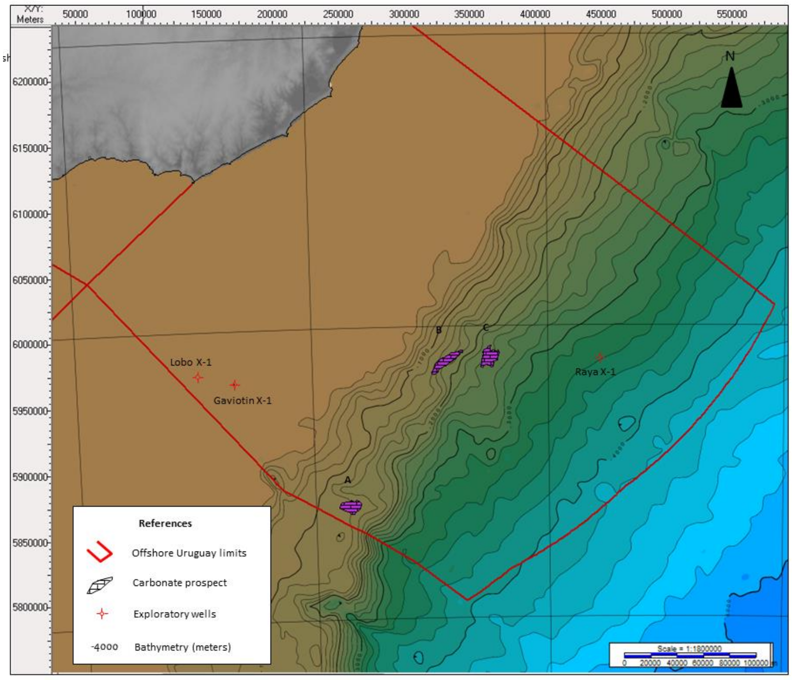


Fig. 7 – Location of the selected prospects (A, B and C respectively). Courtesy of ANCAP.

A general overview of Prospects A, B and C is presented in the next sections.

3.1.1 Prospect A

Prospect A is a structural trap located 270 Km from the shore, in bathymetries ranging between 1,173 and 1,270 m. The reservoir is constituted by a carbonate construction deposited in a horst structure between halfgrabens in Aptian-Albian times and is covered by Upper Cretaceous marine shales that act as a seal. The potential source rocks are represented by Aptian marine shales. The sediment overburden varies between 4,593 and 4,999 m. This prospect is presented in Fig. 8.

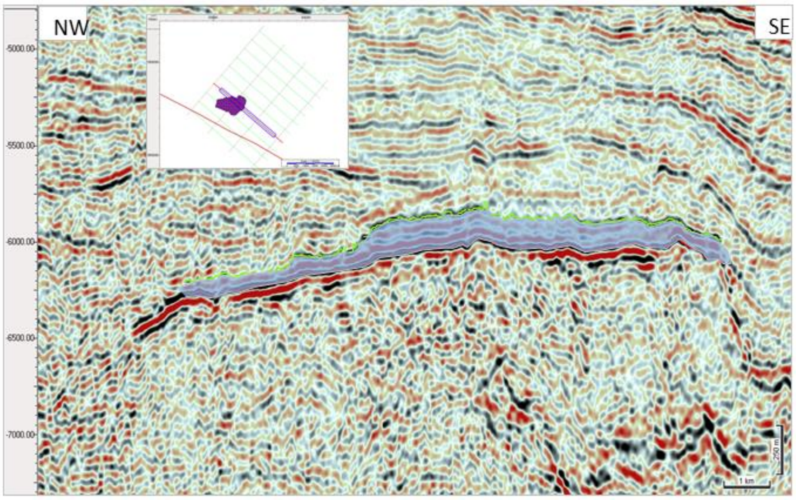


Fig. 8 – 3D seismic crossline showing Prospect A with interpreted top and base horizons. Courtesy of ANCAP.

3.1.2 Prospect B

Prospect B is presented in Fig. 9. In this case, it is 207 Km away from the shore and the bathymetries range from 1,532 to 1,803 m. It also constitutes a carbonate construction deposited in a horst structure between halfgrabens in Aptian-Albian times. The potential source rocks in this case are Barremian lacustrine shales and the potential seal is formed of Cretaceous marine shales. The sediment overburden varies between 3,624 and 4,244 m.

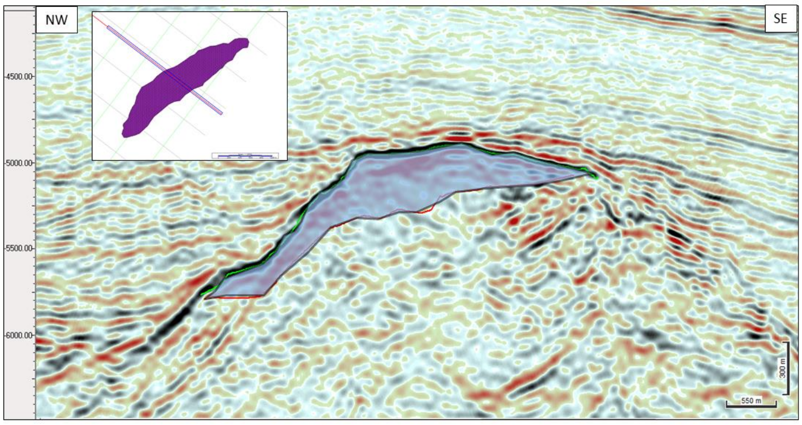


Fig. 9 – 3D seismic crossline showing Prospect B with interpreted top and base horizons. Courtesy of ANCAP.

3.1.3 Prospect C

Prospect C is presented in Fig. 10. In this case, it is 226 Km away from the shore and the bathymetries range between 2,299 and 2,531 m. Similarly to prospects A and B, it constitutes a carbonate construction deposited in a horst structure between halfgrabens in Aptian-Albian times. The potential source rocks are Barremian lacustrine shales and Aptian marine shales and the potential seal is formed of Cretaceous marine shales. The sediment overburden varies between 4,808 and 5,299 m.

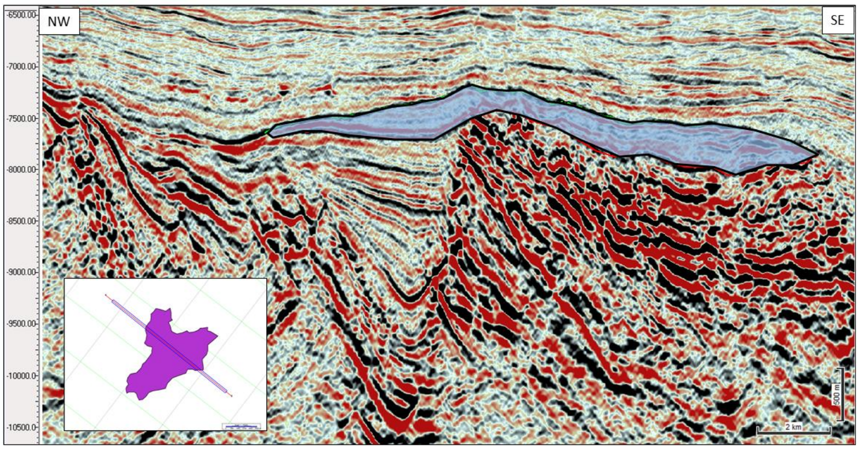


Fig. 10 – 3D seismic crossline showing Prospect C with interpreted top and base horizons. Courtesy of ANCAP.

4. Methodology

4.1 Resources' Volumetric Estimation

4.1.1 PRMS Outline

A global technical guideline was developed with the objective of ensuring a consistent and transparent definition, estimation, classification and categorization of petroleum resources, complying with different stakeholders' requirements: the Petroleum Resources Management System (PRMS) (Senturk 2011).

The basic resources' classification and categorization framework proposed in the PRMS is presented in Fig. 11.

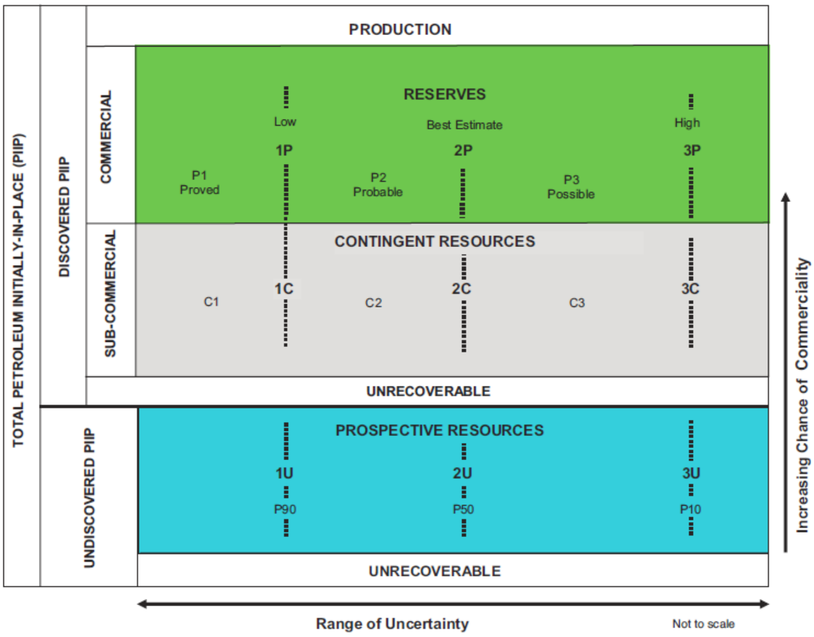


Fig. 11 – Resources classification and categorization framework (SPE 2018)

This system covers all the petroleum resources, the "Petroleum Initially In Place" (PIIP): discovered and undiscovered, both recoverable and unrecoverable. The recoverable quantities of discovered resources include Production, Reserves and Contingent Resources, whereas recoverable quantities of undiscovered resources are called Prospective Resources. In the particular case of Uruguay, as mentioned before, there has not been any petroleum accumulation discovery yet. Therefore, the analysis is based on potentially recoverable hydrocarbon volumes, corresponding to Prospective Resources.

According to the PRMS document (SPE 2018), the "range of uncertainty" in the horizontal axis of the PRMS matrix (Fig. 11) represents a range of estimated volumes potentially recoverable from an accumulation (or group of accumulations), by a specific project. The uncertainty components include the remaining in-place resources volume, the portion of the total petroleum that can be recovered with the specific project (technical uncertainty) and variations in commercial terms that could impact the quantities recovered and sold (for example if there is a market available or modifications in contracts). This uncertainty in the estimated recoverable quantities is represented by different petroleum resource categories (Low, Best and High estimates).

These estimated recoverable hydrocarbon quantities can be calculated using deterministic and probabilistic methods. In the deterministic method, one input value is selected for each calculation parameter (geoscience, engineering and economic) as the most appropriate for the corresponding resources' confidence category. Therefore, a single outcome is derived for each scenario. On the other hand, in the probabilistic method the uncertainty is explicitly incorporated in the estimates. Probability distribution functions (PDFs) are assigned to the different geoscience, engineering and economic parameters, generating a range of estimates with associated probabilities. In general, in early development stages with more limited data (more uncertainty), the probabilistic approach is used, and deterministic estimates are performed as project maturity increases. Therefore, for the development of this work, the probabilistic method is chosen considering the low-maturity-level of the project. In particular, simulation procedures for the probabilistic determination of resources' quantities handle more efficiently the complexity of various input parameters, including their potential dependencies (Cronquist 2001).

Then, the Low Case is a conservative estimate, with a high confidence (a very high probability) that this value or grater will be recovered from an accumulation with the project considered. If probabilistic methods are used, there should be at least a 90% probability that the volume corresponding to the Low Estimate or more will be recovered (P90).

The Best Case is an estimate considered "not optimistic and not conservative", representing the most likely case and it is often the base case for decision making. If probabilistic methods are used, there should be at least a 50% probability that the volume corresponding to the Best Estimate or more will be recovered (P50).

The High Case is an optimistic estimate with a low probability that this value will be achieved. If probabilistic methods are used, there should be at least a 10% probability that the volume corresponding to the High Estimate or more will be recovered (P10) (Lee 2017; SPE 2018).

4.1.2 Methods for Resources' Volumes Estimation

The estimation of recoverable volumes of petroleum can be performed using "static" methods (based on volumetric data) and "dynamic" methods (based on performance data). Static-data based methods include the analogy and volumetric analysis and are indirect procedures for the volumetric estimation which are mostly used during exploration, discovery, post-discovery, appraisal and initial development of E&P recovery projects. On the other hand, dynamic methods comprise material balance, production performance analysis methods (decline curve) and reservoir simulation and are used when there is enough performance data available, such as rates and pressures (SPE 2011). The different methods can be used for verification of the estimated volumes (cross check), since each of them requires different data and therefore they are independent (Wright 2015).

In this work, the resources estimation methods are centered in static-data based approaches, since the cases that will be evaluated are located in Uruguay offshore basins, which are frontier basins without any discovery of hydrocarbons, as mentioned before.

4.1.2.1 Volumetric Analysis

The equation for the determination of the Oil Initially In Place (OIIP) in stock tank barrels (STB) is,

$$OIIP = 7{,}758 \cdot \frac{A \cdot h \cdot \phi \cdot S_{oi}}{B_{oi}} \qquad Eq. 1$$

Where,

A is the drainage area, in acres
h is the average thickness of the net pay, in feet
ϕ is the average porosity (fraction)
S_{oi} is the average initial oil saturation (fraction)
B_{oi} is the initial oil formation volume factor, in RB/STB
7,758 is a conversion factor, in bbl/acre-ft

For the determination of Gas Initially In Place (GIIP), the equation is similar,

$$GIIP = 43{,}560 \cdot \frac{A \cdot h \cdot \phi \cdot (1 - S_{wi})}{B_{gi}} \qquad Eq. 2$$

Where,

S_{wi} is the average initial water saturation (fraction)
B_{gi} is the initial gas formation volume factor, in rcf/scf
43,560 is used to convert acres into cubic feet

The Estimated Ultimate Recovery (EUR) refers to the total estimated volume of hydrocarbons produced or recovered from the accumulation over its entire economic life. Therefore, it includes the volumes potentially recoverable from a reservoir, plus those quantities that have already been produced. Then, the EUR defined previously can be calculated by multiplying the Petroleum Initially In Place (oil or gas), by the Recovery Factor (RF),

$$EUR = PIIP \cdot RF \qquad Eq. 3$$

Additionally, in the case of oil fields producing Associated Gas, this gas can be determined using the Gas-Oil-Ratio (GOR, scf/STB),

$$Associated\ Gas = EUR \cdot GOR \qquad Eq. 4$$

The main sources of data are the following (Mian 2011b; Wright 2015),

- The drainage area is estimated based on experience, type of reservoir, the mechanism of production, analogy to other wells that produce from similar horizons in other areas, and from geologic maps. Seismic can also be helpful in the determination of the area. In general, this term is subject to the largest errors.
- Formation thickness is determined from well logs or cores. It can also be calculated from the gross pay thickness, multiplied by a net-to-gross factor (NTG).
- For obtaining porosity and water saturation, well logs, core analysis or both are used.
- B_{oi} or B_{gi} are obtained through fluid analysis in the laboratory, or from empirical correlations.
- The recovery factor is best determined from appropriate analog reservoirs. It can also be obtained from numerical simulation or empirical correlations. However, even approximate RF estimates from near-analogs are preferable than empirical correlations (SPE 2011; Senturk 2011). This is another factor that often presents the largest errors (Wright 2015).

4.1.2.2 Analogy

The basis of this method is the assumption that the analogous reservoir or well and the subject reservoir or well are comparable, regarding the features that control ultimate petroleum recovery, so that they will perform similarly (Cronquist 2001; Wright 2015). In general, the analogous reservoirs are at a more advanced development phase than the reservoir that is being assessed (SPE 2018).

As mentioned before, this methodology is useful, particularly for cases in which the data is limited. The information that can be obtained from analogy includes the recovery factor, ultimate oil and/or gas reserves, and the most likely production behavior (Mian 2011b). In fact, as stated in the PRMS guidelines (SPE 2018), with an adequate analogous reservoir selection, and if performance data of equivalent development plans are available, it is possible to forecast a similar production profile. This methodology can also be used for the determination of the parameters that are required for resources' estimation in the volumetric method.

Even though analogous reservoirs are determined considering similar characteristics to the evaluated reservoir, not all the parameters are required to be similar for taking a reservoir as analog. This is determined by the evaluator, and it depends on the specific application (the comparative features must be relevant to the project) and on its adequacy for providing assistance in the recoverable resources estimation (SPE 2018).

Considering the carbonate plays described in Section 3.1 and with the objective of obtaining data for the corresponding Prospective Resources' volume estimation, it was decided that the Aptian carbonates of the "presalt" of Santos and Campos Basins in Brazil will be used as analogs for this evaluation.

4.1.3 Simulation Under Uncertainty

The most widely used practice for probabilistic estimation of resources volumes is simulation. "Simulation is a quantitative technique used for evaluating alternative courses of action, based upon facts and assumptions, with a computerized mathematical model, in order to represent actual decision making under conditions of uncertainty" (Mian 2011b). As indicated before, if analysis is performed through simulation, the different input variables, as well as the results are probability distributions instead of single values. Stochastic simulation is preferred for modeling diffusion phenomena of oil and gas systems. Even though Monte Carlo experimentation is a way of following and measuring the detailed behavior of the stochastic simulation, the most efficient method of sampling is with Latin Hypercube (McLeroy 2017).

There are two types of sampling available for stochastic simulation: Monte Carlo sampling and Latin Hypercube sampling. In the first one, the entire range is available for sampling in subsequent trials. It usually results in sample clustering in some parts of the distribution, and other parts may not be sampled. In Latin Hypercube sampling, however, the method is improved. In this case, the distribution function is divided in intervals of equal probability, according to the number of iterations. As an example, if there are 10 iterations, the distribution is partitioned in 10 equal parts and the random samples are taken from each interval. Then, the advantage of this sampling technique is that it ensures the representation of all probabilities and gives equal weight to all probabilities (Mian 2011b). This can be observed in Fig. 12.

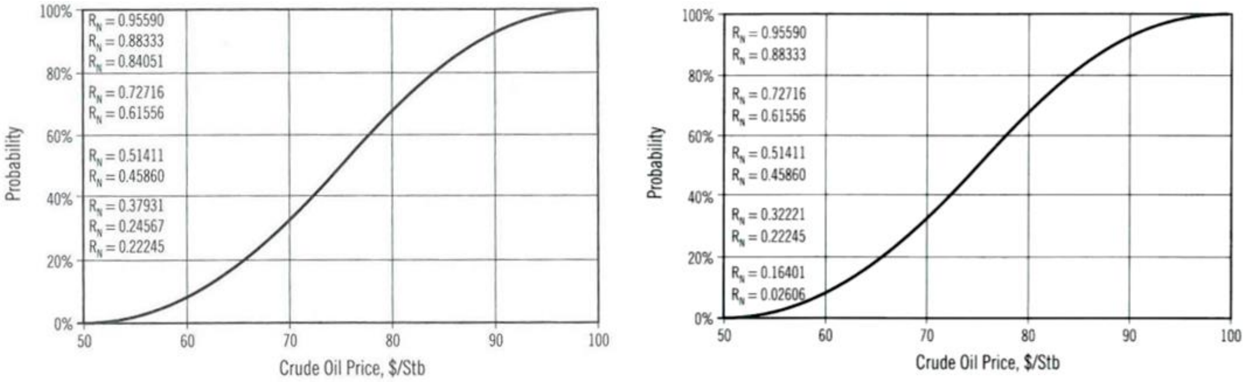


Fig. 12 – Schematic of Monte Carlo (left) and Latin Hypercube (right) sampling (Mian 2011b)

Then, Latin Hypercube sampling makes the majority of the samples to be included in a small fraction of the standard error, therefore mean values will be much closer to each other compared to Monte Carlo sampling. The consequence of this feature is that Latin Hypercube sampling converges faster than Monte Carlo sampling (McLeroy 2017).

4.2 Economic Assessment Methodology

4.2.1 Exploration and Field Development

As indicated in Section 3.1, the bathymetry of the prospects to be evaluated ranges between 1,200 and 3,500 m (deepwaters). Therefore, drillships will be considered for drilling exploration, appraisal and production wells because they have been proven to be useful in this range of water depths (Laik 2018). Moreover, Raya X-1 well, which presented an even higher water depth, was successfully accomplished by means of a drillship after a thorough evaluation of the specific conditions of the area, without encountering any operational issues.

Regarding production, Floating Production Storage and Offloading (FPSO) units will be employed, which are also widely used in the Brazilian analog fields considered. These types of structures are suitable in places with severe weather conditions such as the ones existing offshore Uruguay and these systems provide the facilities for the reception, processing and storage of production from offshore wells (Laik 2018). Afterwards, the oil can be transported by means of oil tankers (Allahyarzadeh-Bidgoli et. al 2018), and this is particularly important since oil pipelines are non-existent in the area of study. Additionally, FPSOs include the processing equipment for performing the separation of water and associated gas that is produced with the oil, with the options of gas export, reinjection and application for energy generation (Allahyarzadeh-Bidgoli et. al 2018; Laik 2018; Rigzone 2019). FPSOs can also perform water injection processes (Rigzone 2019).

The wells are connected to the FPSOs through flexible flowlines and umbilical lines for control operations, with a system of manifolds (ANP 2018), and each production unit operates with one Subsea, Umbilical, Riser and Flowline (SURF) system (Rodrigues and Sauer 2015).

4.2.2 Production Profile

Based on empirical observations, Arps (1945) indicated that the production rate as a function of time can be represented with Eq. 5.

$$Q(t) = Q_i(1 + bD_it)^{-\frac{1}{b}} \qquad Eq.5$$

Where,

Q_i is the initial production rate, in volume/time units
Q is the production rate after some time "t", in volume/time units
D_i is the nominal decline rate, in 1/time
t is the time between Q_i and Q, in time
b is a decline constant, dimensionless

Three types of curves are also distinguished,

- Exponential, when b = 0
- Hyperbolic, for 0 <b < 1
- Harmonic, for b = 1

Using Eq. 5, it is possible to define the production profile of a type well, which will serve as the basis for construction of the production profile of the field, depending on the specific time in which the different wells are put in production.

4.2.3 Expenditures

Capital Expenditures (CAPEX) refer to geological and geophysical costs, drilling costs, costs of oil tankers, costs involved in offshore platforms construction and installation and costs of pipelines for gas transportation. On the other hand, Operating Expenditures (OPEX) include costs associated to regular operations (fixed cost, variable cost which depends on the production rate, and costs related to maintenance and well interventions).

4.2.4 Uruguayan Petroleum Fiscal Regime

The different financial and contractual arrangements of the international oil and gas business for the exploration and production of hydrocarbons are typically referred to as the “fiscal regime”. It includes all legislative, taxation, contractual, and fiscal elements. An ideal fiscal system presents a simple application and provides the Contractor with a reasonable rate of return on investment, in proportion to the project risks. At the same time, it provides the Host Government with an adequate resource for rent, resulting in a convenient situation for both parties (Mian 2011a). Although there are different petroleum fiscal systems, particular consideration will be given to Production Sharing Contracts (PSCs), since these are the type of E&P Contracts that are used in Uruguay.

As already mentioned, ANCAP is the National Oil Company (NOC) in Uruguay. Uruguayan Hydrocarbons’ Law (Decree-Law Nº 14181) dates back to 1974, and has been slightly modified since then, through various versions of the Mining Code. However, it still includes the concepts that “all hydrocarbon resources and extracted substances belong to the Uruguayan State and they can only be explored or exploited by the State” and that “ANCAP is the State entity to execute all activities, business and operations of hydrocarbon industry (by itself or by third parties)”. Exploration and Production contracts with private companies are signed by ANCAP after its approval by the Executive Branch and the type of contracts are PSCs (Ferro et al. 2017).

During the several processes of offshore bidding rounds, the general fiscal and contractual terms have remained almost unchanged. In particular, the most important characteristics included in the Uruguayan PSC model approved for the current system (Open Uruguay Round) which are of special interest for the economic evaluation, are described in the following sections, based on ANCAP (2019c).

4.2.4.1 Contract Term

- The total duration of the contract is 30 years, which could be extended for 10 additional years in case it is requested by the Contractor for acceptable reasons and approved by the executive Branch.
- The total Exploration Period is divided in three phases. In the Basic Subperiod, the Contractor has to complete the committed exploratory work. If the Contractor decides to move to the Supplementary Subperiod, it is possible to follow a pathway A) (in which drilling exploratory wells is required), or it can follow an alternative pathway B) (commitment to drill exploratory wells is not required, but the Contractor has to commit more exploratory work and relinquish 50% of the area). The Extension Subperiod is also optional and must include other exploratory wells and the relinquishment of 30% of the area. These aspects are illustrated in Fig. 13.

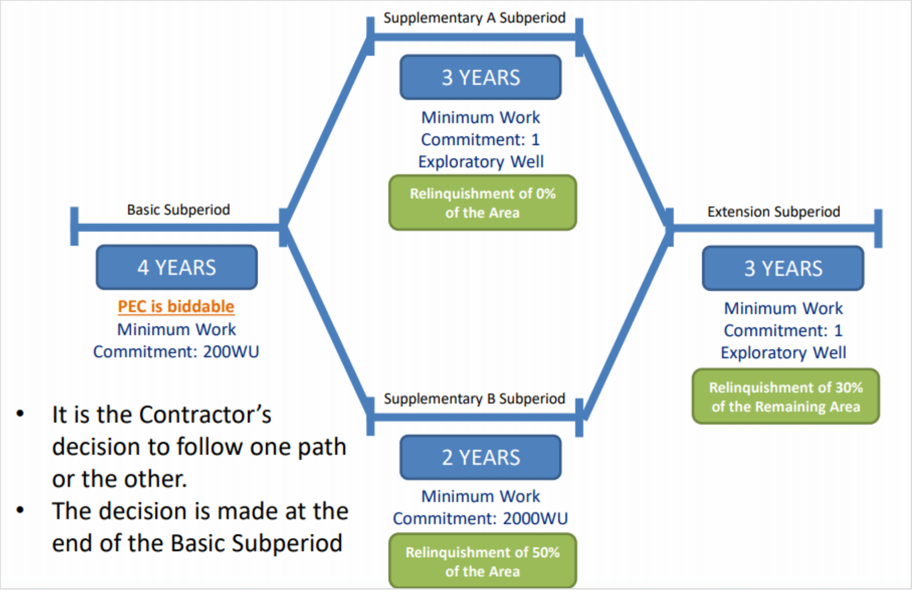


Fig. 13 – Exploration period diagram for deep offshore areas (Ferro 2019)

4.2.4.2 ANCAP's Association

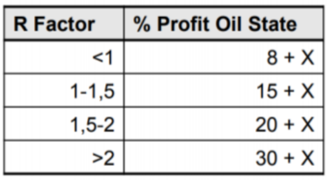
- After the commerciality of a discovery is declared, ANCAP has the right to decide to associate with the Contractor for exploitation of the area. The bidding company must propose the maximum ANCAP's association percentage, in the range between 20% and 40%, and this parameter is used for comparison of offers.
- After ANCAP's association to the Contractor, the prorated share of development and exploitation costs are paid by ANCAP, receiving its prorated share of revenues.

4.2.4.3 Oil and Gas Prices

- For Oil, price is fixed as the actual value of international oil prices, considering crudes of similar features.
- For Natural Gas, price is considered as an average of four terms:
    - Henry Hub index in USD/MMBTU
    - National Balancing Point (UK) in USD/MMBTU
    - a regional gas price index
    - the result of the formula [0.1*P-3], where P is the Oil Price established before.

4.2.4.4 Cashflow Analysis

- Payment of royalties, bonuses or surface rentals is not required.
- The production income is divided in three portions: Cost Oil, Profit Oil for the Contractor and Profit Oil for the Uruguayan State.
    - Cost Oil is defined as the portion of actual production used to compensate the Contractor for Costs and Investments associated with the Exploration and Exploitation Periods.
    - The maximum share of production that is available for Cost Oil Recovery in each quarter is established in 60% in case of oil production and 80% in case of natural gas production. For any quarter, if Cost Oil is more than this maximum, the unrecovered amount is carried forward and recovered in the following quarter until it is completely recovered.
    - Profit Oil is "the amount of production after deducting Cost Oil from the actual production". It is divided between the State and the Contractor in a proportion that depends on the ratio between the accumulated Gross Income and accumulated Cost Oil in a quarterly basis (R-factor). This is illustrated in Table 2, where X corresponds to a value between 0 and 70 that has to be proposed by the bidder for each type of hydrocarbon (oils of °API>25, oils of °API<25 and natural gas).



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 Uruguayan State vs. R factor (ANCAP 2019c)

- Operating costs include purchase of materials, fixed and variable operating expenditures and are recovered quarterly. The capital investments include drilling of wells, construction of infrastructure (such as platforms, pipelines and equipment) and are recovered in 20 quarterly installments. Cost Oil is deducted from gross income before sharing the production profit.
- Starting in the first quarter of the Calendar Year in which the Contractor estimates that 50% of the total recoverable reserves will be reached, and for each quarter, the Contractor has to make a deposit in the "Abandonment Fund". This amount is calculated with Eq. 8.

$$FA_i = CA \cdot \frac{NP_i - EUR * 0.5}{EUR * 0.5} - FAA_i \qquad Eq. 6$$

Where,

FA_i is the amount to be deposited in the Abandonment Fund in the quarter (USD)
CA is the Total Updated Estimated Abandonment Costs (USD)
NP_i is the accumulated production until the beginning of the i quarter (BOE)
EUR is the Total Estimated Recoverable Reserves (BOE)
FAA_i is the Total of amounts paid to the Abandonment Fund before the i quarter (USD)

- Additionally, the Contractor is required to deposit USD 250,000 per quarter beginning in the first year of production in case that the amount calculated with Eq. 6 is less than USD 250,000.

- The Contractor pays Income Tax on its share of Profit Oil. Economic Activities Income Tax is 25% (Law N° 18083).

As it is presented in Fig. 14, the gross income arising from the gross production can be split in costs (which includes both capital and operating expenditures), net margin for ANCAP, net margin for the IOC, taxes and Uruguayan State profit. The Uruguayan State's rent is composed of the following three mechanisms: Uruguayan's State share of Profit Oil, ANCAP's net margin and Income Tax (applied to both ANCAP's and IOC's Profit Oil share). This is illustrated in the shaded boxes of Fig. 14 (Ferro et al. 2017).

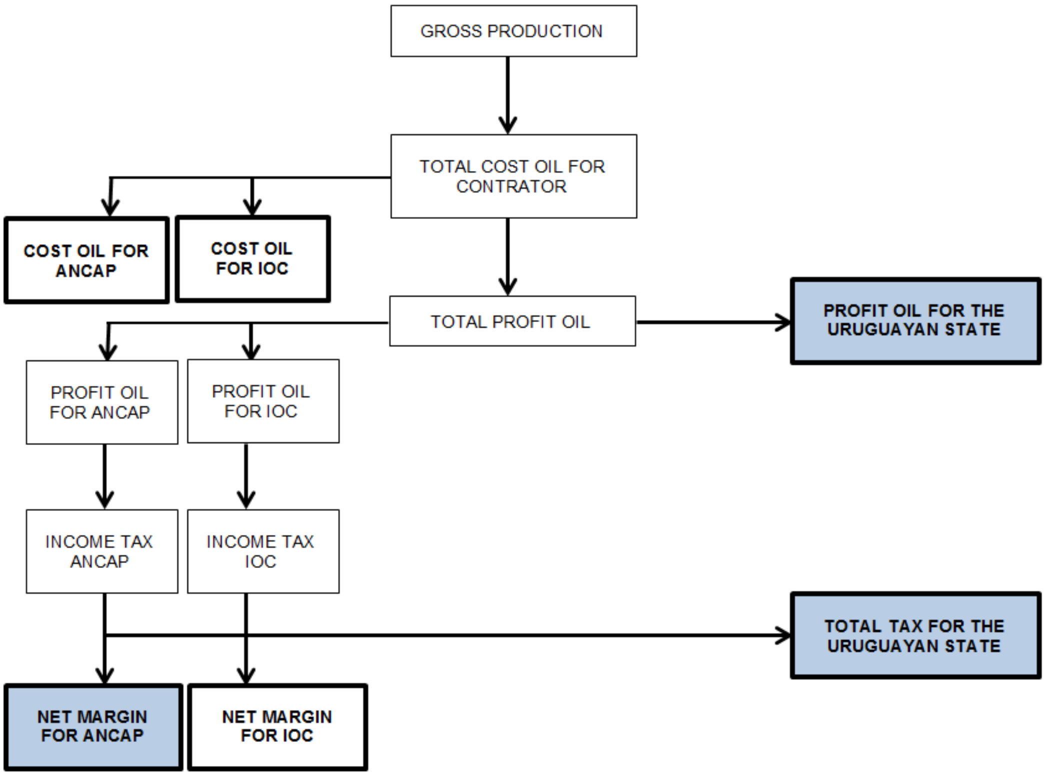


Fig. 14 – Uruguayan PSC cash flow diagram (Ferro et. al 2017)

4.3 Probability of Success and Expected Monetary Value

The probability of geologic success (PoS) is associated to a situation of discovery and can be estimated according to the risk tables presented by Milkov (2015), which provide a consistent methodology taking into account six aspects: structure, presence of reservoir facies, reservoir deliverability, seal, source presence and maturity, and migration. Considering the different features of the prospects to be evaluated with respect to such parameters, the PoS was estimated in 13%.

On the other hand, the probability of economic success (P_e) is estimated as the probability that the Net Present Value (NPV) is greater than zero. NPV will be considered discounted at 10% (PV10).

The expected value is the weighted average of possible results of a certain variable after several iterations. In particular, when such variable is expressed in monetary terms, it is called Expected Monetary Value (EMV). Therefore, assuming that the different investment alternatives to be assessed are mutually exclusive, the selection is based on the one that presents the largest EMV (Mian 2011b). The EMV of drilling an exploratory well can be estimated as:

$$EMV = P_g \cdot (P_e \cdot PV_{10} - (1 - P_e) \cdot CostAppWells) - \left(1 - P_g\right) \cdot CostExplWell \qquad Eq.7$$

Where,

CostAppWells is the cost associated to drilling appraisal wells after the commercial discovery
CostExplWell is the cost associated to drilling an exploration well

Finally, the Internal Rate of Return makes reference to the discount rate at which NPV equals zero (Mian 2011a).

In particular, for this assessment the key outputs are the PV10, the IRR and the EMV. Additionally, payout time and Maximum Negative Cashflow (MNCF) were also computed for each case.

5. Description

5.1 Resources' Volumetric Estimation

It is assumed that the fluid to be produced is light oil (32 °API) with associated gas and that the fluid presents low sulfur and CO_2 content.

The area of each prospect was determined using depth structural maps of top reservoir, shown in Fig. 15. P10 is a maximum area which comprises the whole identified prospects, whereas P90 is a minimum area of the structure which is inferred to be charged with hydrocarbons (highest closed structure of each anticlinal). The determination of the corresponding gross pay thicknesses was performed through seismic interpretation. The distributions used are shown in Table 3.

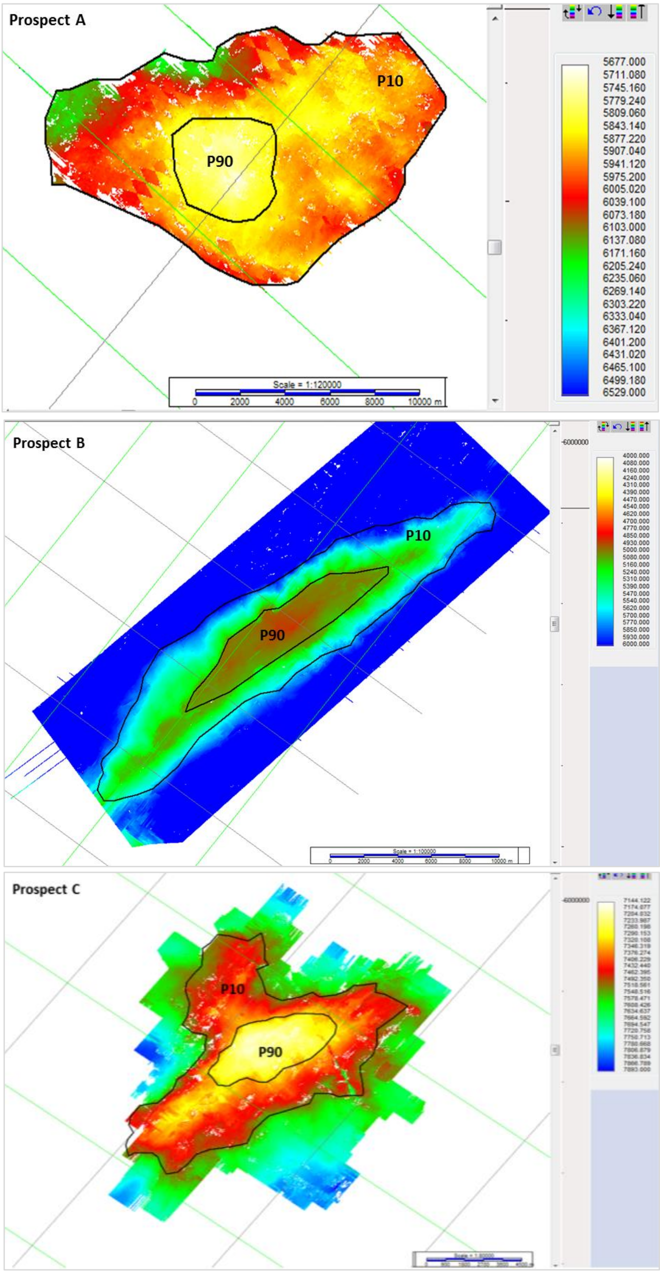


Fig. 15 – Depth structural maps of top reservoir for Prospects A, B and C. Areas identified as P90 and P10 are shown. Courtesy of ANCAP.

	Area (Km^2)			Thickness (m)		
Distribution	Lognormal			Triangular		
Prospect	A	B	C	A	B	C
Mean/Most Likely	73.1	80.1	47.5	153	208	320
P90	17.1	29.4	14.7	-	-	-
P10	129.1	130.7	80.3	-	-	-
Min	10			82	100	172
Max	300			224	315	467

Table 3 – Area and thickness estimation for prospects A, B and C.

The rest of the reservoir properties (porosity, oil saturation, net-to-gross ratio, oil formation volume factor, recovery factor and gas oil ratio) were estimated taking into consideration general features of Santos and Campos Basins in Brazil, as well as from analogues, in particular the following fields in Santos Basin: Tupi (Lula), Iara (Berbigâo, Sururu and Atapu), Franco (Buzios), Libra (Mero) and Guará (Sapinhoá) (Gaffney, Cline & Associates 2010; Petersohn et. al 2013; Moczydlower 2014; Boyd et. al 2015; Turazzi Naveiro and Haimson 2015; Carlotto et. al 2017; Macedo Dias 2018). The distributions assigned to every parameter are presented in Table 4.

	Porosity (%)	So (%)	Bo (RB/STB)	GOR (scf/STB)	NTG (%)	RF (%)
Distribution	Normal	Triangular	Uniform	Triangular	Normal	Triangular
Mean/Most Likely	12	82	-	1,454	75	23
P90		-	-	-	-	-
P10	25	-	-	-	84	-
Min	0	70	1.43	1,035	10	8
Max	40	90	2.00	2,513	100	48

Table 4 – Parameters' distributions for probabilistic volumetric calculation

Considering all the previous parameters, Eq. 1, 3 and 4, were considered for the probabilistic determination of OOIP, EUR and Associated Gas respectively, using the Excel Risk Analysis tool, @Risk. The normal and lognormal distributions were truncated, considering the minimum and maximum values presented in the Table 4. The simulation was set for 10,000 iterations and was carried out with Latin Hypercube sampling, and it was assumed that none of the inputs were correlated with each other.

5.2 Economic evaluation

5.2.1 Exploration, Appraisal and Field Development

The economic analysis comprises production costs, surface costs and transportation costs. Additionally, it will be considered a 40-year Exploration and Production contract signed in 2019, and this is considered as "Year 0". It is assumed that the Contractor completes the Basic Exploratory Subperiod of 4 years and decides to proceed to the Supplementary Subperiod, choosing pathway A), for which an exploratory well is drilled in Year 5. Afterwards, two appraisal wells are drilled in Years 6 and 7. The Field Development Plan is assumed to take place during Year 8, and Development of the field is performed during Years 9 and 10. Finally, Production starts in Year 11 until the end of the contract. The two appraisal wells are considered to be put in production.

With regards to the general operation, it is assumed that the oil will be transported by means of oil tankers and produced water will be treated after separation from the produced fluids and will be reinjected in the reservoir. Waterflooding is used in both Campos and Santos basins, and has proved to be an efficient method for reservoir pressure maintenance (Bruhn et. al 2003; Salomão et. al 2015).

Additionally, it is assumed that 4.3% of the produced gas is used for generation of power and heat (Allahyarzadeh-Bidgoli et. al 2018). For the rest of the gas, two situations will be assessed; the first situation assumes that the gas is treated and transported to onshore installations through gas pipelines for being sold, requiring the construction of a gas pipeline. The second situation is that the gas is reinjected.

5.2.2 Type well production curve

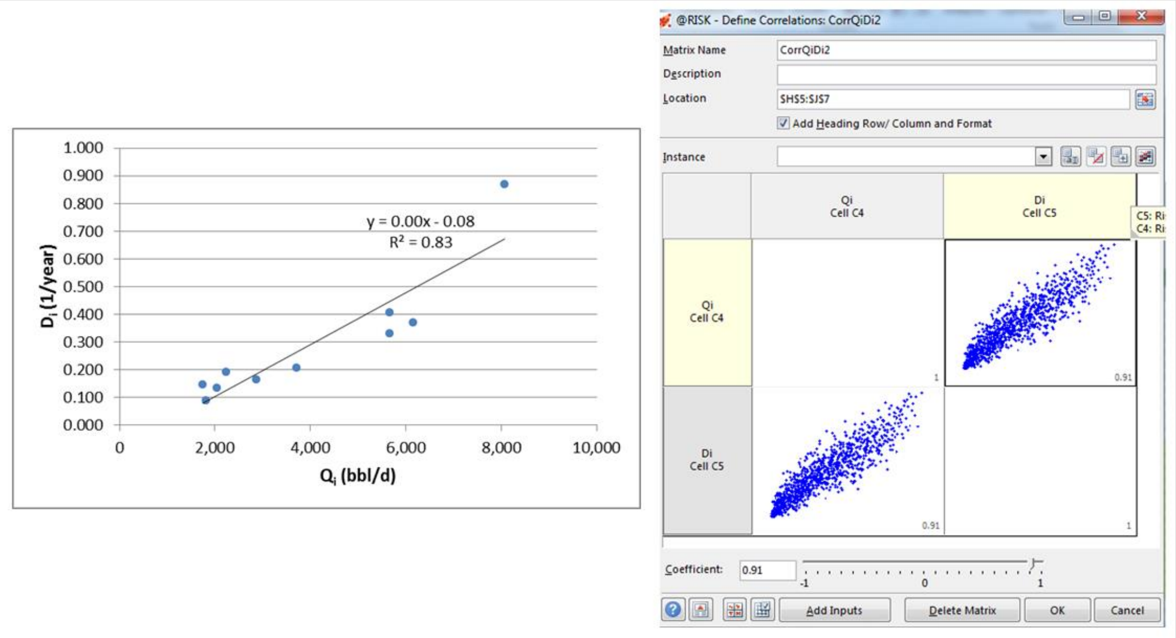
Garoupa Field was the first oil field discovery of Campos Basin (offshore Brazil), which occurred in 1974 and the reservoirs consist of Albian carbonates. Based again on analogy, production data from 10 wells of this field were obtained (ANP 2019), and a Decline Curve Analysis (DCA) analysis could be performed. For each of the 10 wells, the production data provided was used to match the hyperbolic decline curve shown in Eq. 5 (DCA Regression), using the Excel tool SOLVER. The parameters Q_i, D_i and b were the variables and the target was to minimize the squared residuals of annual production values. The residuals were the difference between the measured values and the values computed from the regression.

After repeating this procedure for the 10 wells, 10 values of Q_i, D_i and b were generated (Table 5) and a distribution fitting was carried out for each parameter, using the tool in @Risk "Distribution Fitting". For the models' construction, the possible functions that were considered were uniform, triangular, normal and lognormal, ranked by Chi-Sq parameter (this means that the distribution with the lowest Chi-Sq value was chosen in each case). Additionally, the distributions were truncated, considering the minimum and maximum values obtained of Q_i, D_i and b respectively.

Well	Q_i (bbl/d)	D_i (1/year)	b
1	3,720	0.206	0.449
2	5,662	0.332	0.972
3	6,151	0.371	0.393
4	2,879	0.164	0.383
5	2,047	0.133	0.000
6	5,658	0.406	1.017
7	2,245	0.190	0.323
8	1,752	0.148	0.000
9	1,820	0.090	0.000
10	8,072	0.870	0.920

Table 5 – Hyperbolic decline parameters for Garoupa Field wells

From a plot of Q_i vs. D_i (Fig. 16, left) it can be seen that there is a linear correlation between those parameters. Fitting the data points through a straight line, it is represented by a R^2 value of 0.83, giving a correlation coefficient value (R) of 0.91; therefore, there is a strong correlation between these parameters for the analog field. This correlation coefficient between Q_i and D_i was imposed in @Risk, giving the correlation matrix of Fig. 16 (right).



@RISK - Define Correlations: CorrQiDi2

Matrix Name: CorrQiDi2

Description:

Location: $H$5:$J$7

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Instance:

Coefficient: 0.91

Fig. 16 – Plot of Q_i vs. D_i obtained for ten wells in Garoupa Field (left) and correlation matrix used in the @Risk model (right).

The type curve is then constructed by replacing the distributions of Q_i, D_i and b in the hyperbolic decline curve of Eq. 5. The annual volumes can be calculated with this type curve for obtaining the production profile of each well that will be put in production in the field. Also, the cumulative oil production of one well for the 40-year period can be obtained. Additionally, considering the total number of production wells, a total annual production rate can be obtained for the whole field.

5.2.3 Production features

The number of production wells is calculated as the ratio between the calculated oil EUR of the field and the cumulative production of the type well for the 40-year period. In Table 6, the general aspects of the different phases up to Year 20 of the Contract are shown.

Phase	z year	Wells put into production
Contract signature	0	0%
Exploration	1	0%
	2	0%
	3	0%
	4	0%
	5	0%
Appraisal	6	0%
	7	0%
FDP	8	0%
Development	9	0%
	10	0%
Production	11	20%
	12	20%
	13	20%
	14	15%
	15	10%
	16	10%
	17	5%
	18	0%
	19	0%
	20	0%

Table 6 – Project schedule until Year 20, showing percentage of wells put into production during the Production phase

Gas production is estimated multiplying the oil production by the corresponding GOR, subtracting the corresponding fraction for power generation (4.3%). In the case of gas injection, the number of gas injection wells is obtained dividing the maximum gas production by a gas injection rate. This rate is assumed as a triangular distribution varying between 5 MMscf/d and 75 MMscf/d, with a most likely value of 40 MMscf/d (Wheaton and Manu 2012; Agrawal et. al 2016).

Water production is estimated as the difference between the initial oil production rate and the actual oil production rate. The number of water injection wells is obtained dividing the water production by a water injection rate. This rate is assumed as a triangular distribution varying between 31,000 bbl/d and 50,000 bbl/d with a most likely value of 45,000 bbl/d (Salomão et. al 2015; Nunes et. al 2016; De Abreu Campos et. al 2017).

Based on analog fields, FPSO processing capacity is assumed to be 150,000 bbl/d of produced oil, 212 MMscf/d of injected gas and 200,000 bbl/d of injected water (SBM Offshore 2016a). Then, the number of FPSOs required is calculated as the maximum of the following numbers:

- Maximum oil production rate in the 40-year period, divided by 150,000 bbl/d

- Maximum water production rate in the 40-year period, divided by 200,000 bbl/d
- Maximum gas production rate in the 40-year period, divided by 212 MMscf/d

5.2.4 Expenditures

CAPEX was estimated taking into account the following considerations:

Based on Whiteside (2019), the cost of the drilling rig is assumed as a triangular distribution varying between 130,000 and 270,000 USD/d, with a most likely value of 240,000 USD/d. The average drilling rate is estimated in 55 m/d, considering the average value corresponding to analogue fields (Bnamericas 2019). Based on data from IOCs that worked offshore Uruguay, the cost corresponding to logistics, well services, consumables and supervision triples the rig cost, and the mobilization and demobilization times account for 20 days each. Additionally, a contingency factor of 1.5 was taken for the total drilling days. Based on data from OGUK (2018), the average number of interventions per well and per year is set in 0.14, with a cost of 2 MMUSD per intervention.

The cost of each FPSO is taken as a triangular distribution from 1,500 to 1,800 MMUSD, with a most probable value of 1,675 MMUSD (Nunes et. al 2016; SBM Offshore 2016b). SURF expenditures are estimated considering that one set of SURF facilities will be used by each FPSO. Each set of SURF facilities is estimated to cost between 750 and 1,125 MMUSD, with a most likely value of 1,100 MMUSD (BEI 2019b; Veazei 2019). Pipeline costs are taken also as a triangular distribution varying between 1.5 and 4 MMUSD/Km, with a most likely value of 2.3 MMUSD/Km (Kaiser 2016; BEI 2019a).

OPEX was estimated including the following aspects:

Based on data from IOCs that worked offshore Uruguay, a fixed quarterly expenditure was taken into account, varying between 1.5 and 2.5 MMUSD, with a most likely value of 2 MMUSD. A variable factor was also considered, taken as a triangular distribution, varying between 10 and 20 USD/BOE, with a most likely value of 15 USD/BOE (ENERCOM 2018; OGUK 2018). Oil transportation costs were taken as a triangular function varying in the range 1 – 1.5 – 2 USD/bbl for oil tankers (Nightingale 2019) and gas transportation fee was considered as 1.44 USD/Mscf (MIEM 2019).

FPSO, SURF and Gas pipeline costs were allocated in Years 8, 9 and 10, in percentages of 40%, 40% and 20% respectively in each year. Abandonment Fund deposit was calculated according to Section 4.2.4.4., taking the total estimated abandonment costs (CA) as 5% of the total CAPEX (Weijermars et. al 2017).

In the case that gas is commercialized, CAPEX is divided as oil and gas costs, prorated according to the ratio of oil (or gas) EUR, with respect to the total field EUR.

5.2.5 Price

According to Section 4.2.4.3, prices are set as follows:

- Initial Oil Price is considered as a fixed value for the whole life of the project. However, a sensitivity analysis is performed based on this parameter, performing different simulations for oil prices varying among 30, 60, 80 and 100 USD/bbl.
- Gas Price is calculated as the average of four items: the Henry Hub index (US), estimated in 2.56 USD/MMBTU (Markets Insider 2019); the National Balancing Point (UK), estimated in 4.39 USD/MMBTU (TradingView 2019) a regional gas price estimated in 15 USD/MMBTU and the result of the formula [0.1*P-3], where P is the Oil Price established before.

5.2.6 Cashflow Analysis

Regarding cashflow analysis, the general considerations are taken according to Section 4.2.4.4. and in particular, ANCAP’s association is set as 25%. Also, the increment of Profit Oil for the Uruguayan Sate is set is set in zero (the value of X presented in Table 2 is set in zero).

Considering all the previous parameters, the cashflow analysis was performed for the different scenarios studied. The probabilistic determination of PV10 and IRR was performed, using the Excel Risk Analysis tool, @Risk. Similarly to the volumetric estimation, the simulations were set for 10,000 iterations and were carried out with Latin Hypercube sampling, and it was assumed that none of the inputs were correlated with each other.

6. Results

6.1 Volumetric Resources' Estimation

The Prospective Resources' estimation for each prospect is presented in Table 7. The 10th, 50th and 90th percentile values of each resulting distribution correspond to the 1U, 2U and 3U Prospective Resources, respectively.

	OOIP (MMbbl)			**EUR (MMbbl)**			**Associated Gas (TCF)**		
	1U	**2U**	**3U**	**1U**	**2U**	**3U**	**1U**	**2U**	**3U**
Prospect A	458	2,146	7,164	104	529	1,913	0.168	0.861	3.223
Prospect B	835	3,519	10,477	191	878	2,816	0.312	1.427	4.806
Prospect C	770	3,179	9,637	177	802	2,580	0.282	1.303	4.444

Table 7 – Prospective Resources of Prospects A, B and C

Tornado charts are a graphical way of showing the sensitivity of each output variable to the input distribution in the model, therefore it was also of interest in this assessment. The probability density functions of EUR and Associated Gas for Prospect A are presented in Fig. 17. The corresponding tornado chart is shown in Fig. 18. For Prospects B and C, the resulting distributions and sensitivity plots are similar.

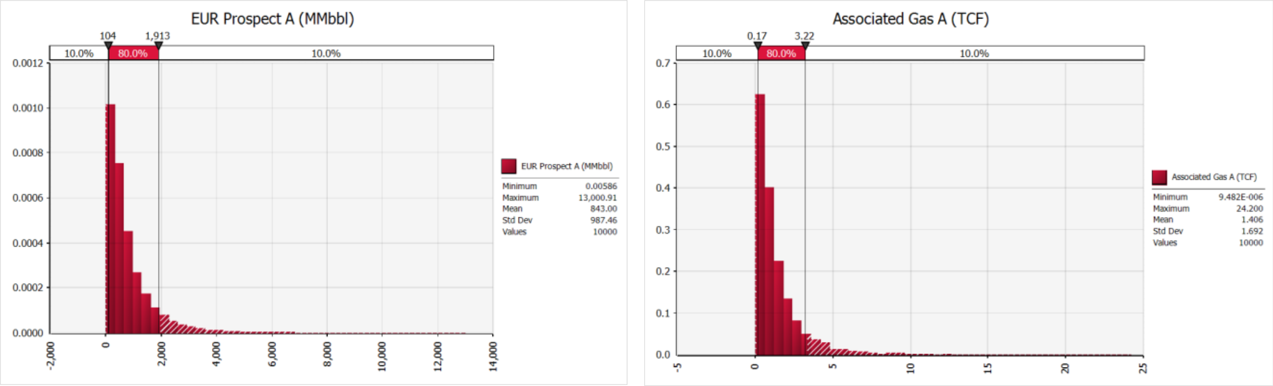

Fig. 17 – Probability distribution of EUR for Prospect A (left) and Associated Gas for Prospect A (right)

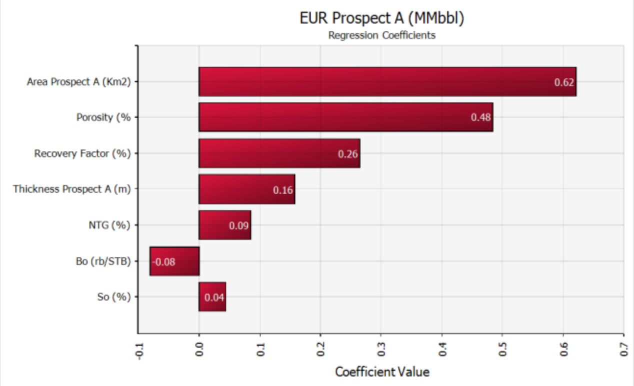

Fig. 18 – Tornado chart for EUR calculation of Prospect A

Considering that Prospects B and C are close to each other (18 Km away) and taking into account that FPSOs can handle fields which are at least 45 Km apart (Weijermars et. al 2017), it is interesting to evaluate as well the scenario in which such prospects are developed simultaneously. The volumetric calculation of these prospects gave the results that are presented in Table 8.

	OOIP (MMbbl)			EUR (MMbbl)			Associated Gas (TCF)		
	1U	2U	3U	1U	2U	3U	1U	2U	3U
Prospect B+C	1,962	7,561	18,727	455	1,861	5,181	0.726	3.030	8.827

Table 8 – Prospective Resources of Prospects B and C when developed simultaneously

6.2 Economic evaluation: summary of results

A summary of the results is presented in Table 9 for gas injected and gas sold, respectively. Best estimate values are reported, corresponding to PV10, IRR, Payout time, CAPEX, OPEX and Total Costs per BOE, MNCF, Government and Contractor's Take, probability of economic success and EMV.

GAS INJECTED		Prospect A	Prospect B	Prospect C	Prospect B+C
		P50	P50	P50	P50
EUR (MMBOE)		678	1,127	1,029	2,434
PV10 IOC (MMUSD)	USD 30/bbl	-2,954	-2,259	-4,221	-8,265
	USD 60/bbl	-988	-595	-1,372	-1,845
	USD 80/bbl	-176	453	-79	904
	USD 100/bbl	794	1,322	1,243	3,848
IRR (%)	USD 30/bbl	-11%	-4%	-11%	-9%
	USD 60/bbl	3%	7%	4%	6%
	USD 80/bbl	9%	13%	10%	13%
	USD 100/bbl	15%	17%	15%	18%
Payout (Years)	USD 30/bbl	41	41	41	41
	USD 60/bbl	29	19	26	22
	USD 80/bbl	18	16	18	17
	USD 100/bbl	16	15	16	15
CAPEX/BOE (USD/BOE)		26	26	25	22
OPEX/BOE (USD/BOE		14	12	13	13
Total Cost/BOE (USD/BOE)		40	39	39	35
MNCF (MMUSD)	USD 30/bbl	-9,012	-7,053	-13,186	-26,101
	USD 60/bbl	-5,549	-5,221	-7,992	-15,493
	USD 80/bbl	-4,832	-4,946	-6,851	-13,353
	USD 100/bbl	-4,538	-4,844	-6,336	-12,272
Government Take	USD 30/bbl	47%	48%	47%	47%
	USD 60/bbl	50%	51%	50%	50%
	USD 80/bbl	52%	54%	52%	53%
	USD 100/bbl	54%	57%	54%	56%
Contractor's Take	USD 30/bbl	53%	52%	53%	53%
	USD 60/bbl	50%	49%	50%	50%
	USD 80/bbl	48%	46%	48%	47%
	USD 100/bbl	46%	43%	46%	44%
Pe (%)	USD 30/bbl	0%	0%	0%	0%
	USD 60/bbl	4%	12%	4%	11%
	USD 80/bbl	43%	65%	47%	68%
	USD 100/bbl	77%	90%	83%	94%
EMV (MMUSD)	USD 30/bbl	-104	-87	-110	-99
	USD 60/bbl	-108	-94	-116	-124
	USD 80/bbl	-104	-35	-102	-1
	USD 100/bbl	-4	90	49	405

GAS SOLD		Prospect A	Prospect B	Prospect C	Prospect B+C
		P50	P50	P50	P50
EUR (MMBOE)		678	1,127	1,029	2,434
PV10 IOC (MMUSD)	USD 30/bbl	-2,259	-2,707	-3,109	-5,556
	USD 60/bbl	-595	-85	-555	21
	USD 80/bbl	453	1,431	831	3,048
	USD 100/bbl	1,322	2,726	2,124	5,792
IRR (%)	USD 30/bbl	-4%	-2%	-4%	-2%
	USD 60/bbl	7%	10%	8%	10%
	USD 80/bbl	13%	16%	14%	17%
	USD 100/bbl	17%	20%	18%	21%
Payout (Years)	USD 30/bbl	41	41	41	41
	USD 60/bbl	19	17	19	18
	USD 80/bbl	16	15	16	15
	USD 100/bbl	15	14	15	14
CAPEX/BOE (USD/BOE)		26	22	25	21
OPEX/BOE (USD/BOE		12	12	12	11
Total Cost/BOE (USD/BOE)		39	33	37	32
MNCF (MMUSD)	USD 30/bbl	-7,053	-9,140	-9,991	-18,921
	USD 60/bbl	-5,221	-6,911	-7,137	-13,523
	USD 80/bbl	-4,946	-6,630	-6,676	-12,490
	USD 100/bbl	-4,844	-6,557	-6,505	-12,059
Government Take	USD 30/bbl	48%	49%	49%	50%
	USD 60/bbl	51%	52%	52%	53%
	USD 80/bbl	54%	55%	54%	56%
	USD 100/bbl	57%	58%	57%	59%
Contractor's Take	USD 30/bbl	52%	51%	51%	50%
	USD 60/bbl	49%	48%	48%	47%
	USD 80/bbl	46%	45%	46%	44%
	USD 100/bbl	43%	42%	43%	41%
Pe (%)	USD 30/bbl	0%	0%	0%	0%
	USD 60/bbl	23%	46%	27%	50%
	USD 80/bbl	66%	85%	75%	90%
	USD 100/bbl	84%	93%	91%	97%
EMV (MMUSD)	USD 30/bbl	-104	-87	-110	-99
	USD 60/bbl	-117	-83	-123	-85
	USD 80/bbl	-49	92	-8	288
	USD 100/bbl	63	270	169	671

Table 9 – Summary of P50 results for all cases studied

Additionally, development and production results are presented for each assessed project in Table 10. Best estimate results of maximum production of oil, gas and water are presented for each project. Also, the number of FPSOs, oil production and water injection wells are reported, together with the total gas injection wells in the corresponding Gas Injection cases.

	Prospect A	Prospect B	Prospect C	Prospect B+C
	P50	P50	P50	P50
Max Prod Oil (bbl/d)	137,908	224,147	202,835	469,661
Max Prod Gas (MMscf/d)	214	350	317	726
Max Prod Water (bbl/d)	282,842	467,595	420,882	971,629
Number of FPSOs	2	4	3	6
Number of oil production wells	110	174	154	323
Number of gas injection wells	7	12	10	21
Number of water injection wells	10	15	14	28

Table 10 – Development and production results (best estimates)

An example of the total oil production profile of the field is shown in Fig. 19 for the gas reinjection scenario, whereas in Fig. 20, the oil and gas production profiles are displayed for the Gas Sold scenario.

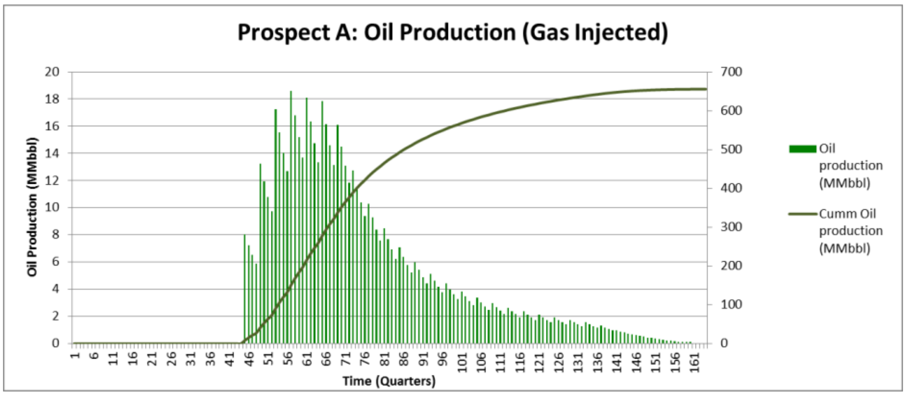

Figure 19: Oil production (P50) for Prospect A (Gas injected Case)

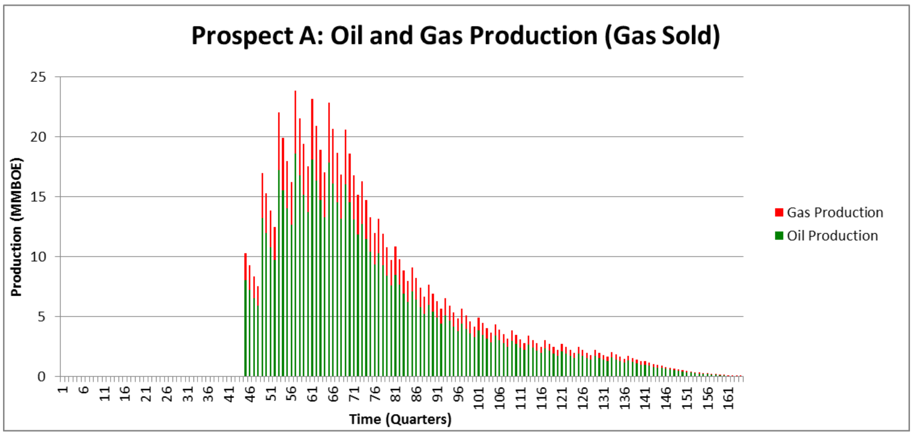

Figure 20: Oil and Gas Production (P50) for Prospect A (Gas Sold Case)

6.3 Net Present Value and Internal Rate of Return

The different results for the scenarios studied are presented as follows. Figs. 21 and 22 show how PV10 and IRR change as a function of the oil price for the different projects considered and for both the Gas Sold and Gas Injection scenarios.

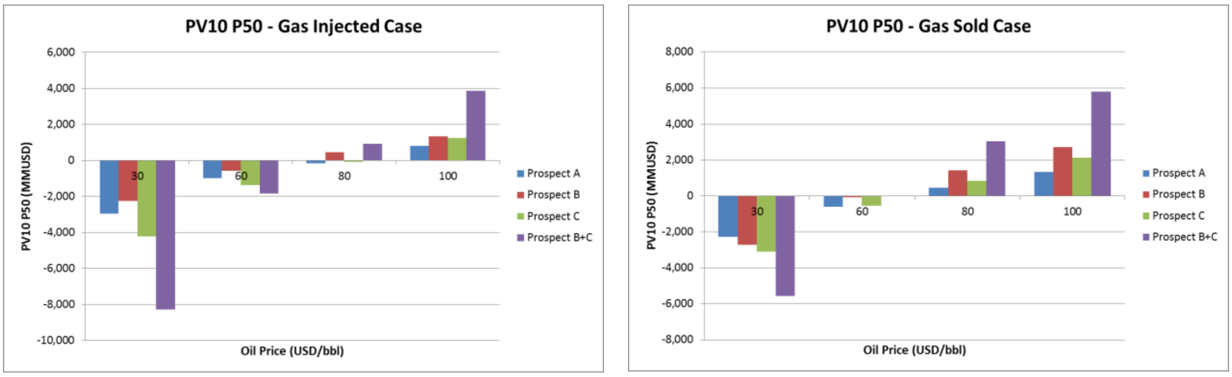

Fig. 21 – Result of PV10 P50 (IOC) as a function of Oil Price, for scenarios of Gas Sold and Gas Injected

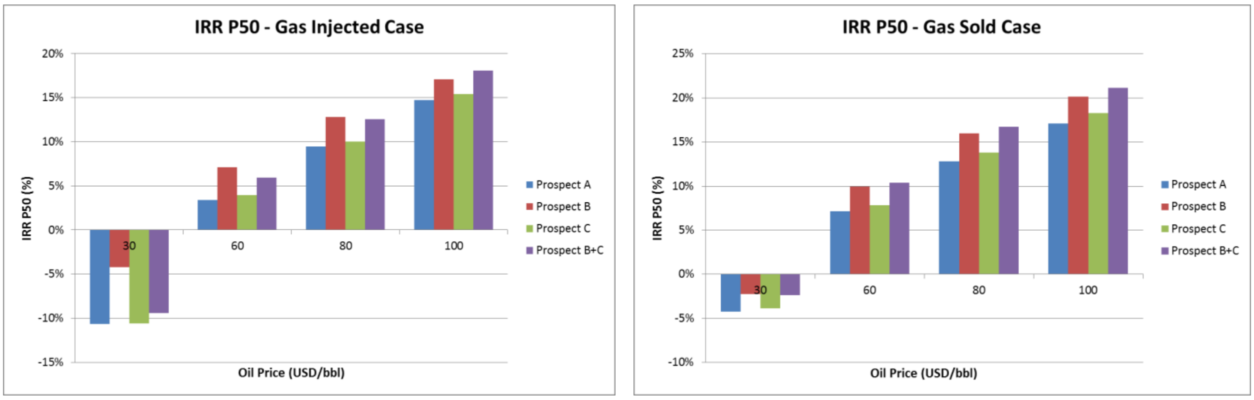

Fig. 22 – Result of IRR P50 for scenarios of Gas Sold and Gas Injected

In particular for Prospect A, in Fig. 23 it can be seen a comparison of the IRR as a function of oil price, for the cases studied of Gas Sold and Gas Injected.

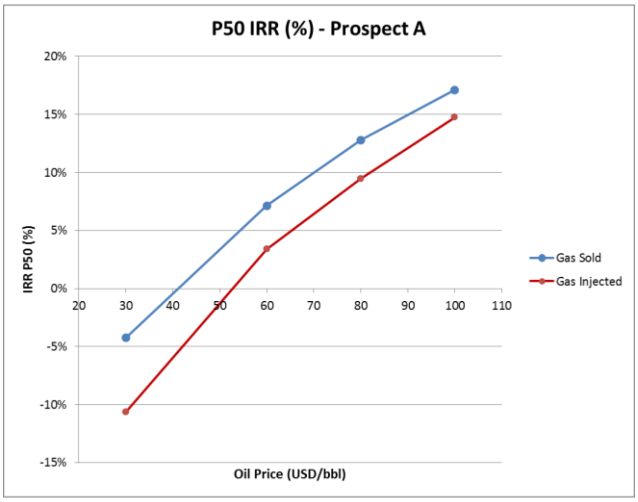

Fig. 23 – P50 values of IRR vs. Oil Price, for Prospect A (Gas Sold and Gas Injected cases)

6.4 Costs

The total costs per recoverable BOE are shown in Fig. 24 for all the cases,

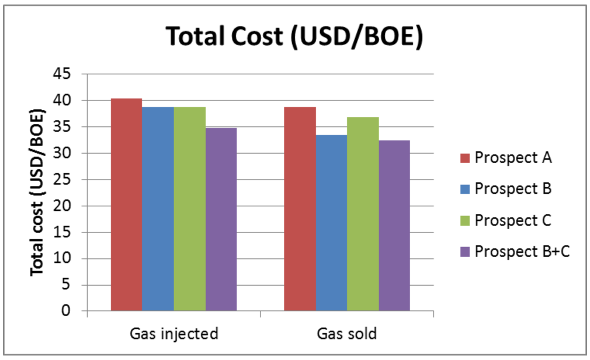

Fig. 24 – Total Cost/BOE (P50 values) for the scenarios of Gas Sold and Gas Re-injection

From this total cost, which is composed by CAPEX and OPEX, the CAPEX structure in each case can be observed in Fig. 25, for Prospect A. Similar behaviors were found for the rest of the prospects evaluated.

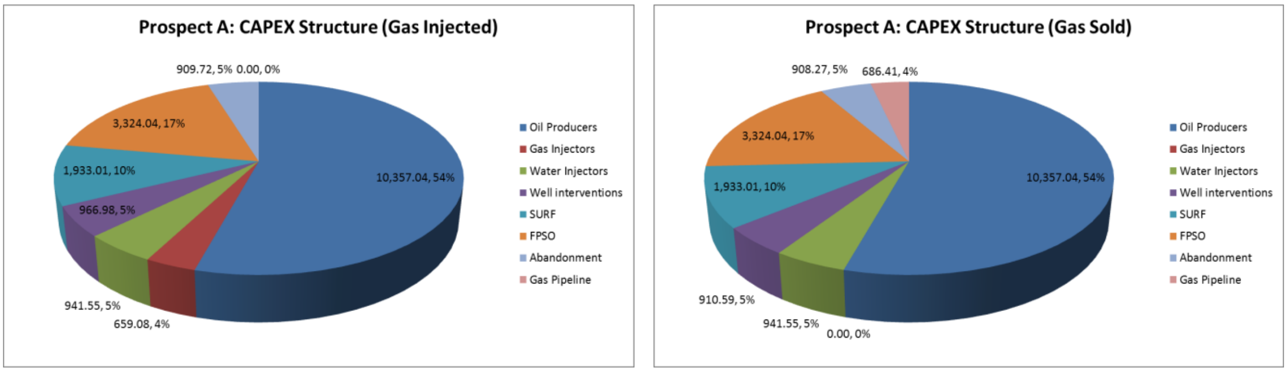

Fig. 25 – CAPEX Structure (P50) for Gas Injected (left) and Gas Sold (Right) for Prospect A

6.5 PSC Share

One of the results for the PSC flow diagram is presented in Fig. 26.

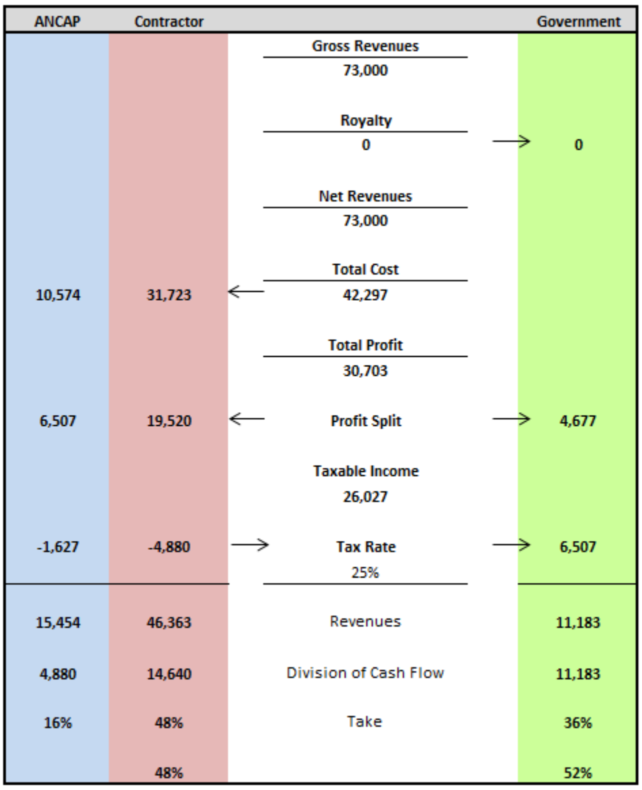

Fig. 26 – PSC flow diagram for Prospect B (Gas Sold Case)

6.6 Expected Monetary Value

Based on Eq. 7 presented in Section 4.3, a Decision Tree can be constructed in each case. The resulting Decision Tree for Prospect A in the Gas Injected case is presented as an example in Fig. 27.

When deciding to drill an exploratory well, the outcome of a dry well implies that the cost of drilling such exploratory well was a lost investment. On the other hand, after a commercial discovery is made, the corresponding amount of money allocated for this case is given by the value of PV10 after development. If there is no commercial discovery, the amount of money corresponding to this outcome is the cost of the appraisal wells. All these considerations are implied in the application of Eq. 7 for the calculation.

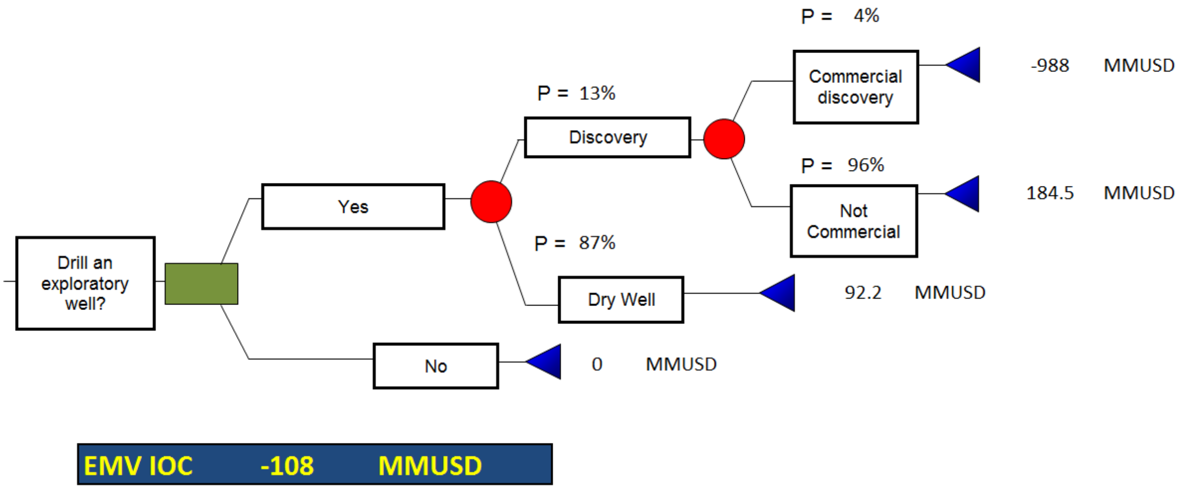

Fig. 27 – Decision Tree for Prospect A (Gas Injected case, Oil Price 60 USD/bbl)

7. Discussion

In the present work, firstly a description of the exploratory status in Uruguay was presented. Then, the geological context was summarized, including the selected prospects to be evaluated, which were identified through seismic data (Prospects A, B and C).

Afterwards, the Petroleum Resources Management System (PRMS) outline was presented. In this sense, as Uruguay is still in an underexplored condition regarding its offshore basins and there has not been any discovery of oil or gas yet, it was indicated that the assessment would be focused on Prospective Resources, as part of the undiscovered resources.

Additionally, the methodology to be used for the resources' volumes estimation was described, concentrating the description in static-data based methods, since the cases considered are located in frontier basins. In particular, the methods considered adequate for this specific situation were the volumetric method, combined with analogy. Additionally, stochastic simulation was presented and was employed with Latin Hypercube sampling. Analogy served as the basis for the determination of different parameters that were used in the volumetric calculation, and it was explained that the analogue fields to be employed in this work would be Santos and Campos Basins in Brazil. For the cashflow analysis considerations, the petroleum fiscal regime in Uruguay was also described.

Based on the production of a type well, also constructed based on an analogue field, a production profile was created for the different wells of the project. Additionally, two different scenarios were considered; in the first scenario the gas produced was sold, in which case an extra capital cost of a pipeline construction for transportation onshore was considered, as well as transportation cost for such gas. In the second scenario, the produced gas was reinjected in the reservoir. Regarding oil prices, even though a constant price was considered for the entire life of the projects, different simulations were performed for different oil prices (30, 60, 80 and 100 USD/bbl respectively).

Regarding the volumetric calculation, it can be seen from Table 7 that the three prospects present a fairly similar size considering the best estimates (P50). The largest prospect is Prospect B, with a EUR P50 value of 878 MMbbl of oil and 1.427 TCF of associated gas, giving a best estimate value of 1,127 MMBOE. The lowest estimated volume corresponds to Prospect A, which has a EUR P50 value of 529 MMbbl of oil and 0.861 TCF of associated gas, giving a best estimate value of 678 MMBOE. Finally, Prospect C shows a result of EUR P50 of 802 MMbbl of oil and 1.303 TCF of associated gas, giving a best estimate value of 1,029 MMBOE. Another case was also studied, which implied the development of prospects B and C simultaneously, given that such locations are close. In this case, the best estimate of the total recoverable volume accounted for 2,434 MMBOE (1,861 MMbbl EUR oil and 3.030 TCF gas).

As it can be seen in the tornado chart presented in Fig. 18, the most influential variable in the reserves estimation is the area of the prospect, as expected, followed by the porosity and the recovery factor. They all have a positive correlation with resources, therefore when any of these variables increase, the reserves also increase. Both B_o and S_o are the variables that present the least influence in the volumetric estimation.

In Figs. 21 and 22, the different economic results of PV10 (IOC) and IRR are plotted for the Gas Injected and Gas Sold scenarios, respectively. In general terms, for higher prices PV10 increases, and in particular, the Gas Sold case results in higher PV10 values with respect to the case of gas injection. It can be seen that PV10 is negative in all cases when oil price is the lowest (30 USD/bbl). For the gas injection case, even a higher price of USD 60/bbl keeps PV10 below zero (and, accordingly, IRR below 10%), while for the gas sold case, developing the larger prospects (B and B+C) makes IRR to be equal to the hurdle rate of 10%. For a price of 80 USD/bbl, in the case of injected gas, only the larger prospects (B and B+C) make NPV positive, while for the gas sold case all the projects considered present a positive PV10. Finally, for the highest oil price considered (100 USD/bbl), all the cases present a positive PV10 value. Prospect A, which is the smallest, shows the lowest PV10 value in general, and the simultaneous development of Prospects B and C makes PV10 more than double with respect to developing those prospects separately.

Regarding IRR, it can also be observed that it increases as oil price rises, and in general IRR values are higher for the Gas Sold Case than for the Gas Injected case. These results are also presented in Fig. 23 for the particular case of Prospect A. For instance, for an oil price of 60 USD/bbl, if we take a discount rate of 5%, the resulting NPV for the Gas Sold case will be a positive value, whereas for the Gas Injected case NPV will be negative. Therefore, for the same oil price, admitted discount rates in Gas Sold scenarios are lower with respect to Gas Injection. Accordingly, for a fixed discount rate, Gas Sold projects admit lower prices for NPV to be positive.

Best estimate values of payout time are reduced as oil price increases, and in Table 9 is also shown that the best cases are associated to the development of Prospect B and B+C. Best estimates of MNCF vary between -4.5 and -26 Billion USD for the Gas Injected scenario and between -4.8 and -18.9 Billion USD in the Gas Sold case. Total costs per BOE produced are plotted in Fig. 24 and it can be seen that are between 32 and 40 USD/bbl. For the different cases, total costs per BOE are higher for the Gas Injected case. Also, the cost of producing each BOE is the highest for the smallest prospect (Prospect A), in both scenarios (Gas Sold and Gas Injected).

In particular, CAPEX structure presented in Fig. 25 shows that in both cases (Gas Sold and Gas Re-injected), the most important elements that contribute are the expenditures corresponding to the drilling of oil producers, representing more than 50% of the total CAPEX. These are followed by the costs related to FPSOs and subsea processing equipment (SURF). For the Gas Injected case, there are costs associated to gas producing wells which are not present in the Gas Sold case, and also well intervention costs are slightly higher, as expected. Gas Sold scenario presents an additional component of gas pipeline costs.

Government Take included in Table 9 refers to the “total take”, considering both ANCAP’s fraction and Government’s fraction itself. Government and Contractor's Take differ slightly between cases. However, Table 9 shows that higher values of Government Take are obtained in the Gas Sold case with respect to the Gas Injection case. Also, Government Take increases with oil price. Finally, the development of Prospects B and B+C simultaneously yield the highest value of Government Take.

Regarding the EMV results, the Gas Sold case is always more favorable than the Gas Injection case. For oil price scenarios of 30 and 60 USD/bbl, EMV values are lower than zero, and therefore none of the projects results feasible. For a higher oil price of 80 USD/bbl, the projects studied for Gas Injection are not feasible either; however, in the Gas Sold case, both the development of Prospect B and B+C (the largest prospects) result viable. Finally, for the highest-price scenario of 100 USD/bbl, the development of Prospect A is still not feasible in the Gas Injection scenario, while the rest of the projects present a positive EMV value. For the Gas Sold scenario, all the studied projects are profitable.

It is important to point out that the analogue fields located in Santos Basin are very prolific, with reported initial oil rates up to 40,000 bbl/d per well (Bruhn et. al 2017). However, given that wells in such fields have been producing for a relatively short period of time (a few years), it was decided to work on the history of Garoupa Field in Campos Basin, which dates back to the early 80s. Many technological improvements as well as cost optimization processes have been implemented since then in the petroleum industry; thus, this has a direct impact in the considered production profile and the accumulated production per well, impacting on the whole project.

This effect can also be demonstrated after performing a similar analysis with OOIP values of “Tupi Extended” Field in Santos Basin. In this case, PV10 value yields a negative result, while in the evaluation performed by a consulting firm contracted by the Brazilian petroleum agency, the best estimate of PV10 is positive (Gaffney, Cline & Associates 2010). This is coherent with the fact that in the evaluation carried out by such consulting firm, an initial oil rate value of 15,000 bbl/d was used, and cumulative oil production per well reached 45 MMbbl, more than seven times than the value obtained in the present study according to the best estimate result.

8. Conclusions

The largest prospect is Prospect B, with a EUR 2U value of 878 MMbbl of oil and 1.427 TCF of associated gas, giving a best estimate value of 1,127 MMBOE. The lowest estimated volume corresponds to Prospect A, which has a EUR 2U value of 529 MMbbl of oil and 0.861 TCF of associated gas, giving a best estimate value of 678 MMBOE. Finally, Prospect C shows a result of EUR 2U of 802 MMbbl of oil and 1.303 TCF of associated gas, giving a best estimate value of 1,029 MMBOE. Finally, the simultaneous development of prospects B and C gave a best estimate of total recoverable volume that accounted for 2,434 MMBOE (1,861 MMbbl EUR oil and 3.030 TCF gas).

The most influential variable in the reserves estimation is the area of the prospect, as expected, followed by the porosity and the recovery factor. They all have a positive correlation with resources, therefore when any of these variables increase, the reserves also increase. Both B_o and S_o are the variables that present the least influence in the volumetric estimation.

For an oil price of 100 USD/bbl, all cases studied yield a positive PV10, and for this oil price value only Prospect A in the Gas Injection case still presents a negative EMV. For oil prices of 80 USD/bbl, all Gas Sold cases show positive PV10 values, however, only the largest prospects (B and B+C) show a positive EMV. On the other hand, for this price of 80 USD/bbl considering the Gas Injection scenario, even though PV10 values obtained for Prospect B and B+C are greater than zero, all EMVs are negative values. Finally, for the lower prices considered (30 and 60 USD/bbl), none of the studied alternatives give favorable results in terms of PV10 and EMV. Consequently, in a situation like today's oil price, slightly over 60 USD/bbl, none of the projects is feasible.

Finally, it is important to mention that the production profile considered in this study was from an analogue field which development dates back to the early 80s and since then, many technological and costs improvements have taken place in the oil and gas industry all over the world. Therefore, the methodology presented with the probabilistic volumetric estimation of resources and subsequent probabilistic economic evaluation is considered adequate for the purpose of this work.

9. Nomenclature

A: Drainage area
b: decline constant
BOE: Barrels of oil equivalent
B_{gi}: initial gas formation volume factor
B_{oi}: Initial oil formation volume factor
CAPEX: Capital Expenses
DCA: Decline Curve Analysis
D_i: Nominal decline rate
EMV: Expected Monetary Value
EUR: Estimated Ultimate Recovery
FPSO: Floating Production Storage and Offloading
GIIP: Gas Initially In Place
GOR: Gas-Oil-Ratio
h: Reservoir average thickness
IOC: International Oil Company
IRR: Internal Rate of Return
Q: oil production rate after some time "t"
Q_i: initial oil production rate
MNCF: Maximum Negative Cashflow
NE: North East
NOC: National Oil Company
NPV: Net Present Value
NTG: Net-to-gross factor
NW: North West
OIIP: Oil Initially In Place
OPEX: Operating Expenses
PIIP: Petroleum Initially In Place
PoS: probability of geologic success
PRMS: Petroleum Resources Management System
PSC: Production Sharing Contract
PV10: Net Present Value at a discount rate of 10%
P_e: Probability of economic success
R: correlation coefficient value
RB: Reservoir barrels
RF: Recovery factor
scf: standard cubic feet
SE: South East
STB: Stock Tank Barrels
SURF: Subsea, Umbilical, Riser and Flowline
SW: South West
S_{oi}: Initial oil saturation
S_{wi}: Initial water saturation
TWT: Two-way time
Φ: Porosity

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