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Probabilistic Techno-Economic Appraisal of Prospective Hydrocarbon Resources in Five Turbidites, Offshore Uruguay

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Abstract

This paper presents a probabilistic techno-economic evaluation of several turbidite prospects recognized, through 3D seismic, in deep to ultra-deep water 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 in Uruguay's maritime zone after analyzing data from the world's deepest water-depth well (Raya-X1) drilled in 2016.

The estimated ultimate recovery of oil and gas was determined, for each prospect, by carrying out probabilistic resource analyses (Monte Carlo simulations) using 3D seismic and key parameters from analog turbidite fields located in sedimentary basins along the Atlantic margin. Black oil fluid was assumed and the production concept involves 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, 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. Considering a plausible base case of 20% ANCAP association and no incremental profit oil for the state, the results show that, for the biggest prospects, the breakeven oil price is situated near 60 USD/bbl. The analysis also shows that the smaller prospects would need to be developed as satellites of the nearby principal prospects in order to become attractive for development.

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 Uruguay Open Round licensing regime, may be interested in the exploration and imminent development of the Uruguayan offshore sedimentary basins.

**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 1988). Turbidites have also been a popular exploration target in places like West Africa and the southern region of North Falkland Basin, amongst others. At least five major analog turbidite prospects occur offshore Uruguay and these potential hydrocarbon traps are first evaluated in detail in the present study.

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, through the Raya-X1 well (Fig. 1). The well confirmed that the prospect was a good quality Cenozoic turbidite reservoir, but it did not contain hydrocarbons. One additional objective of that well was to collect detailed data from the reservoir, which was mapped with 3D seismic. This prospect was the first ever-drilled turbidite in the offshore of Uruguay and the well is a current world record in matters of water depth (Wood Group Mustang 2018).

![Figure 1—Offshore Uruguay 3D seismic and well data used in this paper](image)

The geological and geophysical database used in this paper comprises three 3D seismic surveys: UR13_3D, BG12_3D and TO12_3D, and well log data from three offshore wells: Lobo-X1 and Gaviotin-X1, drilled by Chevron in 1976, and Raya-X1, drilled by Total in 2016. The geographical location of these datasets is shown in Fig. 1.
This work is focused on five potential turbidite targets. Three of them are Cretaceous turbidites and are located within the area of the UR13_3D survey, one is a Cenozoic turbidite located within the area of the BG12_3D survey, while the last one is a Cretaceous turbidite located within the area of the TO12_3D survey.

The volumetric analysis required a detailed interpretation of the turbidite prospects that were selected for this study: Chafalote, Maspoli, Jasper, Emerald-Deep and Emerald (see Appendix A for further details) and their locations within the 3D seismic surveys used in this work are shown in Fig. 2.

After completing the probabilistic volumetric resource evaluation of each prospect, probabilistic economic analyses were performed. They considered the most updated fiscal terms of the applicable production-sharing contract, for offshore assets in Uruguay.

**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-X1 and Gaviotin-X1 were drilled by Chevron in 1976 (Fig. 1). These were the first exploratory wells drilled in the offshore of Uruguay, but despite of some gas indications in the wireline logs of Gaviotin-X1, both wells 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

![Figure 2—Map of the analyzed turbidite prospects](image-url)
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: eleven oil companies qualified, nineteen offers were received, there was competition for five areas and it resulted in the signature of eight new contracts, out of fifteen offered areas, with more than 1.5 billion USD as 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 km² of 3D seismic data.
- The acquisition of a large 3D Controlled Source Electromagnetics (CSEM) survey, with an approximate coverage of 13,000 km².
- Several piston core seabed samples were taken for geochemical analyses.
- Raya-X1 well was drilled.

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

At present, Uruguay offers an open round licensing regime, named "Uruguay Open Round", which allows blocks to be awarded every six months to oil companies that have qualified and submitted offers (ANCAP 2019a).

**Geological framework**

In the offshore of Uruguay there are three passive margin type sedimentary basins (Fig. 3): Punta del Este basin, Pelotas basin and Oriental del Plata basin (Morales et al. 2017a). Punta del Este basin, which encompasses the south-western portion of the margin, presents the main geological structures found in the offshore of Uruguay. They are associated to rift faulting during the South Atlantic break-up. In the north-eastern portion of the margin, which covers the southernmost part of the Pelotas basin, the rift sequence is not significant, it only presents some minor structures.
The sedimentary infill of these basins consists of sediments from three different phases: pre-rift, syn-rift and post-rift (passive margin). The passive margin phase starts in the Cretaceous and continues to the present (Conti et al. 2017). Due to the absence of significant deformation of the sedimentary sequences, the main hydrocarbon plays occur in stratigraphic traps, such as turbidites, basin floor fans, channels and pinch-outs. The recognizance of the turbidite prospects analyzed within this work required a previous sequence stratigraphy analysis of the main depositional sequences that comprise the sedimentary infill of the basins. From that analysis, different system tracts were defined in order to identify potential turbidites related to sea-level variations.

**Offshore Uruguay speculative petroleum systems**

For the sedimentary basins of the Uruguayan offshore, Morales et al. (2017b) and Morales (2013) proposed four speculative conventional petroleum systems that are based on analogies with other offshore basins as well as the onshore basins of Uruguay. They are:

A. **Pre-rift marine petroleum system.** It is restricted to the proximal sectors of the offshore basins and its petroleum system elements are:
   - Source Rocks: pre-rift marine Devonian and Permian oil-prone shales.
   - Reservoirs: pre-rift fluvial-deltaic and aeolian Permian sandstones.
   - Seals: pre-rift Permian marine shales, Mesozoic lacustrine shales and basalts of the syn-rift sequence.

B. **Syn-rift lacustrine petroleum system.** Its petroleum system elements are:
   - Source Rocks: syn-rift Early Cretaceous lacustrine shales.
Reservoirs: syn-rift Cretaceous alluvial conglomerates and sandstones, syn-rift lacustrine fans and fluvial-deltaic sandstones and post-rift shelfal sandstones and basin floor fans.
Seals: syn-rift lacustrine shales and volcanic rocks as well as post-rift regional marine shales of Paleocene age.

C. **Cretaceous post-rift marine petroleum system.** The elements of this petroleum system are:

- Source Rocks: post-rift Aptian-Albian and Turonian shales.
- Reservoirs: post-rift Cretaceous basin floor fans, slope fans, lowstand wedges and shelf-edge deltas.
- Seals: post-rift regional marine shales of Paleocene-Eocene age as well as upper Cretaceous shales.

D. **Cenozoic post-rift marine petroleum system.** Its petroleum system elements are:

- Reservoirs: post-rift Paleogene and Neogene sandstones corresponding to basin floor fans, lowstand wedges and deltaic and shelfal deposits.
- Seals: post-rift regional marine shales of Paleogene and Neogene age.

For the prospects analyzed in this paper, based on their location within the stratigraphic column and the location of the interpreted source rocks, the applicable petroleum system are: B', C' and D' (syn-rift lacustrine petroleum system, Cretaceous post-rift marine petroleum system and Cenozoic post-rift marine petroleum system respectively). Pre-rift rocks are not recognized in the studied areas; therefore the pre-rift marine petroleum system A' was discarded.

**Assumed reservoir fluid and offshore oil & gas indicators**

All the prospects analyzed in this paper are assumed to contain a black oil fluid with a density of 30° API, gas gravity is assumed equal to 0.8 (air = 1) and Gas Oil Ratio (GOR) was assumed to vary between 0 and 2,000 scf/STB. This choice of fluid properties is supported by the results of two independent fluid inclusions analyses, which found, in unwashed cuttings from Lobo-X1 and Gaviotin-X1 wells (Fig. 1), light oil inclusions of nearly 32° API (**Tavella and Wright 1996; Soto et al. 2016**).

From the analysis of Gaviotin-X1 wireline logs, two interesting Neutron-Density porosities crossovers (potential gas indications) within the Cretaceous sequence were recognized. The first one is located below 1,808 m (**Fig. 4**, highlighted in red), which corresponds to the Cretaceous-Tertiary boundary, and the second one is located below 2,150 m (**Fig. 5**, highlighted in red). In both cases, there is a shale interval at the top that act as a seal. From the petrophysical analysis it is deducted that gas quantities are not significant. This is due to the low bulk resistivities that imply high water saturations, and also because the intervals that present the crossover effects are not very thick.
Database of turbidite reservoir parameters

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). This database is entirely based on public information, it contains: field name, location data (country and sedimentary basin), reservoir age, water depth limits, reservoir depth, porosity ($\phi$), GOR, oil density, water saturation ($S_w$), area, gross thickness, net to gross ratio (NTG), net pay, recovery factor (RF) and initial oil formation volume factor ($B_{oi}$). For this paper, probability density functions (PDF) were found for NTG, $S_w$, GOR and RF parameters, by distribution fitting the presented values within the created database. The resultant distributions are shown in Fig. 6. They are the outcome of this process of distribution fitting the data and were considered for the evaluation of every single prospect.
Methodology for the probabilistic volumetric analysis

The probabilistic volumetric resource analyses consisted of Monte Carlo simulations that were carried out in Microsoft® Excel® spreadsheets running Palisade® @Risk® add-in.

The inputs of the created database of turbidites were used, as analogous, to support the parameters of PDFs for key reservoir variables used in the volumetric formula (Wright 2015; Cronquist 2001) for Estimated Ultimate Recovery of oil \((EUR_{oil})\):

\[
EUR_{oil} = \frac{6.29 \times GRV \times NTG \times \phi \times (1 - S_w)}{1,000,000 \times B_{oi}} \times RF
\]

Where:

- Gross Rock Volume (GRV) is expressed in \(m^3\) leading to an EUR_oil in million STB. The parameters required to define its PDF are obtained from the 3D seismic interpretation of the prospects. GRV was automatically computed, using the seismic interpreted surfaces that correspond to the top and base of the turbidite bodies. A maximum value is obtained directly from the entire volume interpreted in the seismic data, the P10 (optimistic) and P90 (conservative)
volumes are obtained by calculating the prospect GRV restricted to a delimitation polygon defined from the analysis of the seismic amplitude maps. For this variable, a LogNormal distribution was chosen.

- NTG is defined as a BETA distribution and it is constructed from values obtained from the previously analyzed turbidite reservoirs.
- $\phi$ is constructed with values that result from applying the relationships between porosity and sedimentary overburden published by Ehrenberg and Nadeau (2005) for sandstones (see Appendix B for further details). Its PDF is defined as a BETA distribution and its P10, P50 and P90 parameters are obtained from the mentioned publication. 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).
- $S_w$ is constructed with values obtained from the previously analyzed turbidite reservoirs and it is defined as a BETA distribution.
- RF is defined as a BETA distribution, it is constructed with values obtained from the previously analyzed turbidite reservoirs and it is truncated at 50%.
- $B_{oil}$ PDF is defined as a BETA distribution. Its 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 (see Appendix B for further details).

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

$$EUR_{\text{gas}} = \frac{EUR_{\text{oil}} \times GOR}{1,000,000}$$  \hspace{1cm} (2)

Where:

- GOR is expressed in scf/STB leading to a gas EUR in Tscf. Its PDF is defined as a BETA distribution and it is constructed with values obtained from the previously analyzed turbidite reservoirs. Additionally, it is truncated at 2,000 scf/STB because a black oil fluid was assumed.

The distribution types chosen are justified by the fact that, GRV is well defined by a LogNormal distribution (Liner 2016), and BETA distributions are quite versatile and can approximate very well the most popular distributions such as: Uniform, Triangular, Normal and Lognormal (Olea 2011).

A summary of the inputs used for the probabilistic volumetric analyses of the analyzed prospects are shown in the Appendix C.

**Methodology for probabilistic economic analysis**

After completing the probabilistic volumetric resource evaluation of each prospect, probabilistic economic analyses were performed considering the most updated fiscal terms of the applicable production sharing contract (PSC), for offshore assets in Uruguay (Appendix D). These analyses consisted of Monte Carlo simulations carried out in Microsoft Excel spreadsheets running Palisade @Risk add-in.

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.

The probabilistic economic analyses results includes, for each prospect, several key performance indicators such as: net present value (NPV), internal rate of return (IRR), maximum negative cash flow (MNCF), breakeven oil price (BE), 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 (CAPEX and OPEX, respectively) 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.

Finally, in order to create a ranking of prospects, the Expected Monetary Value (EMV) was determined for each prospect based on the probabilistic NPV estimates and the chance of geologic success ($P_g$).

**Oil Price**

Local oil sales price is stipulated in the PSC to be equal to the international price of a basket of oils with similar characteristics (Appendix D).

In the analyses performed for this paper the following oil price scenarios were considered:

- Fixed price 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% ("User Defined Price" in Fig. 7).
- Energy Information Administration (EIA) Low, Reference and High Brent oil price forecasts up to year 2050, extended with straight line trends up to year 2060.

![Historical and Forecasted Price of Brent Oil](image)

**Figure 7—Oil price forecast example**

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). 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, using the last 20 years of EIA forecasted data, up to year 2060, with straight line trends.

All the above-mentioned forecasts as well as the historical Brent oil price are shown in Fig. 7.
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, and a parity formula relating natural gas price to oil price.

In this paper the following assumptions were made for gas price computation:

- Regional gas price was assumed equal to 17.5 USD/MMBTU, which corresponds to an approximate average gas importation cost from Argentina.
- UK NBP gas price was set equal to 5.5 USD/MMBTU, which corresponds to the average NBP NG price between 1996 and 2017 (Ycharts 2019).
- HH gas price was set equal to 3 USD/MMBTU unless an EIA price forecast is selected, in that case, as it 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.
- The oil price dependent term in the formula used for natural gas price calculations is: 0.1*(Oil Price) – USD 3, and for its computation it uses the defined oil price scenario.

Taking into account the previous considerations, the assumed NG price formula is:

\[ NG\_price = \frac{HH\_NG\_price + 5.5 + 17.5 + [0.1*(Oil\_Price) - 3]}{4} \]  

(3)

Operating Expenditures

OPEX are divided into two categories: fixed and variable. Fixed OPEX is defined as a triangular distribution with a minimum value of USD 4 million/quarter, a most probable value of USD 5 million/quarter and a maximum value of USD 6 million/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 (Rystad Energy 2015). 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 1).

Table 1—Cost to produce one oil barrel in selected countries

<table>
<thead>
<tr>
<th>Country</th>
<th>CAPEX (USD/bbl)</th>
<th>OPEX (USD/bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>UK</td>
<td>21.8</td>
<td>30.7</td>
</tr>
<tr>
<td>Brazil</td>
<td>17.3</td>
<td>31.5</td>
</tr>
<tr>
<td>USA</td>
<td>21.5</td>
<td>14.8</td>
</tr>
<tr>
<td>Norway</td>
<td>24</td>
<td>12.1</td>
</tr>
<tr>
<td>Angola</td>
<td>18.8</td>
<td>16.6</td>
</tr>
<tr>
<td>Mexico</td>
<td>18.3</td>
<td>10.7</td>
</tr>
<tr>
<td>MIN:</td>
<td>17.3</td>
<td>10.7</td>
</tr>
<tr>
<td>AVG:</td>
<td>20.3</td>
<td>19.4</td>
</tr>
<tr>
<td>MAX:</td>
<td>24</td>
<td>31.5</td>
</tr>
</tbody>
</table>

Using the statistics from Table 1, variable OPEX is defined as a triangular distribution with a minimum value of 10.7 USD/bbl, a most probable value of 19.4 USD/bbl and a maximum value of 31.5 USD/bbl.

Finally, an additional variable OPEX cost of 1 USD/bbl of produced water (Botechia et al. 2016) is assumed for produced water treatment and disposal to the sea.
Capital Expenditures
The CAPEX required for the development of the prospects is divided into the following costs:

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

Drilling Expenditures. The proposed field development projects for the analyzed prospects include both vertical and horizontal wells. The exploratory, appraisal and injection wells were defined to be vertical, while production wells were defined to have a horizontal section. In order to estimate well costs, a simplified 'L' shaped well was considered, therefore the cost to drill a well was estimated as:

\[
Well \ cost = Rig.\ cost \times \left(\frac{vert.\ sec. + horiz.\ sec.}{average.drilling.rate}\right) \times \left(1 + A_1\right) \times A_2 + mob.demob.\ days
\]  

(4)

Where:

- **Rig.\ cost** is the average drillship cost per day. It is defined as a triangular distribution with a minimum of USD 200,000 per day, a most probable value of USD 250,000 per day and a maximum of USD 350,000 per day. These values are based on an IHS Markit (2019) report.
- **vert.\ sec.** is the vertical section drilled by the well and it is assumed equal to the average sedimentary overburden on the prospect, which was determined from the 3D seismic.
- **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 1,200 m, therefore, a horizontal section of 1,000 m was assumed for the production wells.
- **average.drilling.rate** is an average value for the 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.
- **A_1** is a contingency factor for total drilling days, it was set equal to 50%.
- **A_2** 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-X1 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, it was assumed equal to 40 days.

Once the wildcat 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 20% well cost reduction percentage was assumed for the appraisal wells. Production wells are defined to have an additional horizontal section and therefore will require more drilling days, which is translated into an additional cost. Despite of that, a well cost reduction percentage of 40% was assumed for production wells and 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 in order to account for that, a number of interventions per well was defined, for the simulations, and was set equal to 0.0450 interventions per quarter (0.18
interventions per year). This value is based on an analysis performed by Hauge and Horn (2005) for the case of production wells from the Troll field. 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 USD 5 million, which is a conservative average of what was reported by Small et al. (2015) for a case study in the Gulf of Mexico.

**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 USD/BOE, a most probable value of 5 USD/BOE and a maximum of 6 USD/BOE.

The cost of production processing (FPSO cost) was defined as a triangular distribution with a minimum of 4 USD/BOE, a most probable value of 5 USD/BOE and a maximum of 6 USD/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 2.

<table>
<thead>
<tr>
<th>Pipeline name</th>
<th>Location</th>
<th>Deepest Point (m)</th>
<th>Capacity (MMscf/d)</th>
<th>Diameter (in.)</th>
<th>Cost (million USD)</th>
<th>Length (km)</th>
<th>Cost/km (million USD)</th>
<th>References</th>
</tr>
</thead>
<tbody>
<tr>
<td>Medgaz</td>
<td>Mediterranean Sea</td>
<td>2,155</td>
<td>773.29</td>
<td>24 ID</td>
<td>1,017.0</td>
<td>210</td>
<td>4.843</td>
<td>de Lemos et al. (2015); PAC (2018a); d'Huart (2018)</td>
</tr>
<tr>
<td>Route 2</td>
<td>Brazil (Santos Basin)</td>
<td>2,233</td>
<td>459.03</td>
<td>24 OD</td>
<td>2,222.8</td>
<td>402</td>
<td>5.529</td>
<td></td>
</tr>
<tr>
<td>Route 3</td>
<td>Brazil (Santos Basin)</td>
<td>2,296</td>
<td>628.52</td>
<td>24 OD</td>
<td>1,526.0</td>
<td>355</td>
<td>4.299</td>
<td></td>
</tr>
</tbody>
</table>

With these cost references the cost per kilometer for a 24 in. gas pipeline from the prospect area to shore is defined as a triangular distribution with a minimum value of USD 4.299 million/km (the minimum value in Table 2), a most probable value of USD 4.843 million/km and a maximum value of USD 5.529 million/km (the maximum value in Table 2). The total cost of the pipeline required is therefore estimated as the product of the previous distribution by the total length of the required pipeline.

**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" (see Appendix D for further details). For this project the estimated abandonment cost was set equal to 5% of the capital expenditures.

**Exploratory approach**

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

- An initial basic exploratory sub-period of four years (Table 3). 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. In this sub-period, which has no mandatory drilling commitment, no exploratory wells are assumed to be drilled.
- After the basic exploratory sub-period, the supplementary sub-period A is chosen (see Fig. D-1). 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 3). After this moment the contract enters in the Field Development Planning (FDP) phase.

Table 3—Proposed schedule for the Exploration and Appraisal phases

<table>
<thead>
<tr>
<th>Year:</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phase:</td>
<td>Exp.</td>
<td>Exp.</td>
<td>Appraisal</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Field Development
The Field Development Plan is addressed on the eighth year (Table 4). 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.

Table 4—Proposed schedule for the development phases

<table>
<thead>
<tr>
<th>Year:</th>
<th>8</th>
<th>9</th>
<th>10</th>
<th>11</th>
<th>12</th>
<th>...</th>
<th>39</th>
<th>40</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phase:</td>
<td>FDP</td>
<td>Development</td>
<td></td>
<td>Production</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Production phase begins at the start of year 11. The successful appraisal wells (assumed equal to 1 out of 2) 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 oil production at a plateau, therefore production well drilling activities are phased according to the following schedule:

- 20% 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% are drilled during year 11 and are put in production at the start of year 12.
- 10% are drilled during year 12 and are put in production at the start of year 13.
- 10% 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.

Oil production type well. Since there is no hydrocarbon production history in Uruguay, published data from Campos and Santos basins fields was used in order to create analogous production profiles for use in the economic simulations. Oil production is assumed to present an exponential decline. Based on production rates reported in Bruhn et al. (2003) initial oil production rate \( q_{oi} \) 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. 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%. These values are based on analyses shown by Dumas et al. (2018) and Nascimento and Schiozer (2017). The nominal annual decline is then found using the formula shown in Eq. 5 (Wright 2015):

\[
D = -\ln(1 - D_e)
\]
In this analysis, a production well is kept active only if its oil production rate is greater than 100 bopd 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:

\[
q_w(t) = q_{oi} - q_o(t)
\]  

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

\[
q_g(t) = q_o(t) \cdot GOR
\]  

A synthetic production profile, from a hypothetical type well, is shown in Fig. 8. In this example the initial oil production rate is 10,976 bopd 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).

![Type well production profiles](image)

Figure 8—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 (type well \(N_{p30yr}\)), which according to the proposed field development schedule, would be the longest a well may produce under the same contract, therefore:

\[
\# \text{Wells} = \frac{\text{Prospect EUR}_{oil}}{\text{Type well } N_{p30yr}}
\]  

Produced water management. Drilling injection wells for water disposal would be too costly in field development projects of new hydrocarbon plays. Instead, in the presented development solutions, the produced water will be treated and disposed to the sea as commonly done in Campos fields (Souza et al. 2005; Nunes et al. 2011).

Produced gas management. The produced gas in Campos basin fields has several applications: gas flaring, internal consumption, use in gas lift, re-injection into the reservoir and flow to the shore through existing pipelines (Bruhn et al. 2017; Motta et al. 2005). 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. Since gas flaring is not a valid option in Uruguay (ANCAP 2019a), in this analysis only 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, which has a maximum design capacity of 174 MMscf/d (Wikipedia 2019; Gasoducto Cruz del Sur 2019).

It was assumed that 5% of the produced gas will be used for internal consumption at the FPSO regardless of the fact that produced gas is re-injected or sold. In the case of gas re-injection, the number of required gas injection wells, is determined by dividing the remaining gas production (95% of the total) by a hypothetical gas injection rate. The PDF for gas injection rate (per well) was assumed as a triangular distribution, and its parameters are based on gas injection values reported in the literature (Weathon and Manu 2012; Agrawal et al. 2016; Etuhoko and Lewis 2004; Silva et al. 2007), 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.

Field production. Field production is computed by aggregating single well productions, Fig. 9 shows an example of it.

![Field production](image)

**Figure 9—Example of annual field production**

**Economic Scenarios**
The economic proposal of an international oil company (IOC) interested in submitting a bid for an offshore area in Uruguay (Appendix D) must be 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 percentage 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 for light oils, X’ for heavy oils and Xg for natural gas). These variables must be between 0% and 70%.

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 a potential contractor, while the other, named Scenario 2, is a conservative case.

**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. ANCAP's maximum association percentage is assumed equal to the minimum stipulated value (A=20%), while incremental profit
oil, which is based on a predefined recovery factor (Table D-1), for both the case of oil and natural gas is assumed equal to 0% (X=X'=Xg=0%). This scenario is considered quite probable and it is justified by the current long lasting low oil prices and the modest industry interest in the Uruguayan offshore prospectivity, where currently there are no contracts in force, while in 2014 there were ten (Ferro et al. 2017).

**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 assumes a maximum ANCAP association percentage equal to 30% (A=30%) and incremental profit for oil and gas production equal to 25% (X=X'=Xg=25%).

**Performance Indicators**

During the economic simulations various key performance indicators were calculated, some of them are: NPV for the IOC with a 10% discount rate (NPV10_IOC), IRR for the IOC (IRR_IOC), MNCF the IOC will face, Lifting Entitlement for the IOC, Government Take and the project's NPV with a 10% discount rate.

NPV10_IOC is calculated from the IOC's quarterly after tax cash flows discounted with a 2.5% quarterly (10% annual) discount rate.

The MNCF for the 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 "corresponds to the reserves a company can book". The Lifting Entitlement of an IOC, 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, the project NPV10 is an indicator that measures the profitability of the Project, which is very useful because it is independent of the economic arrangement established in the PSC for each party.

**Economic simulations**

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

**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:

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

**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, 60, 70, 80, 90, 100 and 140 USD/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.

**Sensitivity to the offered economic variables.** 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 (for oil and gas production). These sensitivity analyses were only performed for Chafalote. They are intended to show how the offered economic variables affect the economics of a project. For all these analyses oil price was fixed at 70 USD/bbl and one variable was varied at a time while the rest were kept constant.

**Expected Monetary Value.** The EMV was determined for each prospect based on probabilistic NPV estimates and considering the estimations of \(P_g\) shown on the Appendix A. This key indicator was used to create a ranking of prospects, which is based on the following assumptions:

- Oil and gas prices are assumed to be equal to the EIA Reference forecasts.
- Economic offer Scenario 1 was selected, which is considered more probable for future contracts.

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 and the other one is the probability of economic success \((P_e)\). 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:

\[
P_e = \frac{\text{Amount of simulations with } NPV10\_IOC \geq 0}{\text{Total number of simulations run}} \times 100
\]  

The decision tree used to calculate the EMV for drilling an exploratory well in a prospect is shown in Fig. 10. The first chance node is related to the \(P_g\), 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 of the field \((NPV10\_IOC \geq 0)\).

![Decision tree for drilling an exploratory well on a prospect](image)

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

\[
EMV_{IOC} = (1 - P_g) \times (\text{wildcat well cost}) + P_g \times (P_e \times NPV10\_IOC + (1 - P_e) \times (\text{appraisal wells cost}))
\]  

(10)
Results

This section presents the results of the volumetric and economic analyses of the turbidite prospects analyzed in this paper. As mentioned earlier, all the analyses consisted of Monte Carlo simulations, each one with 10,000 iterations and using Latin Hypercube sampling.

Volumetric Results

Monte Carlo volumetric simulations were run, for every single prospect. A summary of the inputs used for the probabilistic volumetric analyses of the analyzed prospects are shown in the Appendix C.

The results of these simulations are volumes, which according to the Petroleum Resources Management System (SPE 2018), must be classified as "Prospective Resources". A summary of the calculated resources is shown in Table 5:

<table>
<thead>
<tr>
<th>Prospect</th>
<th>Low Estimate (1U)</th>
<th>Best Estimate (2U)</th>
<th>High Estimate (3U)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chafalote</td>
<td>759.82</td>
<td>1,828.47</td>
<td>4,020.55</td>
</tr>
<tr>
<td>Maspoli</td>
<td>905.06</td>
<td>2,224.96</td>
<td>4,880.26</td>
</tr>
<tr>
<td>Jasper</td>
<td>103.61</td>
<td>257.24</td>
<td>566.84</td>
</tr>
<tr>
<td>Emerald-Deep</td>
<td>54.55</td>
<td>140.12</td>
<td>330.99</td>
</tr>
<tr>
<td>Emerald</td>
<td>60.25</td>
<td>175.59</td>
<td>468.88</td>
</tr>
</tbody>
</table>

Economic Results

Several probabilistic economic analyses were run, through Monte Carlo simulations, for various oil price scenarios as well as for the previously defined economic offer scenarios.

Table 6 shows some simulation results, for Chafalote and Maspoli, which are independent of the oil price scenario and of the offered economic variables. In those prospects the gas management strategy is to export 95% of the produced gas through a gas pipeline (to be constructed) to the city of Montevideo, while the remaining 5% is used for internal consumption at the FPSO.

Table 6—Chafalote and Maspoli field development statistics

<table>
<thead>
<tr>
<th>Variable</th>
<th>Chafalote</th>
<th>Maspoli</th>
</tr>
</thead>
<tbody>
<tr>
<td># Production Wells</td>
<td>18</td>
<td>21</td>
</tr>
<tr>
<td>Max. Field Oil production (BOPD)</td>
<td>121,178</td>
<td>140,049</td>
</tr>
<tr>
<td>Max. Field Water production (BWPD)</td>
<td>192,607</td>
<td>226,377</td>
</tr>
<tr>
<td>Max. Gas production (MMscf/d)</td>
<td>44.7</td>
<td>52.3</td>
</tr>
<tr>
<td>CAPEX (million USD)</td>
<td>12,762.1</td>
<td>13,621.1</td>
</tr>
<tr>
<td>OPEX (million USD)</td>
<td>14,878.8</td>
<td>15,756.8</td>
</tr>
<tr>
<td>CAPEX/BOE (USD/BOE)</td>
<td>13.05</td>
<td>12.04</td>
</tr>
<tr>
<td>OPEX/BOE (USD/BOE)</td>
<td>14.80</td>
<td>14.72</td>
</tr>
<tr>
<td>TOTAL_COST/BOE (USD/BOE)</td>
<td>29.06</td>
<td>27.84</td>
</tr>
<tr>
<td>Exp. Well Cost (million USD)</td>
<td>100.16</td>
<td>46.69</td>
</tr>
<tr>
<td>Prod. Well Cost (million USD)</td>
<td>66.92</td>
<td>34.83</td>
</tr>
<tr>
<td>Gas Pipeline Cost (million USD)</td>
<td>1709.1</td>
<td>1823.0</td>
</tr>
</tbody>
</table>

For the remaining prospects, Jasper, Emerald-Deep and Emerald, gas management strategy is to re-inject 95% of the produced gas into the reservoir. Table 7 shows some of their simulation results.
After the completion of all the single prospect analyses and based on the prospects location, an additional study case was considered, and referenced as Emerald-Complex. It accounts for the case that a wildcat well drilled through Jasper, drilled at a location that also tests Emerald-Deep and Emerald reservoirs, results in a discovery and finds additional hydrocarbons in those upper prospects (Fig. 11).

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. This probabilistic aggregation led to the prospective resources results shown in Table 8.

Table 8—Prospective resources of Emerald-Complex

<table>
<thead>
<tr>
<th></th>
<th>Oil (million STB)</th>
<th>Associated Gas (million BOE)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1U</td>
<td>2U</td>
</tr>
<tr>
<td></td>
<td>3U</td>
<td>1U</td>
</tr>
<tr>
<td>Exp. Well Cost</td>
<td>97.03</td>
<td>112.40</td>
</tr>
<tr>
<td>Inj. Well Cost</td>
<td>52.76</td>
<td>61.12</td>
</tr>
<tr>
<td>Prod. Well Cost</td>
<td>65.04</td>
<td>75.34</td>
</tr>
<tr>
<td>CAPEX/BOE (USD/BOE)</td>
<td>14.81</td>
<td>17.87</td>
</tr>
<tr>
<td>OPEX/BOE (USD/BOE)</td>
<td>20.63</td>
<td>26.88</td>
</tr>
<tr>
<td>TOTAL_COST/BOE (USD/BOE)</td>
<td>38.90</td>
<td>44.96</td>
</tr>
<tr>
<td>Exp. Well Cost (million USD)</td>
<td>97.03</td>
<td>112.40</td>
</tr>
<tr>
<td>Inj. Well Cost (million USD)</td>
<td>52.76</td>
<td>61.12</td>
</tr>
<tr>
<td>Prod. Well Cost (million USD)</td>
<td>65.04</td>
<td>75.34</td>
</tr>
</tbody>
</table>

Table 9 shows some development statistics for this particular study case.
Table 9—Emerald-Complex development statistics

<table>
<thead>
<tr>
<th>Variable</th>
<th>P90</th>
<th>P50</th>
<th>P10</th>
</tr>
</thead>
<tbody>
<tr>
<td># Prod. Wells</td>
<td>7</td>
<td>17</td>
<td>34</td>
</tr>
<tr>
<td>Max. Field Oil production (BOPD)</td>
<td>66,247.4</td>
<td>107,516.4</td>
<td>174,734.1</td>
</tr>
<tr>
<td>Max. Field Water production (BW/PD)</td>
<td>81,383.2</td>
<td>173,145.2</td>
<td>313,838.6</td>
</tr>
<tr>
<td>Max. Gas production (MMscf/d)</td>
<td>30.61</td>
<td>57.07</td>
<td>102.74</td>
</tr>
<tr>
<td>CAPEX (million USD)</td>
<td>7,058.48</td>
<td>10,968.86</td>
<td>17,281.49</td>
</tr>
<tr>
<td>OPEX (million USD)</td>
<td>7,128.88</td>
<td>13,498.24</td>
<td>23,656.96</td>
</tr>
<tr>
<td>CAPEX/BOE (USD/BOE)</td>
<td>14.44</td>
<td>16.33</td>
<td>20.42</td>
</tr>
<tr>
<td>OPEX/BOE (USD/BOE)</td>
<td>15.85</td>
<td>20.33</td>
<td>25.65</td>
</tr>
<tr>
<td>TOTAL_COST/BOE (USD/BOE)</td>
<td>31.46</td>
<td>37.05</td>
<td>43.96</td>
</tr>
<tr>
<td>Exp. Well Cost (million USD)</td>
<td>90.19</td>
<td>104.48</td>
<td>123.47</td>
</tr>
<tr>
<td>Inj. Well Cost (million USD)</td>
<td>48.86</td>
<td>56.37</td>
<td>66.61</td>
</tr>
<tr>
<td>Prod. Well Cost (million USD)</td>
<td>60.94</td>
<td>70.59</td>
<td>83.42</td>
</tr>
<tr>
<td>Gas Pipeline Cost (million USD)</td>
<td>1572.4</td>
<td>1683.4</td>
<td>1807.3</td>
</tr>
</tbody>
</table>

**Sensitivity to EIA oil price forecasts.** The NPV10 and IRR indicators (for an IOC) that resulted of the sensitivity analyses carried out during each economic evaluation, performed to the EIA forecasts of future oil and gas prices, are included in Appendix E. From these analyses it can be concluded 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 (Scenario 1 and Scenario 2). Regarding the EIA Low oil price scenario, the simulations show that for that case none of the prospects are profitable because 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 (see Figs. E-1 through E-6).

Table 10 shows a brief summary of other key performance indicators (average government take and average IOC entitlement), which were obtained during the techno-economic evaluation of the studied prospects. In these tables these indicators are shown for the two economic scenarios considered within this paper. 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 10—Average Government Take and IOC Entitlement for the analyzed prospects

<table>
<thead>
<tr>
<th>Prospect</th>
<th>Scenario 1 Average Government Take</th>
<th>Scenario 1 Average IOC Entitlement</th>
<th>Scenario 2 Average Government Take</th>
<th>Scenario 2 Average IOC Entitlement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chalvate</td>
<td>52.8%</td>
<td>69.1%</td>
<td>71.8%</td>
<td>50.1%</td>
</tr>
<tr>
<td>Maspoh</td>
<td>53.3%</td>
<td>68.5%</td>
<td>72.2%</td>
<td>49.4%</td>
</tr>
<tr>
<td>Jasper</td>
<td>51.2%</td>
<td>71.2%</td>
<td>70.4%</td>
<td>52.9%</td>
</tr>
<tr>
<td>Emerald-Deep</td>
<td>50.3%</td>
<td>72.2%</td>
<td>69.6%</td>
<td>54.1%</td>
</tr>
<tr>
<td>Emerald</td>
<td>50.8%</td>
<td>71.6%</td>
<td>70.0%</td>
<td>53.5%</td>
</tr>
<tr>
<td>Emerald-Complex</td>
<td>52.6%</td>
<td>69.6%</td>
<td>71.6%</td>
<td>50.9%</td>
</tr>
</tbody>
</table>

**Averages:** 51.8% 70.3% 71.0% 51.8%

**Sensitivity to fixed oil price scenarios.** The analyses performed for the different fixed oil price scenarios were used to determine the breakeven oil price percentiles P90, P50 and P10 (BE_90, BE_50 and BE_10 respectively) for an IOC. The results of these analyses are summarized in Table 11.
Table 11—Breakeven oil price results for the analyzed prospects

<table>
<thead>
<tr>
<th>Prospect</th>
<th>Scenario 1</th>
<th>Scenario 2</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>BE_90 (USD/bbl)</td>
<td>BE_50 (USD/bbl)</td>
</tr>
<tr>
<td>Chafalote</td>
<td>53.80</td>
<td>62.63</td>
</tr>
<tr>
<td>Maspoli</td>
<td>51.16</td>
<td>59.20</td>
</tr>
<tr>
<td>Jasper</td>
<td>57.99</td>
<td>76.61</td>
</tr>
<tr>
<td>Emerald-Deep</td>
<td>66.36</td>
<td>83.59</td>
</tr>
<tr>
<td>Emerald</td>
<td>63.62</td>
<td>78.70</td>
</tr>
<tr>
<td>Emerald-Complex</td>
<td>59.64</td>
<td>69.47</td>
</tr>
</tbody>
</table>

Considering the plausible Scenario 1 base case, for the largest prospects (Maspoli and Chafalote), the average breakeven oil price (P50 percentile) is situated near 60 USD/bbl, while for the smallest prospects, the average breakeven oil price is situated near 80 USD/bbl (Table 11). 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 (P50 percentile) of 69.5 USD/bbl, while the average breakeven oil price for its ungrouped prospects is 79.6 USD/bbl. Furthermore, for a higher economic offer for the Uruguayan State, the average breakeven oil prices are shifted upwards. This shifting is around 11 USD/bbl for the economic offer Scenario 2 case (Figs. F-1 through F-6).

**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, considering only the case of Chafalote, were performed for each one of these variables.

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.

**Sensitivity to ANCAP’s maximum association percentage (A).** The assumptions made for this analysis were: zero incremental profit oil percentage for the State and oil price was fixed at 70 USD/bbl without escalation. The results for NPV10_IOC and IRR_IOC are shown in Fig. 12.
Fig. 12a 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 since a change in ANCAP's maximum association percentage does not affect the profitability for the IOC.

This analysis reveals that offering a high association percentage for ANCAP, such as 40%, would increasingly reduce the NPV10_IOC. However, in case of high competition for winning the lease area, IOCs can significantly increase their total bid score (Eq. D-1) by offering the largest possible ANCAP share (40%, see Appendix D). 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.

**Sensitivity to incremental profit oil for light oil production (X).** The assumptions made for the sensitivity analysis that was performed to the offered incremental profit oil for the case of light oil production were: zero incremental profit oil for the State for produced gas (Xg=0%), ANCAP's maximum association percentage was set equal to the minimum bid threshold of 20% and oil price was fixed at 70 USD/bbl without escalation. The results for NPV10_IOC and IRR_IOC are shown in Fig. 13.

![Figure 13—Chafalote sensitivity to X](image)

In Fig. 13 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 a fixed 70 USD/bbl oil price scenario, it is highly risky for the IOC to offer an X greater than 20% for the area, because that would lead to a 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 the prospect.

**Sensitivity to incremental profit oil for gas production (Xg).** The assumptions made for the sensitivity analysis that was performed to the offered incremental profit oil for the State for the case of gas production are: zero incremental profit oil for the State (X=0%), 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 Fig. 14.
In Fig. 14 it is observed that both NPVIOC and IRR_IOC are almost unaffected by the offered Xg. This is 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 (Eq. D-1).

**Final ranking of prospects based on EMV and associated IRRs.** To conclude this paper, a ranking of the studied prospects, based on their EMVs, is presented in Table 12. This ranking is based on the results obtained for the economic simulations performed considering the EIA Reference oil and gas price forecasts and the economic offer Scenario 1.

<table>
<thead>
<tr>
<th>Prospect</th>
<th>Best Estimate EMV (million USD)</th>
<th>Best Estimate IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maspoli</td>
<td>1,520.45</td>
<td>19.82%</td>
</tr>
<tr>
<td>Chafalote</td>
<td>800.19</td>
<td>18.62%</td>
</tr>
<tr>
<td>Jasper</td>
<td>-16.76</td>
<td>15.87%</td>
</tr>
<tr>
<td>Emerald</td>
<td>-25.68</td>
<td>15.07%</td>
</tr>
<tr>
<td>Emerald-Deep</td>
<td>-67.42</td>
<td>13.97%</td>
</tr>
</tbody>
</table>

**Conclusions**

Technical and economic analyses were run to appraise five turbidite prospects recognized in the Offshore of Uruguay. The probabilistic volumetric evaluation results (Table 5) show that two of the prospects present a prospective resources best estimate of near 2 billion barrels of oil and 1 Tscf of associated gas.

The sensitivity analyses, done during each economic evaluation, 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 show that for that case none of the prospects are profitable.

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 10). 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 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 USD/bbl, while for the smallest prospects, the average breakeven oil price is situated near 80 USD/bbl (Table 11). The analysis also shows that the smaller prospects would need to be developed, as satellites of the nearby principal prospects in order to become attractive for development. For a higher economic offer for the Uruguayan State, the average breakeven oil prices are shifted upwards. This shifting is around 11 USD/bbl for the economic offer Scenario 2 case.

As the economic offer for the Uruguayan State improves, the NPV10 and IRR for the IOC reasonably 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. Additionally, it can be demonstrated that for the case of a dry gas discovery Xg would be the most sensitive variable, while X' would be the most sensitive one in the case of a heavy oil discovery.

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, an IOC may offer an amount of working units greater than the predefined minimum for the area. This will help to increase its bid's probability of success and it also creates a valuable opportunity in order to reduce uncertainty in the $P_g$ estimate, which is an important variable when it comes the time to decide whether the project's updated EMV outcome of the exploration effort will merit further appraisal investments.

**Acknowledgements**

The authors would like to thank ANCAP, for the permission to use the seismic and well data that was required for this paper.

**References**


7. Botechia, V.E., Correia, M.G. and Schiozer, D.J. 2016. A Model-Based Production Strategy Selection Considering Polymer Flooding in Heavy Oil Field Development. Presented at the SPE Trinidad and Tobago Section Energy Resources Conference, Port of Spain, Trinidad and Tobago, 13–15 June. SPE-180838-MS. https://doi.org/10.2118/180838-MS


Appendix A

Prospects descriptions

Chafalote

Chafalote was recognized in the TO12_3D seismic survey (location shown in Fig. 2), and completely lies in the Pelotas basin. It is 375 km from Montevideo, the average water depth in this area is around 2,750 m and the average reservoir true vertical depth is 7,200 m.

Regarding the proposed petroleum system (Fig. A-1), 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.

Chafalote presents a chance of geologic success of 17.64% (Table A-1). 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 50% because it is a Cretaceous seal. Finally, trap probability is 70% because it is a combined trap with a clear seismic amplitude anomaly mapped with 3D seismic.
Maspoli was recognized in the BG12_3D seismic survey (location shown in Fig. 2), and completely lies in the Punta del Este basin. It is 400 km from Montevideo, the average water depth in this area is around 3,325 m and the average reservoir true vertical depth is 5,162 m. The volume of this prospect may be greater than what was interpreted for this paper because it is constrained by the seaward extension of its 3D survey (Fig. 2).

Regarding the proposed petroleum system (Fig. A-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.

Maspoli presents a chance of geologic success of 23.33% (Table A-2). 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

<table>
<thead>
<tr>
<th>Probability of Geologic Success</th>
<th>Probability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrocarbon generation</td>
<td>80%</td>
</tr>
<tr>
<td>Migration &amp; timing</td>
<td>90%</td>
</tr>
<tr>
<td>Reservoir</td>
<td>70%</td>
</tr>
<tr>
<td>Seal</td>
<td>50%</td>
</tr>
<tr>
<td>Trap</td>
<td>70%</td>
</tr>
<tr>
<td>$P_g$</td>
<td>17.64%</td>
</tr>
</tbody>
</table>

Table A-1—Chafalote probability of geologic success

Figure A-2—Seismic section along Maspoli with interpreted petroleum system elements (courtesy of ANCAP)
reservoir is present is 90%. Seal probability is 90% because there are clear Miocene shales on top acting as seal. Finally, trap probability is 60% because it is a pure stratigraphic trap and it has a clear seismic amplitude anomaly mapped with 3D seismic.

<table>
<thead>
<tr>
<th></th>
<th>Probability of Geologic Success</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrocarbon generation</td>
<td>80%</td>
</tr>
<tr>
<td>Migration &amp; timing</td>
<td>60%</td>
</tr>
<tr>
<td>Reservoir</td>
<td>90%</td>
</tr>
<tr>
<td>Seal</td>
<td>90%</td>
</tr>
<tr>
<td>Trap</td>
<td>60%</td>
</tr>
<tr>
<td>( P_g )</td>
<td>23.33%</td>
</tr>
</tbody>
</table>

Table A-2—Maspoli probability of geologic success

**Jasper**

Jasper was recognized in the UR13 3D seismic survey (location shown in *Fig. 2*), and completely lies in the Punta del Este basin. It is 345 km from Montevideo, the average water depth in this area is around 1,300 m and the average reservoir true vertical depth is 5,597 m.

Regarding the proposed petroleum system (*Fig. A-3*), 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.

![Seismic section along Jasper with interpreted petroleum system elements (courtesy of ANCAP)](image)

Jasper presents a chance of geologic success equal to 17.64% (*Table A-3*). 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 70%. 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 mapped with 3D seismic.

Table A-3—Jasper probability of geologic success

<table>
<thead>
<tr>
<th>Factor</th>
<th>Probability of Geologic Success</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrocarbon generation</td>
<td>80%</td>
</tr>
<tr>
<td>Migration &amp; timing</td>
<td>90%</td>
</tr>
<tr>
<td>Reservoir</td>
<td>70%</td>
</tr>
<tr>
<td>Seal</td>
<td>50%</td>
</tr>
<tr>
<td>Trap</td>
<td>70%</td>
</tr>
<tr>
<td>$P_g$</td>
<td>17.64%</td>
</tr>
</tbody>
</table>

Emerald-Deep

Emerald-Deep was recognized in the UR13 3D seismic survey (location shown in Fig. 2), and completely lies in the Punta del Este basin. It is 345 km from Montevideo, the average water depth in this area is around 1,350 m and the average reservoir true vertical depth is 5,167 m.

Regarding the proposed petroleum system (Fig. A-4), 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.

Emerald-Deep presents a chance of geologic success equal to 17.64% (Table A-4). 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 70%. 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.

Table A-4—Emerald-Deep probability of geologic success

<table>
<thead>
<tr>
<th>Pg: Probability of Geologic Success</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrocarbon generation</td>
<td>80%</td>
</tr>
<tr>
<td>Migration &amp; timing</td>
<td>90%</td>
</tr>
<tr>
<td>Reservoir</td>
<td>70%</td>
</tr>
<tr>
<td>Seal</td>
<td>50%</td>
</tr>
<tr>
<td>Trap</td>
<td>70%</td>
</tr>
<tr>
<td>Pg</td>
<td>17.64%</td>
</tr>
</tbody>
</table>

Emerald

Emerald was recognized in the UR13_3D seismic survey (location shown in Fig. 2), and completely lies in the Punta del Este basin. It is 345 km from Montevideo, the average water depth in this area is around 1,350 m and the average reservoir true vertical depth is 5,100 m.

Regarding the proposed petroleum system (Fig. A-5), 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.

Figure A-5—Seismic section along Emerald with interpreted petroleum system elements (courtesy of ANCAP)
Emerald presents a chance of geologic success equal to 24.7% (Table A-5). 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 70% 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.

**Table A-5—Emerald probability of geologic success**

<table>
<thead>
<tr>
<th>Pg: Probability of Geologic Success</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrocarbon generation</td>
</tr>
<tr>
<td>Migration &amp; timing</td>
</tr>
<tr>
<td>Reservoir</td>
</tr>
<tr>
<td>Seal</td>
</tr>
<tr>
<td>Trap</td>
</tr>
<tr>
<td>( P_g = )</td>
</tr>
</tbody>
</table>
Appendix B

Estimation of formation volume factor and porosity

Formation Volume Factor

In order to define a realistic probability distribution function for the initial formation volume factor \((B_{oi})\), the Levitan and Murtha (1999) correlation for formation volume factor at the bubble point pressure \((B_{ob})\) was considered (Eq. B-1).

\[
B_{ob} = 1 + 0.0005 \times GOR \times \left( \frac{\gamma_g}{\gamma_o} \right)^{0.25} + \frac{0.0004 \times (T_r - 60)}{\gamma_o \times \gamma_g}
\]  
(B-1)

Where \(T_r\) is the reservoir temperature expressed in °F.

In order to apply Eq. B-1 the following assumptions were made:

- **Average reservoir temperature was estimated as:**
  \[
  T_r(°C) = T_{sb} + \frac{30°C}{\text{km}} \times h_{sed}
  \]  
(B-2)

Where:

\(\Rightarrow h_{sed}\) is the sedimentary overburden in km.

\(\Rightarrow\) Seabed temperature \(T_{sb}\) is obtained from the World Ocean Atlas 2013 (Locarnini et al. 2013) at the nearest available data point to each prospect.

\(\Rightarrow\) Geothermal gradient was assumed equal to 30 °C/km, which is the worldwide average temperature gradient.

- Oil density was assumed equal to 30°API \(\Rightarrow \gamma_o = \frac{141.5}{121.5 + 30} \equiv 0.93\)

- Gas gravity \(\gamma_g\) was assumed equal to 0.8 (air=1)

- Reservoir pressure was assumed greater than bubble point pressure \((p_r > p_b)\) and oil compressibility \((c_o)\) was assumed negligible \(\Rightarrow B_o \equiv B_{ob}\)

Applying Levitan and Murtha (1999) correlation for \(B_{ob}\) with the previous assumptions:

\[
B_o \equiv B_{ob} = 1 + 0.0005 \times GOR \times \left( \frac{0.8}{0.93} \right)^{0.25} + \frac{0.0004 \times (T_{sb} + 30 \times h_{sed} - 60)}{0.93 \times 0.8}
\]  
(B-3)

Porosity

Several authors have analyzed the variation of rock porosity with burial depth (Ehrenberg and Nadeau 2005; Schmoker and Gautier 1988). With increasing burial depth, porosities tend to decrease due to the diagenetic processes that occurs (increase in pressure and temperature, amongst others).

In order to create realistic porosity distributions the results from Ehrenberg and Nadeau (2005) for sandstones are taken into account.

Considering the average P90, P50 and P10 values, from the sandstones datasets they analyzed (Table 1 from their paper), the graph shown in Fig. B-1 is constructed.
Taking the second order polynomial approximation that best fits the points from the previous graph, it follows that:

\[
\begin{align*}
\phi_{P90} &= -0.0917\cdot h_{sed}^2 - 0.8773\cdot h_{sed} + 14.019 \\
\phi_{P50} &= -0.0191\cdot h_{sed}^2 - 2.2925\cdot h_{sed} + 23.457 \\
\phi_{P10} &= -0.0636\cdot h_{sed}^2 - 1.863\cdot h_{sed} + 31.309
\end{align*}
\]  

Where \( h_{sed} \) is the sedimentary overburden expressed in km.

The presented equations (Eq. B-3 through B-5) were validated against measured reservoir data from offshore Uruguay:

- The turbidite drilled by Raya-X1 well has an average sedimentary overburden of approximately 2.210 km, therefore:

  \[
  \begin{align*}
  \phi_{P90} &= -0.0917 \times (2.210)^2 - 0.8773 \times (2.210) + 14.019 = 11.63\% \\
  \phi_{P50} &= -0.0191 \times (2.210)^2 - 2.2925 \times (2.210) + 23.457 = 18.3\% \\
  \phi_{P10} &= -0.0636 \times (2.210)^2 - 1.863 \times (2.210) + 31.309 = 26.88\%
  \end{align*}
  \]

  For this particular case, and considering that the drilled reservoir presented an average effective porosity (PHIE) equal to 24%, these equations lead to conservative results since the average porosity value is closer to the P10 percentile of the estimated porosity, however the average effective reservoir porosity does lie within the estimated porosity range.

- From the petrophysical analysis of Gaviotin-X1 well, and particularly for the intervals that present the gas effect on porosity (Fig. 4 and Fig. 5), the histogram of PHIE shown in Fig. B-2 was created.
In this well, the seabed is at 81.4 m, therefore the sedimentary overburden of the analyzed intervals are 1.727 km and 2.069 km.

In the first interval (zone A in Fig. B-2) the estimated porosity range using the proposed correlation is:

\[
\phi_{p90} = -0.0917 \times (1.727)^2 - 0.8773 \times (1.727) + 14.019 = 12.23\% \\
\phi_{p50} = -0.0191 \times (1.727)^2 - 2.2925 \times (1.727) + 23.457 = 19.44\% \\
\phi_{p10} = -0.0636 \times (1.727)^2 - 1.863 \times (1.727) + 31.309 = 27.9\%
\]

In the second interval (zone B in Fig. B-2) the estimated porosity range using the proposed correlation is:

\[
\phi_{p90} = -0.0917 \times (2.069)^2 - 0.8773 \times (2.069) + 14.019 = 11.81\% \\
\phi_{p50} = -0.0191 \times (2.069)^2 - 2.2925 \times (2.069) + 23.457 = 18.63\% \\
\phi_{p10} = -0.0636 \times (2.069)^2 - 1.863 \times (2.069) + 31.309 = 27.18\%
\]

In these two reservoir intervals of Gaviotin-X1 well, the effective porosity range (presented at the legend of Fig. B-2) mostly lies between the best estimate and the optimist values, therefore the presented equations (Eq. B-3 through B-5) can be used for the identified reservoirs in this well and they even cover more pessimistic scenarios.
## Appendix C

**Inputs for the volumetric evaluation of the prospects**

### Chafalote

Table C-1—Reservoir and fluid properties used for the volumetric analysis of Chafalote

<table>
<thead>
<tr>
<th>Parameter</th>
<th>MIN</th>
<th>Low Estimate</th>
<th>Best Estimate</th>
<th>High Estimate</th>
<th>MAX</th>
<th>Distribution Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>GRV (m³)</td>
<td>0</td>
<td>17,798,080,300</td>
<td>22,643,884,159</td>
<td>28,809,033,400</td>
<td>39,353,639,500</td>
<td>LogNormal</td>
</tr>
<tr>
<td>NTG (%)</td>
<td>0</td>
<td>34.8%</td>
<td>66.6%</td>
<td>90%</td>
<td>100%</td>
<td>Beta</td>
</tr>
<tr>
<td>δ (%)</td>
<td>0</td>
<td>7.9%</td>
<td>12.5%</td>
<td>21.9%</td>
<td>48%</td>
<td>Beta</td>
</tr>
<tr>
<td>S_w (%)</td>
<td>0</td>
<td>10.3%</td>
<td>23.4%</td>
<td>41.6%</td>
<td>100%</td>
<td>Beta</td>
</tr>
<tr>
<td>GOR (scf/STB)</td>
<td>0</td>
<td>248.7</td>
<td>545.4</td>
<td>935.2</td>
<td>2,000</td>
<td>Beta</td>
</tr>
<tr>
<td>B_o (RB/STB)</td>
<td>1.12</td>
<td>1.24</td>
<td>1.38</td>
<td>1.57</td>
<td>2.08</td>
<td>Beta</td>
</tr>
<tr>
<td>RF (%)</td>
<td>0</td>
<td>22.4%</td>
<td>31%</td>
<td>38.7%</td>
<td>50%</td>
<td>Beta</td>
</tr>
</tbody>
</table>

### Maspoli

Table C-2—Reservoir and fluid properties used for the volumetric analysis of Maspoli

<table>
<thead>
<tr>
<th>Parameter</th>
<th>MIN</th>
<th>Low Estimate</th>
<th>Best Estimate</th>
<th>High Estimate</th>
<th>MAX</th>
<th>Distribution Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>GRV (m³)</td>
<td>0</td>
<td>12,455,660,000</td>
<td>17,840,818,100</td>
<td>25,554,229,200</td>
<td>32,061,675,800</td>
<td>LogNormal</td>
</tr>
<tr>
<td>NTG (%)</td>
<td>0</td>
<td>34.8%</td>
<td>66.6%</td>
<td>90%</td>
<td>100%</td>
<td>Beta</td>
</tr>
<tr>
<td>δ (%)</td>
<td>0</td>
<td>11.9%</td>
<td>19.2%</td>
<td>28.1%</td>
<td>48%</td>
<td>Beta</td>
</tr>
<tr>
<td>S_w (%)</td>
<td>0</td>
<td>10.3%</td>
<td>23.4%</td>
<td>41.6%</td>
<td>100%</td>
<td>Beta</td>
</tr>
<tr>
<td>GOR (scf/STB)</td>
<td>0</td>
<td>248.7</td>
<td>545.4</td>
<td>935.2</td>
<td>2,000</td>
<td>Beta</td>
</tr>
<tr>
<td>B_o (RB/STB)</td>
<td>1.04</td>
<td>1.16</td>
<td>1.31</td>
<td>1.49</td>
<td>2.00</td>
<td>Beta</td>
</tr>
<tr>
<td>RF (%)</td>
<td>0</td>
<td>22.4%</td>
<td>31%</td>
<td>38.7%</td>
<td>50%</td>
<td>Beta</td>
</tr>
</tbody>
</table>

### Jasper

Table C-3—Reservoir and fluid properties used for the volumetric analysis of Jasper

<table>
<thead>
<tr>
<th>Parameter</th>
<th>MIN</th>
<th>Low Estimate</th>
<th>Best Estimate</th>
<th>High Estimate</th>
<th>MAX</th>
<th>Distribution Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>GRV (m³)</td>
<td>0</td>
<td>2,205,529,300</td>
<td>3,098,054,356</td>
<td>4,354,572,800</td>
<td>4,727,982,300</td>
<td>LogNormal</td>
</tr>
<tr>
<td>NTG (%)</td>
<td>0</td>
<td>34.8%</td>
<td>66.6%</td>
<td>90%</td>
<td>100%</td>
<td>Beta</td>
</tr>
<tr>
<td>δ (%)</td>
<td>0</td>
<td>8.3%</td>
<td>13.3%</td>
<td>22.7%</td>
<td>48%</td>
<td>Beta</td>
</tr>
<tr>
<td>S_w (%)</td>
<td>0</td>
<td>10.3%</td>
<td>23.4%</td>
<td>41.6%</td>
<td>100%</td>
<td>Beta</td>
</tr>
<tr>
<td>GOR (scf/STB)</td>
<td>0</td>
<td>248.7</td>
<td>545.4</td>
<td>935.2</td>
<td>2,000</td>
<td>Beta</td>
</tr>
<tr>
<td>B_o (RB/STB)</td>
<td>1.11</td>
<td>1.23</td>
<td>1.37</td>
<td>1.56</td>
<td>2.07</td>
<td>Beta</td>
</tr>
<tr>
<td>RF (%)</td>
<td>0</td>
<td>22.4%</td>
<td>31%</td>
<td>38.7%</td>
<td>50%</td>
<td>Beta</td>
</tr>
</tbody>
</table>
### Emerald-Deep

Table C-4—Reservoir and fluid properties used for the volumetric analysis of Emerald-Deep

<table>
<thead>
<tr>
<th>Parameter</th>
<th>MIN</th>
<th>Low Estimate</th>
<th>Best Estimate</th>
<th>High Estimate</th>
<th>MAX</th>
<th>Distribution Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>GRV (m³)</td>
<td>0</td>
<td>979,545,400</td>
<td>1,540,444,642</td>
<td>2,422,521,400</td>
<td>3,251,806,200</td>
<td>LogNormal</td>
</tr>
<tr>
<td>NTG (%)</td>
<td>0</td>
<td>34.8%</td>
<td>66.8%</td>
<td>90%</td>
<td>100%</td>
<td>Beta</td>
</tr>
<tr>
<td>ϕ (%)</td>
<td>0</td>
<td>9.0%</td>
<td>14.4%</td>
<td>24.0%</td>
<td>46%</td>
<td>Beta</td>
</tr>
<tr>
<td>Sw (%)</td>
<td>0</td>
<td>10.3%</td>
<td>23.4%</td>
<td>41.6%</td>
<td>100%</td>
<td>Beta</td>
</tr>
<tr>
<td>GOR (scf/STB)</td>
<td>0</td>
<td>248.7</td>
<td>545.4</td>
<td>935.2</td>
<td>2,000</td>
<td>Beta</td>
</tr>
<tr>
<td>Bw (RB/STB)</td>
<td>1.10</td>
<td>1.22</td>
<td>1.36</td>
<td>1.55</td>
<td>2.06</td>
<td>Beta</td>
</tr>
<tr>
<td>RF (%)</td>
<td>0</td>
<td>22.4%</td>
<td>31%</td>
<td>38.7%</td>
<td>50%</td>
<td>Beta</td>
</tr>
</tbody>
</table>

### Emerald

Table C-5—Reservoir and fluid properties used for the volumetric analysis of Emerald

<table>
<thead>
<tr>
<th>Parameter</th>
<th>MIN</th>
<th>Low Estimate</th>
<th>Best Estimate</th>
<th>High Estimate</th>
<th>MAX</th>
<th>Distribution Type</th>
</tr>
</thead>
<tbody>
<tr>
<td>GRV (m³)</td>
<td>0</td>
<td>966,696,500</td>
<td>1,993,187,971</td>
<td>4,109,664,500</td>
<td>5,245,375,600</td>
<td>LogNormal</td>
</tr>
<tr>
<td>NTG (%)</td>
<td>0</td>
<td>34.8%</td>
<td>66.6%</td>
<td>90%</td>
<td>100%</td>
<td>Beta</td>
</tr>
<tr>
<td>ϕ (%)</td>
<td>0</td>
<td>9.2%</td>
<td>14.6%</td>
<td>24.0%</td>
<td>48%</td>
<td>Beta</td>
</tr>
<tr>
<td>Sw (%)</td>
<td>0</td>
<td>10.3%</td>
<td>23.4%</td>
<td>41.6%</td>
<td>100%</td>
<td>Beta</td>
</tr>
<tr>
<td>GOR (scf/STB)</td>
<td>0</td>
<td>248.7</td>
<td>545.4</td>
<td>935.2</td>
<td>2,000</td>
<td>Beta</td>
</tr>
<tr>
<td>Bw (RB/STB)</td>
<td>1.10</td>
<td>1.22</td>
<td>1.36</td>
<td>1.55</td>
<td>2.06</td>
<td>Beta</td>
</tr>
<tr>
<td>RF (%)</td>
<td>0</td>
<td>22.4%</td>
<td>31%</td>
<td>38.7%</td>
<td>50%</td>
<td>Beta</td>
</tr>
</tbody>
</table>
Appendix D
Uruguayan oil and gas Fiscal Regime

General characteristics
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 Production Sharing Contracts (PSC).

The relevant characteristics of the Uruguayan PSC for offshore areas, as explained in Ferro et al. (2017) and in ANCAP (2019a), 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 the 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 OPEX and 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 D-1), 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 °API>25, X' for oils with °API<25 and Xg for natural gas) is biddable and is used for comparison of offers.

<table>
<thead>
<tr>
<th>R Factor</th>
<th>% Profit Oil Uruguayan State</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt; 1</td>
<td>8 + X</td>
</tr>
<tr>
<td>1 – 1.5</td>
<td>15 + X</td>
</tr>
<tr>
<td>1.5 - 2</td>
<td>20 + X</td>
</tr>
<tr>
<td>&gt; 2</td>
<td>30 + X</td>
</tr>
</tbody>
</table>

Table D-1—Profit Oil for the Uruguayan State vs. R factor (ANCAP 2019a)
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 °API>25, X' for oils with °API<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. D-1, and the area is awarded to the company that presented the offer with the highest score.

\[
Total\ Score = 60 \cdot \left(\frac{A}{A_{max}}\right) + 120 \cdot \left(\frac{WU}{WU_{max}}\right) + 40 \cdot \left(\frac{X}{X_{max}}\right) + \left(\frac{X'}{X'_{max}}\right) + \left(\frac{X_g}{X_{g_{max}}}\right)
\]

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.
- \(X_{g_{max}}\): is the Uruguayan State maximum Profit Oil increase for natural gas offered for the area.

**Exploration periods**

Nowadays, there is an open round regime, and blocks are awarded every six months to oil companies that have qualified and presented offers (ANCAP 2019a). The exploratory phase have a first exploration sub-period of 4 years (Fig. D-1).
In the initial stage of exploration the required minimum work commitment is very low. After the 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. D-1), 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.

**Abandonment**

When a contract for an area in the offshore Uruguay enters in the Production phase, the contractor has the obligation to quarterly deposit a predefined amount of USD 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 USD 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 EUR. After the accumulated production surpasses that threshold, the amount to be deposited in the "i" quarter will follow the following formula:

\[
FA_i = CA \cdot \frac{NP_i - EUR \cdot 0.5}{EUR \cdot 0.5} - FA_{Ai}
\]  

(D-2)

Where:

- \( FA_i \): is the amount, in USD, to be deposited in the Abandonment Fund in the "i" quarter.
- \( CA \): is the total updated estimated abandonment cost, in USD.
• $NP_i$: 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 USD, before the "i" quarter.
Appendix E

Sensitivity to EIA oil price forecasts

Figure E-1—Chafalote sensitivity to various EIA oil price forecasts

Figure E-2—Maspoli sensitivity to various EIA oil price forecasts

Figure E-3—Jasper sensitivity to various EIA oil price forecasts
Figure E-4—Emerald-Deep sensitivity to various EIA oil price forecasts

Figure E-5—Emerald sensitivity to various EIA oil price forecasts

Figure E-6—Emerald-Complex sensitivity to various EIA oil price forecasts
Appendix F
Sensitivity to fixed oil price scenarios

Figure F-1—Chafalote sensitivity to oil price fluctuations

Figure F-2—Maspoli sensitivity to oil price fluctuations
Figure F-3—Jasper sensitivity to oil price fluctuations

Figure F-4—Emerald-Deep sensitivity to oil price fluctuations
Figure F-5—Emerald sensitivity to oil price fluctuations

Figure F-6—Emerald-Complex sensitivity to oil price fluctuations