Prospective Resources of Mexico: Perdido Area, Mexican Ridges and Saline Basin, deepwater Gulf of Mexico

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1. INTRODUCTION

Until the energy sector reforms passed by the Mexican government at the end of 2013, Petroleos Mexicanos (Pemex), the National Oil Company of Mexico, was the only institution responsible for assessing and quantifying the prospective resources of hydrocarbons of the Nation.

The identification, localization and quantification of prospective resources within national territory is crucial for hydrocarbons' exploration and production activities, as well as for planning and managing the Nation's energy resources. Therefore, Mexico must continually update and increase knowledge of the subsoil through methodological processes based on international best practices, which, similar to the previous processes of assessment, are based on the analysis and integration of exploration information available, to finally assess potential hydrocarbon reservoirs and their related plays.

When the results obtained from studies evaluating areas with prospective potential, carried out by the technical unit of the National Hydrocarbons Commission, national and international oil companies, and authorized companies are integrated, this ensures subsoil knowledge increase and updating. The National Hydrocarbons Commission is responsible for the integration and management of this data, as part of its role as a Coordinated Regulatory Body in the Mexican energy sector.

In this first assessing stage, the quantification of prospective resources updating is done within three deepwater areas, including the identification of prospects and play-based analysis.

Prospects were interpreted and assessed internally using homogeneous criteria and following the fundamental principles of resource evaluation and classification of the Petroleum Resources Management System (PRMS), published jointly by the Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), the Society of Petroleum Evaluation Engineers (SPEE), the Society of Exploration Geophysicists (SEG), the Society of Petrophysicists and Well Log Analysts (SPWLA), and the European Association of Geoscientists and Engineers (EAGE).

Moreover, play-based assessment was performed using the concept of the Total Petroleum System (Magoon and Schmocker, 2000) to include within a defined geographical extension, known discovered hydrocarbon accumulations, undiscovered accumulations identified as prospects and undiscovered remnant accumulations that are estimated to be identified in the future; which both represent the total of yet-to-find resources.

Playbased assessment of total prospective resources is carried out at lifetime, that is, without a timeframe limit and based on current exploration information and available studies, as well as on characteristics and recoverable volumes of discovered reservoirs belonging to a play at a certain date. The results of the quantification of prospective resources constitute a comparative measure of the total amount of estimated hydrocarbons that could exist in certain areas and do not imply a discovery or future production rate within a specific period of time.

According to the PRMS, prospective resources assessment is a complex process that involves interpretation stages and consists of several subprocesses, whose execution can

be extended for considerable periods of time depending on factors that have to do with the availability, quality and type of exploration information, such as seismic data, surface samples and information obtained from wells and discovered fields, the geological environment to be assessed, as well as the geological complexity of the area.

The evaluation and quantification of prospective resources of the country that the National Hydrocarbons Commission updates and integrates is conducted at different stages. In this first stage, the prospective resource assessment of Perdido Area, the northern portion of the Mexican Ridges and the central portion of the Saline Basin are updated, all located in deepwater Gulf of Mexico.

The consolidation of prospective resources' quantification in Mexico, consists of the updates made by the National Hydrocarbons Commission and those previously reported, including updates that operators make in compliance with applicable regulations.

2. BACKGROUND

Before the 2013 energy sector reforms, Petroleos Mexicanos, as a state-owned company, was the only institution responsible for assessing and quantifying prospective resources of hydrocarbons in Mexico.

As part of the national reforms, the National Hydrocarbons Commission (hereinafter, Commission) via the Resolution CNH.11.001 / 13 published in the Official Gazette (DOF) in December 2013, establishes the Guidelines for the analysis and assessment of prospective and contingent resources of the Nation and the oversight process of exploration activities. Through these Guidelines, the Commission establishes the elements, procedures and requirements that Petroleos Mexicanos must comply with, to report the evaluation of petroleum resources owned by the Nation, as well as to verify that the methodology and procedures used for the classification and quantification of hydrocarbon resources are in accordance with industry best practices.

Thus, Petroleos Mexicanos reports periodically to the Commission the information of conventional and unconventional prospective resources in the country, using pre-established templates and according to the methodology and procedures verified by the Commission. Based on this information, the Commission creates databases with the results of prospects and plays assessments for conventional and unconventional resources.

Through this procedure, the Commission analyzes the information to prepare studies, analyses, opinions and proposals related to the exercise of its regulatory functions, as well as for the reporting and creation of statistics on prospective resources.

On December 20th 2013, the Decree that amends and adds various provisions of the Political Constitution of the United Mexican States on energy matters was published in the Official Gazette (DOF), includes the following premises:

- Article 27 establishes that, with the purpose of obtaining income for the State, the activities of exploration and extraction of oil and other hydrocarbons will be

carried out through entitlements adjudicated to State-owned companies and through contracts tendered to these or to private companies.

- Article 28 establishes that the Executive Power will establish Coordinated Regulatory Bodies in Energy Matters, among them, the National Hydrocarbons Commission.

In accordance with this constitutional mandate, on August 11th 2014, the Hydrocarbons Law and the Law of Coordinated Regulatory Bodies in Energy Matters were published in the Official Gazette (DOF) in order to regulate the organization and operation of the Commission, as well as establishing its powers.

Regarding the liabilities of the Commission, in relation to the assessment of the hydrocarbon resources of the Nation, the Hydrocarbons Law establishes the following:

- Article 1 states that it corresponds to the Nation the direct, inalienable and imprescriptible property of all hydrocarbons in any physical state that are in the national territory subsoil, including the continental shelf and the exclusive economic zone located in Mexico's territorial sea and adjacent to it.

- Article 5establishes that hydrocarbons' exploration and extraction activities are considered strategic under the Political Constitution of the United Mexican States. Only the Nation will carry out these activities, in terms of the Hydrocarbons Law, through Entitlements and Contracts.

- Article 7 establishes that in Entitlements, the National Hydrocarbons Commission is responsible for the technical administration and compliance supervision of the Entitlements' terms and conditions.

- Article 19 states that regarding Exploration and Extraction Contracts, these will include clauses on the observance of international best practices for operation in the Contract Area. Article 31 states that the National Hydrocarbons Commission will manage and supervise, in technical matters, these Exploration and Extraction Contracts.

- Article 43, in its fraction I and II, states that the following functions correspond to the National Hydrocarbons Commission:

  I. Create regulation and supervise its compliance by Entitlement, Contract and Authorization holders, in matters of its authority and specifically in the activities of Reserves and Prospective and Contingent Resources quantification.

  II. Quantify the hydrocarbons' potential of the country, for which it should estimate the prospective and contingent resources in Mexico.

Regarding the Regulatory Bodies Law, its Article 39 states that the Commission shall perform its duties, ensuring that these projects are conducted according to the following principles:

I. Accelerate the knowledge development of the petroleum potential of the country.

II. The hydrocarbons reserves replacement from prospective resources, as the guarantor of the energy security of the Nation, based on available technology and in accordance to the economic viability of the projects.

Based on the Constitution of the United Mexican States, the Federal Public Administration Law and the Coordinated Regulatory Bodies in Energy Matters Law, on December 8th 2014 the Commission issued its Internal Rules of Procedures, which was amended and published in the Official Gazette on June 27th 2019, establishing its organizational structure and operational processes.

In accordance to the organizational structure of the Commission, the General Directorate of Petroleum Potential Assessment (DGEPP) has the following duties, as indicated in Article 34 of the Internal Rules of Procedures of the National Hydrocarbons Commission:

- As a department within the Technical Unit for Exploration and its Supervision, the DGEPP is responsible for conducting studies for the quantification of the hydrocarbons' potential of the country, considering the prospective and contingent resources' estimation.

Thus, Article 34 fraction VIII of the Internal Rules of Procedures of the National Hydrocarbons Commission specifically grants to the DGEPP the responsibility of conducting studies to quantify the hydrocarbons potential of the country by estimating prospective resources.

In this regard, the DGEPP progress in updating the quantification of hydrocarbons prospective resources of the country is presented in here, including the classification and the methodological processes adopted by the Commission to carry out such updating from previous assessments, aligned with international best practices.

3. PROCESS AND METHODS FOR CONVENTIONAL PROSPECTIVE RESOURCES ASSESSMENT

3.1. OVERVIEW

Prospective resources are the volume of hydrocarbons, estimated at a given date, that are inferred to be potentially recoverable from undiscovered accumulations through the application of future projects (SPE, 2018). These potential resources are located in the subsoil and cannot be directly counted or inspected; however, they can be estimated based on data evaluation that indirectly provides evidence of the amount of hydrocarbons potentially recoverable.

That estimated amount, if discovered, is neither absolute nor definitive until the productive life of a field or reservoir has ended. Therefore, all resource estimates invariably contain some degree of uncertainty, which decreases as the associated project develops (SPE, 2018).

Typically, reserves are defined in greater detail than are resources, due to the more advanced stage in the project life cycle and the greater amount of technical data available for its study and description (Figure 1); in this way, prospective resources and even reserves are defined by a range of values and not as a fixed amount. This range of values can be described qualitatively and quantitatively by deterministic or probabilistic methods.

Only commercially recoverable remaining oil quantities from a known accumulation can be classified as a reserve through its association with a development project (SPE, 2011), while other quantities must be classified as contingent resources or prospective resources (Figure 1). However, all types of accumulations represent a value, either for the production asset or for future development opportunities, since in any of these cases, they have to be measured and managed (SPE, 2011).

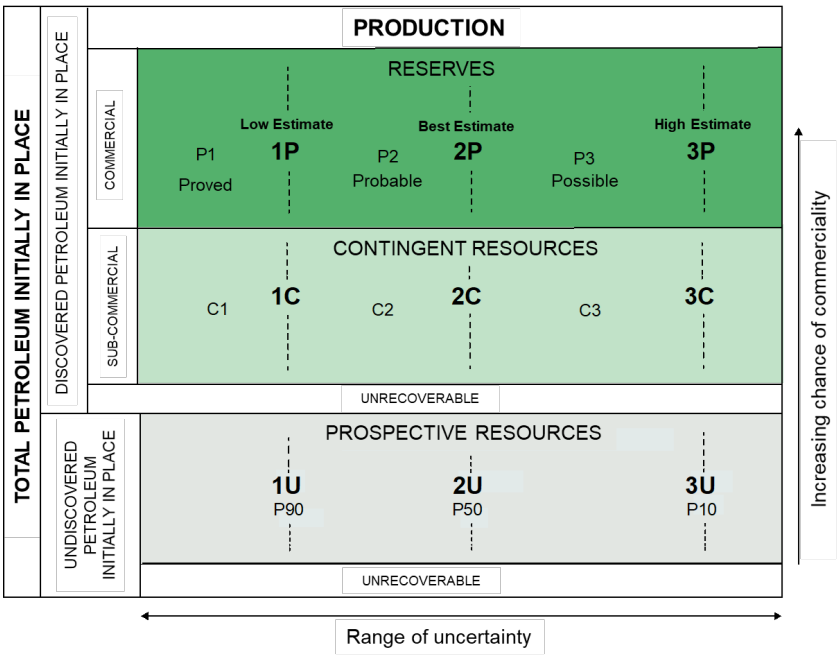


Figure 1. Categorization and classification of hydrocarbon volumes according to the level of technical uncertainty and the viability of developing a commercial project (SPE, 2018).

To assess and quantify prospective resources of hydrocarbons, the Commission uses the fundamental principles of evaluation and classification of the PRMS, which dictates a methodological basis and criteria for the evaluation of prospective resources related to exploration prospects. In a complementary way, play-based assessment is carried out at lifetime, using the concept of the Total Petroleum System (Magoon and Schmocker, 2000; Pemex, 2012).

Conventional prospective resources assessment in a given area might be misunderstood, as the simple result of adding the individual assessments of each and every geological structure capable of being a hydrocarbon reservoir in that given area. However, there are several factors such as lack of information in frontier areas, limitations in the quality of seismic data as prospects are deeper, very complex geological areas, lack of geological knowledge or operational issues related to project execution times and available technology, for which it is very difficult to identify and assess each one of the potential hydrocarbon reservoirs that could exist in a certain area.

In that sense, for conventional prospective resources assessment to be done in a comprehensive manner, it must be carried out taking into account discovered accumulations, identified prospects based on the available information and, in addition, considering the potential hydrocarbon reservoirs that have not yet been identified due to current limitations and that they may be identified as technology and exploration activities progress in an area. The latter is done through a play-based exploration analysis.

An exploration play can be defined as a group of prospects within a geographicaly delimited area, which must have a group of mutually related geological factors that permit hydrocarbons accumulations; but at the same time, it requires more information and / or evaluation to define specific prospects or leads (Magoon, 1995; CCOP, 2000; SPE, 2011). The discovered fields or reservoirs within the geographical extension of the same play are characterized by having a set of specific geologicalfactors in common and therefore can be distinguished from other discovered fields or reservoirs belonging to other plays.

3.2. CONVENTIONAL PROSPECTIVE RESOURCES ASSESSMENT IN EXPLORATION PROSPECTS

Various methodologies have now been developed for prospective resources assessment and can be grouped mainly in deterministic, probabilistic and geostatistical methods; being able to be applied in a combined way to perform an integrated analysis (SPE, 2018). In resource assessment, different methods are generally used according to the project maturity stage; that is, if the project is in the exploration, appraisal or development stage, several methods are often integrated to better define and manage uncertainty.

In the exploration stage, given the uncertainty that exists due to subsoil complexity conditions and the indirect methods' limitations used in hydrocarbons exploration, among other factors, methodologies based on probabilistic estimates related to analogs' analysis are generally the most accepted.

By an appropriate selection of analogs and a probabilistic assessment of resources, the goal is to determine the range of uncertainty that exists in the early stages of exploration when direct information from the subsoil is generally limited.

According to PRMS (SPE, 2018), the use of analogs along with a probabilistic approach improves the understanding of the range of uncertainty present in key parameters in the volumetric estimation of resources, such as:

- Petrophysical properties (for example, gross and net thickness, porosity, fluids saturation, etc.).
- Conditions of the possible reservoir (for example, pressure and temperature, geometry and heterogeneity, hydrocarbons accumulation size, etc.).
- Fluid properties (for example, hydrocarbon type, composition, density, etc.).
- Reservoir rock quality variations, geological features, type of fluids, saturation value changes (vertical and horizontal).
- Understand and communicate the level of uncertainty of resource estimates.

Statistical uncertainty of the volumetric parameters that a reservoir can present is used to calculate the statistical uncertainty of the estimated in place resources' volumes. Once a potential in place volume has been estimated, the recoverable portion can be estimated based on the performance of one or more similar fields or discovered reservoirs by analyzing the different operational conditions; for example, relating the size of the in place volume along with a defined set of wells and / or through modeling or simulation studies based on the available information.

Often, a stochastic method is applied to generate probability functions by entering random sampling distributions (for example, a Monte Carlo simulation), where these functions allow for the definition of a representative distribution of the full range of possible values of potential in place or recoverable volume.

Since the result of the resource estimates is directly related to the distributions of the input parameters (both the type of distribution and the value range used), it is recommendable to document and justify the suitability of applied parameters to the potential reservoir to be evaluated, to real conditions of the used analogs.

The recoverable resource estimates must then reflect the combined uncertainty of the in place volumes and the recovery efficiency, based on the volumetric parameters and analog value ranges applied to the potential reservoir.

3.2.1. Seismic applications

Today, geophysical studies utilizing seismic reflection are one of the main tools used to assess the amount of hydrocarbons that can potentially be present in a reservoir. Interpretations and conclusions that can be obtained through the analysis of seismic studies, well logs analysis, pressure tests, core rock samples descriptions and studies, stratigraphic-sedimentary models and basin analysis, among many other types of studies, are key in prospective resources assessment.

Data derived from wells are key in hydrocarbon exploration and especially in the prospective potential assessment of a given area. Each time a new well is drilled, seismic interpretation has to be reviewed and recalibrated in order to take advantage of the new direct subsoil information; in such a way that, as the new information is integrated, the interpretations that were originally ambiguous gradually become reliable, reducing the uncertainty between the seismic response and the rock properties in the subsoil (SPE, 2011).

Regarding the type of seismic information, weighing the use of 3D seismic on 2D is highly recommended, when structural geology or rock and fluid prediction studies are conducted and used for prospective resources assessment. However, in frontier areas where there is no 3D seismic, 2D seismic plays an important role in making an initial estimate of hydrocarbon resources (SPE, 2011).

Two-dimensional or three-dimensional seismic data interpretations that are performed for prospective resources volume estimation can be grouped to reach two main objectives:

- To define structure and trap geometry; and
- To characterize rock and fluid properties (SPE, 2011).

3.2.2. Trap geometry

The geometry of a potential hydrocarbons trap is determined by the geological configuration of the rock layers and their relation to structural events in space and time, the strike and dip of reservoir and seal rocks, the location and position of faults, as well as other kind of geological barriers or discontinuities that facilitate or impede the passage of fluids, such as fractures, salt, shales, igneous rocks or specific stratigraphic characteristics (such as wedges or pinch-outs, lateral facies changes, etc.) (SPE, 2011).

Through different visualization and seismic interpretation tools available on the market and the multiple processes they currently offer, the trap geometry can be mapped by interpreting three-dimensional meshes of seismic amplitudes reflected at the acoustic/elastic impedance limits, related to the types and characteristics of rocks (commonly referred to as seismic horizons), as well as a preliminary assessment of the possible types of fluids contained in and around them.

Seismic studies are acquired in time domain, measuring the time it takes for acoustic waves from the source to the receiver through rocks in the subsoil (seismic reflection). This seismic velocity data, in combination with acoustic data at the well level, is used to create velocity functions or models to convert time measurements to depth. Also, the interpretation of seismic horizons made in time can be done in depth.

Today, there are seismic wave migration processes directly to depth (for example, RTM or Reverse Time Migration); however, it is recommended to tie seismic information with well data.

This seismic information in depth, forms the basis for estimating the geometry, thickness and volume of a potential reservoir, which will later be integrated with an estimate of its possible properties, such as porosity, net thickness, hydrocarbon saturation, etc., to perform a calculation of the potential in-place volume of hydrocarbons.

Since the definition of the structural elements or geometry, as well as thickness and depth estimations, result from the seismic data and well information interpretation, it is important to be aware of the uncertainty that may arise in the potential in place volumes estimates due to the following factors (SPE, 2011):

- Incorrect positioning of structural elements during seismic processing
- Misinterpretations
- Errors in time to depth conversion

3.2.3. Rock and fluid properties

Another important application of seismic information analysis, especially of three-dimensional seismic, is the prediction of physical properties of rocks and fluids contained in porous space. The reservoir properties that can be predicted from 3D seismic, when the quality of the information allows it, are porosity, lithology, and presence and saturation of hydrocarbons.

Predictions that eventually can be made must be supported by at a minimum the following information:

- Well control

- A representative sedimentary model.

Depending on the particular conditions of the study, as well as the quantity and quality of the information used, the predictions can be quantitative or qualitative. Some methods considered by PRMS (2011) to predict rock and fluid properties are briefly described below.

The lithology or rock type, including gross and net thicknesses, as well as porosity, can be estimated with a certain range of uncertainty, using a sedimentary model of the potential reservoir rock, which should be supported by available data from wells (generally at reasonable distances from the area of interest), 3D seismic facies analysis and analog wells or reservoirs. Knowing the sedimentary system related to the potential reservoir rock (for example, river, delta deepwater, etc.), you can have a general geological framework and predict these properties within appropriate ranges from analog wells or reservoirs (SPE, 2011).

If the available information is good enough, it is possible to make predictions with greater certainty and higher resolution, based on the application of seismic attributes (e.g., Brown, 1996; Chopra and Marfurt, 2007). According to PRMS, the use of seismic attributes is conditioned on the following:

- Well log scale relationship exists between the attributes and specific characteristics of the potential reservoir;
- This relationship is conserved at seismic scale (which has lower vertical resolution);
- The quality of seismic information is adequate; and
- There is a reliable correlation between seismic information and well logs.

It is important to note that the aforementioned points are systematically corroborated before making predictions about the possible physical properties of rocks. Additionally, it is important to ensure that the seismic models calibrated with well logs (synthetic seismograms) are properly tied to seismic data.

An example of how to estimate predictions qualitatively about the possible stratigraphic extension of a potential reservoir in terms of reservoir rock properties and fluid content is by extracting relatively simple attributes associated with seismic velocity, amplitude, frequency, as well as the variation of any of the previous ones respect to time or space.

For instance, an amplitude attribute generally used to define the possible extension of a potential reservoir is RMS (Root Mean Square), which consists in squaring amplitude value to highlight anomalies produced by impedance contrasts (product of seismic velocity and density), which in turn is related to potential reservoir rocks saturated with a fluid that can be hydrocarbons.

Hydrocarbon presence generally reduces seismic velocity and reservoir rock density, and therefore modifies the impedance contrast respect to the surrounding rocks of the same type, but water saturated (usually brine). This type of amplitude anomalies related to the presence of hydrocarbons can be used as a direct hydrocarbon indicator (DHI) and its definition as such, must be supported by the analysis of rock properties and their seismic response, to ensure that the strength and polarity of seismic reflections are consistent with the trap geometry.

An amplitude anomaly typically considered as a DHI is the seismic reflection increase that produces bright spots. However, not all bright spots are caused by the presence of hydrocarbons, since acoustic impedance increases also may be caused by high porosity.

So, if a bright spot is identified, it must be consistent with the structure; that is, the amplitude changes must match the structural contours.

Another type of anomaly used as a DHI are flat spots that are generally observed in seismic as an abnormally horizontal reflector. This is not considered as an amplitude anomaly and occurs when there is contact between hydrocarbons and water within a limited area, such that it appears as a flat or horizontal positive reflector, which contrasts with other surrounding reflectors that are typically not horizontal because of structural geology of the related trap.

A lithological or sedimentary pattern change, low saturation of residual hydrocarbons or multiple unresolved reflections, can give the appearance of flat spots. Therefore, it is important to identify this type of anomalies from depth migrated seismic, to confirm that the anomaly is really flat.

Dim spots can also indicate the presence of hydrocarbons. This low amplitude seismic anomaly is caused by the decrease in acoustic impedance, for example when hydrocarbons replace water in porous rocks. However, not all dim spots are caused by the presence of hydrocarbons, since changes in sedimentary facies also can cause reductions in acoustic impedance.

Finally, polarity reversals are amplitude anomalies that may indicate the presence of hydrocarbons from impedance contrasts in a potential reservoir, given the interaction of hydrocarbon-saturated rocks, brine-saturated rocks and surrounding seal rocks. It is important to keep in mind that the effects of compaction could generate polarity reversals; however, at relatively greater depths these changes are not uniform.

When a potential hydrocarbons trap is being identified and assessed, seismic attributes serve as a tool to increase confidence in the possible presence of hydrocarbons. However, the predictions from seismic data to define trap geometry and the properties of the rock-fluid system have inherent uncertainty, since the accuracy of these predictions will depend mainly on the quality of the seismic data (bandwidth, frequency content, signal-to-noise ratio, acquisition and processing parameters, overload effects, etc.) and well data used for calibration.

3.2.4. Geostatistical methods

According to PRMS (2018), geostatistical methods are constituted as a variety of techniques and processes used for the analysis and interpretation of geoscience and engineering data to describe the variability and uncertainty of reservoirs. Geostatistical methods can be used to preserve the spatial distribution of information through a static model; for example, by incorporating seismic information into a geostatistical model, the understanding of the distribution of properties of interest to potential reservoirs can be improved and resources estimates results can be more reliable.

The objective is to generate a geometric model that incorporates seismic and well information, which from geostatistics can be quantitative. Geostatistical characterization requires the integration of data, allowing spatial heterogeneities correlation that a potential reservoir may have.

Spatial propagation of properties of interest with a geostatistical approach can be carried out following different methodologies (e.g. Dubrule, 2003; Avseth et al., 2005; Bosch et al.,

2010). Generally, the properties estimation of a reservoir based on seismic and wells uses geostatistical methods through seismic inversion processes or from elastic properties calibration (acoustic impedance).

Geostatistical methods generally used to estimate properties from seismic and wells are kriging or cokriging methods. Calibration of a well punctual information with seismic is carried out by variograms construction, which statistically estimate the spatial correlations of the acoustic impedance with one or several properties of interest.

The first element to consider in the construction of a simulation model is the structural framework that consists of surfaces, horizons, faults and other geological elements from which the population of certain properties of interest will be made.

The link between the structural model and the properties model is the stratigraphic framework from which the type of modeling to be performed will be defined, specifically, whether it is a cell-based model or an object-based model (Dubrule, 2003). Whichever the approach to be used, an appropriate cell size (stratigraphic grid) should be adopted depending on the resolution of the seismic data and the available well information.

The integration of well information (e.g. well logs, rock cores, etc.) with seismic derived properties must be calibrated, so that the heterogeneities at sub-seismic scale can be correlated with geological information, as well as within the gaps between wells.

The object-based model assumes that different stratigraphic architectures (such as channels, fans, crevasse splays or channel overflows, etc.) can be described using simple geometries; while in a cell-based model, it assumes only the statistical relationships between the different types of sedimentary facies that could be present in each individual cell of the model.

In most cases, the stratigraphic model is not distinguishable from seismic information; that is, there are no clear patterns of geologically interpretable geometries of facies, sedimentary patterns are altered by diagenetic and/or structural issues, sedimentary geometries have complex patterns, etc. So, cell-based models are the most popular and use variograms (spherical, gaussian or exponential) to define a spatial correlation in the seismic information.

The combination of geostatistical methods with seismic and well information is based on the principle that there is a spatial correlation of geological characteristics, where this spatial correlation is quantified and used to assign values related to properties of interest, to areas not sampled through wells.

3.2.5. Volumetric assessment of exploration prospects

Calculations to estimate in-place volumes and similar methods to estimate recovery efficiency or recovery factor are indirect procedures used during the exploration, discovery, appraisal, and development phases in the upstream value chain of any exploration and production project (Figure 2).

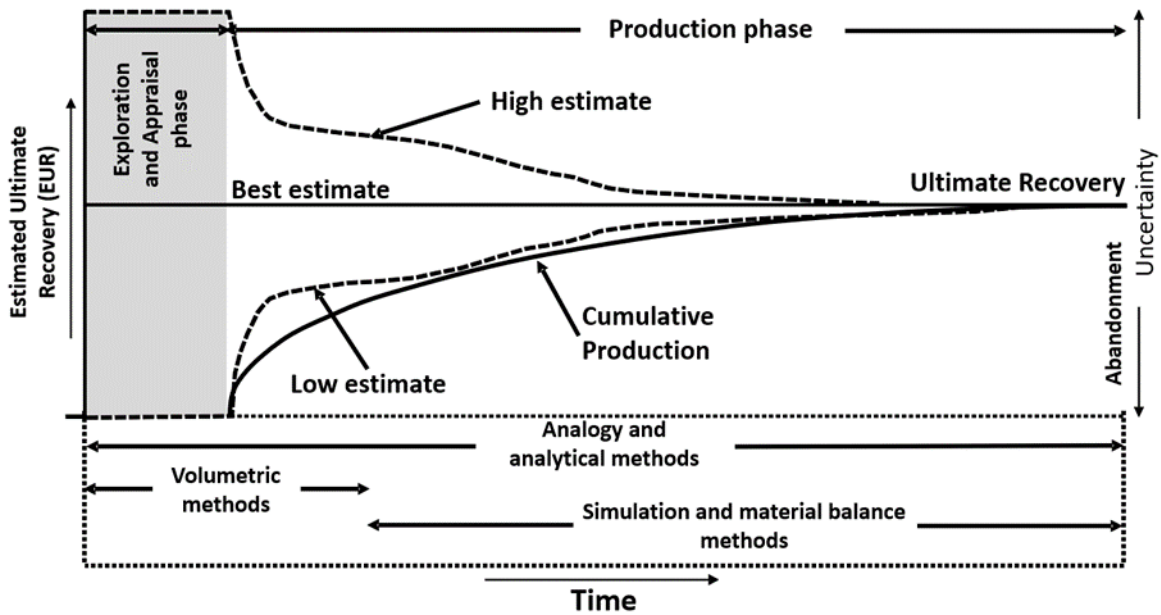


Figure 2. Change in uncertainty and assessment methods of the estimated ultimate recovery EUR (SPE, 2011).

These procedures are called indirect because the estimated ultimate recovery (EUR) is not calculated directly from data measured in the subsoil. The calculation of the EUR (commonly expressed in standard barrels STB or standard cubic feet scf) requires the independent estimation of the volume of petroleum initially in place (PIIP), while the recovery factor (RF), is generally expressed in terms of a simple volumetric relationship defined by:

$$EUR\ (STB\ o\ scf) = PIIP\ (STB\ o\ scf) \times FR\ (a\ fraction\ of\ PIIP) \qquad \text{(a)}$$

While the generalized volumetric equation to obtain the PIIP volume, which in the case of liquid hydrocarbons is OIIP (Oil Initially In Place) and in the case of gaseous hydrocarbons is GIIP (Gas Initially In Place) is:

$$PIIP\ (STB\ o\ scf) = A\ h\ \emptyset\ (Sh)\ /\ Bhi \qquad \text{(b)}$$

Where, the expressed variables correspond to:

A = area
h = net pay or net thickness
$\emptyset$ = porosity
Sh = hydrocarbons saturation
Bhi = hydrocarbon formation volume factor, expressed in Rm^3/Sm^3 for oil and Rcf/Scf for gas. Where (R) refers to reservoir pressure and temperature conditions, and (S) to standard surface conditions. In the case of oil it is expressed as B_{oi}, while in the case of gas it is expressed as B_{gi}.

It is recommended that the estimation and assignment of the RF be based on analogs data analysis. According to PRMS, it is preferable to estimate this factor from near analogs or similar reservoirs related to the same play, rather than to calculate it through the use of analytical methods based on physical properties, which can lead to meaningless estimates (SPE, 2011).

As mentioned in previous sections, due to the high degree of uncertainty of the variables that involve the volumetric assessment of hydrocarbon resources in a project that is in exploration, appraisal or early development, deterministic assessment of prospective resources in exploration prospects is not a fully accepted methodology by the industry. However, it is a preamble for the probabilistic evaluation of prospective resources.

3.2.6. Probabilistic estimation of prospective resources and risk assessment of exploration prospects

Probabilistic estimates of prospective resources in exploration prospects consist of two phases. The first phase is the volumetric calculation, which is based on a probabilistic method where the values that will be introduced in the hydrocarbon volume calculation formula are randomly selected to form a distribution of possible results.

Subsequently, an assessment and a quantitative estimation of the probability of the presence and the geological efficiency of the elements and processes of the petroleum system is performed, which includes an analysis to determine the degree of reliability of the databases used for its assessment. The elements and processes of the petroleum system, although they are somehow implicit in each of the parameters used in the volumetric calculation, are assessed separately in order to estimate an independent quantitative risk value, commonly called probability of success (PoS) or geological success (Pg).

Once the volume of prospective resources and a quantitative value of probability of success have been established, it is possible to determine risked volumes by multiplying the distribution of the volumes obtained through the probabilistic method, by the probability of geological success (Pg), which is a representative value of the assessment of the considered elements and processes of the petroleum system (Figure 3).

Typically, the elements and processes to be evaluated in the petroleum system are the presence of reservoir rock, the presence of a trap (structural, stratigraphic or combined), the presence and capacity of hydrocarbon generation of a source rock, the presence of a seal that allow the accumulation and preservation of hydrocarbons and finally, that there is evidence of migration pathways from a source rock to the trap, in addition to the necessary conditions of synchronicity in time and space; that is, that the trap has formed before the hydrocarbons migration has ceased (Magoon and Dow, 1994).

These essential elements and processes of the petroleum system must occur in the correct time and space, so that the organic matter included in a source rock can be converted into a hydrocarbons accumulation. A petroleum system can be defined, where all these essential elements and processes occur or are believed to have a reasonable chance of occurring; on the other hand, if one of the elements of the petroleum system fails, the necessary conditions for a hydrocarbons accumulation will not exist.

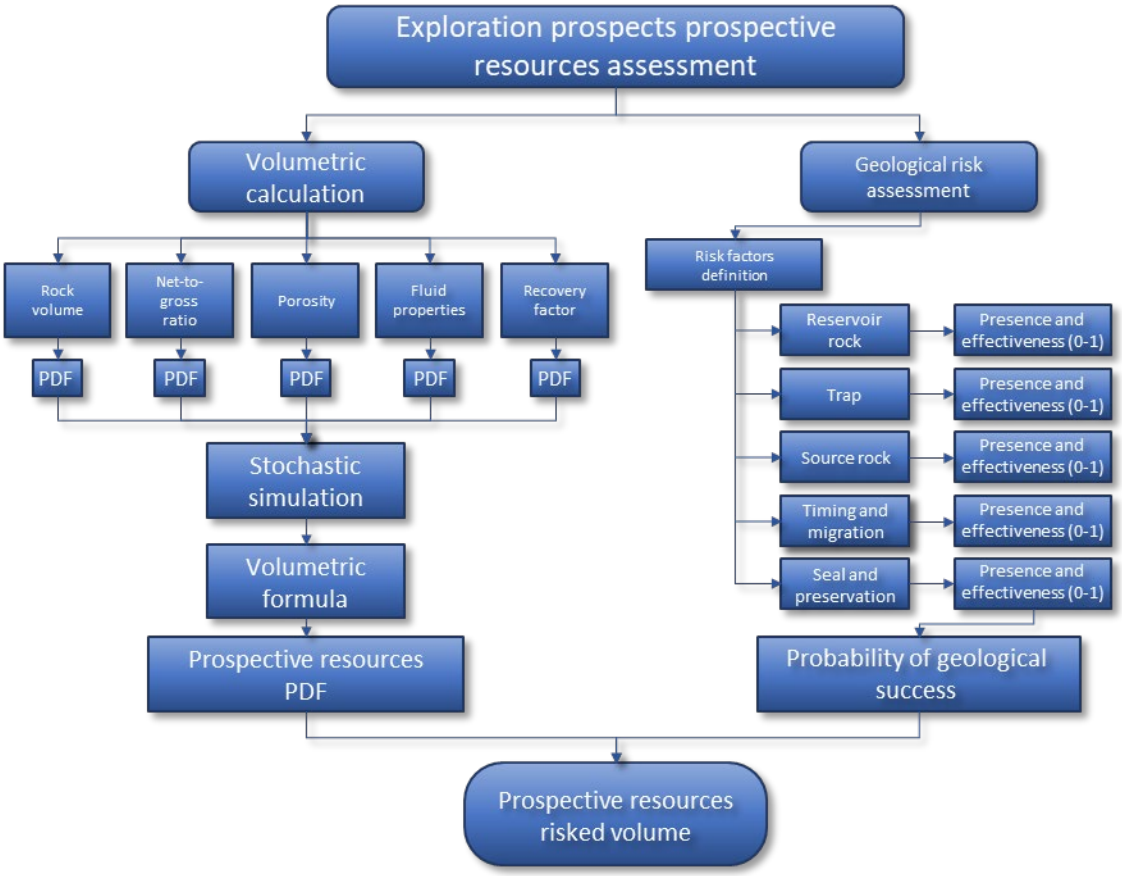


Figure 3. Chart that shows the process scheme used for prospective resources assessment in exploration prospects.

3.2.6.1. Probabilistic estimation of prospective resources

In the probabilistic method, a range of values that could reasonably occur in each volumetric parameter is used to estimate the resources in a given prospect (formula b), this will allow for the generation of a range of possible volumetric results in the estimation of prospective resources.

To do this, the first step is to identify the parameters according to the variables of the volumetric formula and the prospective resources are determined as a probability density function (PDF). The PDF is a probability function that describes the uncertainty around each individual volumetric parameter based on geological and engineering data.

The type of distribution of the PDF may vary for each of the parameters used and depends on the variable behavior, given the geological context and its nature. Using a stochastic sampling procedure, a value for each parameter will be randomly defined, as well as a recoverable volume of prospective resources and, by repeating this process a sufficient number of times, it will be possible to generate a potentially recoverable resources PDF (SPE, 2011).

This stochastic sampling methodology is known as Monte Carlo simulation and is shown schematically in Figure 4.

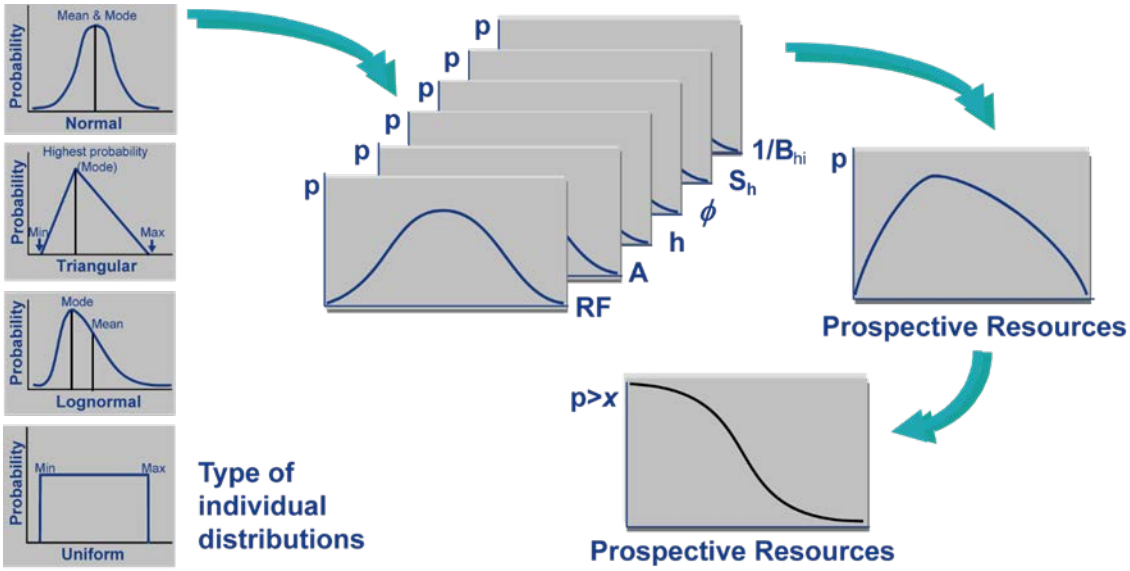


Figure 4. Schematic diagram showing the process of generating probability density functions of the volumetric formula parameters, which in turn are the basis for the generation of a probability density function and stochastic sampling (Monte Carlo simulation) for estimation of prospective resources (modified from SPE, 2011).

3.2.6.2. Volumetric parameters and their uncertainty distribution

The uncertainty in volumetric estimates of prospective resources is related to each parameter involved in the volumetric equation, which is described below.

Net rock volume (A*h). Estimation of the net reservoir rock volume is derived from the product of the area, the net thickness and a geometric correction factor, which is associated with the structural shape of the trap, the thickness of the potential reservoir within the trap area and the true dip angle, this factor can be estimated using predefined correction curves (Gehman, 1970; White and Gehman, 1979; White, 1987).

According to PRMS (2011), the net reservoir rock volume estimation usually concentrates most of the volumetric uncertainty of an exploration prospect and this uncertainty is mainly related to the following factors:

- An accurate definition of the prospect limits from seismic data interpretation;
- Time-depth conversion of seismic data;
- Dips on top of prospect objectives (correct migration of reflectors);
- Existence and position of faults; and
- The role of faults respect to fluids flow within the potential reservoir, that is, if they are seal or migration pathways.

This parameter depends critically on the geometric interpretation of the trap and on the estimation of the area and thicknesses since the volume of the prospect will increase or decrease proportionally with the variation of these parameters.

Rock properties: net-to-gross ratio and porosity (Ø). The uncertainty associated with the reservoir rock properties has its origin in the natural variability of the sedimentary sequences and is determined through petrophysical considerations or cut-off values

used in the evaluation of an exploration prospect, or in such a case, determined from the seismic response and its interpretation and correlation. Analogs in the establishment of these parameters can be representative only of a limited portion of a prospect objective, so it is important to make the correct selection of the analog or analogs in the equivalent portions to the objectives of interest.

Fluid properties. To estimate the type and fluid properties, especially the type of expected hydrocarbon, an evaluation of the potential source rock is required; this evaluation generally comes from a predictive modeling of the quality, effectiveness, maturity, type of organic matter, among other geological-geochemical parameters. These types of simulations are generally carried out with commercial software for sedimentary basins modeling or petroleum system analysis and through which it is possible to build maps of reservoir rock maturity, the type of expelled hydrocarbons, potential migration routes and potential drainage areas.

Otherwise, the type of expected hydrocarbons, as well as its expected physical properties, can also be determined based on analogs fields, surface seeps sampling and analysis, among other kinds of hydrocarbon emanations.

Since there is a great uncertainty in type and fluid properties estimation, due to the several geological processes that control the variability and homogeneity that hydrocarbons can have in a reservoir (secondary migration, presence of more than one source rock, biogenic degradation, etc.), it is recommendable to make probabilistic estimates in which the proportions of oil and gas may be present in a given exploration prospect.

Recovery factor (RF). Recovery factor estimation is recommended to be based on analogs, although it can also be estimated from engineering simulations and modeling studies, according to the potential properties of a possible reservoir. Once a volume of petroleum initially in place (PIIP) is estimated, the portion that can be recoverable from a certain number of wells and operating conditions should reflect the combined uncertainty of the estimation of the in-place volume and the recovery efficiencies of the development projects applied in the used analogs (SPE, 2018), where the range of uncertainty can be based on sensitivity analysis.

Selection of the distribution function type for each of the volumetric parameters. In the probabilistic estimation of prospective resources, it is an evaluator's task to specify the PDF that best depicts the available data's behavior. Some modern statistical tools allow us to select a PDF from a wide range of options (normal, log-normal, triangular, Poisson, etc.) (Figure 4).

The PDFs commonly used to describe uncertainty are the normal and log-normal distributions; however, its disadvantage is their lack of a limit, which can lead to unreal scenarios. One option is to truncate these distributions into fair values, although if the truncation impacts significantly the final form of the distribution, then it is more convenient to use another more appropriate distribution.

3.2.6.3. Risk assessment of exploration prospects

In the context of exploration prospects assessment, the probability of geological success or probability of success (Pg or PoS; respectively) is a numerical value that gives a quantitative measure of the probability of discovering producible hydrocarbons. This, without specifying productivity, hydrocarbon type or commercial factors.

On the other hand, in the same context, risk means the probability of failure related to the estimation of the probability of geological success (that is, Risk = 1-Pg) and uncertainty, refers to the range of possible values or dimension that the expected result may have (Bailey et al., 2001).

Thus, risk assessment is an analysis of the database confidence and the probability of occurrence of the geological models that support a possible discovery and its volumetric estimation (Rose, 2001). In that sense, probability of geological success estimation is based on the assessment of the elements and processes of the petroleum system, whose analysis involves knowledge and study of historical information, models, extrapolations and assumptions of geological phenomena, as well as a component of subjective judgments about local geological parameters.

Magoon and Dow (1994) define the petroleum system as a natural system that encompasses a hydrocarbon generating pod from an active source rock, which includes all the essential geological elements and processes for an accumulation of hydrocarbons to exist. The essential elements include the source rock, the reservoir rock, the seal rock and the associated processes are burial, the trap formation and the processes of generation-migration-accumulation of hydrocarbons.

As mentioned above, each of these elements are essential requirements for the existence of a hydrocarbons accumulation; for this reason, with the lack of presence or effectiveness of any of these, there will be no such accumulation. In order to evaluate the elements of the petroleum system that define the probability of geological success and assuming that the individual evaluation of each element and process is independent, the estimation of the probability of geological success can be obtained by multiplying the individual probability of the following factors (Murtha, 1995; Delfiner, 2000; Rose, 2001, Pemex, 2012):

- Source rock (P_{RG});
- Trap (P_T);
- Reservoir rock (P_{RA});
- Seal (P_S); and
- Timing and Migration (P_{SM});

Rose (2001) suggests that each of the five factors related to the probability of geological success should be assessed independently, even if each factor can be composed of several subcomponents and there is interdependence between them.

Currently, there are several proposed schemes and parameter combinations to estimate the probability of geological success. However, most authors and companies have arrived at the use of four or five critical probability factors, sometimes with disaggregated subfactors related to a main factor.

Whichever system is used, the principle must be the same; based on geological evidence and available information, evaluators estimate the confidence in each parameter expressed as decimal fractions or percentage, regarding the existence and effectiveness of the specific geological conditions in the subsoil for each prospect to be evaluated. Likewise, the serial multiplication of the probability factors numbers used should result in the probability of geological success of the prospect to be evaluated ($Pg= P_{RG} x P_T x P_{RA} x P_S x P_{SM}$).

According to Rose (2001), the expression of the probability of geological success then comes generally from subjective evaluations and depends mainly on three factors:

1. Reliability of data (direct, indirect, information quality, etc.)
2. Congruence of the used information, based on a judgment of suitability of the volumetric parameters used (area, thickness, recovery factor, etc.)
3. The evaluator's experience in estimating the different factors, based on regional geological knowledge and characteristics of the different analogs.

One of the biggest challenges in estimating the probability of geological success is to provide a probability value that represents both the effectiveness of the geological factors that make up the petroleum system and the reliability of the databases used to assess the volumetric calculation.

In that sense, there are several commercial software programs, computing tools and authors that propose systems and analytical matrices to estimate the probability of success of each factor that compose the probability of geological success (e.g. Otis and Schneidermann, 1997; CCOP, 2000; Pemex, 2012; Rose, 2001; Milkov, 2015), which invariably involve judgments about the quality and quantity of information, about the confidence of the interpretations made and about the analysis of the available geological information from wells results, analog fields and other information about the exploration history where the prospect to be evaluated is located.

Rose (2001) proposes a general analytical matrix and a subjective probability scale to estimate the relative certainty or uncertainty of the factors that integrate the probability of geological success in a given prospect (Figure 5).

The practical principle of this analytical matrix is to make assessments of the level of confidence within specific ranges, based on the quality and quantity of the available information, as well as the conclusions reached when interpreting the information. This is done, when it is possible, to obtain an assessment that can encourage or discourage the forecast, if there is a considerable amount of good quality information. Conversely, the lack of information or having low-quality information often limits the assessments to moderate or low values.

Many authors, including several commercial software programs and computer packages, find this matrix quite useful for assigning probability values in a consistent and standardized manner to each individual factor that composes the probability of geological success of a prospect. When using this analytical matrix proposal, we should keep in mind that the lack of information does not necessarily imply a negative result, just because of the lack of information when evaluating a given prospect.

Additionally, the individual assessment of the various factors that comprise the probability of geological success allows them to be analyzed more completely and objectively, improving the geological understanding of the prospect to be evaluated. It also permits the identifying of the factor or factors with the lowest probability; that is, identifying the "critical factors" helps to concentrate the analysis and revision in elements of greater uncertainty.

Since the probability of geological success of a given prospect can be obtained by multiplying five critical factors (Murtha, 1995; Delfiner, 2000; Rose, 2001; Pemex, 2012), some important aspects to be considered are described in general below, in the

assessment of the probability values for each individual factor, based on the given information and geological knowledge for a prospect to be assessed.

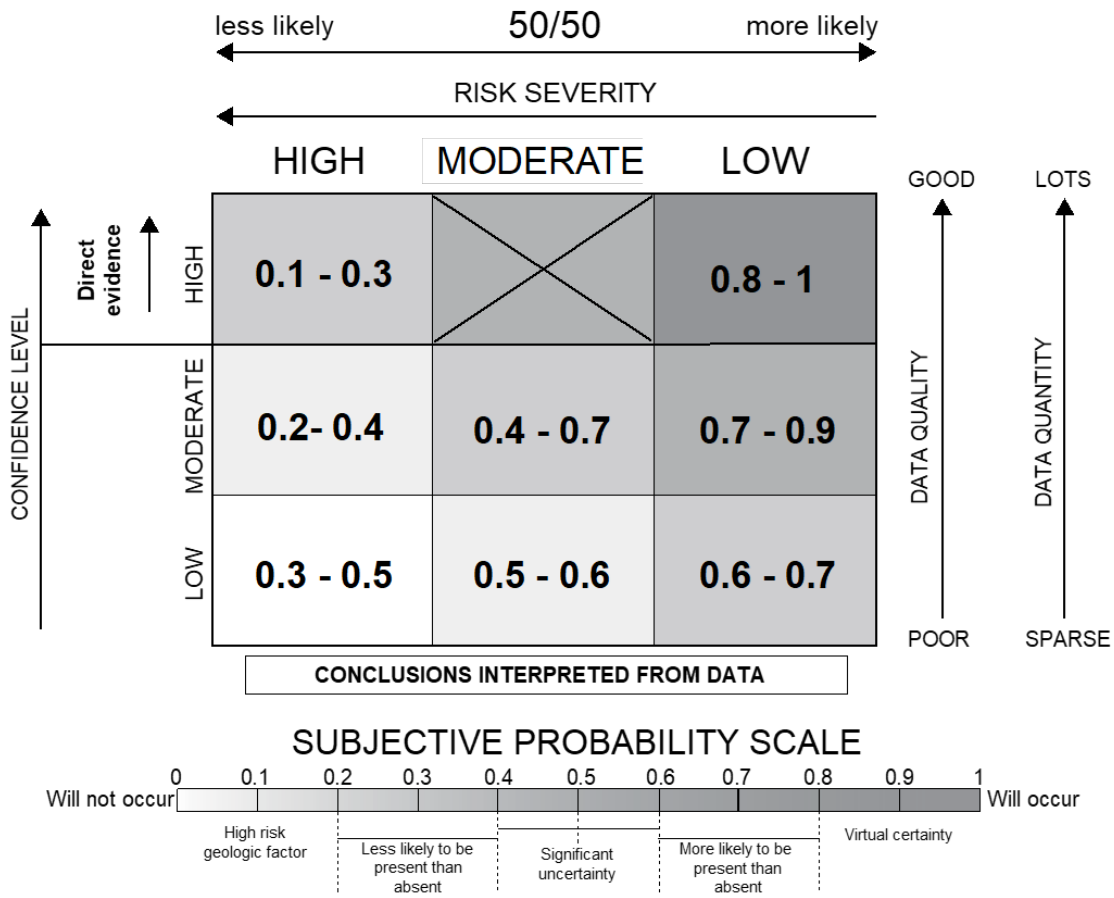


Figure 5. Generalized analytical matrix and subjective probability scale (modified from Rose, 2001) to estimate the certainty or relative uncertainty of the factors that integrate the probability of geological success in a prospect.

Source rock

The source rock probability factor represents the degree of confidence that one or more rocks exist that are capable of generating hydrocarbons, with sufficient surface extension, thickness, organic richness, thermal maturity, and kerogen type to generate a volume of hydrocarbons that allows for the charging of potential traps.

Also, its effectiveness can be assessed based on an analysis of the discoveries in the area and the source rock/oil correlations. This evaluation should take into account the number of control points and their distance to the prospect area.

Evaluation of source rock effectiveness is commonly carried out by analyzing the results of models and 1D, 2D, or 3D petroleum system simulations, according to the available information and through some specialized software. These types of studies also consider the sedimentary environment of the source rock, aiming to predict the lateral changes and the surface extension of the source rock facies.

Trap

The trap is a structural and/or stratigraphic feature which can be characterized geometrically, to which a closure is associated and in whose volume of rock it is possible to store a certain amount of hydrocarbons. Regarding the estimation of its probability factor, the existence of a closure should be considered, and that the area and thickness related to the closure (vertical relief) is sufficient to retain hydrocarbons.

The trap probability factor assessment usually depends on its interpretation from the seismic resolution, well information and in general, from the confidence analysis performed to the information used to map the prospect to be evaluated. There are several commercial interpretation software programs and methods to characterize the trap geometry, whether structural, stratigraphic or combined, they also help to define the closure area, volume and features of the geological objectives, allowing the user to analyze and to describe the location of faults, discontinuities, stratigraphic characteristics, spatial relationships of the spill point, among other characteristics.

Additionally, these tools also help to estimate the closure area rock volume, through interpretations and seismic attributes such as acoustic impedance analysis, amplitude variations, phase changes, etc., which allow volumetric representations to be made from seismic information in colors and perspectives, highlighting the characteristics of the trap and their associated rock volume.

When characterizing a potential trap and assessing its probability factor, it is essential to consider the following:

- Interpret all the identified objectives of the prospect to be evaluated, detailing the corresponding top and base objectives surfaces.

- Establish the geological model related to the geological structure mechanism of formation and corroborate that the characterization of the trap is consistent with the tectonic and structural context of the region where the prospect is located.

- Delineate and carefully map the area corresponding to the spill point of the trap.

- Assess the uncertainty associated with changes in seismic information domain from time to depth, and assess the quality of the seismic information used to determine the uncertainty that the interpreted trap exists and is in the correct location.

- Consider the use of seismic attributes to identify anomalies to help reduce uncertainty in the geometric and volumetric estimates of the trap, for example, by using attributes considered as direct indicators of hydrocarbons (DIH), RMS attributes (Root Mean Square) to delineate the distribution of potential reservoir rocks within the trap, among other kind of seismic attributes.

Reservoir rock

Reservoir rock probability factor assessment represents the degree of confidence of its existence in two components. The first regarding its presence, that is, according to geological and geophysical information, its existence is estimated in adequate thickness and distribution; and the second, that the reservoir rock has certain minimum

petrophysical conditions as assigned in the volumetric estimation, such as porosity, thickness and saturation of hydrocarbons.

Commonly, the components associated with the quality of reservoir rock are configured to meet or exceed the estimated minimum ranges of thickness, porosity, saturation and surface extent, so that there is a net volume of adequate reservoir rock to reach a stabilized and measurable hydrocarbons flow.

During prospect assessment, the distribution estimation of lateral and vertical properties of a potential reservoir can be made by constructing theoretical models or analog models from other basins, analysis of analog well logs, core samples analysis, etc., with the particular objective of establishing reasonable values of net thickness, porosity, saturation, etc. While in reservoir rock risk assessment, it includes the probability of its presence within the trap closure and that its quality characteristics, are equal to or greater than the estimated minimum value.

Seal

The seal probability factor assessment represents the degree of confidence related to the presence of rocks or geological elements that act as seals adjacent to the reservoir rocks and, in addition, that hydrocarbons that may have been placed have been preserved.

According to the combined element or elements that act as a seal, these can be in general grouped in structural elements (e.g. faults) or impervious rocks (e.g. salt rock, shales) that can sometimes correspond to stratigraphic discontinuities (e.g. facies changes, pinch-outs or wedges). In both cases, the main sealing mechanism is generated by differential permeability given a lithological contrast.

In the case of structural elements, the main characteristics to be evaluated are the type of faulting, the magnitude of dip angle, depth and pressure, lithological juxtaposition and the inclination angle of the strata through the fault; while in the case of impermeable rocks, the main characteristics to be evaluated are the type of lithology and its ductility, thickness, continuity and its integrity respect to the existence of fractures or faults that could affect its sealing capacity (Otis and Schneiderman, 1997).

Seal effectiveness assessment to estimate a probability factor will depend on the analysis performed on the surfaces that enclose the estimated volume of reservoir rock and in the context of the trap geometry; that is, the analysis performed on the top, base and the lateral sealing elements must be considered of equal importance. This assessment on the seal effectiveness in an exploration prospect should ideally be carried out under the assumption that the trap is filled with hydrocarbons at a certain time and that the sealing elements have the ability to retain a minimum hydrocarbons column.

For the preservation issues analysis, it is necessary to consider the geological events after the accumulation that may have affected hydrocarbons retention, as potential escape routes through faulting or degradation of the potential stored hydrocarbons by biological, chemical or thermal agents.

Timing and migration

A critical factor that must be carefully considered is the timing and spatial relationship of the petroleum system elements and the processes of generation, migration and accumulation of hydrocarbons, relative to the formation of the trap; that is, that the trap

has been formed in such a period of time that it has allowed the accumulation of migrated hydrocarbons.

Generally, the probability factor assessment for timing and migration is based on numerical models and petroleum systems simulation using specialized software. Regarding the timing, through the construction of geological events diagrams and burial history it is possible to represent the age, time periods and the spatial relationship of the essential elements and processes of the petroleum system, as well as the critical moment.

The critical moment is that point in time that best depicts the generation-migration-accumulation of most hydrocarbons in a petroleum system (Magoon and Dow, 1994) and is estimated based on various geological analyses and interpretations of the available information. The construction of geological events diagrams and burial history, as well as the identification of the critical moment, are of great help in evaluating the timing of the elements of the petroleum system.

On the other hand, migration assessment consists in determining the confidence level about the effectiveness of the conduits or routes that are visualized, so that the hydrocarbons have moved from the source rock to the trap. When analyzing potential migration mechanisms and pathways, it is necessary to consider the hydrocarbon type, structural complexity, the dip angle and direction of visualized routes, lithologies involved and the possible barriers existing along the route.

3.2.6.4. Risked resource volumes

Having a probability of geological success value and the estimation of prospective volumes, the risked resource volumes can be obtained, combining risk and uncertainty. Delfiner (2000), defines risked resource volumes as the portion of volume distribution in case of failure (1-Pg) plus the portion of the volume distribution in case of success through the following expression:

$$f_R\,(N) = (1 - \mathrm{Pg})\delta_0(N) + \mathrm{Pg}\, f(N) \qquad \text{(c)}$$

Where the expressed variables correspond to:

$f_R\,(N)$ = probability density function of risked resources
1-Pg = failure probability
$\delta_0(N)$ = probability component at the value zero ($\delta_0(N) = 0\ if\ N > 0$)
Pg = probability of geological success
$f(N)$= probability density function of resources given success (unrisked volumes)

The product of Pg by the mean value of the expected resources volume distibution given success, that is Pg*$E(N)$, is commonly known as the risked mean, and is equal to the mean or the average of the distribution values resulting from $f_R\,(N)$. Considering the portion of the curve of the probability density function (1-accumulated of at least one success), graphically the value at N =0, corresponds to the Pg and the area under the curve is equal to the risked mean.

For any given value of prospective volumes, risked volumes represent the value that is expected to be obtained at minumumt, given the probability of geological success. Considering that the mean is the most representative value of the resources volume distribution, the risked mean represents the minimum expected value of resources volume to be obtained given success.

3.2.6.5. Multiple geological objectives exploration prospect assessment

Prospects with multiple targets or geological objectives tend to have a higher value than those with a single objective, either because the aggregate volume is greater if more than one objective results in a reservoir or because the probability of success in more than one objective is also greater; or a combination of both.

When assessing prospects with multiple objectives, it is critical to keep in mind that the total prospective resources are not the sum of the volumes of each individual objective, nor is the probability of geological success representative of the prospect a simple arithmetic average or the sum of the individual probability of each objective. Adding more than one objective to an exploration prospect requires an analytical procedure that allows one to obtain a more appropriate estimate, involving concepts of conditional probability and stochastic simulation to model potential prospective volumes dispersion.

In the case of most exploration prospects with multiple objectives, these are partially dependent because they share probability factors for some of the elements that define the probability of geological success (Pg); that is, if given the success or failure in the first objective of the prospect to evaluate, this result will redefine the probability of the second objective, and so on. In the event that there is total dependence between objectives of the same prospect, then the objectives can be managed as one, including both in the estimation of net thickness (Pemex, 2012).

For example, given that two or more objectives in the same prospect generally correspond to the same geological structure, these may present independence from any of the geological elements, such as reservoir rock and seal, but be highly dependent on source rock and timing and migration. The geological factors shared between objectives of the same prospect are known as common factors (CCOP, 2000; Rose, 2001).

Since there are many possible combinations; that is, different geological factors can be independent, dependent or partially dependent, it is necessary to perform a dependency analysis for multiple objectives, considering the probability values for each factor that compose the probability of geological success and the distribution of prospective volumes for each of the objectives.

Murtha (1995) suggests a combined method to assess prospects with multiple objectives, through the analytical application of Bayes theorem (conditional probability) and Monte Carlo simulation (stochastic simulation). This method allows us to estimate a new probability of geological success and a prospective volume distribution for the aggregate of the objectives, considering that there is dependence or independence between them; that is, volume distribution and probability of geological success consolidated for the prospect.

Assuming that the exploration drilling of a prospect is conducted from the shallower to the deepest perspective of its objectives in sequential layers (layered prospects), the probability of success for the aggregate of the objectives is a composite event. For a prospect with *n* objectives number, there will be 2^n-1 scenarios through which it can be successful.

For example, considering a prospect with three objectives named A, B and C, there will be seven ways in which success can be achieved in at least one of the objectives:

- Exactly one success (three cases): A only, B only, C only;
- Exactly two successes (three cases): A and B, A and C, B and C;
- Exactly three successes (one case); A, B and C.

In that context, the probability of success of the prospect (for all its objectives or its consolidated value) can be interpreted as the probability that at least one objective is successful, so that the discovery of a certain volume of hydrocarbons occurs.

Murtha (1995) and other authors (e.g. Rose, 2001; CCOP, 2000; Delfiner, 2000) agree that the probability of geological success of a prospect can be defined as Pg = 1-P(failure), where P(failure) is the probability that all objectives will result in failure. For its estimation, it is necessary to specify dependencies between the objectives according to the Bayes theorem, considering the number of possible scenarios according to the number of objectives, the disaggregated probability values for each individual geological factor and considering an order in layered or sequential objectives.

This process can be represented by constructing a probability matrix that correlates the individual geological factors of each objective and the conditional probability factors, or by making of a decision tree diagram, which allows to map success and failure cases, starting from the shallower objective and branching to the deepest objective.

To estimate the probability of geological success of a multi-objective prospect, considering all possible scenarios according to the number of objectives, Murtha (1995) proposes a solution by solving a linear equations system, where the input data includes all the disaggregated probabilities by objective, plus certain conditional probabilities defined from the supposed sequential success of the objectives in drilling direction. Details on this systematic procedure can be found in the paper published by Murtha (1995).

It is important to be aware that the consolidated value of probability of geological success of a prospect will depend on the degree of dependence defined for each of the geological factors of its objectives. Having completely independent geological factors will result in a consolidated probability of success greater than when there is one or more dependent geological factors; that is, that the dependence increases between the geological factors will gradually reduce the consolidated value of probability of geological success of the prospect.

In that sense, the consolidated value of probability of geological success of a prospect can vary in a range that goes from the case where all the geological factors are fully independent to the case where all the geological factors are highly dependent, but without establishing a total dependency.

Although most prospects with multiple objectives have geological factors that in fact have some degree of dependence, it is necessary to carry out the conditional probability analysis carefully to avoid reducing the apparent probability of success significantly or to incorporate independence in the geological factors to illusively improve the value of the geological success of the prospect.

Another essential factor to consider is that the dependence between objectives increases dispersion in the distribution of the consolidated volume of the prospect; thus,

aggressively adding objectives or subdividing them to increase their attractiveness will only lead to a marginal increase in the total volume of the prospect and increase risk. For this reason, the definition of each objective of a prospect should be made considering that it is economically independent, whether or not there is any geological dependence.

Once the probability of occurrence of all possible success scenarios has been estimated according to the number of objectives, the distribution of potential prospect resources can be obtained through a stochastic or Monte Carlo simulation.

This random sampling simulation is done based on the calculated volumes for each objective in the form of probability distributions of the potentially recoverable resources and on the possible success cases of the objectives. The result of the iteration will give an aggregate volume that comes from the sum of the sampled values of each volume distribution per objective, related to the success case that is sampled in the simulation.

For example, considering again a prospect with three objectives named A, B and C, assuming a sampled volume for each objective of A = 10 million barrels of oil equivalent (MMboe), B = 15 MMboe and C = 20 MMboe, and a case of sampled success corresponding to the success in objectives A and C; then the aggregate volume will be 10 + 20 = 30 MMboe and a number of successes = 2.

After performing random sampling at sufficient number of times, a set of aggregated volume output values will be taken along its corresponding assumption of successful objectives that, through the statistical analysis of the cumulative distribution of output values, a probability density function will be createdcorresponding to the aggregate volume for the objectives of the prospect.

This resulting volume distribution, together with the probability value that at least one objective is successful, represents the consolidated values of the prospect. The representative objective of the prospect, that is, the consolidated objective, will be the one that, given its estimated volume and probability of occurrence, adds the largest volume to the distribution.

3.3. PLAYS PROSPECTIVE RESOURCE ASSESSMENT

A petroleum system is a natural system that encompasses a hydrocarbon-generating pod from an active source rock, which includes all the essential geological elements and processes for the accumulation of hydrocarbons to exist; using this definition, Magoon and Dow (1994) formalized the criteria for identifying, mapping and naming petroleum systems.

Using this concept of a petroleum system, only discovered hydrocarbons were considered; thus, Magoon (1995) incorporated the concept of complementary plays into the definition to include undiscovered accumulations and the risk associated with exploration. Therefore, the main difference between the play and the petroleum system is that in a play the accumulations of hydrocarbons are not discovered, while in the petroleum system the accumulations are already discovered; that is, the play is only that part of the petroleum system that has not yet been discovered (complementary play).

However, this differentiation separates the prospective component from the accumulations discovered in a given area, hindering the use of analogs in exploration and integral analysis.Considering this, Magoon and Schmocker (2000) define the Total Petroleum System concept to include within a defined geographical extension all the discovered accumulations, the accumulations not yet discovered but potentially identified by exploration prospects, and the remaining accumulations that are yet to be identified and discovered.

The Total Petroleum System covers the petroleum system of Magoon and Dow (1994) plus the sum of all potential accumulations not discovered in complementary plays. Therefore, under the unified concept of Total Petroleum System, the play analysis considers all fields and prospects within a geographically defined area that has a group of geological factors in common and shares one or more closely related source rocks.

Fields and reservoirs within a play have reservoir rocks with similar geological and petrophysical characteristics and, therefore, also have similar production patterns and behaviors; likewise, exploration prospects, reservoirs and fields within a play will have similar characteristics of structural styles, seals and timing and migration processes. Assuming that a set of fields, reservoirs and prospects have a group of geological factors in common, a coherent log-normal distribution can be constructed by analyzing the values of their recoverable volumes or resources (Rose, 2001).

In terms of prospective resources assessment, one of the fundamental goals of play analysis is to estimate the volumes that remain to be identified and discovered within its geographical extent, as well as its probabilities and uncertainty, considering the hydrocarbon volumes of each field or reservoir discovered and all assessed objectives of the prospects that belong to the play. The analysis of the distribution of the volumes already discovered is used to calibrate and give congruence to the estimates of the undiscovered resources for plays where there have not yet been discoveries the calibration can be performed from suitable geological analogs.

Play prospective resources assessment is carried out at lifetime; that is, all the resources that could exist in a play without a time limit are assessed, based on the available exploration information, on the characteristics of all the discovered fields and reservoirs and considering the identified prospects within a play at a certain date. Important updates in exploration and well information, as well as the discovery of new volumes, will motivate prospective resource updating; it is an international practice that resources estimates be reviewed after a period of 3 to 5 years (Pemex, 2012).

There are several ways to assess prospective resources at play level and this depends on their maturity, the information available and the computer tools available to make the estimates. Table 1 shows a summary of some of the most common methods used in assessing the yet-to-find or prospective resources in a play.

Given the variety of possible methodologies based on the information available, the advantages and disadvantages they offer and the objective for assessing plays, it is possible to combine them to meet specific objectives or needs, or to take advantage of certain characteristics of one to complement another.

For example, the Norwegian Petroleum Directorate (NPD) makes probabilistic estimates of prospective resources volume (yet-to-find resources), considering the mapped and unmapped prospects as a total in a play, where the input information for the estimate is

a volume distribution of prospects, a number of additional prospects that could occur in the play and an average probability of success (Østvedt et al., 2016).

Table 1. Summary of some of the most common methods used in assessing prospective resources in a play, indicating some of the institutions that use them.

Method	Required information	Complexity	Description	Limitations
Areal Yield	minimum	simple	Consists of extrapolating based on an analog, a resource volume per unit area.	Does not consider geological variations in the play elements.
Geochemical balance or source rock mass balance (e.g. ANH Colombia)	high	complex, from spreadsheets and basin modeling	Consists of estimating the amount of hydrocarbons generated in the basin and therefore, how much could be trapped in a play.	Losses due to migration processes are difficult to assess, difficulty to distribute volumes in more than two plays over the same area, difficulty modeling more than one source rock and biogenic gas.
Creaming curves (Meisner and Demirmen, 1981)	low	easy	Consists of plotting accumulated discovered volumes as a function of time or a number of wells. From a volume normalization, future success is predicted in a play and the volumes to be discovered, defining whether the discoveries have an upward trend (immature play) or a constant trend (mature play).	This approach assumes that larger fields will be discovered towards the early stages in the exploration of a play and as progress is made in exploration, smaller fields will be discovered. Plays in early exploration stages tend to have underestimated volumes under this approach, do not consider geological risk factors and as discoveries are made in a play, the curve will be drastically distorted.
Field Size Distributions	low	easy	Consists of plotting the discovered fields volume by size and under the assumption that the distribution follows a pattern, it is possible to identify the gaps or missing volume in the distribution to estimate a prospective volume that fits the distribution.	A drawback to this approach is that the field size distributions do not follow a pattern in all cases and it is necessary to limit the maximum and minimum ranges. Additionally, it is necessary that the play has a certain number of discoveries or analogs for the analysis to be representative.
Prospect inventory summation (p.e. UK Oil & Gas Authority, 2016)	high	complex, it is necessary to estimate risked prospective volumes for each prospect	Consists of adding the risked mean prospective volume of all the prospects identified within a play.	This approach does not allow estimating prospective volumes in unmapped areas within a play, or in areas with petroleum potential where exploration prospects have not yet been identified and assessed.
Stochastic simulation of future discoveries or Feature count stochastic prediction (p.e. BOEM, USGS)	moderate	easy, if computer tools or appropriate software is available for the simulation	Consists of probabilistically estimating the number of future discoveries based on the size distribution of discovered fields, geological success and an estimated number of exploration wells to be drilled.	This approach depends on the establishment of a number of prospects to be drilled based on the history of play, which is difficult to estimate, especially in early exploration plays. Generally, the density of discovered fields in a play determines the total number of fields and volumes that will be discovered in the future.

According to Østvedt et al. (2016) and Blystad and Sødenå (2005), the NPD has a large inventory of prospects generated from various regional studies, applications to participate in bidding rounds, and licensee reports, so that an important input for prospective resources estimation at play level is made up of the number of identified prospects.

In the case of mature plays, the assessment is done by combining the information of discovered fields with identified prospects through the historical analysis of discoveries or creaming curves, by sequentially ordering the discoveries and assuming that the larger volume prospects will be drilled sequentially, calculating the deviation resulting from an

ideal curve. Finally, statistical analysis is performed to model the remaining number and size of unidentified prospects through a probability distribution.

In the case of underexplored plays or plays without discoveries, the information from the identified prospects is the main source of information. Its volume and spatial context in the play provide the basis for the estimation of total prospective resources.

In both cases, once the average probability of success is established, a stochastic simulation is performed to generate prospective resources distributions. The total resources in the play represent the sum of the prospects identified and the unmapped prospects, taking into account the probability of success (NPD, 2016).

NPD assessment shows the application of three different approaches to estimate prospective resources in a play: the sum of identified prospects, a historical analysis of discoveries or creaming curves and stochastic simulation of future discoveries or feature count stochastic prediction.

Despite the differences that exist in the approaches to estimate undiscovered resources in a play, there is agreement about the importance of prospects as a strategic element in exploration. Magoon and Dow (1994) illustrate this importance within their four levels of investigation in petroleum exploration, which ranges from sedimentary basin and petroleum system to the play and the prospect.

Since the identified exploration prospects provide a geological basis for prospective resources volumes estimation, it is important to consider them within the play assessment. By grouping the accumulations already discovered and the identified prospects as a geologically related family, one can have a better view of the possible characteristics of the prospects yet to be identified in a given area.

According to the above, prospective resources quantities in a play can be estimated as follows:

Prospective Resources in a Play *= (Number of future discoveries)*(Mean size volume of the future discoveries)*

Where in turn:

Number of future discoveries*= (Number of identified prospects within the play + Number of unidentified prospects)*(Probability of geological success)*

Mean size volume of the future discoveries *= Mean volume distribution of the future discoveries within a play*

In order to perform the assessment at play level based on the above, it is necessary to conduct the following analyses:

1. Definition of the play and its geographical extent.
2. Distribution of the number and size of discovered fields or reservoirs and identified prospects.
3. Estimation of the number of future discoveries.
4. Size distribution of future discoveries.

It is important to consider that the play assessment analysis to estimate the potential volumes to be discovered can be performed in the entire geographical extent inferred for

the play or in a portion of its total extent. In the case of partial extent assessment, the subdivision is generally due to administrative reasons (e.g., state, international bordering limits), technical reasons (e.g., 3D seismic partial coverage, poor quality information zones), economical (e.g., water depth technical drilling limits, special economic zones) or just for convenience.

Prospective resource quantification at play level is useful as a comparative measure of the total amount of hydrocarbons estimated to exist in a given area, based on the information available at a certain date. However, the assessment results do not imply a discovery rate or a probability of commercial success within a specific time frame; that is, it is highly uncertain to use quantities of prospective resources at play level directly to estimate a conversion rate of prospective resources to reserves and, ultimately, to production.

The workflow used is schematically represented in Figure 6. This workflow to estimate prospective resources at play level is briefly described below.

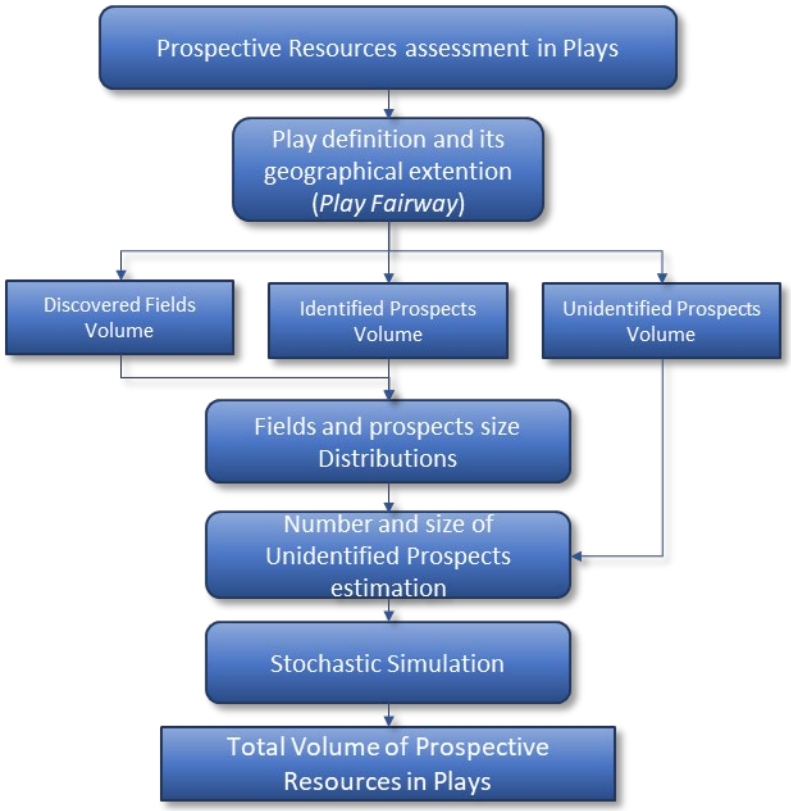


Figure 6. Chart that shows the process used for prospective resources assessment in plays.

3.4.1. Play definition and its geographical extension: play fairway analysis

To assess a play, the systematic mapping of the main elements of the petroleum system is essential to identify geographically, the limits where all factors converge so that an accumulation of hydrocarbons exists. The process by which all available information is integrated to determine the current maximum geographical area where the elements

and processes of the petroleum system coincide at a specific stratigraphic level is known as play fairway analysis.

Play fairway analysis allows us to generate distribution maps of source rocks, reservoir rocks and seal elements (lithological and/or structural elements) within a specific area, where the same source rock can charge several reservoir rocks and traps in different stratigraphic horizons and in turn, the same reservoir rock and trap can contain hydrocarbons from several active source rocks. Similarly, the associated seal elements are usually present regionally, like wide distributed shale formations, intercalated shale packages, characterized by one or more structural styles, or as a combination of lithological and structural seal elements.

For this reason, for each group of plays defined by its reservoir rock in a given area it is generally possible to create a single map that represents the distribution of the source rocks and, sometimes, of the seal elements. That is, the plays are essentially defined by the stratigraphic horizon that contains the reservoir rocks (Allen and Allen, 2003).

Authors such as Demaison (1984), White (1988), Grant et al. (1996) and Fugelli and Olsen (2005), characterize play fairway as the maximum possible extension of the reservoir rocks within a specific stratigraphic range of the play; however, in addition, to define the maximum reservoir rocks extent, it is important to establish their relationship with the existence of seal elements (regional or local) and hydrocarbon charge. The mapping of structural elements is also used to identify and define the characteristics of potential traps.

Currently, three different approaches are generally used to refer to a specific play, based mainly on the characteristics of the reservoir rocks (Doust, 2010):

- Stratigraphic definition (e.g., Neogene, Lower Miocene, Albian-Cenomanian, etc.), where the age of the main reservoir rock determines the play.

- Lithological facies definition (lithology or depositional environment), where the sedimentary facies or the associated formation name of the main reservoir rocks determines the play.

- Structural definition (common structural style), where the type of traps geometries determines play.

Additionally, the categories in which a play can be placed usually refer to its level of certainty, regarding the petroleum system in which it is located (Magoon and Beamount, 2003), or regarding its status in exploration (Doust, 2010):

- Speculative plays, where their existence has not been detected in a particular area of a basin, but is considered to be present and is inferred conceptually or by analogy in similar basins.

- Unproven plays, where its existence may have been identified and its concept has been shown to work but has not yet been drilled.

- Emerging plays, which despite including producing fields, are still considered of high risk.

- Mature plays, which have had a long history of production in an advanced state of exploration and development.

Generally speaking, they can be grouped into hypothetical plays (the first two) and established plays (the last two).

To create maps that allow for the definition of distribution of the main elements of the petroleum system that act as a support to play fairway analysis, it is necessary to have an understanding of the regional geological model of the area of interest, as well as the development of the present stratigraphic sequences, sedimentary environments and lithological facies distribution. These types of maps are known as gross depositional environment (GDE).

The main objective of GDE mapping is to provide an overview of the stratigraphic framework of the play and allow more reliable predictions about its distribution and a better representation of the present sedimentary environments. For its generation, it is necessary to analyze and interpret data and well correlations (core rock samples, well logs, etc.), seismic facies analysis, structural interpretation of horizons in time/depth and be supported by using seismic attributes (amplitude, spectral decomposition, etc.), so that there is an understanding of all the sedimentary environments present, their associated lithological facies and their characteristics.

For GDE mapping, it is possible to consider up to two main levels of seismic interpretation: definition of lithotypes applied to the entire stratigraphic column; that is, to distinguish between different lithological types or facies based on seismic attributes, or stratigraphic sequences interpretation (sequence stratigraphy) to determine facies distribution.

Within the same play, all discovered fields and prospects share common geological factors of the petroleum system; however, due to the interaction and variations in the probability of occurrence of each geological factor over the entire area of the play fairway, there are spatial variations in the value of the probability of geological success of the play. That is, the probability of geological success of the play will hardly be homogeneous over its entire extent.

This variation allows us to divide the surface on which the source rocks, reservoir rocks and seal elements are distributed into segments, where each segment will have a probability of local geological success and within the surface of each segment the probability is constant or common. In this way, it is possible to divide regional distribution maps of risk elements into common risk segments (CRS).

The number of maps related to the geological probability factors for the construction of the CRS can vary, although it is common practice that these maps not be complex and include information on the play at the reservoir rock, source rock and seal elements level, in order to describe the total risk satisfactorily (Shell E&P, 2015).

All regional risk maps for each element in a specific play can be spatially or geographically combined to create a single map that shows the overall risk variation throughout the play. These types of maps are referred to as composite common risk segment (CCRS), or play fairway summary risk maps.

Generally, the CRS and CCRS maps show common relative risk areas qualitatively, assigning low-risk areas in green, moderate risk areas in yellow and high-risk areas in red,

as a widely used convention. According to Grant et al. (1996), the low-risk green areas imply that in that area, the element of risk is favorable, that is, there is evidence from the regional analysis that the element is present; the moderate-risk yellow implies that the element reflects contradictory evidence or possibly is absent and the high-risk red implies evidence that the element is unfavorable or may be absent.

The probability of geological success of an exploration prospect is the evaluation of local geological factors, while the geological risk of the play obtained through the play fairway mapping is a way to risk geographically, it is regionally obtained and is not specific about any prospect, although it is a good way to contextualize the prospects assessment along with the play.

According to Rose (2001), the play probability is defined as the probability that in the play area, the applied probability of geological success factors to all assessed prospects are satisfied, that is, that there is an active petroleum system somewhere in the area and within the defined stratigraphic range of the play. When multiplying the average probability values of each element of the petroleum system in the prospects, the result of the probability of exploration success in the play should be very close to the average probability of geological success (Pg) of the prospects in the play.

The probability of geological success of a prospect is obtained from each of the individual factors assessed of the petroleum system $Pg_{prospect} = P_{RG} \times P_T \times P_{RA} \times P_S \times P_{SM}$ (section 3.2.6.3), where CRS maps can influence these values but not modify them directly. Some variations to this approach involve estimating the geological risk at play level based on the common relative risk of segments and combining it with the geological risk of the prospects to finally manage it as a total risk; that is, $Pg_{TOTAL} = Pg_{play} \times Pg_{prospect} = (P_{RG\ play} \times P_{RA\ play} \times P_{Splay}) \times (P_{RGprospect} \times P_{Tprospect} \times P_{RAprospect} \times P_{Sprospect} \times P_{SMprospect})$.

Several authors (e.g. Pemex, 2012; Rose, 2001; Grant et al., 1996) propose to risk prospective volumes of the play with the Pg_{TOTAL} value, which impacts the total undiscovered resource volumes, especially in hypothetical plays, since for established plays $Pg_{play} = 1$.

The disadvantage of this approach is that is more complex, the sum of the risked mean value of resources for identified prospects will tend to be greater than the total of undiscovered resources at play level, and finally is interpretative; since it is only a matter of how to assign and weigh the risk on the play surface. Therefore, if this approach is adopted, the risk must be carefully managed to avoid risking the prospective volume twice.

Common risk maps of plays are usually used only to qualitatively estimate regional risk distribution and to identify specific areas where hydrocarbon accumulations are most likely to be found. On the other hand, the GDE maps are key in spatial or geographical analysis of discovered fields and identified prospects, which serve as the basis for the estimation of the number of unidentified prospects.

3.4.2. Discovered fields and identified prospects size distribution

After play definition, the first step for its volumetric assessment is the construction of the probability density function derived from the set of discovered fields and the geological objectives of all the identified prospects that belong to the play. The assessment of the total hydrocarbons volume that may exist in the play is based on recoverable amounts of

hydrocarbons in all discovered accumulations (commercial and non-commercial) and in the volume estimation of those that have not yet been discovered.

Just as discovered fields may have different stratigraphic reservoir intervals, the identified prospects can be multi-objective; in both cases, each field reservoir and prospect geological objective has its own characteristics and a given volume. For this reason, it is very important to assign prospect geological objectives and field reservoirs consistently to a certain play when analyzing distribution of their volumes.

If two or more reservoirs in the same field, belong to the same play, their recoverable volumes can be added as part of the total volume in the play. However, in the case of two or more geological objectives of the same prospect given its characteristics have to be grouped in the same play, it is recommendable to calculate the consolidated volume for the objectives of the prospect located in the same play to avoid overestimating the prospective volume.

Using volumetric analysis of a play, through the construction of a joint probabilistic distribution between fields and identified prospects, it is possible to obtain a field size distribution and compare the congruence of data regarding the size distribution of the identified prospects in a play (Figure 7). The comparison of the identified prospects volume along with recoverable volume of discovered fields could be done considering the mean volume values in equivalent units.

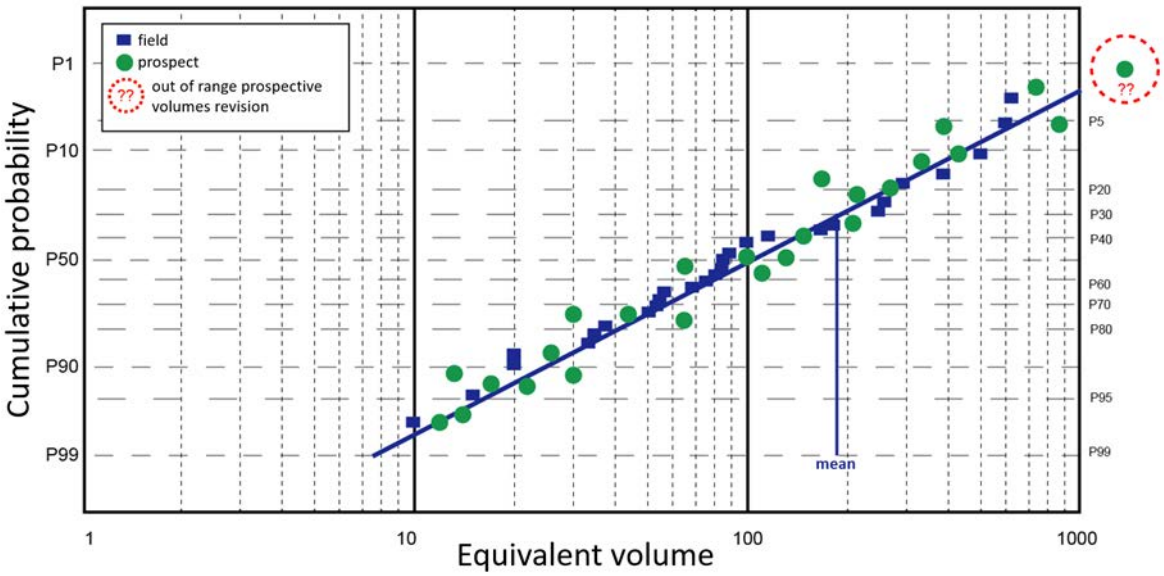


Figure 7. The comparison of volumetric distributions of discovered fields and identified prospects allows for the definition of congruence between prospective volumes and the history of discoveries of a play (modified from Shell E&P, 2015).

In some cases, the prospects mean volumes could exceed the maximum trend of fields volume distribution, for example, when there are segments underexplored in a play or for the lack of technology that have limited the exploration, or areas with high influence of salt tectonics, where the seismic image below the salt tends to be of poor quality. When this is not the case, the detection of out-of-range prospects' volumes requires a review and, where appropriate, reassessment of the prospects volume that are outside of a reasonable range, if there is not enough geotechnical basis to justify them.

For hypothetical plays or plays with a recent exploration history, identified prospects are the main source of information for their volumetric distribution, so it is recommended to calibrate the volumetric distribution in this kind of plays with a discoveries history in a mature analog play. Since it has been observed that there is a general tendency to overestimate identified prospects volume (Blystad and Sødenå, 2005), it is important to carefully assess those prospects with a high prospective volume; this, despite the fact that larger volume prospects generally present a high risk also, high volume prospects have a direct impact on the total prospective volume distribution of a play.

3.4.3. Assessment of the number and size of future discoveries

For established and hypothetical plays, total undiscovered or prospective resources include the mean volume of identified prospects and a volume of unidentified but inferred prospects within the play. To estimate unidentified prospects' volume, the integrated distribution of recoverable volumes of discovered fields and identified prospects is the basis for assessing a potential volume that remains to be identified and discovered.

For the assessment, geological success is assumed for identified prospects and, based on the surface extent of the play and the density of fields and identified prospects per unit area, a number of prospects to be identified can be determined by spatially analyzing play characteristics using GDE maps. Feature counting is done using the geographical distribution of sedimentary and structural features, as well as the identified trends in the play and seismic coverage, considering gaps that could be in the geographical distribution of identified prospects, fields or, if it is the case, structures previously drilled in the play that resulted in dry holes (Figure 8).

Assuming that in GDE mapping all available information is analyzed and the prospective play area is determined, the unidentified prospects count will concentrate in those areas where the play is inferred, but where it is not possible to visualize prospects. Considering an average density of discovered fields and identified prospects per unit area, the number of unidentified prospects and their size volume is given as a range or distribution, with which, by assigning a probability of occurrence, it is possible to generate a new volume distribution related to future prospects to be identified through a stochastic sampling simulation (Monte Carlo simulation).

Prospective resources of plays represents the total amount of recoverable hydrocarbons corresponding to identified and unidentified prospects considering the probability of geological success, which is an estimate of what is technically possible to discover in the future. Total prospective resources in a play reflect the exploration potential associated with the current knowledge and the information available at a certain date, so that the progress in exploration activities that provide new information will cause adjustments in the estimates and in the prospective resources assessment.

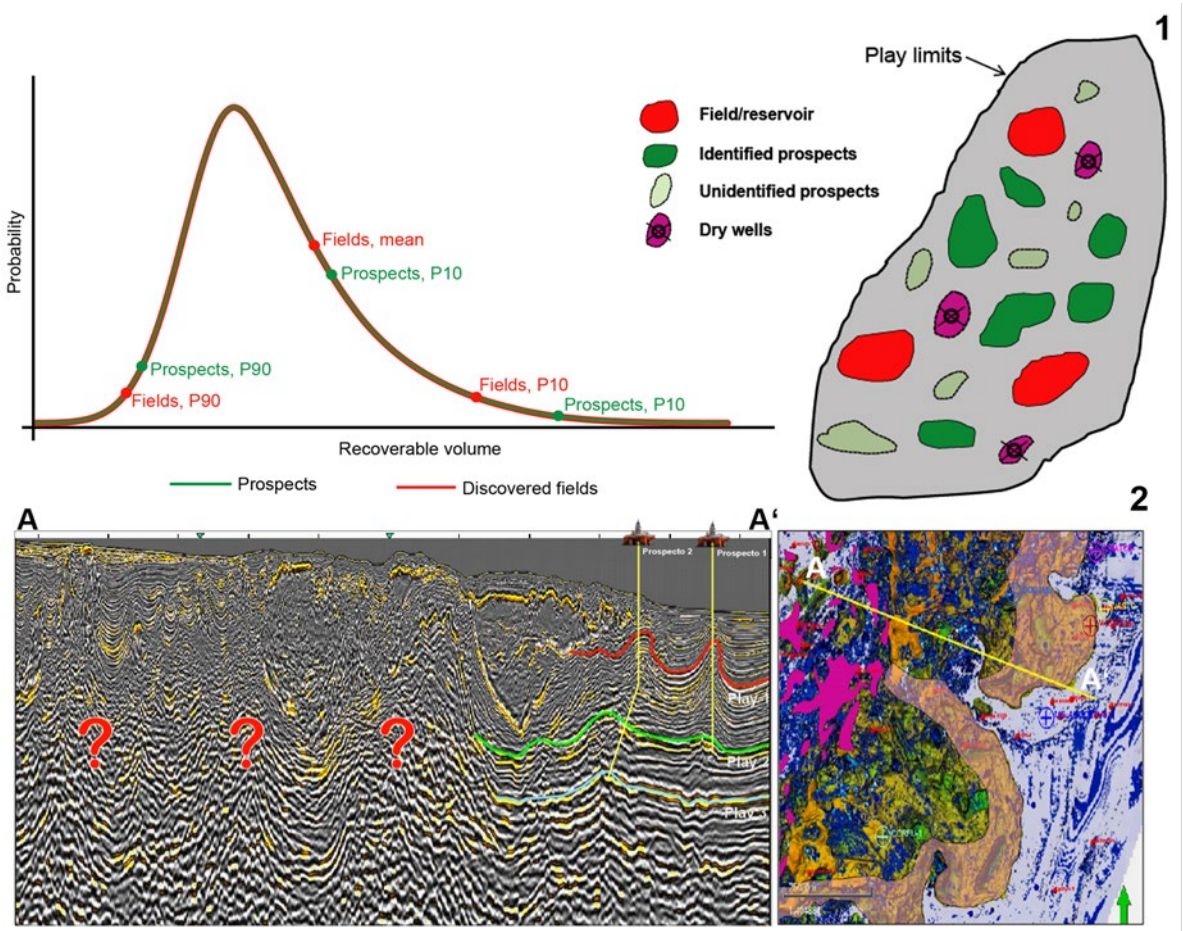


Figure 8. (1) To estimate the unidentified prospects volume, the integrated distribution of recoverable volumes of discovered fields and identified prospects is the basis to asses a potential volume that remains to be identified and discovered, along with the analysis of geographical distribution of sedimentary and structural features in the play. Unidentified prospect count and its related potential volume, focuses on those areas where it is inferred that play exists, but it is not possible to visualize prospects (2).

4. DEEPWATER PROSPECTIVE RESOURCES

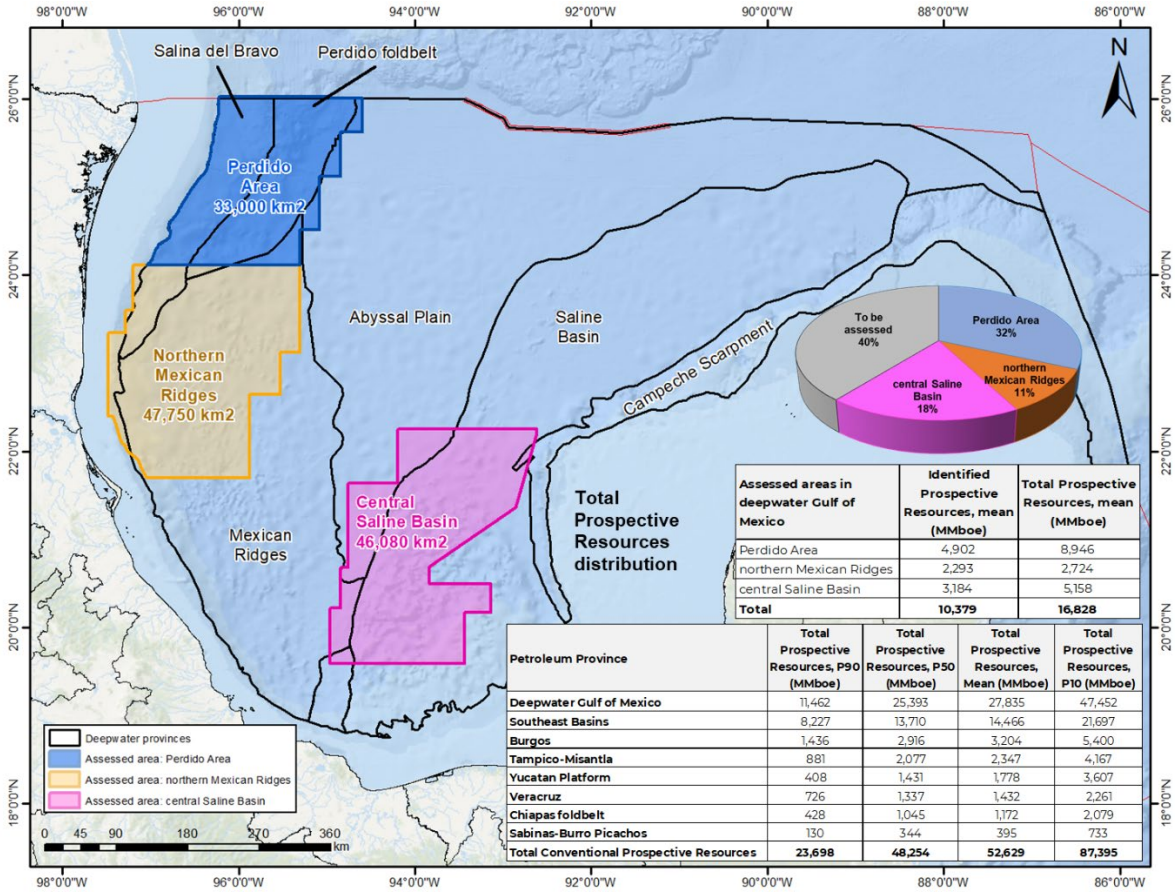
As of 2018, total conventional prospective resources inof Mexico average 52.6 billion barrels of oil equivalent (Bboe), of which approximately 53% is located in deepwater Gulf of Mexico; that is 27,835 MMboe. This amount is distributed in a total of 11 different plays previously identified and defined through deepwater Provinces (Figure 9).

Since 2015, various actions have been implemented to increase the exploration information collection of the country and knowledge of the Mexican subsoil, such as the geological and geophysical information permits program (ARES, by its Spanish acronym), which allowed to carry out several kind of studies and information acquisition with the objective of locating potential hydrocarbons accumulations in the subsoil. From this program implementation, 2D and 3D seismic coverage of the Mexican part of the Gulf of Mexico increased from 35% to 100% with different acquisition technologies and processing algorithms.

Furthermore, as oil and gas exploration and extraction activities progress, new exploration wells have been drilled in deepwater that have provided new information, which together with the new seismic information, lead to an update of the prospective petroleum potential in deepwater Gulf of Mexico. In that sense, prospective resources assessment of the country is updated progressively, from high petroleum potential underexplored areas (frontier areas) and starting within specific regions where new and relevant information is now available, allowing to support prospective resource assessment updating.

In this first stage, the prospective resources assessment is updated in a total surface area of 126,830 km^2, approximately, corresponding to the Perdido Area (33,000 km^2), northern Mexican Ridges (47,750 km^2) and central Saline Basin in deepwater (46,080 km^2). These three selected regions concentrate approximately 60% of the total quantified mean prospective resources in deepwater (16,834 MMboe), which is equivalent to just over a third of the conventional total mean prospective resources of the country.

The map in Figure 9 shows the three selected areas for prospective resources assessment updating, within the context of deepwater Geological Provinces and to the previous conventional mean prospective resources quantification as of 2018. Table 2 shows the general balance of prospective resource estimates within the areas assessed and updated in this first stage.



Assessed areas in deepwater Gulf of Mexico	Identified Prospective Resources, mean (MMboe)	Total Prospective Resources, mean (MMboe)
Perdido Area	4,902	8,946
northern Mexican Ridges	2,293	2,724
central Saline Basin	3,184	5,158
Total	**10,379**	**16,828**

Petroleum Province	Total Prospective Resources, P90 (MMboe)	Total Prospective Resources, P50 (MMboe)	Total Prospective Resources, Mean (MMboe)	Total Prospective Resources, P10 (MMboe)
Deepwater Gulf of Mexico	11,462	25,393	27,835	47,452
Southeast Basins	8,227	13,710	14,466	21,697
Burgos	1,436	2,916	3,204	5,400
Tampico-Misantla	881	2,077	2,347	4,167
Yucatan Platform	408	1,431	1,778	3,607
Veracruz	726	1,337	1,432	2,261
Chiapas foldbelt	428	1,045	1,172	2,079
Sabinas-Burro Picachos	130	344	395	733
Total Conventional Prospective Resources	**23,698**	**48,254**	**52,629**	**87,395**

Figure 9. Map showing the selected areas for prospective resources assessment updating, in the context of deepwater Geological Provinces of the Gulf of Mexico and conventional prospective resources estimates as of 2018.

Table 2. General balance of conventional prospective resources estimates as of 2018, for the areas assessed and updated in this first stage.

Assessed areas in deepwater Gulf of Mexico	Identified prospective resources (MMboe)					Total prospective resources (MMboe)			
	P90	P50	Mean	P10	Risked mean	P90	P50	Mean	P10
Perdido Area	3,420	11,104	15,502	34,430	4,902	4,130	8,373	8,946	16,588
Northern Mexican Ridges	1,103	5,987	11,586	29,948	2,293	815	2,054	2,724	5,949
Central Saline Basin	2,552	9,277	13,551	31,093	3,184	1,928	4,703	5,158	9,411
Total	**7,075**	**26,368**	**40,639**	**95,471**	**10,379**	**6,873**	**15,130**	**16,828**	**31,948**

Prospective resources assessment updating in selected areas is done at play level, under Total Petroleum System concept (section 3.3) using a probabilistic approach, where prospective resources in identified and unidentified prospects, constitutes the total prospective resources volume in a play. Likewise, the sum of prospective resources in each defined play within the evaluated polygons, will result in the total prospective resources volume of the area and the mean value is considered as the best estimate.

This approach is compatible with the one used in previous assessments, so the estimated prospective volumes within the areas where the assessment is updated, are comparable and complement each other in the context of the total conventional prospective resources.

Plays delimitation within the three assessed areas, sometimes corresponds to portions of a geological play that has been subdivided for assessing convenience, due to a combination of administrative factors regarding water depths and international borderlines, as well as technical factors related to exploration information coverage and morpho-structural styles. Play definition is mainly dominated by the distribution of the stratigraphic horizon that contains the potential reservoir rocks, in combination with its classification according to its state in exploration.

So, defined and delineated plays within the assessed areas will have a composite nomenclature related to the Petroleum Province (GP = Deepwater Gulf of Mexico), the assessed area name (AP = Perdido Area; CM = Mexican Ridges; CS = Saline Basin), its category according to its state in the exploration (E = Established; H = Hypothetical) and finally, the chronostratigraphic interval associated with the potential reservoir rocks age, their lithology, associated facies, depositional environment, formation name, or a combination of all.

5. PERDIDO AREA

5.1. STUDY AREA CHARACTERISTICS

Perdido Area is located northwestern of the Mexican side of the Gulf of Mexico in front of the coastline of the Tamaulipas State, in water depths that vary from 500 to 3,600 m and limits the marine borderline with the United States of America to the north. The assessed area is about 33,000 km^2 (Figure 10).

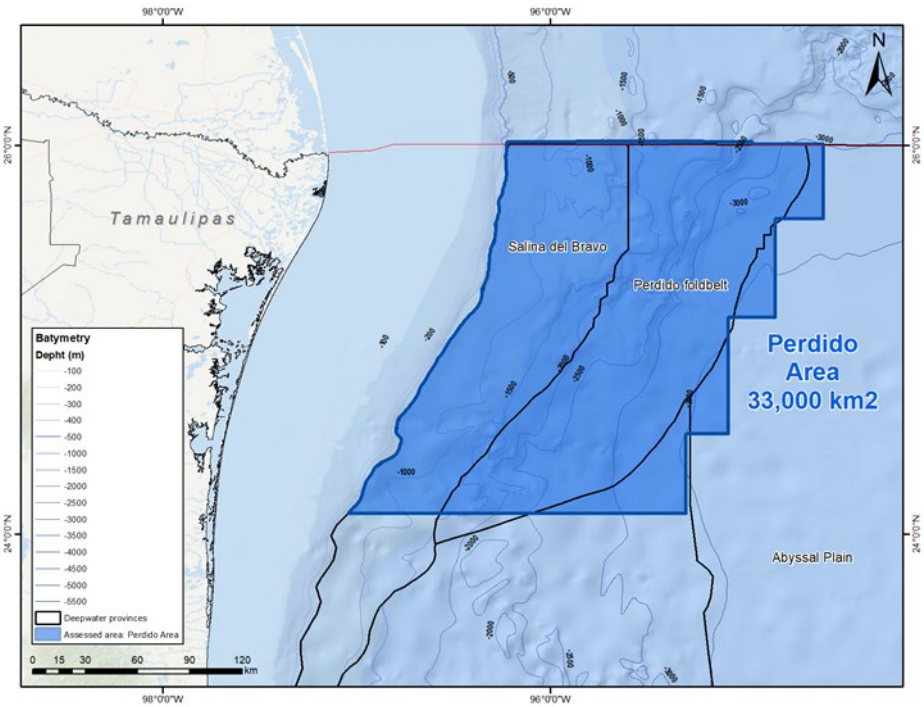


Figure 10. Geographical delimitation of Perdido Area.

The 500 m isobath is taken as the west limit of the Perdido Area, which is considered as the beginning of the deepwater zone, its east limit is the Gulf of Mexico abyssal plain and to the south it goes as far as the northern limit of the assessed area of northern Mexican Ridges. The Perdido Area wraps up almost the totality of the Perdido foldbelt Geological Province, and partially the Salina del Bravo Province.

Salina del Bravo Province has salt sheets and salt canopies linked to salt diapirism injected from west, resulting in a rugged topography of the seabed, in addition, Paleogene mud intrusions had been identified as diapirs and walls; in contrast, the Perdido foldbelt is characterized by long and tight folds up to 40 km in length, generated by the gravitational collapse of the continental shelf and its related Jurassic salt mobility (Escalera and Hernández, 2010).

Currently, 22% of Perdido Area surface is operated by Petroleos Mexicanos (Pemex), 4% corresponds to a Pemex's farmout in the Trión block, 51% were awarded during the fourth call of the first and second bidding rounds (Rounds 1.4 and 2.4, respectively), still remaining 23% of Perdido Area unawarded (Figure 11).

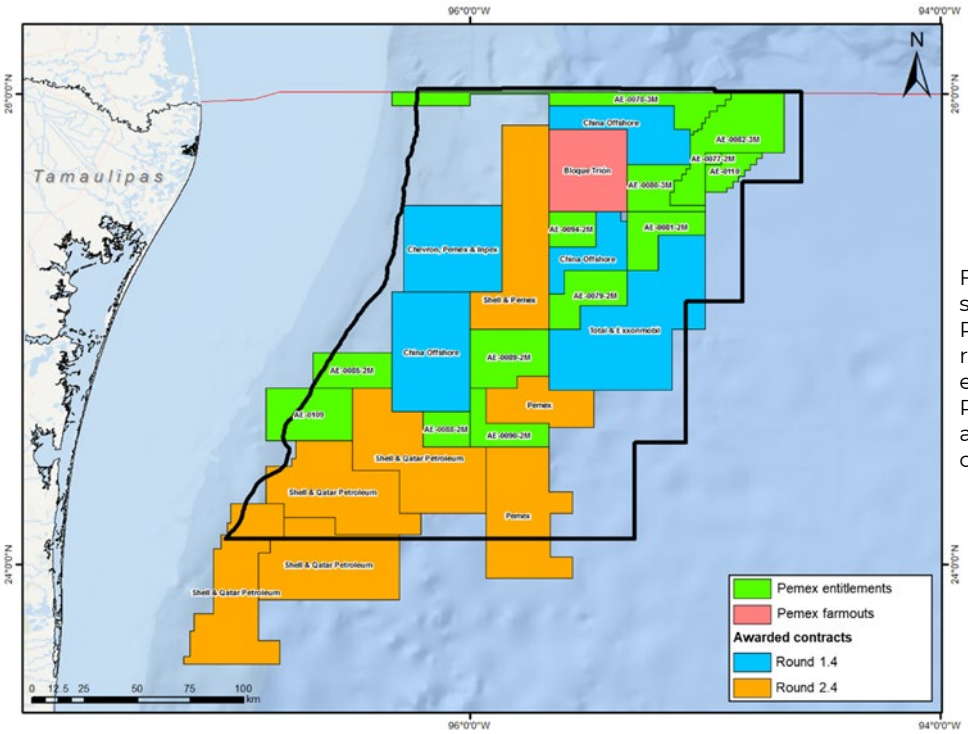


Figure 11. Current situation of Perdido Area, regarding areas entitled to Pemex, Pemex's farmouts and awarded contracts.

5.2. GEOLOGICAL FRAMEWORK

The Perdido Area covers mainly Perdido foldbelt, peripheral foldbelt and subsaline belt sectors, as well as a structural sector characterized by salt or mud diapirs, minibasins and folding (Comisión Nacional de Hidrocarburos, 2015), whose development is related with gravitational processes in the outer Burgos continental shelf and shale and salt tectonic processes during the Oligocene-Miocene (Figure 12).

The minibasins domain is located in the west zone of the Perdido Area, arranged in a stripe nearly parallel to the external border of the continental shelf, in which the salt and mud diapirs are related to gravitational extensional processes at shallow detachment levels above Upper Eocene shale deposits, developing Neogene sin-sedimentary infilling stratigraphic structures as wedge-like geometries or pinch-outs against mud or salt diapirs.

The subsalt belt was formed under a shortening regime, building a set of wide NE-SW oriented fault-propagation folds with reverse faults in crests and limbs, salt-cored detachment folds, and allochthonous salt sheets and canopies above Middle Eocene sedimentary deposits, which post-date salt intrusions.

Perdido foldbelt sector is related to shortening and thickening of salt layers by the lateral flow of salt (salt-inflation since McBride, 1998), produced by gravitational tectonics at the western part of the area, which formed wide salt-cored anticlines. Towards the south, the peripheral foldbelt delineates a deformation front caused by the allochthonous mass-salt advance which has a shallower Upper Eocene detachment level.

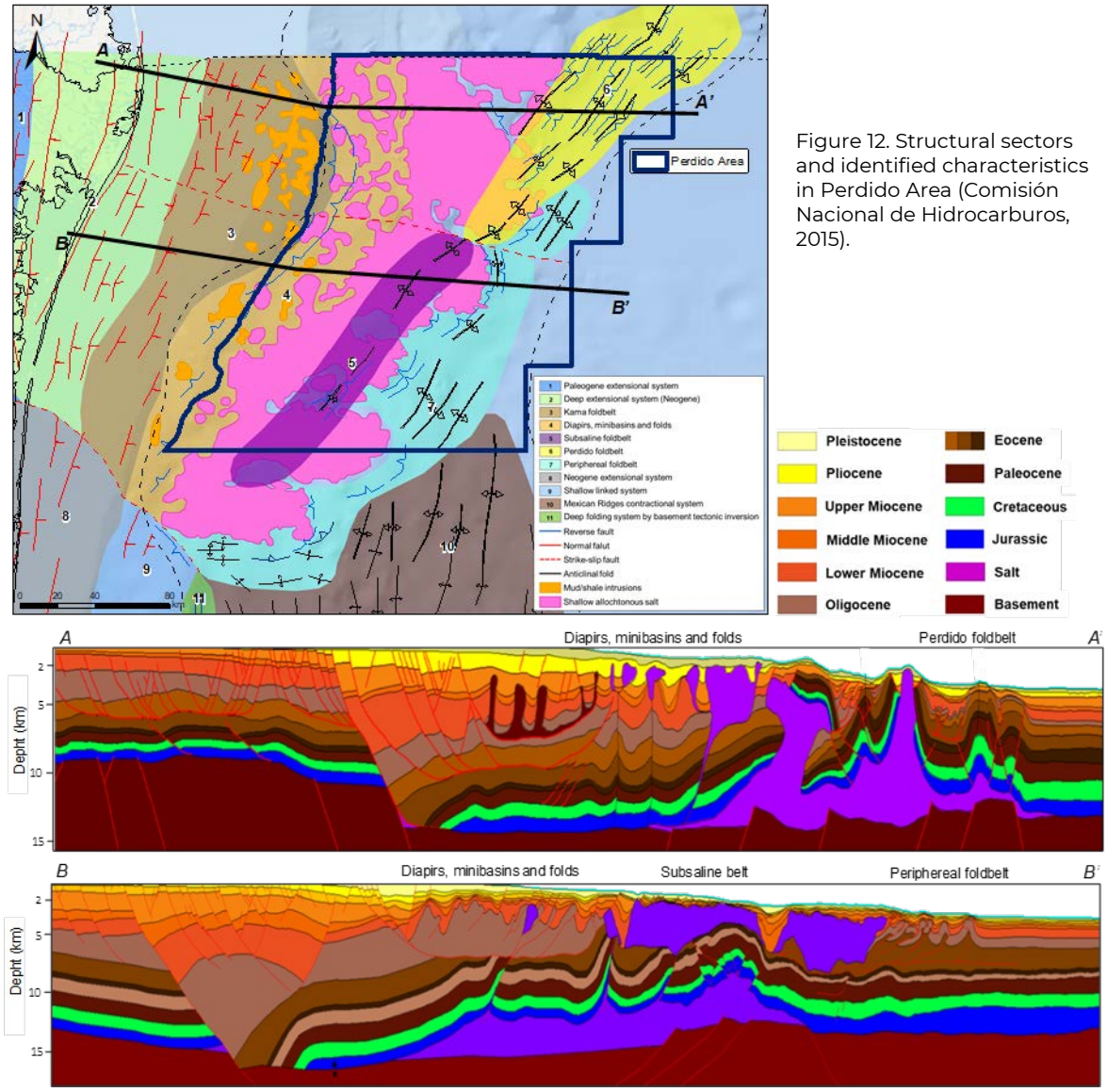


Figure 12. Structural sectors and identified characteristics in Perdido Area (Comisión Nacional de Hidrocarburos, 2015).

In the Perdido Area, the sedimentary column overlies an inferred Paleozoic metamorphic basement intruded by igneous bodies. Over this basement there is Triassic-Lower Jurassic evaporites and limestones deposits, overlaid by Middle Jurassic-Upper Cretaceous clastic and carbonate deposits and by Cenozoic siliciclastics in rhythmic successions of sandstones, siltstones, and shales (Figure 13).

The Middle Jurassic is composed of red beds deposits, in a transitional change to thick evaporites (salt) related to the initial phase of Gulf of Mexico opening. The Upper Jurassic is mainly composed of inner to outer ramp limestones facies, with lateral variations to dolomites and siliciclastic deposits; towards Upper Jurassic top, a maximum transgression Tithonian event deposited organic matter rich basin-floor limestones, which forms a characteristic stratigraphic horizon deposited on anoxic environments.

Cretaceous rocks are composed mainly by deepwater basin carbonate sequences, deposited during several sea-level fluctuations cycles; at the middle level of these sequences, it is inferred the presence of a secondary source rock of Turonian age, with a

high content of organic matter, deposited in anoxic environments. In the Upper Cretaceous, calcareous sandstones were deposited by locally distributed turbidite lobes.

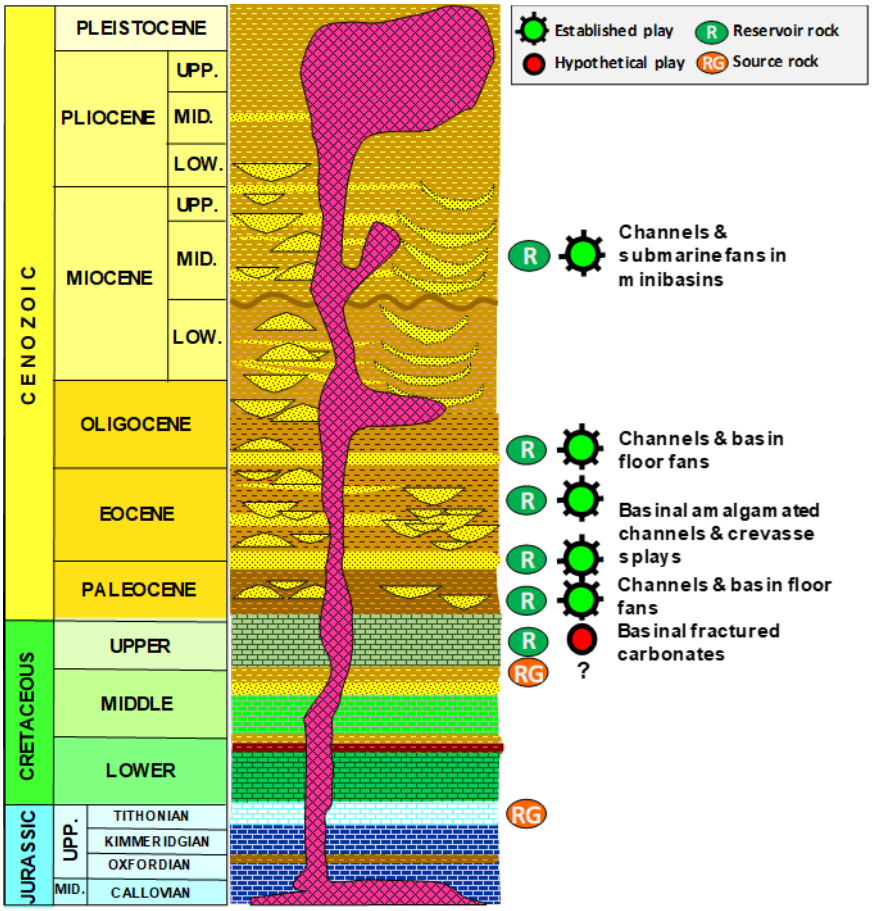


Figure 13. Schematic sedimentary column for the Perdido Area, indicating levels identified as reservoir rocks and source rocks.

The Paleocene is a period where the sea level in the Gulf of Mexico was low (Rosenfeld and Pindell, 2003), at this time widely extended sandstones bodies (informally referred as “Whooper”, equivalent to Lower Wilcox Formation) were deposited in amalgamated channel and lobe facies by turbiditic and laminar flows in deepwater fans environments.

Galloway et al. (2000) and Galloway et al. (2011), conclude that the main sediment source is from southeastern Texas fluvial-deltaic system (Houston delta), where sediments were transported in a northeast-southeast direction, and in a minor proportion by the northwest-southeast oriented Rio Grande system (Rio Bravo). Towards Upper Paleocene the shale content increases, caused by a high sea-level period where hemipelagic silty shale beds were deposited in basinal facies (informally known as “Big Shale” member).

During Upper Paleocene and Lower Eocene, sedimentary deposits consist mainly of turbidite sandstone packages, in facies of amalgamated channels, crevasse splays, and deepwater fans, which evolves to lower bathyal environments by the Middle Eocene, changing the sedimentation regime to shales with thin intercalations of siltstones in hemipelagic basinal environments.

The sedimentary conditions remain unaltered from Upper Paleocene to Lower Eocene, with the main difference that the deepwater fan systems front reached deeper zones of the basin (Galloway et al., 2000).

During Upper Eocene, thin sandstone layers in lobe and crevasse splays facies, were deposited by the fluvial-deltaic axes of the Rio Grande and the Houston-Brazos fluvial system, this depositional event is related to a rapid sedimentation pulse (1 to 2 million year-long), which is equivalent to the Burgos Basin Yegua-Jackson Formations (Galloway et al., 2011). An important change in the clastic sediment source area is evident after Upper Eocene time, due to the first appearance of several big scaled igneous complexes, that include the ignimbritic belt of the Sierra Madre Occidental (Ferrari et al., 2005).

By Lower Oligocene time, the main sediment provenance to Perdido Area comes from mixed sources located in northern Mexico and southwestern United States, transported mainly by the fluvial-deltaic Rio Grande system and the Houston-Brazos system in second term (Galloway et al., 2011).

The lithics and feldspathic clastic contents in Oligocene rocks are related to the onset of the widely distributed vulcanism of Sierra Madre Occidental and of Texas Trans-Pecos area (Loucks et al., 1986), where large volcanic calderas extruded significant volumes of volcaniclastics, ash, and volcanic glass towards the west and central zones of the Gulf of Mexico.

The Upper Oligocene is characterized by a long period of extended retrogradation of sedimentary sequences, and therefore, by the confluence of fluvial-deltaic systems towards the outer shelf, leading mainly silty shale deposits towards deepwater zones (Galloway et al., 2010).

The Oligocene Epoch is characterized by deposition of thin intercalations of fine-grained sandstones and shales deposited in meandering channels and distal lobes facies, coeval to the main deformation pulses caused by the allochthonous salt displacement. Therefore, from this time and after, the structural configuration of the Perdido Area is modified by plastic deformation of salt bodies.

Finally, by Miocene-Pliocene time, sedimentation occurs in bathyal to nerithic environments, dominated by shaly and silty turbiditic flows with some intercalated sandstones, related with submarine channelized deepwater fans.

The confinement of sand-rich systems was controlled by salt and shale tectonics, affecting the sediment dispersal transported mainly by Rio Grande and Rio Bravo fluvial-deltaic systems, towards the mini-basins zone and towards the east end (Galloway et al., 2011).

5.3. PETROLEUM SYSTEMS AND PLAYS

In the Perdido Area, as part of the Petroleum Province of deepwater Gulf of Mexico, five petroleum systems have been defined (Comisión Nacional de Hidrocarburos, 2015) based on geochemical analysis of hydrocarbon seabed seepages and oil samples recovered from wells. According to Magoon and Dow (1994) and Magoon and Beaumont (1999) classification, four out of those five petroleum systems are known (!) and one still remains speculative (?) postulated from nearby analog wells (Table 3).

Table 3. Summary of petroleum systems identified in the Perdido Area, including examples of exploration wells that have proved them and the analogs to postulate speculative petroleum system.

Source rock	Reservoir rock	Level of certainty (Magoon and Dow, 1994; Magoon and Beaumont, 1999)	Example
Upper Jurassic Tithonian	Miocene	Known (!)	Vespa-1 (Middle Miocene)
Upper Jurassic Tithonian	Oligocene	Known (!)	Supremus-1 (Lower Oligocene)
Upper Jurassic Tithonian	Eocene	Known (!)	Trión-1 (Lower Eocene), Nobilis-101 (Upper Eocene)
Upper Jurassic Tithonian	Paleocene	Known (!)	Pep-1 (Upper Paleocene)
Upper Jurassic Tithonian	Upper Cretaceous	Speculative (?)	Tiber-1 and Baha-2 (analog wells from the US portion of the Gulf of Mexico)

Regionally, the Upper Jurassic Tithonian source rocks constitute the main hydrocarbon source stratigraphic level distributed in Perdido Area. The petroleum systems defined for the Perdido Area, do not consider other identified potential hydrocarbon source subsystems, corresponding to Upper Jurassic Oxfordian, Upper Cretaceous Cenomanian-Turonian and Eocene stratigraphic levels, since their capability as hydrocarbon source rocks and characteristics have not been confirmed in the area.

The essential elements of petroleum systems include source rocks, reservoir rocks, seal elements and processes of trap formation, timing and hydrocarbons migration. The elements and processes of petroleum systems identified in the Perdido Area will be next described.

5.3.1. Source rocks

The Upper Jurassic Tithonian rocks are the main hydrocarbons source in the Perdido Area, notwithstanding that not a single well has reached Tithonian rocks in the area, the interpretation and correlation of geochemical analyses of hydrocarbon samples recovered from wells, conclude that they share the same geochemical signatures found in oil samples from Jurassic reservoirs at Southeast Marine Basins; so it is considered that the oil founded in the Perdido Area are mainly of Jurassic affinity.

The geochemical characteristics of the Perdido Area source rocks are inferred based on Tithonian rocks characteristics at the Burgos and Tampico Misantla basins, from rock samples in wells drilled in the United States (e.g., Norton-1), as well as from biomarker correlations of seabed seepage sampling.

From this information, towards the Perdido Area is expected to find calcareous shaly rocks with total organic carbon values between 1%-5%, with a mixture of kerogen types I and II, thermally mature as oil and gas precursors. Results from previous studies and modeling show that this source rock is active, and is generating hydrocarbons thermogenically.

The Baha-2 well drilled in 2001, located at Alaminos Canyon in the United States sector of the Gulf of Mexico, reached Upper Cretaceous (Cenomanian-Turonian) organic matter rich rocks, which have suitable thermal maturity conditions for hydrocarbon generation; nonetheless, the geochemical biomarker analyses of oil samples recovered from wells and from seabed oil seepages, have not detected enough quantities of biomarkers typically found in oil sourced from Cretaceous rocks, therefore the Cenomanian-Turonian interval is not considered yet as a confirmed source rock subsystem in Perdido Area.

5.3.2. Reservoir rocks

In the stratigraphic column of the Perdido Area, five potential reservoir rocks intervals have been identified (Figure 13):

- **Miocene.** For the Miocene, silty and thin-bedded sandstone sequences of Middle Miocene age are considered as the main reservoir rocks, proved so far by Vespa-1 and Nestok-1 wells drilled by Pemex.

- **Oligocene**. Consists of turbiditic sandstones deposited in channels and crevasse splay facies, where it is common to observe Oligocene sequences with onlapping patterns towards the edges of fold limbs.

- **Eocene-Paleocene**. The Upper Paleocene and Lower Eocene Wilcox Formation consist mainly of turbiditic sandstones in amalgamated channels, crevasse splay and deepwater submarine fan facies. Recently, the Nobilis-101 well confirmed the production potential of Upper Eocene fine-grained sandstones, deposited by turbiditic flows in basin fan environments.

- **Upper Cretaceous.** This potential reservoir rock interval has not been reached by drilling in the area; however, based on Baha-2 and Tiber-1 wells located in the United States sector of the Gulf of Mexico, the presence of calcareous sequences intercalated with clastics is inferred in Perdido Area.

  For the Baha-2 well, its depth to Lower Cretaceous was initially reported, identifying the Middle Cretaceous Unconformity (MCU) by drilling a terrigenous and carbonate sequence towards the top of Cretaceous. However, Winker (2004) noticed that what were actually thought to be the sequences of the MCU, are in fact the Upper Cretaceous stratigraphic units, composed of carbonates and clastics from Cenomanian to Maastritchian.

  These Cretaceous rocks in Perdido Area are expected to be naturally fractured, especially at the crest of anticline structures.

5.3.3. Traps and seal elements

Largest traps identified in Perdido Area consist of asymmetric anticlines with reverse faulting, produced by salt thrusting in diapirs, walls and salt sheets.

Likewise, stratigraphic traps produced mainly by Oligocene-Miocene turbidite deposition have been identified with onlapping relationships on structures limbs and where fold crests have been eroded and buried in angular unconformities. Stratigraphic traps are smaller than structural ones and are generally considered as secondary objectives.

When interpreting events that have structured the area, as well as the sedimentary facies of stratigraphic sequences, in the Perdido Area mainly combined traps (structural-stratigraphic) are present, where the structural component generally presents closures in four or three ways and against faults.

Stratigraphic components are related to confined sandstones bodies within shaly sequences, wedging or pinching-out against salt diapirs, salt walls or folds and/or to the presence of channels and basin floor fans facies deposited from Paleocene to Miocene

time. The structural component linked to folding, is associated with salt tectonics or to shortening related to gravitational tectonics at the edge of the platform.

According to wells stratigraphy and their tie to seismic, traps are additionally protected by seal rocks formed by shaly sequences of great thickness and regional lateral extension. In areas with salt tectonics, allochthonous salt is considered as an efficient seal rock for potential subsaline structures; however, surface hydrocarbons seepages on the seabed are also indicators of seal leakings, which may be associated with movements due to rearrangement of salt bodies and/or faulting.

5.3.4. Timing and migration

Through petroleum systems simulations and basing modeling previously conducted, calibrated with geological and geochemical parameters obtained from wells, in complement to analysis of new information from ARES permits studies, recent drilled wells and calibrations performed using 1D modeling in some selected locations, it has been determined that the Jurassic source rocks are currently thermally mature, within an oil window for the central part of Perdido Area and in gas window towards the east and west ends.

The analysis of this information indicates that the source rocks of Upper Jurassic Tithonian age entered within the oil window at Middle Eocene, reaching its maximum generation peak during Oligocene and evolving towards the wet gas window at the end of Upper Miocene. Also, it has been observed that Tithonian rocks' organic matter transformation rate has reached 100% in most of the area, except some sectors in the central part due to allochthonous salt heat flow effect and the relative uplift of Mesozoic section.

The hydrocarbons expulsion peak is estimated to occur sequentially from Lower Miocene time at the west of the area and from Middle-Upper Miocene time to the east. The maximum hydrocarbons expulsion in areas near from allochthonous salt bodies is estimated to have occurred during the Lower Miocene.

From to date discoveries in the Perdido Area and the hydrocarbons seabed emanations, it is proven that there is a charge of liquid and gaseous hydrocarbons from Tithonian source rock towards Upper Paleocene to Middle Miocene reservoirs, through regional faults that limit the structures on their flanks and/or using welds formed during the salt extrusion from Middle Eocene.

The identified Upper Cretaceous Turonian potential source rocks, are inferred currently in a thermal maturity stage within the oil window. However, as mentioned before, Turonian is not yet considered as a hydrocarbon source subsystem in the Perdido Area.

Figure 14 shows the events chart for the Perdido Area, which summarizes the mechanisms and temporal relationships between the elements and processes of the identified petroleum systems (Table 13), including the geological age of events and the critical moment (Magoon and Dow, 1994), as the time that best depicts the generation, migration and accumulation of most hydrocarbons in the petroleum systems.

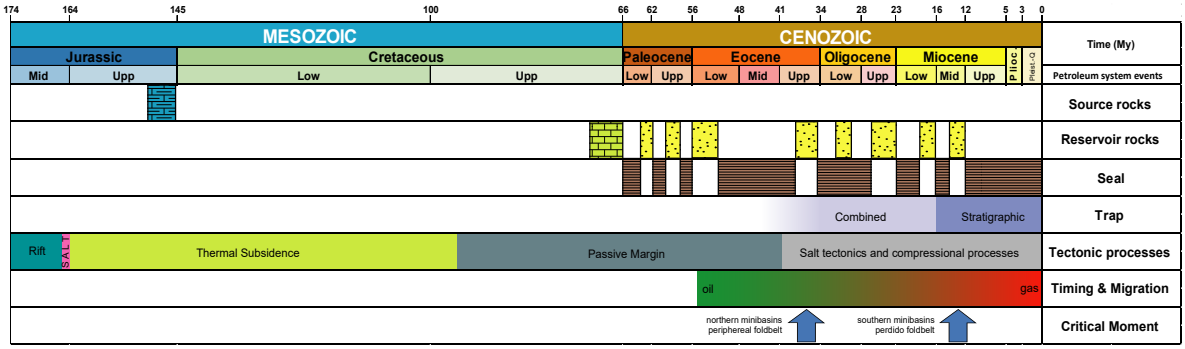


Figure 14. Events chart of identified petroleum systems in Perdido Area.

5.3.5. Plays

The Perdido Area plays are postulated based on current knowledge and the integration and analysis of seismic information, regional studies, well information, and analogs. Plays defined within the Perdido Area have a composite nomenclature, associated with the Petroleum Province (GP = Deepwater Gulf of Mexico), the assessed area name (AP = Perdido Area), its category according to its status in exploration (E = Established; H = Hypothetical) and finally the chronostratigraphic interval of reservoir rocks.

For the plays defined in the Perdido Area, the Upper Jurassic Tithonian source rocks are considered as the main hydrocarbon source, despite other potential source rocks have been identified (Upper Jurassic Oxfordian, Upper Cretaceous Cenomanian-Turonian and Eocene), its potential as hydrocarbon source in the area has not been confirmed. The Mesozoic play until today has a hypothetical status, while the rest of Cenozoic plays have been gradually established (proven) by exploration wells drilled by Pemex in the area.

According to the above, Table 4 shows the summary of the main characteristics of plays assessed in the Perdido Area.

Table 4. Summary of the main characteristics of plays assessed in Perdido Area.

Play	Trap style	Lithology and depositional environment of reservoir rocks	Porosity (%)	Main wells that have investigated the play
GP AP E Neogene	Minibasins and salt related pinch-outs	Sandstones and siltstones of submarine channels and turbiditic basin floor fan	16-25 % Intergranular, intragranular	Vespa-1, Nestok-1
GP AP E Oligocene	Asymmetric folds with shallow detachment levels	Sandstones of submarine channels and crevasse splays	15-33 % Intergranular, intragranular, microporosity	Exploratus-1, Supremus-1, Melanocetus-1, Nobilis-101
GP AP E Eocene	Asymmetric fault propagation folds with autochthonous salt detachment levels	Sandstones and siltstones of submarine amalgamated channels, overbanks and crevasse splays	12-35 % Intergranular, Intragranular, secondary microporosity	Doctus-1, Nobilis-1, Trión-1, Exploratus-1, Maximino-1
GP AP E Paleocene	Asymmetric fault propagation folds with autochthonous salt detachment levels	Sandstones and siltstones of submarine amalgamated channels, overbanks and crevasse splays	10-23 % Intergranular, Intragranular, secondary microporosity	Corfu-1, Pep-1, Tot-1, Clipeus-1, Kokitl-1
GP AP H Mesozoic	Asymmetric fault propagation folds with autochthonous salt detachment levels	Sandstones and siltstones of turbiditic basin floor fan and fractured basinal shaly limestones	Sandstones 10-13 % Limestones 2-4% Intergranular, intragranular and secondary fracture porosity	Baha-2 (analog)

5.3.5.1. Play GP AP H Mesozoic

The Mesozoic play is mainly represented by the Cretaceous, whose reservoir rock consists of carbonate rocks with clastics intercalations, probably equivalent to the Upper Cretaceous rocks investigated by Baha-2 and Tiber-1 wells in the United States, which reported hydrocarbon shows in Cretaceous units. Currently, in Mexico, there is limited information for rocks of this age in the Perdido Area, which could provide more information on their characteristics as a reservoir rock.

The main seal elements for the hypothetical Mesozoic play are the regional sequences of Paleocene shales or intraformational shales within the same Cretaceous rocks, while the associated traps are mainly combined (structural-stratigraphic), with four-way closures. Additionally, possible traps against allochthonous salt walls are considered, where fractured carbonates may be pinching-out against saline intrusions.

The conducted analyses allow to determine that the main risk of this play is the distribution and quality of reservoir rocks, it is expected that the better conditions as reservoir are present mainly on anticline structures crests so that the east sector of the area is inferred that it can meet the most favorable geological conditions to present fractured carbonates.

5.3.5.2. Play GP AP E Paleocene

The Paleocene reservoir rocks are represented by turbiditic sandstones interstratified with thin strata of shales and siltstones, deposited in distal submarine fan environments, where one of the main geological objectives of this play is of Upper Paleocene age (informally referred to as "Whopper" and equivalent to the Lower Wilcox Formation). Through seismic facies interpretation, core sample information and RMS seismic attributes (Root Mean Square), these sequences have been interpreted as channels and crevasse splays in turbiditic basin floor fan system environments.

The main seal rocks for the Upper Paleocene, are shales with layered lodolites and laminar sandstones intercalations that serve as a limit to sandstones bodies, including a regional thick shale interval informally referred to as “Big Shale” member, that reach a thickness of 150 m in Trident-1 well drilled in the United States, and is even thicker in Trión-1 well.

Typically this play is associated with combined traps, four-way structural closures, closures against fault in fault-propagation folds and reverse faulted expulsion block structures (pop-up blocks), including subsaline traps where allochthonous salt acts as the seal element. To date, 7 exploratory wells have proved the play in the area.

5.3.5.3. Play GP AP E Eocene

The stratigraphic sequence of greatest importance so far in the Perdido Area is represented by turbiditic sandstones interstratified with sandy shales and siltstones of the Lower Eocene Wilcox Formation, associated with channelized facies, amalgamated channels, crevasse spalys and basin floor fan lobes. Upper Eocene reservoir rocks have been investigated by Nobilis-101 well only, resulting in light oil producer in turbiditic sheet sandstones and siltstones of basin floor fan facies.

The most effective identified seal element are shales intercalated with lodolites and sandstones in sheet layers of Middle Eocene age, located practically overlying the Lower

Eocene reservoir rocks, which have a regional distribution throughout the area; also, there are shale packages interstratified with Lower Eocene sandstones that act as intraformational seals. For the Upper Eocene, shale intercalations with reservoir sandstones are apparently acting as intraformational seals; however, the observed normal faulting towards structures crests that form the traps, constitutes the main risk factor, associated with the seal effectiveness and it is necessary to expand its analysis.

The main traps identified in the play are combined, with elongated asymmetric anticlines generated by fault propagation or related to confinement due to the action of allochthonous and autochthonous salt bodies, forming structural four-way closures or closures against fault and lateral facies changes. To date, there are 25 exploration wells that have proved the play, which include the most important discoveries made in Perdido Area.

5.3.5.4. Play GP AP E Oligocene

The Oligocene play is mainly represented by lithic and lithic-feldspathic turbiditic sandstones interstratified with shales and siltstones of Lower Oligocene age. Currently, no discoveries have been made in Upper Oligocene; however, it is considered as a prospective geological horizon in objectives where it has been interpreted that fine-grained sandstones deposited in distal deepwater fans could be present.

The Upper Oligocene shale packages act as a seal for the Lower Oligocene objectives, especially towards the east side of the area, while the shale packages present in unconformity relations of Miocene and Lower Pliocene age, are considered as the main regional seal rocks in the minibasins sector of the area. Additionally, Lower Oligocene geological objectives have been identified where allochthonous salt bodies act as sealing elements.

Identified traps in the Oligocene play are mostly combined with a stratigraphic component due to facies changes, with three or four ways structural closures and due to closures against fault, distributed in large elongated folds northeast-southwest oriented, limited by reverse faults at their flanks. Towards the eastern sector of the area, the greatest number of traps with Oligocene geological objectives have been identified, associated with the structural sector of the peripheral foldbelt with a shallow detachment level at Upper Eocene.

For the Oligocene play, the main identified risk factor is the presence and distribution of reservoir rocks, especially for Upper Oligocene geological objectives; however, the presence of faulting at structures ridges may be affecting the top seal and trap integrity. To date, 8 identified exploration wells have proved the play.

5.3.5.4. Play GP AP E Neogene

The primary geological objective of interest for the Neogene play corresponds to the Middle Miocene, composed of litharenites with abundant volcanic rock fragments, carbonates, plagioclase and low quartz content associated with slope and basin floor fan systems, with channelized facies, crevasse spalys and confined lobes of distal basin floor fans.

Vespa-1 and Nestok-1 wells, located in the minibasins and in the Perdido foldbelt sector respectively, founded hydrocarbon accumulations in similar lithologies, both in

calcareous siltstones with scarce very fine-grained sandstone bodies, interpreted as distal crevasse splays; so in both sectors, it is expected to find better conditions of reservoir rock quality towards the channelized facies of their despositional systems. With the result of both wells that have proven the play so far, it can be established that the presence and distribution of reservoir rocks represent the main risk to consider.

In the Perdido Area, Lower Miocene age geological objectives have been identified, based on results of Arietis-1 and Anoma-1 wells drilled by Pemex and located in the Burgos Basin shallow water zone, that presented hydrocarbon shows in interstratified sequences of sandstones, siltstones and shales, interpreted as slope and basin floor fan systems. While for geological objectives identified in Upper Miocene, the presence of sandstones, siltstones and shales deposited in slope and basin floor fan systems is expected, since this kind of facies has been documented by wells that have drilled this stratigraphic level in the area.

Towards the minibasins zone, the allochthonous salt controls seal rocks distribution composed of intraformational shale layers, this because saline bodies intrude into the Miocene sequences and can act as lateral seals. Since at several zones of the area, the potential reservoir rocks horizons are in a relatively shallow position close to the seabed, the ability to contain a hydrocarbon column pressure and access to hydrocarbons charge from deep source rocks, constitute additional risks elements to consider.

The traps for the Neogene play are combined, with a strong stratigraphic component towards the minibasins area, while in Perdido foldbelt and the peripheral foldbelt sectors, stratigraphic traps related to pinch-outs against anticline structures, have amplitude anomalies, flat spots, bright spots and lateral facies changes with a more stratigraphic than structural relevance. To date, 3 identified exploration wells have proved the play.

5.4. EXPLORATION PROGRESS

The first exploration activities occurred in areas adjacent to the Perdido Area, in the United States' portion of the Gulf of Mexico, specifically in the area known as Alaminos Canyon. These activities began in the 1970s with 2D seismic acquisition and during the next 20 years, seismic information analysis, seabed sampling and shallow drilling were carried out under the Deep Sea Drilling Project (DSDP); which was a research project that included 10 well sites at the Mexican part of the Gulf of Mexico.

The first exploration wells in the area were drilled in the 1990s. By 1996, the Baha-1 was drilled in a 2,300 m of water depth, which did not reach the programmed Jurassic-Cretaceous geological objectives due to mechanical problems; however, it was able to identify the hydrocarbon potential in Lower Eocene sandstones corresponding to Wilcox Formation (Meyer et al., 2007).

In 2001, Baha-2 and Trident-1 wells were completed, their results lead to Trident field discovery, located 5.6 km away from the maritime borderline between Mexico and the United States, towards the northern extension of Perdido foldbelt sector. Subsequently, in 2002 the Great White, Tobago and Tiger discoveries were made, which established the hydrocarbon production potential of Wilcox Formation.

With this background, Petroleos Mexicanos (Pemex) began with the exploration of this deepwater region, acquiring 2D and 3D seismic and developing regional and local exploration studies to assess the hydrocarbons potential in the Perdido Area. Between

2002 and 2010, 4 of the main available 3D seismic studies in the area were acquired, which together cover a total surface area of 28,195 km^2; while for the case of 2D seismic, 7 different studies were acquired between 1973 and 2013 with a linear coverage distributed throughout the Perdido Area (Table 5).

Table 5. Seismic studies acquired through 2015 in Perdido Area by Petroleos Mexicanos.

Seismic study	Year of acquisition	Surface coverage km^2	Acquisition technique	Processing
Máximo	2002	2,577	3D	PRESDM, POSTSTM, PRESTM
Máximo Ampliacion	2003	417	3D	PRESDM, POSTSTM, PRESTM
Magno Etapa 1Q	2005	4,147	3D Q	PRESDM, POSTSTM
Centauro	2010	24,742	3D WAZ	PRESDM, POSTSTM
Matamoros	1973	-	2D	POSTSTM
Matamoros Golfo de Mexico A	1994	-	2D	POSTSTM
Cinturon Perdido	1997	-	2D	POSTSTM
Estudio Sismico Interregional Litoral G. de México	1999	-	2D	POSTSTM
Regional Golfo de Mexico	2002	-	2D	POSTSTM
Cinturon Sub-Salino 2D-2008	2009	-	2D	PRESTM
Perdido	2013	-	2D	PRESDM-Kirchoff, PRESDM-RTM

Within the period from 2012 to 2015, Pemex drilled 13 exploration wells in the Perdido Area, with wich mainly Paleogene plays were proved (Table 6) and from which important discoveries were made and an important volume of information was obtained. Based on this exploration progress made in the Perdido Area, the prospective resources were assessed by grouping the analysis into 3 different plays, the Neogene, Paleogene and Mesozoic plays.

Table 6. Wells drilled through 2015 in Perdido Area by Petroleos Mexicanos.

Well name	Drilling completion year	Result	Investigated play
Supremus-1	2012	Oil producer	Oligocene
Trión-1	2012	Oil producer	Eocene
Vespa-1	2013	Oil producer	Neogene
Maximino-1	2013	Oil producer	Eocene
Pep-1	2013	Water flooded	Eocene, Paleocene
Exploratus-1	2014	Oil producer	Oligocene, Eocene
Trión-1DL	2014	Oil producer	Eocene
Maximino-1DL	2015	Oil producer	Eocene, Paleocene
Vasto-1	2015	Mechanical failure	Eocene
Corfu-1	2015	Non-commercial oil producer	Eocene, Paleocene
Exploratus-101	2015	Water flooded	Oligocene, Eocene
Astra-1	2015	Water flooded	Eocene
Cratos-1A	2015	Wet gas producer	Eocene-Paleocene

From 2016 to 2018, Pemex, within its entitlements surface area, has contributed with new progress in the exploration of the Perdido Area. Additionally, with the implementation of the ARES program, new exploration information has been generated by actors different from Pemex; therefore, there is a robust database for prospective resource assessment updating of the Perdido Area.

The map in Figure 15 shows the exploration information generated by 2015 around the Perdido Area by Pemex, in terms of seismic and well information.

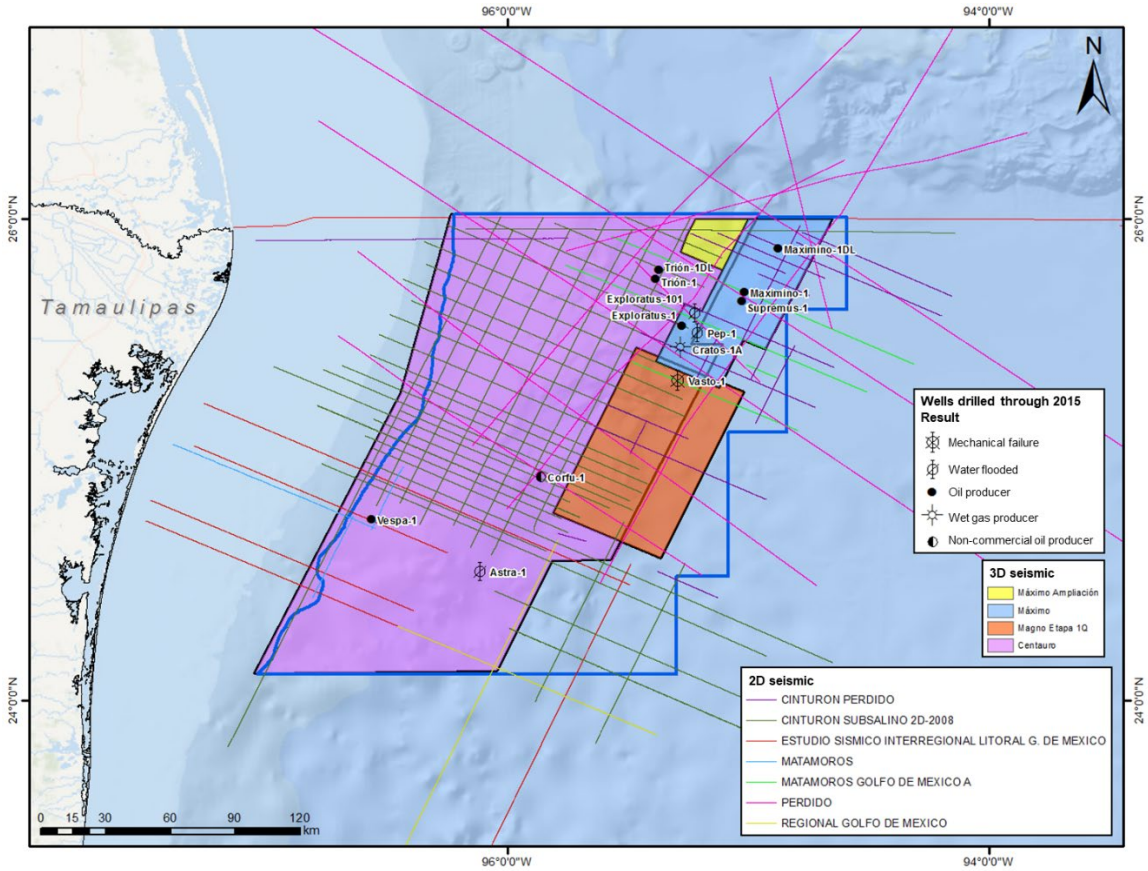


Figure 15. Map showing the exploration information generated through 2015 around the Perdido Area by Pemex in terms of seismic and wells information.

5.4.1. Exploration information used to Perdido Area assessment updating

From 2012 to 2015, Pemex drilled 13 exploration wells in the Perdido Area (Table 6), while in the period from 2016 to 2018, 21 wells have been drilled in only 3 years (Table 7). This significant increase in drilling activity in Perdido Area allowed to increase from 10 to 22 wells drilled in Perdido foldbelt sector, from 2 to 9 wells in the Subsaline belt sector, from 1 to 2 in the minibasins sector, and to drill the first exploration well in the peripheral foldbelt sector.

The exploration drilling campaign that Pemex carried out in allowed to increase subsoil knowledge in all sectors of the Perdido Area and to confirm the production potential of previously established plays. All the information that arises from the 34 exploration wells concluded through 2018 allow to calibrate the previous geological studies that were done until 2015 and to improve the geological, geophysical and geochemical interpretations in Perdido Area.

Additionally, with the implementation of ARES, a significant volume of new exploration information has been generated, including the improvement of previously existing information, especially with regard to seismic studies in the Perdido Area, since is the most important kind of information input for any subsoil analysis.

Most of the information generated through the ARES program in the Perdido Area has focused on the improvement of the seismic imaging through ultimate acquisition techniques and processing algorithms technology, given the geological-structural complexity of the area by salt tectonics processes.

Table 7. Wells drilled from 2016 to 2018 by Petroleos Mexicanos in Perdido Area.

Well name	Drilling completion year	Result	Investigated play
Exploratus-1DL	2016	Gas and condensate producer	Eocene
Melanocetus-1	2016	Non-commercial wet gas producer	Oligocene
Tiaras-1	2016	Non-commercial oil and gas producer	Eocene
Nobilis-1	2016	Oil and gas producer	Eocene
Mirus-1	2016	Non-commercial oil and gas producer	Eocene
Alaminos-1	2016	Non-commercial oil and gas producer	Eocene, Paleocene
Clipeus-1	2016	Non-commercial wet gas producer	Eocene, Paleocene
Maximino-101	2016	Water flooded	Eocene
Vasto-1001	2016	Water flooded	Oligocene, Eocene
Doctus-1	2016	Oil producer	Eocene
Tot-1	2017	Water flooded	Eocene, Paleocene
Nobilis-101	2017	Oil producer	Oligocene, Eocene
Exploratus-2DL	2017	Oil producer	Oligocene
Maximino-2001	2017	Water flooded	Oligocene
Nestok-1	2017	Non-commercial dry gas producer	Neogene
Ambus-1	2017	Dry	Eocene
Doctus-1DL	2018	Oil producer	Eocene
Goliat-1	2018	Pugged due unexpected geological column	-
Ketsin-1	2018	Dry	Eocene
Kili-1	2018	Dry	Neogene
Kokitl-1	2018	Gas and condensate producer	Paleocene

The primary ARES studies in Perdido Area developed through 2018, including 2 new 3D seismic acquisition, 5 different new 2D seismic acquisition projects, 2 different reprocessing projects of previously existing 3D seismic information and a new geochemical biomarkers study from seabed piston cores samples, which are important in the analysis of petroleum systems. Table 8 shows the primary ARES studies located within the Perdido Area.

The set of information used for Perdido Area assessment, mainly includes the information of 34 exploration wells, including a large inventory of well logs and core samples analysis reports, as well as 2D and 3D seismic information acquired through 2015 and the new 2D and 3D seismic information and ARES geochemical studies (Figure 16).

In addition to seismic information and wells, a series of previous regional studies of basin analysis, petroleum systems, plays and geochemical analyzes done in the Perdido Area by Pemex and the Mexican Petroleum Institute (IMP) are available through the National Hydrocarbons Information Center (CNIH). This information is transferred to CNIH in compliance to the Hydrocarbons Law and the Guidelines for the transfer of historical information, published in the Official Gazette (DOF) in April 2016.

Finally, another component of the available information, are the historical databases of prospective resource assessments, in accordance with the Guidelines for the Analysis and Assessment of the Prospective and Contingent Resources of the Nation, published in DOF in December 2013.

All this set of information was analyzed and updated according to the results of recent wells and the new seismic information, through the integration, selection and combination of relevant information, as well as the analysis, interpretation and studies performed by the Commission.

Table 8. Characteristics of the main ARES projects located in the Perdido Area.

ARES permit	Project	Company	Type of study	Modality	Authorization year	Deliverables
ARES-TGS-NO-15-6P1.0417	Geoquímico Golfo de México	TGS AP Investments AS.	Geochemistry	Data acquisition	2015	Geochemical data from raw cores with biomarkers and isotopes
ARES-GXT-EU-15-2Q1.0336	MéxicoSPAN Sísmica 2D	GX Geoscience Corporation, S. de R.L. de C.V.	2D seismic	Data acquisition	2015	Kirchhoff PSTM stack filtered and scaled Kirchhoff PSTM stack RAW
ARES-SRC-AU-15-3B1.0521	Buscador Near-Shore 2D	Searcher Seismic, PTY, LTD.	2D seismic	Data acquisition	2016	Stack PSTM Stack PSDM
ARES-PGS-MX-15-4R6.0183	México MC2D para el Amarre de Pozos	PGS Geophysical AS-Sucursal México.	2D seismic, Gravimetry and Magnetometry	Data acquisition	2015	Kirchhoff PreSTM RTM PreSDM Kirchhoff PreSTM
ARES-TGS-NO-15-6P1.0195	Gigante 2D	TGS AP Investments AS.	2D seismic, Gravimetry and Magnetometry	Data acquisition	2015	Stack PSTM and PSDM Velocities
ARES-PGS-MX-15-4R6.0214	Cordilleras Mexicanas MC2D	PGS Geophysical AS-Sucursal México.	2D seismic, Gravimetry and Magnetometry	Data acquisition	2015	Kirchhoff PreSTM RTM PreSDM Kirchhoff PreSDM
ARES-DSM-MX-15-3P2.0684	Perdido Reimaging 3D	Dowell Schlumberger de México, S.A. de C.V.	3D seismic	Without data acquisition	2015	Kirchhoff PreSTM Controlled RTM (frequency with depth variable)
ARES-CGG-MX-15-3G7.6453	Taurus 3D	CGG México S.A. de C.V.	3D seismic	Data acquisition	2017	TTI Kirchhoff Depth Migration processing Kirchhoff Migrated Stack
ARES-CGG-MX-15-3G7.0187	Perdido 3D WAZ	CGG México S.A. de C.V.	3D seismic WAZ	Without data acquisition	2015	PSDM TTI RTM PSDM TTI Kirchhoff
ARES-PMX-MX-15-7N1.1869	Centauro 3D WAZ	PEMEX Exploración y Producción	3D seismic WAZ	Data acquisition	2016	PSDM RTM with and without filters and scalings PSDM Kirchhoff with and without filters and scalings

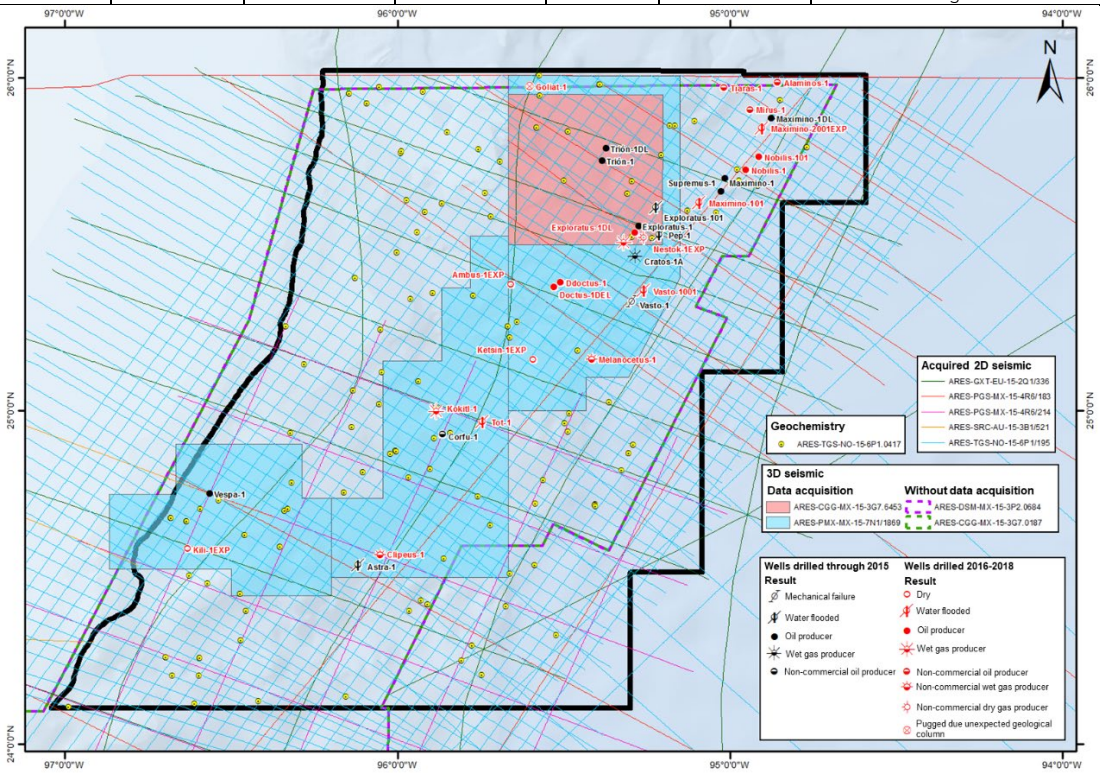


Figure 16. Map showing the primary exploration information used in Perdido Area assessment in terms of geochemical, seismic and well information.

5.5. ASSESSMENT AND INTERPRETATION OF EXPLORATION INFORMATION

5.5.1. Seismic interpretation

The information assessment and interpretation stage consisted of collecting, validating and analyzing all the available information for the Perdido Area, considering the geological-structural complexity in each sector and starting with a regional seismic interpretation of the area, calibrating the interpretations with biostratigraphic data and well stratigraphic markers. The general process of horizons interpretation began in areas with high confidence, where there is the highest density of well information, generating tying sections and alternating correlations between inline and crossline sections in time or depth.

The selection of the most suitable seismic version for interpretation, considered the acquisition method and the processing type mainly, since those parameters control the seismic image quality, taking into account the fact that certain types of acquisition and processing, attenuate certain misleading patterns that are easily confused as real geology (seismic artifacts), as others can also be highlighted. When assessing exploration prospects, a detailed seismic interpretation is required, so the selection of the best available seismic information version is crucial to obtain better results.

Since the Perdido Area is considered as a complex salt tectonics area, time-migrated seismic versions have significant imaging limitations around and below salt bodies, since special velocities cannot be applied to salt bodies and seismic reflections do not locate correctly when refracting through salt. For this reason, the most appropriate seismic version to obtain an adequate image in areas with salt tectonics, generally requires a depth migration before stacking or pre-stack depth migration seismic (PreSDM).

In PreSDM seismic, velocities of salt and of all geological horizons are assigned during processing (velocity model), for which it is necessary to determine salt bodies geometries of and boundaries between horizons, so when working with prestack-depth-migrated data, is needed to be aware that an interpretation of a previous interpretation it will be taking place (Jackson and Hudec, 2017). In that sense, it is imperative to corroborate with the help of well information, that each geological horizon in the velocity model is in its correct position in depth and also, consider the algorithm used for migration, one of the most critical aspects in seismic data processing.

The set of available seismic information in the Perdido Area consists mainly in PreSDM migrations through Kirchhoff and RTM (Reverse Time Migration) algorithms (Tables 5 and 8), which have advantages and disadvantages in regard to the process of seismic interpretation in areas with salt tectonics.

The Kirchhoff PreSDM migration typically preserves the seismic texture and amplitudes, allowing to generate high-quality images towards the top of salt bodies and sometimes also allows to map the base of the salt bodies; this, as long as the geometry of these bodies is simple, it does not allow handling of complicated velocity models and does not generate good image quality in complex salt tectonics areas.

On the other hand, PreSDM RTM migration allows handling the wave equation in multiple paths, increasing the possibility of visualizing complex salt structures and

visualizing the geological characteristics of areas around and below salt bodies. However, the seismic image generated by RTM migration is more sensitive to the used velocity model than in the Kirchhoff migration.

With that in mind, the regional seismic and exploration prospects interpretation in Perdido Area was conducted preferably on 2D and 3D PreSDM RTM seismic versions, prior review and validation of the corresponding velocity model. In certain areas without 3D seismic coverage but linear 2D seismic coverage, the same velocity model was generated and used to convert and adjust migrated versions in time to depth.

5.5.2. Petrophysical evaluation

Based on well logs, geological reports and documentation on core and core samples analysis from exploration wells in Perdido Area, petrophysical evaluations were carried out with conventional techniques to determine the main characteristics of the plays assessed in the area. This analysis included the identification and evaluation of different lithologies throughout the logs, as well as the determination of cutoff petrophysical range values that are key in volumetric assessment of exploration prospects, such as porosity, water saturation, net thickness, etc.

Figure 17 shows an example of the petrophysical evaluations conducted in wells of the Perdido Area, from the well logs and core and core samples analysis.

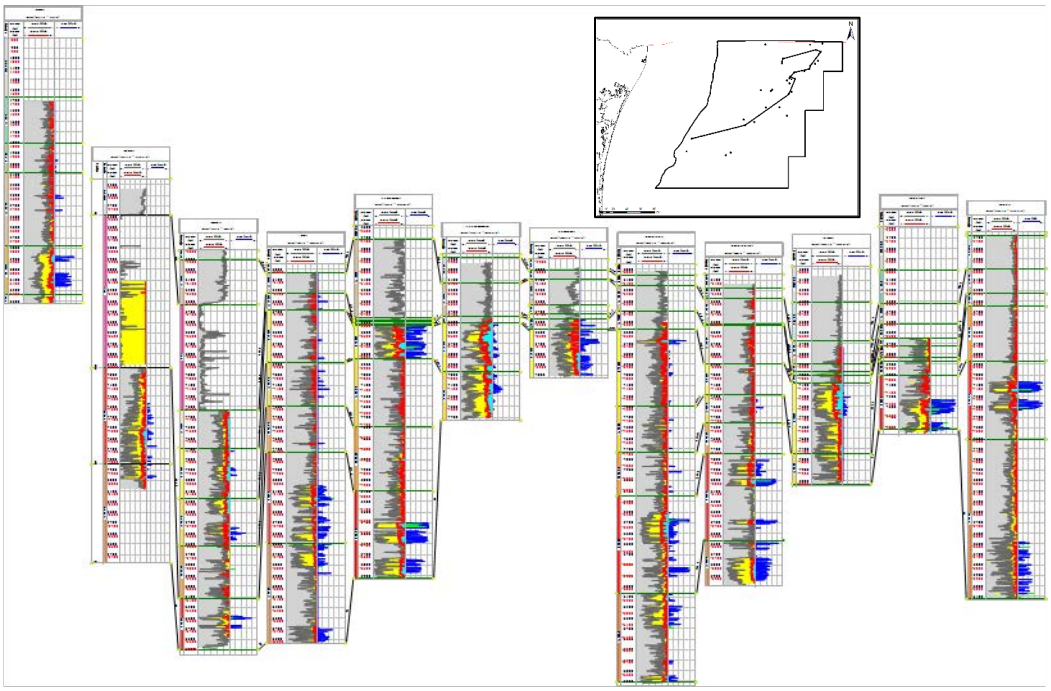


Figure 17. Example of the petrophysical evaluations performed in wells of the Perdido Area, based on well logs and the core and core samples analysis.

5.5.3. Seismic attributes and sedimentary facies interpretation

Seismic attributes (including those considered as direct hydrocarbons indicators) were applied as a tool for interpretation of seismic data (section 3.2.3), looking to highlight

variations in amplitude, phase and frequency of the acoustic signals, independently or in an integrated manner. These variations may have a correlation with geological, sedimentary and structural characteristics, which cannot be observed with the naked eye in conventional seismic images. In general, three types of seismic attributes were mainly applied: instantaneous (mainly RMS or Root Mean Square, phase, frequency), geometric (dip/azimuth, coherence, curvature) and spectral (decomposition in frequency ranges).

Among the most used attributes in the analysis, RMS stands out to try to identify potential fluid content in reservoir rocks that can be hydrocarbons, of coherence to highlight discontinuities such as faults, channel edges and chaotic areas such as mass transport deposits and spectral decomposition to detect lithological changes by frequency content. The combination and use of seismic attributes in the area was a key factor in the identification and delimitation of exploration prospects, in the identification of seismic facies and in GDE sedimentary maps construction (Gross Depositional Environment).

The stratigraphic interpretation of seismic profiles, well information calibration, geological horizons interpretation and the analogs documented for the Perdido Area, allowed to generate the sedimentary facies interpretation for the assessed plays from seismic information.

5.5.4. Estimation of expected hydrocarbon type

This analysis consisted of compilation, integration and updating of the available information through the National Hydrocarbons Information Center (CNIH), which includes several of previous regional studies of basin analysis, petroleum systems, plays and geochemical analyzes done by Pemex and the Mexican Petroleum Institute (IMP) in the Perdido Area.

Additionally, the result of wells drilled as at 2016 and the new geochemical information derived from ARES, served to make updates of the expected hydrocarbon type mapping; in this case, for the Upper Jurassic Tithonian source rock and its situation as the main source rock interval of the area.

With the data integration, in addition to the previously performed 3D modeling, some 1D simulations of recent drilled wells and pseudo wells were performed at strategic points within Perdido Area, punctually estimating the source rock maturity and determining the expected hydrocarbon type, to finally compare these results with previous studies, making the appropriate calibrations and adjustments.

5.5.5. Petrophysical model based on seismic and wells information

According to PRMS (2018), geostatistical methods constitute a variety of techniques and processes for the analysis and interpretation of geoscience and wells data to describe the variability and uncertainty of the subsoil characteristics. In that sense, a petrophysical model was constructed in a northeast portion of approximately 4,200 km2 of the Perdido Area, as part of the prospective resources assessment.

This model focused on an area where the geological complexity and information quality, allows to obtain reliable results and was performed with the objective to populate petrophysical properties of interest through geostatistical methods, using as input well logs data of 11 wells (P velocity, Vp; S velocity, Vs; density and resistivity) and RMS velocity

volumes of Centauro 3D in a PreSDM RTM version. The area and the methodological process for the construction of this model are outlined in Figure 18.

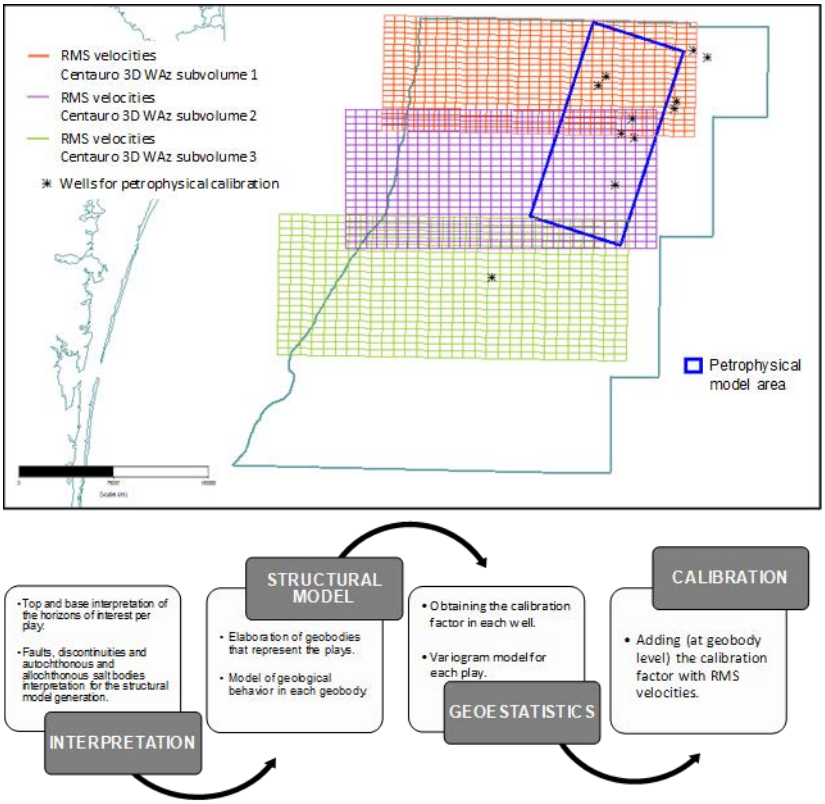


Figure 18. Location and methodological process scheme for the construction of the petrophysical model used in the process of assessing prospective resources in Perdido Area.

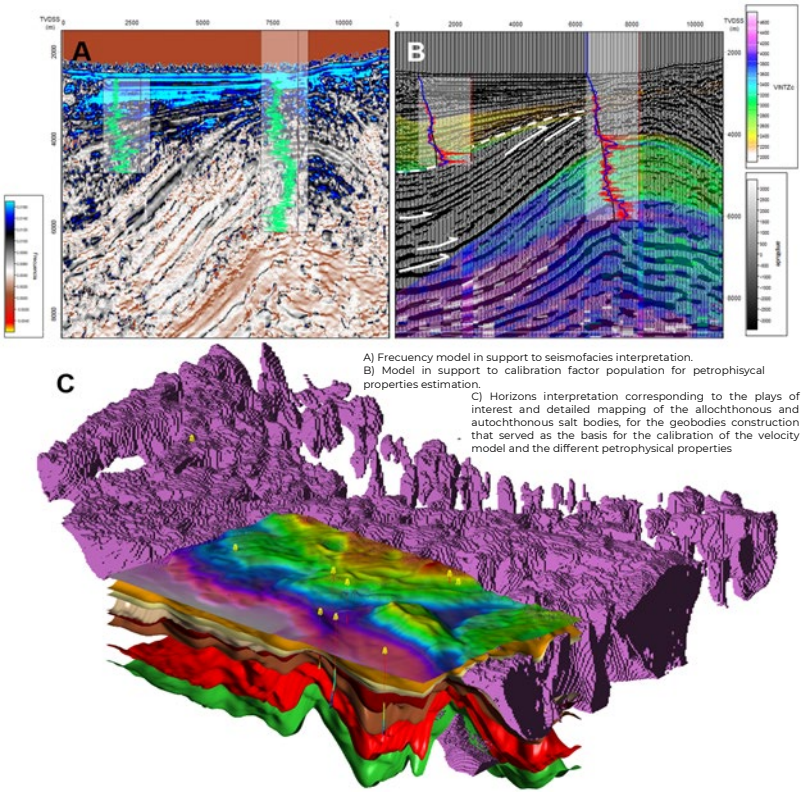


Figure 19. Image that schematically shows the use of some seismic attributes to visualize the stratigraphic behavior and geometry of the analyzed sequences (A), seismic facies calibration with well logs response (B), as well as the detailed mapping of allochthonous and autochthonous salt bodies, for the construction of geobodies, that served as the basis for the calibration of the velocity model and different petrophysical properties (C).

The first step in the generation of the model was geologic horizons interpretation corresponding to the plays of interest (Neogene, Oligocene, Eocene and Paleocene), in addition to detailed mapping of the allochthonous and autochthonous salt bodies, for the construction of the geobodies that served as the basis for the velocity model calibration and the different petrophysical properties (Figure 19 C). Once geobodies were generated, the characteristic seismofacies were identified and interpreted for each play in the area; which are necessary to be able to define a spatial correlation between the calibration factor that comes from the vertical resolution of well logs (Vp, Vs, density and resistivity) and seismofacies.

The simofacies were calibrated with the response of the gamma-ray log and Vp behavior. With the support of some seismic attributes, it was possible to visualize the stratigraphic behavior and geometry of the analyzed sequences (conformities, unconformities, toplap, onlap, offlap, downlap, etc.) (Figure 19 A and B).

Once the stratigraphic and seismofacies models were generated, these models are transferred to each of the blocks that represent a specific play and variograms were generated, taking into account the spatial relationship between the seismofacies, geobodies and the calibration factor (of the P wave, S wave, density and resistivity), looking to obtain a better fit by populating the calibration factor with the geological behavior.

The velocity calibration factors populated model in each geobody is applied to the RMS velocities (converted to intervals), to obtain an interval velocity model that maintains a lithological and structural behavior (Figure 20).

Once the calibrated velocity model for each geobody was generated, different petrophysical parameters were estimated using conventional equations (e.g., shale volume, porosity as a function of density and Vp, water saturation as a function of resistivity, porosity and temperature, etc.), based on the modeled behavior of the calibrated velocities. With the petrophysical properties estimation, the identified prospects were interpreted in detail, assigning ranges of values with their respective uncertainties through probabilistic distributions.

As petrophysical ranges and their uncertainty in the model related to each interpreted prospect are now estimated, the prospective resource was probabilistically estimated according to the geological objectives and the different interpreted geobodies.

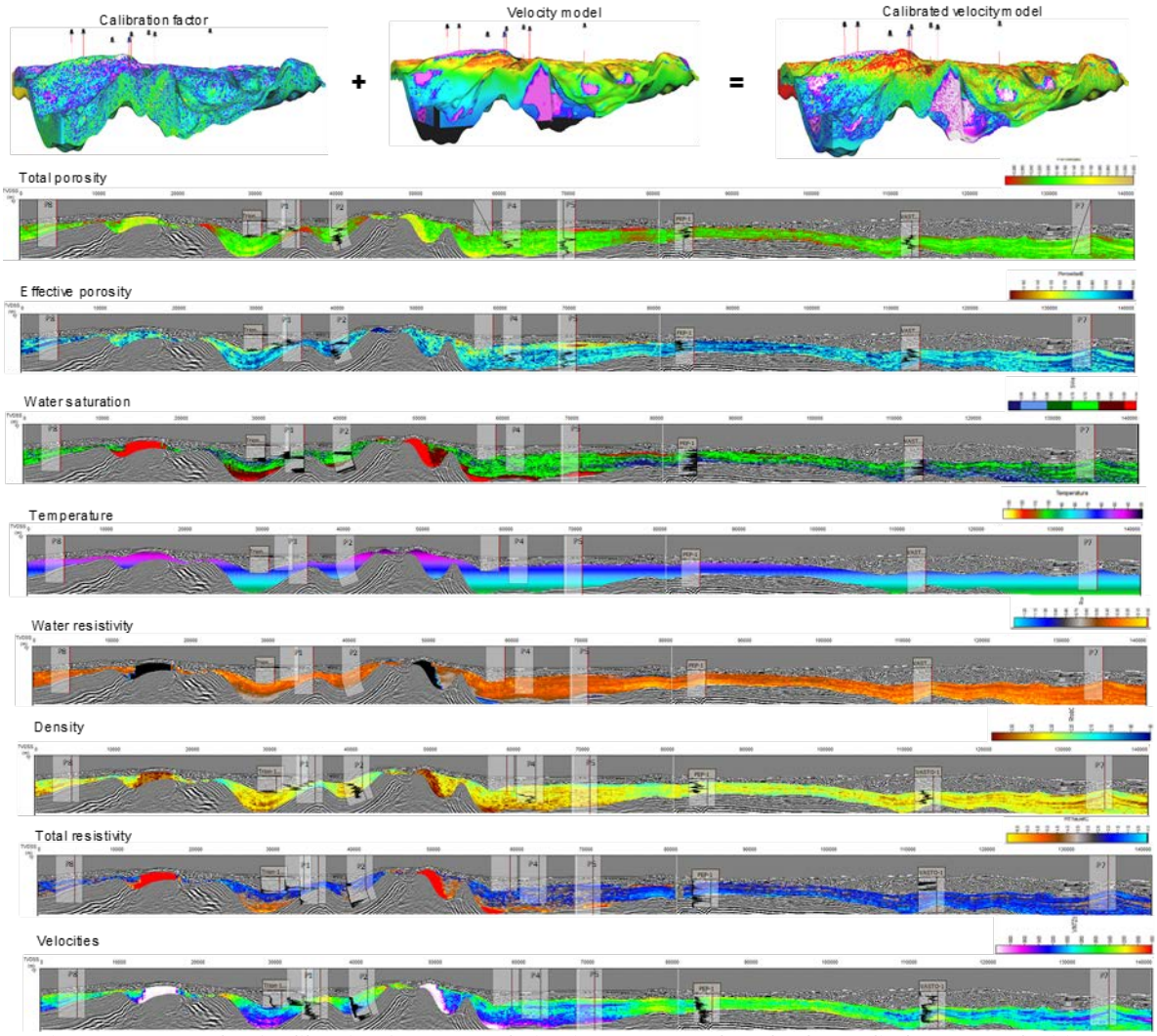


Figure 20. Example of calibration factor population in a generated geobody, applied to RMS velocities to obtain an interval velocity model that maintains a lithological and structural behavior. From this calibrated volume, petrophysical properties were estimated as part of the prospective resources assessment in exploration prospects located within the area of the model.

5.5.6. Identification and assessment of exploration prospects

As discussed in section 5.4.1, an important component of the available information are the historical databases of prospective resources, which served as an important reference for exploration prospects identification in the Perdido Area. Similarly, the information from the exploration plans of the 13 Pemex entitlements and the 11 awarded contracts to date in the Perdido Area, including the Pemex farmout in Trión block (Figure 11), served as a reference for the analysis performed by the Commission for the identification of exploration prospects.

It is essential to clarify that, although the historical prospective resources databases and exploration plans serve as relevant references to know the vision about the potential of resources around the identified prospects, the assessment done by the Commission does not necessarily coincide to the reported assessment by the operators that are developing exploration activities in the area, especially in terms of the applied methodology, seismic interpretation around the prospects, number identified geological objectives,

petrophysical and volumetric parameters, the expected hydrocarbon type, risk analysis for the estimation of the probability of geological success, estimation of the amount of prospective resources, among other factors.

The assessment of exploration prospects carried out by the Commission was done according to the methodology described in section 3.2, using homogeneous criteria and adopting the fundamental principles of evaluation and classification of resources of PRMS (Petroleum Resource Management System). For this reason, many of the prospects or leads and even geological objectives reported by the operators were not considered by the Commission for the prospective resources assessment in exploration prospects.

Based on the analysis and interpretation of new seismic information available, on the 34 wells drilled to date, calibrations and adjustments made to determine the petrophysics and adjustments in the expected hydrocarbon type, as well as models and studies carried out by the Commission, a total of 101 exploration prospects with up to 4 geological objectives were identified and evaluated, where 11 correspond with new prospects identified, which are part of the prospect inventory assessed by the Commission in Perdido Area.

In this way, the identified exploration prospects portfolio of in the Perdido Area is an estimated total risked mean of 4,063 MMboe, a variation of -17% respect to the previous estimates.

Table 9 shows the exploration prospects prospective resource assessment update carried out by the Commission, in comparison to the estimate as of 2018. The graph in Figure 21 shows the resources distribution by main expected hydrocarbon type, according to the identified exploration prospects assessment update.

Table 9. Update of exploration prospects prospective resources assessment carried out by the Commission, compared to the estimate as of 2018

Prospective resources update of identified exploration prospects					
Category	**Prospective Resources P90 (MMboe)**	**Prospective Resources P50 (MMboe)**	**Prospective Resources mean (MMboe)**	**Prospective Resources P10 (MMboe)**	**Prospective Resources risked mean (MMboe)**
Estimation as of 2018	3,420	11,104	**15,502**	34,430	**4,902**
Update	**3,962**	**11,827**	**13,583**	**25,436**	**4,063**
Difference	542	724	**-1,919**	-8,993	**-839**
Difference (%)	14%	6%	**-14%**	-35%	**-17%**

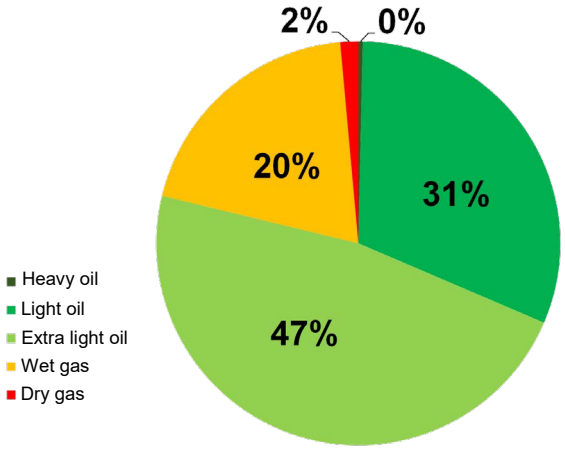


Figure 21. Distribution by main expected hydrocarbon type, according to the assessment update carried out by the Commission, regarding the identified exploration prospects.

5.6. PERDIDO AREA PLAYS ASSESSMENT

The Perdido Area plays are postulated based on current knowledge and the integration and analysis of seismic information, regional studies, well information and analogs. Section 5.3.5 describes the main characteristics of the delimited and defined plays within Perdido Area and Table 4 of section 5.3.5, shows the summary of their main characteristics.

The prospective resource assessment at the play level is based on probabilistic methods, considering the mapped and unmapped prospects as a total in a play, where the input information for the estimate is a distribution of the volume of identified prospects, a number of additional prospects that could occur in the play and an average probability of success. The volume assessment at play level, comes from the construction of a probability density function derived from all of the geological objectives of exploration prospects that belong to the corresponding play, considering recoverable volumes and the discoveries characteristics within a play at a certain date.

The methodology applied for the assessment at play level is described in section 3.3. According to the play fairway analysis done in Perdido Area, 5 plays represented by the stratigraphic horizon containing the potential reservoir rocks were defined, and based on this analysis, generalized play maps were developed to interpret the extension of the 5 assessed plays.

Figures 22 to 26 show schematically the interpreted extension for Mesozoic, Paleocene, Eocene, Oligocene and Neogene plays; respectively in Perdido Area, identifying in an illustrative way, the areas where it is inferred that the play may exist but it is not possible to visualize prospects, mainly due to the geological complexity of the area, associated with salt and shale tectonics or due to poor quality of seismic image. Also, the allochthonous salt extent is indicated schematically, the area corresponding to the abyssal plain and where the absence of the play is interpreted; mainly due to salt intrusions and faults displacement.

The graph in each figure shows the estimation curves of prospective resource volumes for the assessed plays, representing the identified and unidentified prospects (total prospective resource) estimates. The estimated total prospective resources in each assessed play, reflect the exploration potential related to the current knowledge and the available information at a certain date, so that the progress in exploration activities that provide new information, will generate adjustments in the estimates and in the total prospective resources assessment.

In the Mesozoic play case, to date, there are no wells that have investigated the play in Perdido Area; however, it is postulated as hypothetical based on Baha-2 and Tiber-1 analog wells results, drilled in the United States.

For Cenozoic plays, to date, 8 exploration wells have established the Paleocene, 25 the Eocene (which include the most important discoveries made in Perdido Area), 8 the Oligocene and 3 the Neogene. Each indicative map of the interpreted play extension, shows the result of these wells within their corresponding play and the schematic extension of discoveries, including non-commercial accumulations or in which case, exploration wells that were water flooded or dry.

Table 10 shows the total prospective resources assessment update in plays done by the Commission, in comparison with estimates as of 2018.

Table 10. Prospective resources assessment update in plays done by the Commission, compared to the estimates as of 2018

Prospective resources assessment in plays				
Assessed plays as of 2018	**Prospective resources P90 (MMboe)**	**Prospective resources P50 (MMboe)**	**Prospective resources mean (MMboe)**	**Prospective resources P10 (MMboe)**
RN GPAP H Neogene	1,224	2,651	2,845	4,810
RN GPAP E Paleogene	2,488	4,260	4,480	8,752
RN GPAP H Mesozoic	418	1,462	1,622	3,026
TOTAL	**4,130**	**8,373**	**8,946**	**16,588**
2019 Update				
GP AP E Neogene	278	693	876	1,988
GP AP E Oligocene	838	2,105	2,525	5,282
GP AP E Eocene	810	1,772	2,068	3,873
GP AP E Paleocene	156	420	509	1,200
GP AP H Mesozoic	105	290	374	745
TOTAL	**2,187**	**5,280**	**6,352**	**13,088**
DIFFERENCE	-1,943	-3,093	-2,594	-3,500
DIFFERENCE (%)	-47%	-37%	-29%	-21%

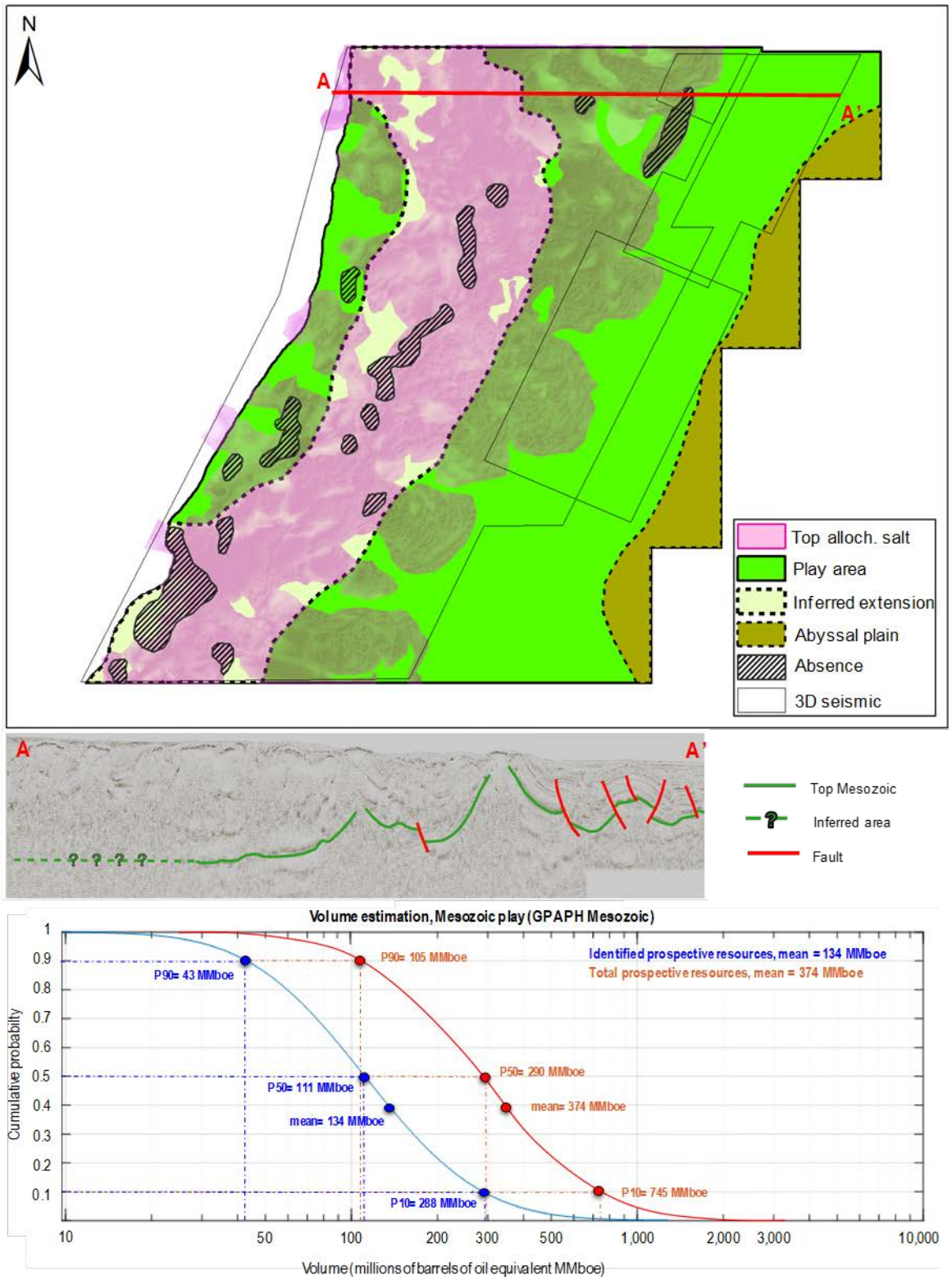


Figure 22. Map that schematically shows Mesozoic play distribution in Perdido Area, the seismic section exemplifies the areas where the play is inferred but it is not possible to visualize prospects and where the absence of the play is interpreted; in this case, mainly due to salt intrusions and faults displacement. The graph shows the probabilistic prospective resource assessment, in terms of identified prospects volume and the total play volume.

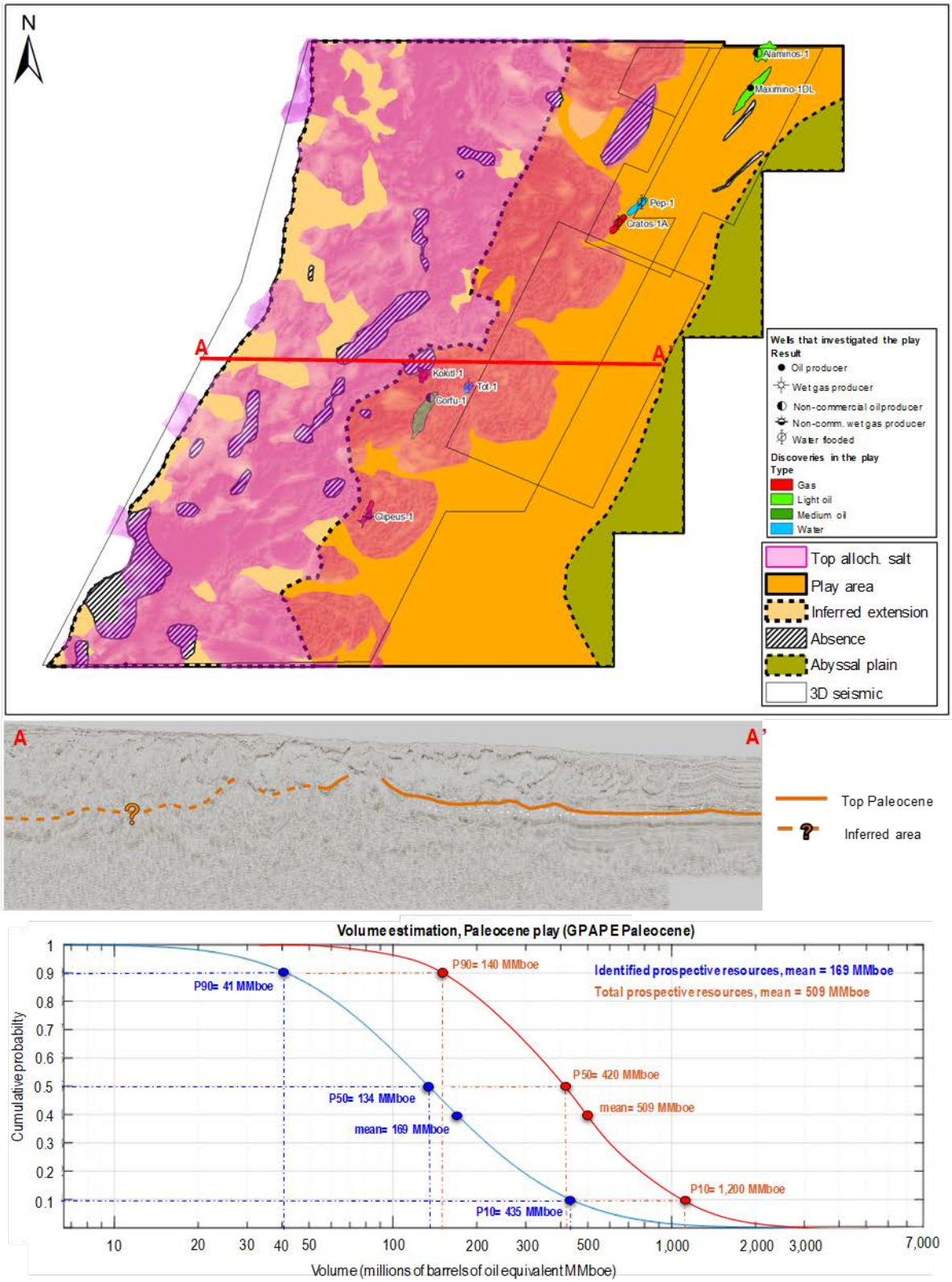


Figure 23. Map that schematically shows Paleocene play distribution in Perdido Area, the seismic section exemplifies the areas where the play is inferred but it is not possible to visualize prospects and where the absence of the play is interpreted; in this case, mainly due to salt intrusions and faults displacement. The graph shows the probabilistic prospective resource assessment, in terms of identified prospects volume and the total play volume.

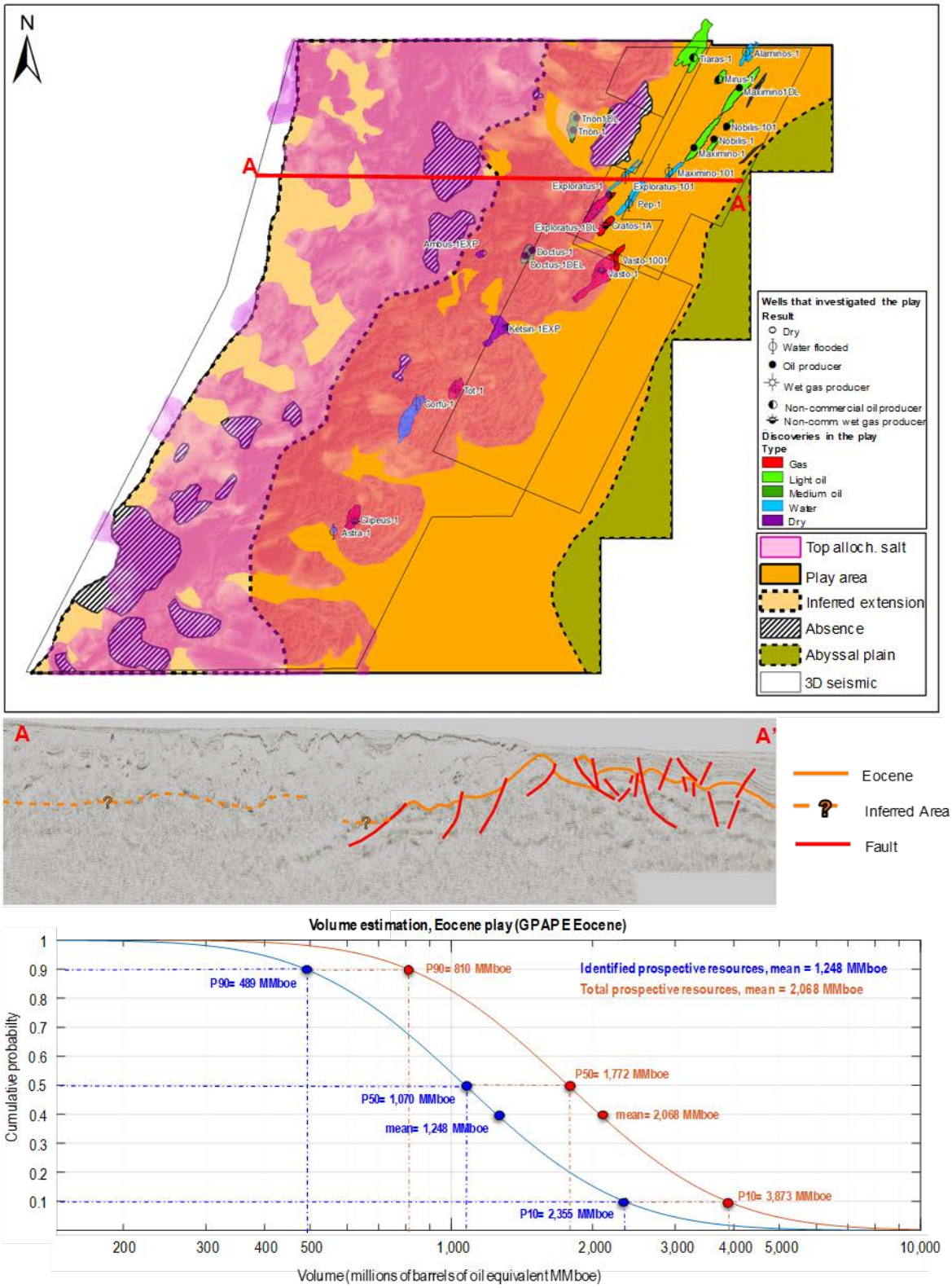


Figure 24. Map that schematically shows Eocene play distribution in the Perdido Area, the seismic section exemplifies the areas where the play is inferred but it is not possible to visualize prospects and where the absence of the play is interpreted; in this case, mainly due to salt intrusions and faults displacement. The graph shows the probabilistic prospective resource assessment, in terms of identified prospects volume and the total play volume.

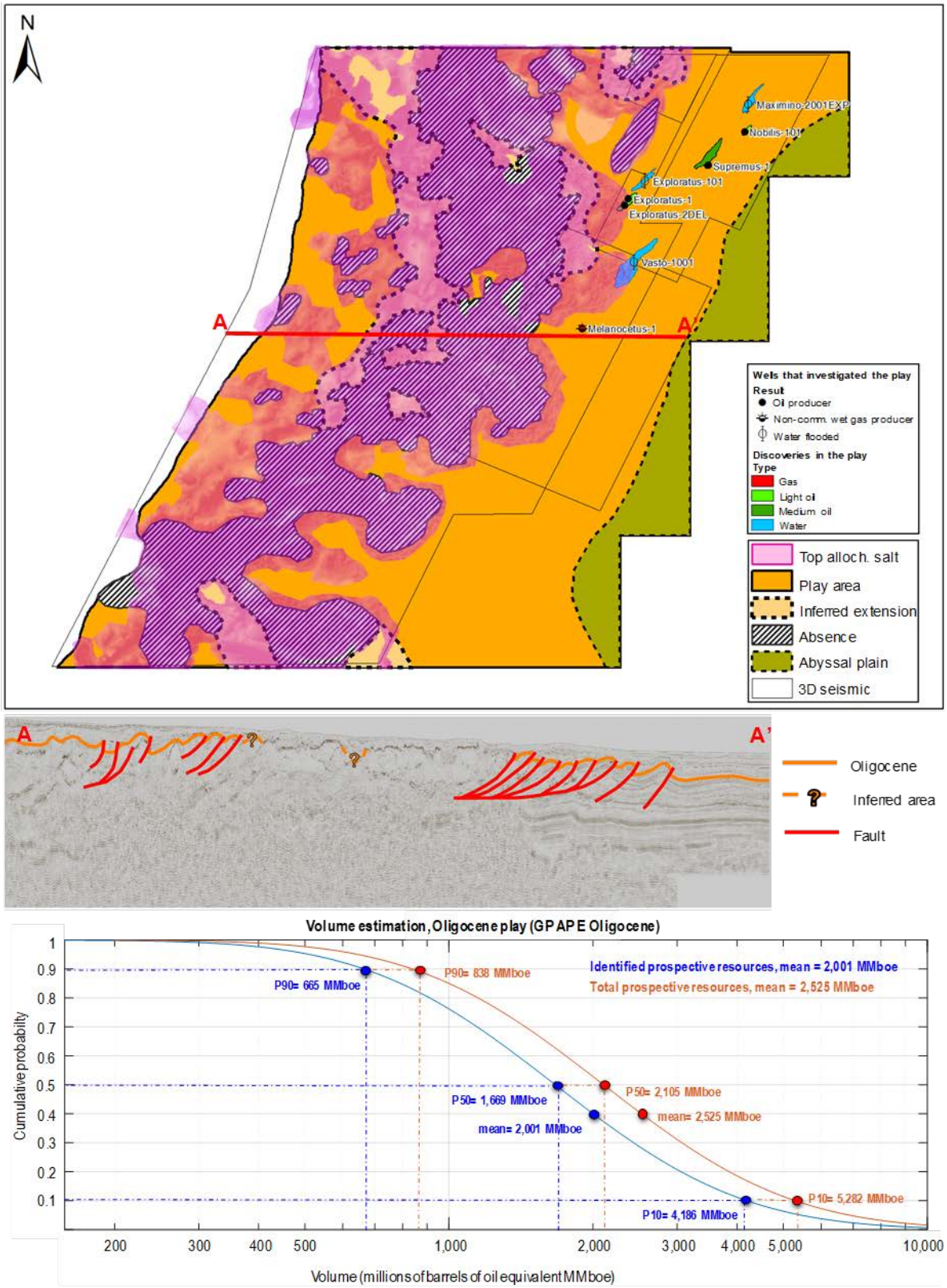


Figure 25. Map that schematically shows Oligocene play distribution in the Perdido Area, the seismic section exemplifies the areas where the play is inferred but it is not possible to visualize prospects and where the absence of the play is interpreted; in this case, mainly due to salt intrusions. The graph shows the probabilistic prospective resource assessment, in terms of identified prospects volume and the total play volume.

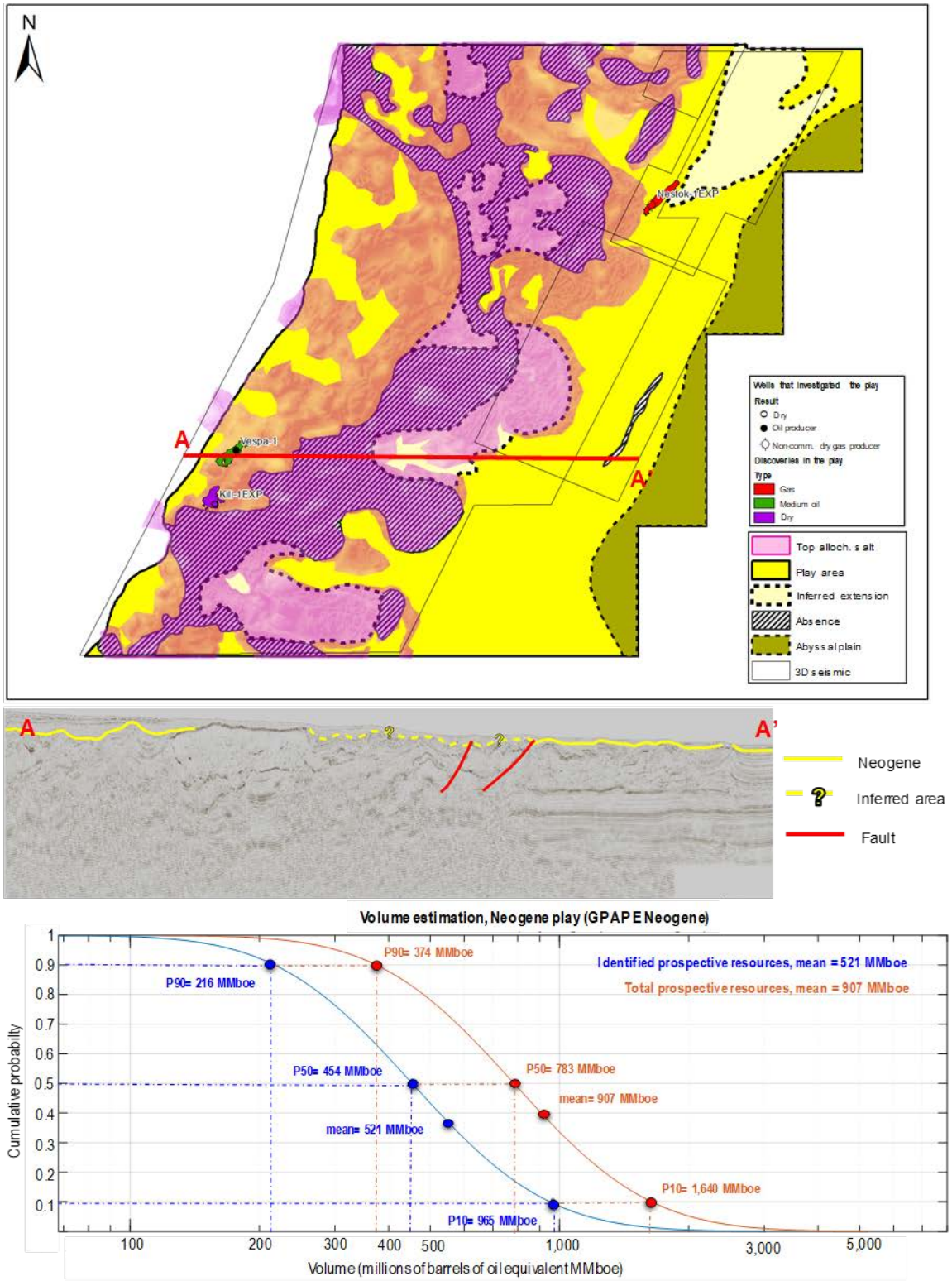


Figure 26. Map that schematically shows Neogene play distribution in the Perdido Area, the seismic section exemplifies the areas where the play is inferred but it is not possible to visualize prospects and where the absence of the play is interpreted; in this case, mainly due to salt intrusions. The graph shows the probabilistic prospective resource assessment, in terms of identified prospects volume and the total play volume.

6. NORTHERN MEXICAN RIDGES

6.1. STUDY AREA CHARACTERISTICS

The northern Mexican Ridges area is located towards the northwestern portion of the Gulf of Mexico, in front of the states of Tamaulipas and northern Veracruz coastlines, in water depths that vary from 400 m to almost 3,500 m. The assessed area covers a surface of approximately 47,750 km^2 (Figure 27).

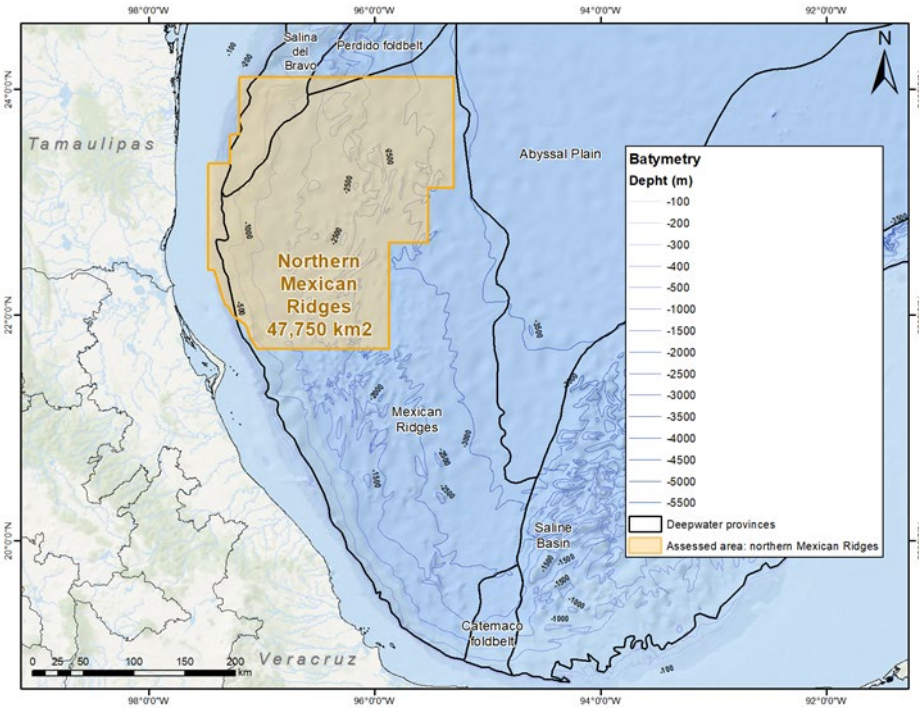


Figure 27. Geographical delimitation of the northern Mexican Ridges area

The Mexican Ridges is a province characterized by the presence of a Neogene aged contraction system, located west of the Mexican continental slope of the Gulf of Mexico (Salomón-Mora et al., 2009). The Mexican Ridges are part of an extensional-contractional linked system, associated with gravitational processes during the Cenozoic, which generated a growth normal fault system at the coast margin and platform, known as the Quetzalcoatl extensional system, transferring and accommodating this deformation towards deeper parts of the basin, with an east direction and under a compressional regime (Salomón-Mora et al., 2011; Escalera and Hernández, 2009).

The Mexican Ridges are characterized by the presence of numerous elongated anticlinal structures, associated with simple detachment folds and fault propagation folds with late reverse faulting development, which mainly develop on Paleogene shale detachment levels (Salomón-Mora et al., 2009). Younger and broader folds tend to concentrate towards the center and south of the province, while in the north, the linked extension-contraction system interacts with salt and shale tectonics.

The structural and stratigraphic features related to the petroleum potential of the province, such as types of potential hydrocarbon traps, characteristics of the seal elements and stratigraphic intervals with characteristics as reservoir rocks, vary throughout the extent of the province.

The Mexican Ridges province can be divided into a northern and southern segments, based on differences in the structural orientation trend of the foldbelt, its extension and length from the continental shelf margin to the basin, variations of the extensional characteristics along the continental shelf and compressional deformation age towards deepwater, among other factors (LeRoy et al., 2008; Salomón-Mora et al., 2011).

The northern portion delimitation of the Mexican Ridges corresponds mainly to the area where there is a northeast-southwest structural orientation tendency of the foldbelt (oblique to the coastal margin), there is interaction of processes of salt and shale tectonics and the onset of compressional deformation, apparently started during Upper Miocene time. While for the southern portion, the structural orientation foldbelt trend is north-south (parallel to the coastal margin), there is no interaction with salt tectonic processes and the onset of compressional deformation, apparently started from Middle Miocene time (Salomón-Mora et al., 2009; Salomón-Mora et al., 2011).

According to the above, the northern Mexican Ridges area limits to the north with the Perdido Area, to the west with the extensional margin with normal growth faulting at the continental shelf and to the east with the abyssal plain of the Gulf of Mexico.

Up to date, there are no Pemex entitlements in the northern Mexican Ridges area, while 14% of the surface corresponds to awarded contracts in the fourth call of the second bidding round (Round 2.4,) and 86% remain as unawarded (Figure 28).

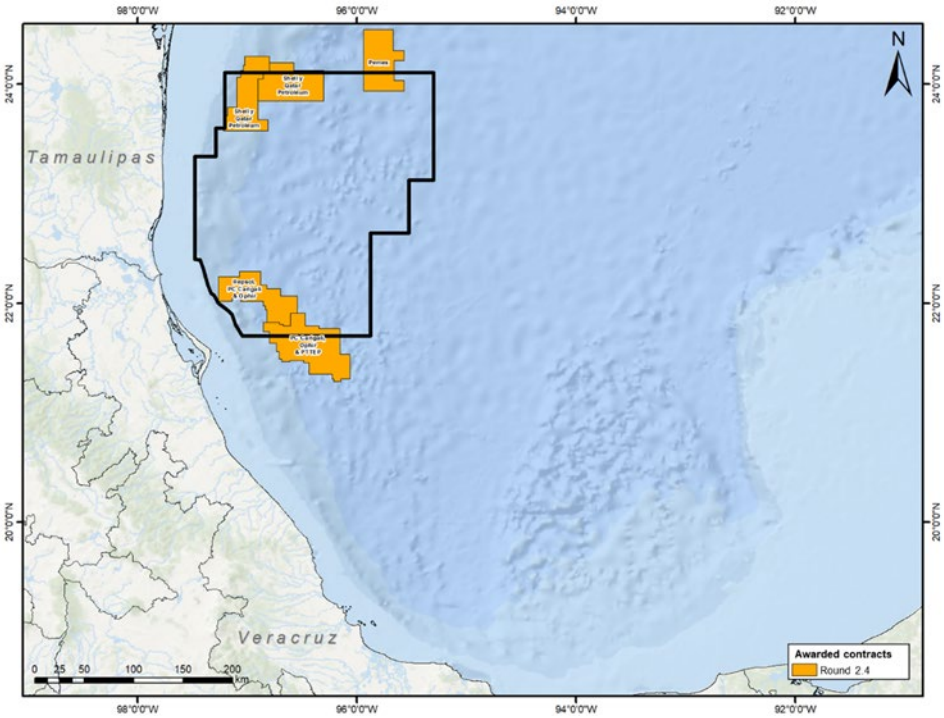


Figure 28. Current status of northern Mexican Ridges, regarding awarded contracts areas.

6.2. GEOLOGICAL FRAMEWORK

The Mexican Ridges is a foldbelt located in the passive margin of western deepwater Gulf of Mexico, whose evolution is related to extensional events associated with normal growth fault systems, due to gravitational collapse at the continental shelf and slope. The

extension processes result in the transfer of deformation to the deepwater zone through a regional detachment surface, forming detachment folds and fault propagation folds, which are distinctive of the Mexican Ridges.

Mexican Ridges is the most extensive contractional system in the Gulf of Mexico and their structural characteristics vary throughout its extent, mainly controlled by variations in gravitational processes that affected the Cenozoic continental shelf and slope margin of western Gulf of Mexico (Solomón -Mora, 2013).

According to Wawrzyniec, et al. (2004), Le Roy et al. (2008) and Salomón-Mora et al. (2011), the Neogene platform extensional system magnitude, decreases progressively towards the south, varying from multiple listric and antithetical faults system at the north, to a single listric growth fault towards the south. Therefore, the width across the contractional system narrows similarly from north to south.

Salomón-Mora (2013) suggests that in addition to the structural differences of the extensional margin from north to south, the compressional deformation in northern Mexican Ridges had a greater advance towards the basin due to salt tectonic processes interaction, in comparison to the southern portion of the province. Based on the analysis of pre and post deformation sequences, Salomón-Mora et al. (2011) establish an age range for compressional deformation, from Upper Miocene until today for the northern sector and from Middle Miocene until today for the southern sector.

Furthermore, Kenning and Mann (2019 in press) attribute the differences in structural characteristics of the north and south Mexican Ridges, to a combination between the distribution and thicknesses of the Paleogene shaley mass transport complexes (Oligocene-Eocene) and the thickness of the Neogene mechanically most competent sequences. To the south of Mexican Ridges, there is a greater thickness of competent Neogene sequences, while in the north the total thickness of the shaley mass transport complexes is noticeably greater.

According to that, Kenning and Mann (2019 in press) propose that the extension and geometry of the Mexican Ridges foldbelt, coincides with variations in thickness and distribution of the Paleogene shale sequences, associated with mass transport complexes. To the north compared to the south, folds are observed in greater quantities, with an irregular tendency, greater amplitude and less spacing between them, forming a characteristic deformation front projection basinward at northern Mexican Ridges (Figure 29).

Structurally, the northern Mexican Ridges area covers different sectors (Figure 29), starting with the continuation to the south of the peripheral foldbelt; created by the allochthonous salt mass advance and with an Upper Eocene detachment level, the Neogene extensional system at the platform or Quetzalcoatl extensional system (Alzaga-Ruiz et al., 2009) and the Mexican Ridges contractional system. Additionally, it includes transitional sectors known as the shallow linked system and the basement inversion deep folding system.

The shallow linked system has only been documented in the northern Mexican Ridges, interpreted as a shallow sliding zone with growth normal faulting that confine Plio-Pleistocene sequences (Figure 29, section B-B'), with an Upper Miocene detachment level and in turn, correspond to a salt weld related to the evacuation a paleo-canopy of salt (Ambrose et al., 2005; Le Roy and Rangin, 2008; Salomón-Mora, 2013).

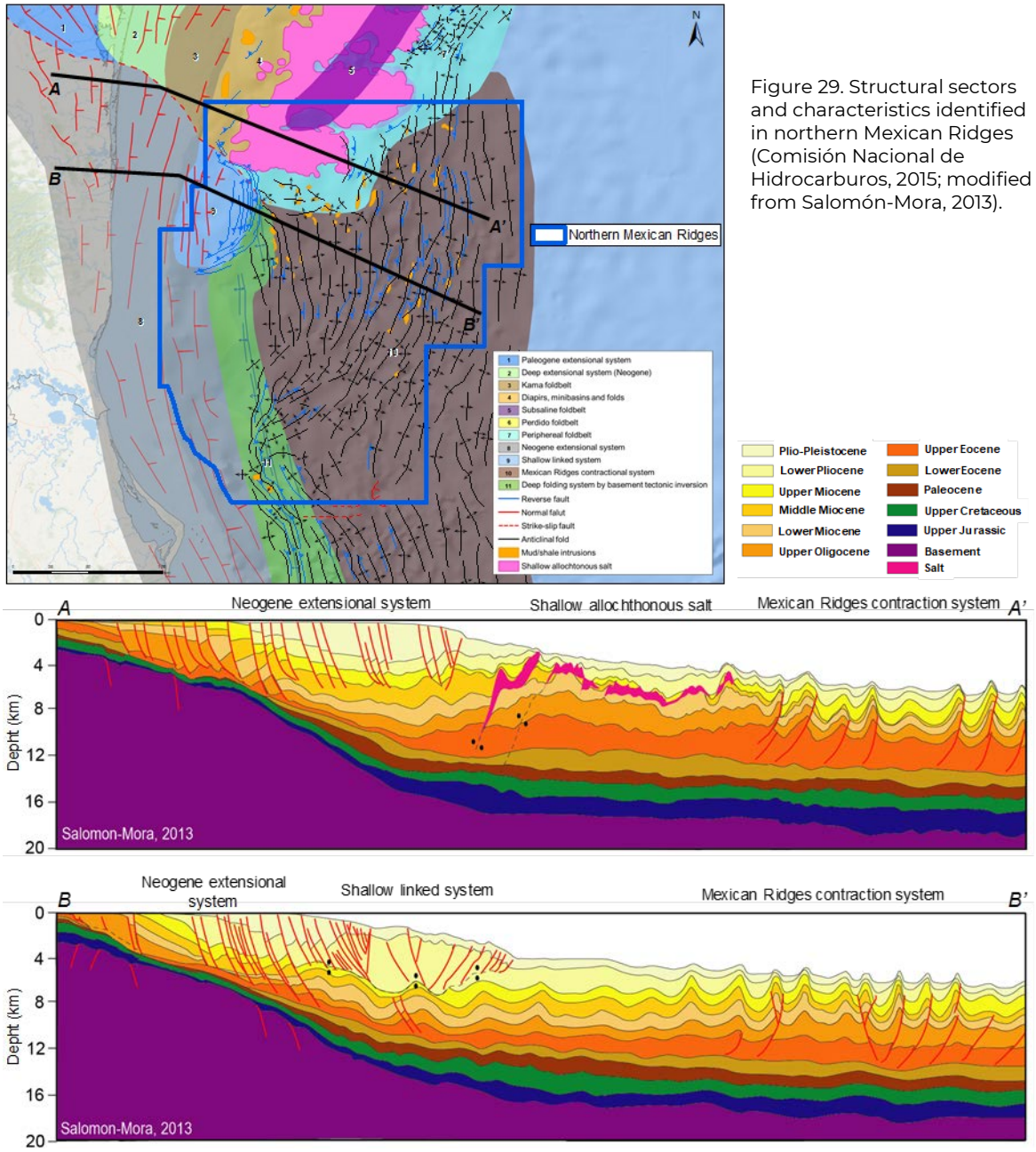


Figure 29. Structural sectors and characteristics identified in northern Mexican Ridges (Comisión Nacional de Hidrocarburos, 2015; modified from Salomón-Mora, 2013).

This type of salt tectonics structure is known as roho system (Diegel et al., 1995; McBride, 1998; Rowan et al., 1999) and is characterized by allochthonous salt bodies that have suffered great displacement in several episodes, leaving behind horizontal sub-weldings along its upward trajectory. In the case of the shallow linked system at northern Mexican Ridges, its formation process is associated with the evacuation of a salt canopie at the southern end or southern termination of the salt present in the Perdido Area.

The deep folding system corresponds to subtle anticlines by basement faulting in rocks mainly of the Mesozoic, generated by tectonic inversion and associated with a transpressional zone with clockwise lateral movement. According to Le Roy et al. (2008),

this area is located along the western limit of the thinned continental crust, where the previous basement faults were reactivated during the Neogene.

The Mexican Ridges province limits to the north to the Perdido Area and to the south to the Saline Basin, where the evolution of these two provinces starts from the opening processes of the Gulf of Mexico during the Lower Triassic-Jurassic and from the syntectonic deposition of salt that has been handled as of Callovian age, on a continental thinned crust in a single sag basin. This large sag basin is splitted later during the oceanic crust generation processes at Upper Jurassic time (Pindell and Kennan, 2009).

The oceanic crust generation and the clockwise rotation of the Yucatan block, accommodated the displacement through a right lateral fault, which is the boundary between the continental crust and the oceanic crust at western margin of the Gulf of Mexico, this fault is known as the Western Main Transform fault (Marton and Buffler, 1994; Román-Ramos et al., 2008; Nguyen and Mann, 2016).

With cessation of oceanic crust generation, the rest of the Mesozoic is characterized by thermal subsidence processes and the establishment of a passive margin, with the development of large carbonated platforms along the continental margin of western Mexico, where its development was controlled by basement highs (Goldhammer and Johnson, 2001).

Within this Mesozoic evolution framework of the Gulf of Mexico, the development of the Mexican Ridges in deepwater occurs mostly on oceanic crust, while the continental shelf (Neogene extensional system), to the west of the Western Main Transform fault, is located on basement highs and lows, corresponding with thinned continental crust and as a result of multiple episodes of extension or rifting (Hudec et al., 2013).

From Upper Cretaceous to Middle Eocene, the exhumation of the continental portion of eastern Mexico formed the Sierra Madre Oriental and the Sierra de Zongolica (Gray et al., 2001; Fitz-Díaz et al., 2018). The tectonic load created by the formation of the Sierra Madre generated flexural subsidence, developing wide and deep foreland basins along the entire deformation front (Alzaga-Ruiz et al., 2009; Galloway et al., 2011) and changing the sedimentary regime from carbonates to siliciclastics by the tectonic front erosion.

Authors such as Galloway et al. (2000), Alzaga-Ruiz et al. (2009) and Salomón-Mora (2013), coincide that the first important siliciclastic sediments pulse to the foreland basins occurred during the Paleocene, where basement highs created barriers that trapped the sediment flow, limiting its influx to deeper parts of the basin.

With the progress of the uplift and erosion of the orogeny during Upper Paleocene, the foreland basins were quickly infilled, developing the first erosive features at the continental slope level that allowed the sedimentary influx to the deepwater zone (e.g. Bejuco-La Laja and Chicontepec paleo-canyons), through deepwater fan systems, mud dominated mass transport complexes and some turbidites with isolated sandstones and siltstones layers (Snedden et al., 2018).

By Lower Eocene time, the continental shelf was dominated by the development of fluvial-deltaic systems (delta-prodelta facies), that generated erosion on the platform and sediment influx directly into deepwater or sediment bypass north and south of the western margin of the Gulf of Mexico (Wawrzyniec et al., 2004; Ambrose et al., 2005; Salomón-Mora, 2013; Snedden et al., 2018), which began prograding towards the basin at the end of Eocene, as a consequence of sediment flow due to the continuous uplifting

and erosion of the tectonic front and related to post-orogenic structural inversion processes.

According to Salomón-Mora (2013), progradation of sedimentary systems controlled the evolution of northern Mexican Ridges passive margin, where there is interaction with salt tectonics processes and moving the first salt paleo-canopie towards the basin, which was fed by autochthonous salt located at the southern edge or termination of the salt present in Perdido Area.

Considering that as fluvial systems continue to prograde, an unstable platform edge and a steep slope were constructed along the western margin of the Gulf of Mexico. Kenning and Mann (2019 in press) suggest that from Upper Eocene, post-orogenic deformation and tectonic inversion processes along the tectonic front edge, produced uplifting of the foreland basins proximal area, as well as uplifting of the adjacent structural highs to the platform, triggering mass transport complexes deposition towards the deepwater zone.

Galloway et al. (2000), mentions that the Oligocene was an important stage of sedimentation towards the Gulf of Mexico, characterized by processes of explosive volcanism, the continuation of tectonic inversion and erosion processes in western Mexico. This, resulted in the sedimentary systems continuing to prograde towards the basin, the progressive burial of structural highs and that the edge of the platform and slope reached a maximum advance by the Middle Oligocene (Gray et al., 2001).

During this post-orogenic inversion period and until Lower Miocene, part of the sediment influx continued beyond the slope towards the deepwater zone of the Gulf of Mexico through basin floor fans (Alzaga-Ruiz et al., 2009). The high sedimentation rate, the progressive progradation of fluvial-deltaic systems and possible sea-level falls, may have induced slope instabilities, which generated stacked sequences of mass transport flows into deepwater (Galloway et al., 2000; Kenning and Mann, 2019 in press).

As submarine fans and mass transport complexes continue depositing during Miocene and until today, progressive accumulation of the sedimentary wedge at the limit of the platform and slope was generated, resulting eventually in gravitational collapse along of the continental platform-slope edge through listric fault systems and rollover structures, accommodating the sliding in the Paleogene shale sequences. The development of the Neogene or Quetzalcoatl extensional system was progressively eastward during Middle Miocene, Upper Miocene and Plio-Pleistocene, based on the geometry of growth strata and with characteristic structural tendencies (Salomón-Mora, 2019).

At the end of Lower Miocene, the first growth faults to the north began to develop, related to the high sedimentation rates of the deltaic system of Rio Grande (Galloway et al., 2000) and which would then progressively extend along the entire platform to the south (Wawrzyniec et al., 2004; Roure et al., 2009; Salomón-Mora, 2013).

At northern Mexican Ridges, salt evacuation processes and frontal displacement of the allochthonous salt bodies continue to the east, mainly during the Upper Oligocene-Miocene time. The salt canopy within northern Mexican Ridges quickly spread radially, generating minibasins due to differential sedimentary load, some welds, compressional deformation by its frontal thrust displacement and where the first structures associated with the peripheral foldbelt are developed mainly from Lower Miocene, on an Upper Eocene shale detachment level (Salomón-Mora et al., 2013).

In the Middle Miocene, growth faults acquire the characteristic listric geometries of the Neogene extensional system at the steep platform edge, derived from the gravitational collapse at the north and south of the western margin of the Gulf of Mexico. The rapid development of listric faults due to the intense sedimentary load, generated overpressure in Upper Eocene shale intervals, giving rise to the first tilted blocks with graben and half graben structures dominated by gravitational extension.

The gravitational extension processes at the platform margin during the Middle Miocene, created the first low relief detachment folds to the south of the Mexican Ridges (Salomón-Mora et al., 2009).

In the Upper Miocene, the extensional system was divided into an upper and a lower portions (up-dip and down-dip; respectively) with the development of a large-scale listric fault called the Faja de Oro fault (Wawrzyniec et al., 2004; Ambrose et al., 2005), which controlled the platform morphology, create depocentres between the growth faults and rollover structures, and influenced sediment distribution to the slope and deepwater.

Warwzinyec et al. (2004) suggests that the sliding along the entire trace of this great listric fault could be generated by sedimentary load, beginning its development to the north and continuing towards the south with a lower level of extensional displacement, as a consequence of a distal sedimentary load and kinematic arrangement of gravitational gliding.

On the other hand, Le Roy et al. (2008) propose that the deep transpressive reactivation of basement structures (tectonic inversion of basement faults), located on the western boundary of the Western Main Transform fault, was a probable mechanism that triggered the gravitational collapse of the platform in the Upper Miocene associated with the Faja de Oro fault, being able to partially influence the development of contractional deformation of the Mexican Ridges.

The advance of the Upper Miocene extensional front, moved its accommodation through Upper Eocene detachment level into deepwater, developing the north folding of the Mexican Ridges and extending rapidly to the south, generating asymmetric fault propagation folds in proximal areas to the continental slope and low amplitude symmetrical detachment folds towards the most distal areas (Salomón-Mora, 2013; Yarbuh and Contreras, 2015).

To the north of the Mexican Ridges, the frontal displacement of allochthonous salt masses continues to advance and the peripheral foldbelt continues its evolution. The extensive lateral spread of the allochthonous salt bodies begins to climb above Lower and Middle Miocene stratigraphic levels, even above some contractional folds of the peripheral foldbelt, initiating the interaction of salt tectonic processes with the lateral propagation of deformation of the northern Mexican Ridges foldbelt (Salomón-Mora, 2013).

According to Ambrose et al. (2005), during the Neogene, sedimentary successions of sandstones from coastal environments and delta fronts were developed on the platform, muddy channelized systems were developed on the slope and mass transport complexes, extensive basin floor fans and channelized lobes were developed in deepwater.

With the continuous progradation of sedimentary systems, the extensional front continues advancing towards the basin for the Lower Pliocene and the gravitational

gliding in the listric faults is increased; where the Faja de Oro fault, accommodated most of the extension and growth strata on the platform (Warwzinyec et al., 2004). This increase in gravitational extension at the continental shelf and slope area, reactivated the compression towards deepwater in the Mexican Ridges, expanding the foldbelt deformation front.

The compression reactivation in the Mexican Ridges during Lower Pliocene resulted in the generation of new detachment and fault propagation folds, as well as an increase in contraction in previously formed folds, inducing the development of late reverse faulting. Some of these reverse faults were generated with an opposite vergence to the main direction of deformation and on a local Oligocene-Miocene shallow detachment level (Salomón-Mora et al., 2009; Kenning and Mann, 2019 in press).

At northern Mexican Ridges, the salt masses evacuation processes continue to Lower Pliocene and the shallow linked system is developed, by the complete evacuation or dissolution of the salt layer located towards the south edge, leaving a salt weld at the Upper Miocene level and growth faults that confined syntectonic Plio-Plestocene sequences (roho system). Additionally, according to Salomón-Mora (2013), shale tectonics in the form of mud diapirs began possibly since Lower Pliocene in some areas of the foldbelt.

Finally, from Upper Pliocene to nowadays, the Mexican Ridges foldbelt continue its eastward advance by propagation and sliding of growth faults at the extensional province on the continental shelf edge, generating the most distal detachment folds and increasing the contraction in the previously formed folds (Salomón-Mora, 2013). Likewise, the shallow linked system completes its current geometry and the minibasins associated with the allochthonous salt masses continue their development, due to differential sedimentary load effects.

With the contraction increase in the Mexican Ridges foldbelt, some mud diapirs resulted in surface mud volcanoes, including some folds that with the increase in the level of contraction, break through the growth strata inducing the appearance of surface mud diapirs and volcanoes. According to Salomón-Mora (2013), these types of structures with collapsed crests tend to be located in the proximal regions of the contractional system.

The tectonic evolution of the area has controlled the development of the environments and the sedimentary column of the Mexican Ridges (Figure 30). The oldest rocks that have been reached by wells in this province (Puskon-1), are constituted by Upper Paleocene intercalations of fine to medium-grained sandstones and calcareous shales, whose deposition is interpreted from well log electrofacies analysis as channel fills related to a distal part of a basin floor fan.

The Gulf of Mexico tectonic evolution, associated with the processes of continental crust thinning or rifting and the generation of oceanic crust, have a direct influence on the sedimentary column in the Mexican Ridges, specifically for the Jurassic.

Goldhammer and Johnson (2001), typify the pre-Callovian sedimentary successions of northeastern Mexico as continental sediments (red beds) and volcaniclastic rocks, deposited in depressions with graben and half-graben geometries generated during the continental crust extension. By the Bajocian-Callovian time as the initial marine incursion comes from west, sediments gradually change to shales, siltstones and volcanic litharenites in marginal or shallow marine environments, deposited coevally with evaporites.

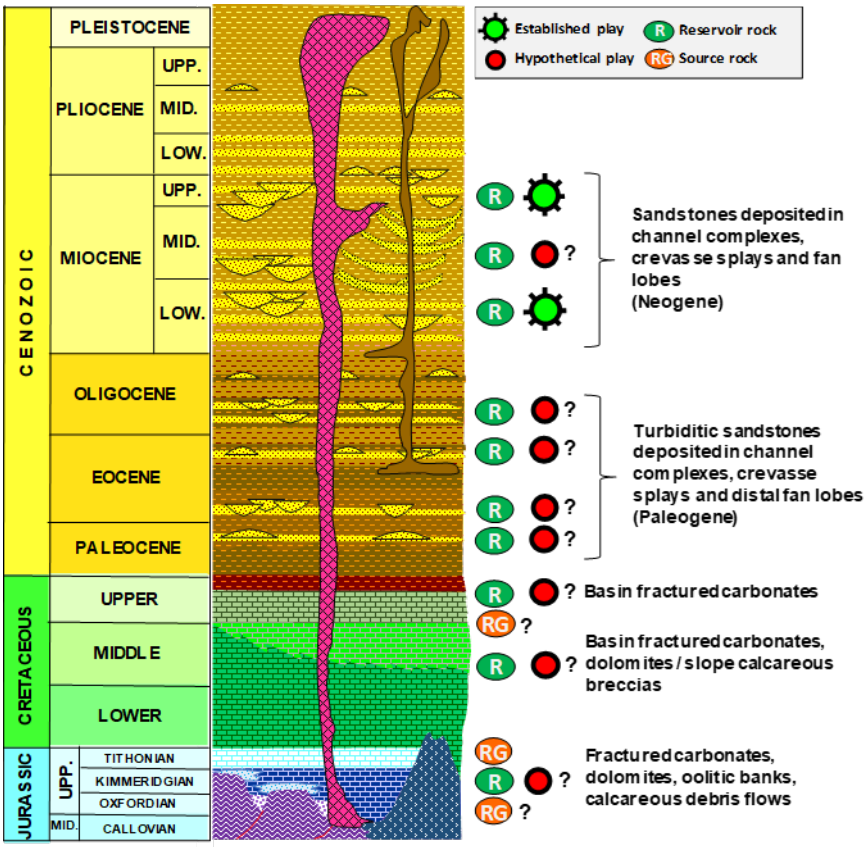


Figure 30. Schematic sedimentary column for the Mexican Ridges area, indicating identified levels as reservoir and source rocks.

These conditions prevail during Callovian and Early Oxfordian time and marine transgression reaches the central part of the paleo-Gulf of Mexico, depositing thick layers of salt in a single large shallow hypersaline basin. As salt deposition ceases and the oceanic crust generation begins, this large saline basin started to be divided into a northern (Louann) and southern portion (Campeche or Saline Basin); where the southwestern end of the Louann salt portion is located in the northern Mexican Ridges.

Lateral variations and thickness of the sedimentary facies at west of Gulf of Mexico during the Oxfordian-Kimmerigdian time, were controlled by basement highs, where the sedimentary environments gradually change towards the basin.Starting from marginal marine environments with clastic sedimentation, represented by coarse-grained sandstones, to shallow carbonate platform and ramp environments, to deep marine environments to the east (Goldhammer and Johnson, 2001).

Limestone with fine-grained textures and dolomites were deposited in the platform and ramp areas, which vary laterally to ooid limestones and oolitic banks associated with basement highs; while at the transition of the external ramp and basin, shaley limestones and shales were deposited. These sequences were deposited unconformably on the Callovian salt.

For the Tithonian time, an important period of marine transgression flooded the basement highs, as well as the previously developed platform and ramp systems west of the Gulf of Mexico, depositing fine-grained marine sediments in euxinic conditions composed of shales, siltstones and calcareous shales (Cunningham et al., 2016).

Based on geochemical analyzes, the Tithonian interval is identified as the main hydrocarbon source rock in the Mexican Ridges and throughout the deepwater region of the Gulf of Mexico (Guzmán-Vega et al., 2001; Jacques and Clegg, 2002; Escalera and Hernández, 2009; Salomón-Mora, 2013; Cunningham et al., 2016). However, the characteristics and distribution of this source rock in deepwater of the Mexican Ridges still remain uncertain, specifically in the portion that is on oceanic crust, although evidence from seabed emanations suggests its existence and capacity to produce thermogenic hydrocarbons.

Tithonian source rocks present variations in thickness and facies, due to the basement paleotopography in zones of continental crust and thinned or transitional continental crust at the western margin of the Mexican Ridges. However, the characteristics and distribution of Tithonian rocks associated with the genesis and evolution of the oceanic crust from Upper Jurassic to Lower Cretaceous (Pindell and Kennan 2009; Hudec et al., 2013; Lin et al., 2019), has not been studied in detail at the western portion of the Gulf of Mexico.

With the cessation of oceanic crust generation by Lower Cretaceous time (Berriasian-Valanginian), processes of thermal subsidence and establishment of a passive margin gave rise to the development of shallow marine clastic environments on Gulf of Mexico margins, which change laterally to deepwater deposits towards the basin. The Gulf of Mexico western margin is characterized by the development of low-angle carbonate platforms towards the basement highs, which vary laterally to carbonates and dolomites of lagoon environments and to fine grained limestones and shales in external ramp and basin environments (Goldhammer and Johnson, 2001).

These thermal subsidence conditions and passive margin development extend to the Cenomanian time, where progressive marine transgression events favor the development of large shallow water reef complexes on the platform, which were the source of calcareous debris flows deposited at the platform margin and slope, which vary laterally to deepwater limestones and shales towards the basin.

Upper Cretaceous time is characterized by an increase in volcanic activity on the Pacific margin of western Mexico and a sea-level fall (Salvador, 1991), which caused that areas in shallow platforms previously formed to be exposed and suffer erosion during the Cenomanian-Turonian time (Mid-Cretaceous unconformity). This generated clastic and vulcanoclastic sediments flow into deepwater, composed by intercalations of pelagic limestones with thin layers of shales and bentonite.

The initial stages of orogenic deformation in western Mexico during the Upper Cretaceous period gradually ended with the carbonate deposition regime by the end of Turonian time (Salvador, 1991; Goldhammer and Johnson, 2001). For the Maastrichtian, the advance of the deformation front of Sierra Madre Oriental and the increase in subsidence, generated the development of foreland basins that accumulated clastic sedimentation resulting from the uplift and erosion.

By the Paleocene, a generalized period of progradation towards the basin of the clastic sedimentary systems begins, including the first Cenozoic shaley system towards deepwater, represented by shale, siltstones and fine-grained sandstones sequences desposited in distal basin floor fans environments. According to Snedden et al. (2018), to the north of Mexican Ridges, there is a sandy sedimentation starvation towards deepwater, since by Paleocene the foreland and Burgos basins trapped the clastic sedimentation at the platform area; while to the south, at Tampico-Misantla area, the

Bejuco-La Laja and Chicontepec paleocanyons acted as input points of clastic sedimentation towards deepwater in submarine fan environments.

The Bejuco-La Laja and Chicontepec paleocanyons expanded during Eocene, extending submarine fans propagation to deepwater, due to the progress in exhumation and erosion of Sierra Madre Oriental. To northwest of the Gulf of Mexico, the paleo fluvial systems of Colorado and Rio Grande rivers provided clastic sedimentation through the Burgos Basin (bypass) into deepwater, depositing submarine fan turbiditic sandstones and shales (Wawrzyniec et al., 2004; Galloway et al., 2011; Snedden et al., 2018).

The Upper Eocene sedimentary systems progradation and post-orogenic deformation processes, resulted in the development of a steep and unstable slope that favored mass transport complexes deposition to north and south deepwater Mexican Ridges (Kenning and Mann, 2019 in press).

In the Oligocene, volcanism and post-orogenic deformation along the Sierra Madre Oriental, provided clastic, vulcanoclastic and volcanic ash sedimentation to the Gulf of Mexico through fluvial systems, which transport fine-grained sandstones to deepwater through lobes and distal fans, as well as by mass transport complexes (Galloway et al., 2000).

As post-orogenic uplift of Sierra Madre Oriental continues by Oligocene-Miocene time, which included foreland basins erosion (Gray et al., 2001), the sedimentation rate increased markedly in the Miocene. Considering that the platform margin was approximately on the current coastline by Lower Miocene time, Ambrose et al. (2003) and Wawrzyniec et al. (2004) typify the Neogene sedimentary successions as wave dominated delta-front thin-bedded sandstones at the shelf, muddy and calcareous channel and levee deposits at the slope, as well as thick channelized lobe and extensive fan-sheet desposits at deepwater.

The Neogene sedimentary environments distribution was affected by the gravitational glidding of extensional system listric faults, by the begining of contractional deformation of the Mexican Ridges, as well as by salt tectonic processes at the north, concentrating sedimentation towards the tilted blocks of the listric faults or at the minibasins.

During the Pliocene-Pleistocene time, the maximum expansion of growth strata in the extensional system of the platform margin was generated, forming graben structures that acted as depocenters. However, according to Wawrzyniec et al. (2004) the sedimentation rate exceeded the kinematic accommodation of growth faults, generating sediment flow to deepwater (bypass) through submarine canyons, mass transport complexes and confined channelized systems.

To the north, at the salt tectonics affected area, the sedimentary sequences consist of confined channelized systems in minibasins with sandstone and shale alternations, muddy mass transport complexes, as well as pelagic and hemipelagic sediments that cover the bathymetric highs (Solomón-Mora, 2013).

6.3. PETROLEUM SYSTEMS AND PLAYS

In the Mexican Ridges, as a part of the deepwater Gulf of Mexico Petroleum Province, four petroleum systems have been defined (Comisión Nacional de Hidrocarburos, 2015) based on the geochemical analysis of seabed hydrocarbons seepages and oil samples

recovered through wells. According to Magoon and Dow (1994) and Magoon and Beaumont (1999) classification, one of those systems is considered as known (!) and three still remain speculative (?), postulated from analog wells and nearby fields located onshore, as well as in shallow and deepwater regions (Table 11).

Regionally, the Upper Jurassic Tithonian source rocks constitute the main hydrocarbon source stratigraphic level, their characteristics and distribution in the Mexican Ridges remain uncertain, specifically in the portion that is on oceanic crust, although the evidence from seabed emanations of thermogenic hydrocarbons, suggest its existence and generation capacity.

The petroleum systems defined to date for the Mexican Ridges do not consider other identified potential hydrocarbon source subsystems, corresponding to the Upper Cretaceous Cenomamian-Turonian or Eocene, since their capability as hydrocarbon source rocks and characteristics have not been confirmed in the deepwater area of Mexican Ridges.

Table 11. Summary of the identified petroleum systems in the Mexican Ridges, including examples of exploration wells that have proved them and examples of nearby analog wells and fields located onshore, as well as in shallow and deepwater regions to postulate speculative petroleum systems.

Source rock	**Reservoir rock**	**Level of certainty** (Magoon and Dow, 1994; Magoon and Beaumont, 1999)	**Example**
Upper Jurassic Tithonian	Miocene	Known (!)	Catamat-1 (Lower Miocene), Piklis-1, Ahawbil-1 (Upper Miocene), deepwater analogs, e.g. Vespa-1 (Middle Miocene)
Upper Jurassic Tithonian	Oligocene	Speculative (?)	Deepwater analogs, e.g. Supremus-1, Exploratus-1 and Nobilis-101 (Lower Oligocene)
Upper Jurassic Tithonian	Eocene-Paleocene	Speculative (?)	Deepwater analogs, e.g. Maximino-1, Cratos-1 (Paleocene-Eocene) and Bukma-1 (Middle Eocene)
Upper Jurassic Tithonian	Mesozoic	Speculative (?)	Analog fields onshore and in shallow water, e.g. Poza Rica and Tamaulipas-Constituciones (Upper Jurassic, Lower and Middle Cretaceous), Arenque, Lobina (Upper Jurassic and Lower Cretaceous) and Náyade (Upper Jurassic and Middle Cretaceous)

The petroleum system elements include source rocks, reservoir rocks, seal elements and the processes of trap formation, timing and hydrocarbons migration. Next, the elements and processes of the identified petroleum systems in the assessed area of northern Mexican Ridges are briefly described.

6.3.1. Source rocks

Upper Jurassic Tithonian source rocks constitute the main hydrocarbon source stratigraphic level in the Mexican Ridges. Its presence and characteristics have been inferred and extrapolated to the deepwater zone by geochemical data from seabed hydrocarbon seepages sampling, source rock sampling from onshore wells, data from producing fields in the continental shelf and from oil samples recovered from nearby onshore and shallow water wells, which have defined the presence of Tithonian source rocks by biomarker correlation.

Based on basin and petroleum systems modeling, the Mexican Ridges area is at different stages of hydrocarbon generation regarding the Tithonian rocks. The thermal maturity conditions and the hydrocarbon generating potential of the source rocks is directly influenced by the type of crust (transitional or oceanic) and depth; in addition to the presence of allochthonous salt at north of the area.

The Upper Jurassic Tithonian in most of the Mexican Ridges area is in an advanced thermal state of maturity, overmaturity and possibly in metagenetic stages (with an exhausted hydrocarbon generation potential), so dry and wet gases are expected mainly. However, to the west towards the slope and continental shelf areas, where depth and thermal maturity of Tithonian rocks decreases, it is possible to find liquid hydrocarbons.

As mentioned before, other identified potential hydrocarbon source subsystems are not considered, corresponding to Upper Cretaceous Cenomanian-Turonian and Eocene stratigraphic levels, since their hydrocarbon generator potential has not been confirmed regionally in the Mexican Ridges.

6.3.2. Reservoir rocks

In the stratigraphic column of the Mexican Ridges, four potential reservoir rocks stratigraphic intervals have been identified (Figure 30):

- **Miocene.** Rocks considered as potential reservoirs in the Miocene, are constituted by alternate sequences of sandstones, siltstones and shales in turbiditic facies of submarine fans, channels and channel overflows deposited in slope and basin environments.

  The Catamat-1, Lakach-1 and Labay-1 wells have confirmed the presence of dry and wet gases in Lower Miocene sandstone intervals; while the Piklis-1 and Ahawbil-1 wells; in addition to Lower Miocene, proved hydrocarbon accumulations in the Upper Miocene.

- **Oligocene.** Based on information from Catamat-1, Talipau-1, Puskon-1, Caxa-1 and Piklis-1 wells that reached Oligocene levels, the representative potential reservoir rocks correspond to turbiditic systems deposits in facies of channels and crevasse splays, as well as deposits associated with the middle and distal parts of submarine fan lobes.

  These sequences are composed of sandstones, siltstones and shales alternations with high bentonite contents, where the Lower Oligocene is the interval that presents the highest sandstone intercalations proportion and therefore, the best characteristics as reservoir rocks.

- **Eocene-Paleocene**. For the Eocene, the Catamat-1 and Caxa-1 wells reached the Upper Eocene level, while the Talipau-1 well reached the Middle Eocene and Puskon-1 the Lower Eocene; in all, the Eocene column was highly shaly. The Eocene sequences penetrated by these wells are generalized as deposits in facies of meandering channels and channel overflows or crevasse splays associated with submarine fan systems, slumps and mass transport complexes, with thin bodies of isolated sandstones related to sediment bypass pulses that reached the deepwater zone.

  However, relatively thick and parallel continuous high amplitude reflectors have been identified at Upper Eocene and Lower Eocene levels, which could correspond to distal basin floor fans, turbidites or sandy lobes, which can act as potential reservoir rocks.

The Puskon-1 well reached the Upper Paleocene, finding important medium to fine-grained sandstones bodies with shale intercalations, associated with submarine fans; which presented important wet gas shows.

- **Mesozoic**. In general, the Mesozoic corresponds to limestones deposited in internal and external shelf-ramp (oolitic banks), slope (calcareous breccias) and basin environments (fractured and/or dolomitized limestones), associated with the Jurassic and Cretaceous sequences.

  Based on onshore and shallow water analogs from Tampico-Misantla basin, within the Upper Jurassic Kimmeridgian stratigraphic level, is expected the presence of oolitic banks deposited in ramp environments, calcareous debris flows in external ramp or slope environments and proximal and distal deepwater fan systems. These types of potential reservoir rocks are related to basement highs, so they correspond to areas on continental crust and/or thinned or transitional continental crust.

  Similarly for the Cretaceous, the presence of fractured basin carbonates is expected, as well as carbonated basin floor fans, distal turbiditic lobes and submarine canyons and channels. At the slope and basin transition zone, it is possible to find slope collapse deposits or carbonate breccias derived from the erosion of the platform edge, where these types of deposits would be similar to the hydrocarbon reservoir breccias located at onshore Tampico-Misantla basin, known as Tamabra breccias.

6.3.3. Traps and seal elements

According to the tectonic events that affected the Mexican Ridges area since the Gulf of Mexico opening processes, different types of traps have been identified, generated by the combination of extension and compression events, in addition to the salt movements at north of the area. The most important traps in Mexican Ridges are those by the extension-compression linked system processes, distinctive of the Mexican Ridges and which led to the formation of detachment folds and fault propagation folds.

To the west of the area in the Mesozoic, traps related to basement highs and to basement tectonic reactivation processes were identified, with stratigraphic components associated with Jurassic sequences pinch-outs against the basement highs; while for the Cretaceous, traps are identified as wide low-angle anticlines, some with faults related to tectonic reactivation and inversion of the basement. Also, calcareous debris flows or breccias derived from the erosion of the platform edge, have stratigraphic components.

For the Neogene at the extensional system area, combined traps are identified in rollover anticlines and faulted blocks, with stratigraphic components in the growth strata. To the north in the area with salt tectonics, pinch-outs are identified against salt welds and against allochthonous salt bodies in minibasins, as well as potential traps under the allochthonous salt bodies.

Towards deepwater of Mexican Ridges, in addition to structural traps formed by detachment and fault propagation folds, including the peripheral folded belt, potential structural closures against salt bodies are identified. Traps associated with anticline folds, have a stratigraphic component related to the irregular distribution of sedimentary systems in the area of structural closures.

Seal rocks for the Mesozoic consist of shaley carbonates interstratified with potentially reservoir intervals. Likewise, Cenozoic sequences include multiple shale deposits with varying thicknesses, including allochthonous salt bodies north of the area.

According to wells information drilled to date in the Mexican Ridges, there are regional lithological seals widely distributed, composed of thick shale horizons, which sometimes correspond to mass transport complexes within the Paleogene and Neogene. The abundance of shale sediments around submarine fan systems, form both the upper and lateral seal of potential reservoir facies.

6.3.4. Timing and migration

Through petroleum systems simulations and basing modeling previously conducted, in addition to new ARES information analysis and studies, a high degree of thermal maturity for Jurassic source rocks in most of the Mexican Ridges has been determined. However, there is a prospective fringe for liquid hydrocarbons, parallel to the continental shelf towards the west of the area, where Jurassic rocks depth decreases.

From these studies, Tithonian source rocks in the Mexican Ridges entered within the oil window in the Eocene and reaching the generation peak in the Upper Eocene, moving to the wet gas window at the Oligocene-Miocene and from Middle Miocene, to the dry gas window. Currently, Tithonian source rocks are within 8,000 and 10,000 m depth, with a generation potential mainly transformed to gaseous hydrocarbons.

The hydrocarbon generation evolution is estimated to have begun in the central-eastern portion of the Mexican Ridges, migrating progressively westward to the slope and continental shelf area. Towards the western zone of the area, Tithonian rocks entered the generation window sequentially from north to south.

Based on the evaluation done by Ambrose et al. (2005) for the extensional system, to the north (Lamprea area) source rocks entered to the oil window in the Lower Miocene, to wet gas window in Middle Miocene and to the dry gas zone from the Upper Miocene. For the southern zone (Faja de Oro-Náyade area), the oil window was reached in the Middle Miocene and since then, the hydrocarbon generation-expulsion processes continue.

In general, hydrocarbons migration has occurred through faults, deep vertical fracture systems (identified by analysis with coherence seismic attributes) that extend through the sedimentary column, as well as by the interface between intrusive salt or shale bodies and the rocks where they are emplaced. This migration is considered as vertically episodic with an important horizontal or lateral component, which has controlled the regional distribution of hydrocarbons.

In the Mexican Ridges foldbelt, reverse faults related to fault propagation folds are limited to a Paleogene detachment level, without reaching the deeper stratigraphic levels where the Tithonian source rock is located. However, deep subvertical fracture and fault systems possibly exist, such as those proposed by Le Roy et al. (2008) and Le Roy and Rangin (2008), which connect deep Mesozoic levels to the Cenozoic sequences.

Furthermore, the wide distribution of seabed hydrocarbon seepages together with the identification of several seismic amplitude anomalies, bright spots and flat spots, as well as bottom simulating reflectors (BSR), suggest that adequate migration routes exist for

hydrocarbons migration from Mesozoic levels to the Neogene, through the thick lithological seals.

Towards the area with salt tectonics, the potential migration routes consist of fault and salt weld systems related to the lateral displacement of allochthonous salt bodies. While for the extensional system area, growth faults tend to connect Mesozoic levels with structural and stratigraphic Cenozoic traps.

Figure 31 shows a petroleum system events chart for the Mexican Ridges, which summarizes the mechanisms and their temporal relationship with the elements and processes of the identified petroleum systems (Table 11), including the geological age of the events and the critical moment (Magoon and Dow, 1994), as the moment in time that best represents the generation, migration and accumulation of most hydrocarbons in petroleum systems.

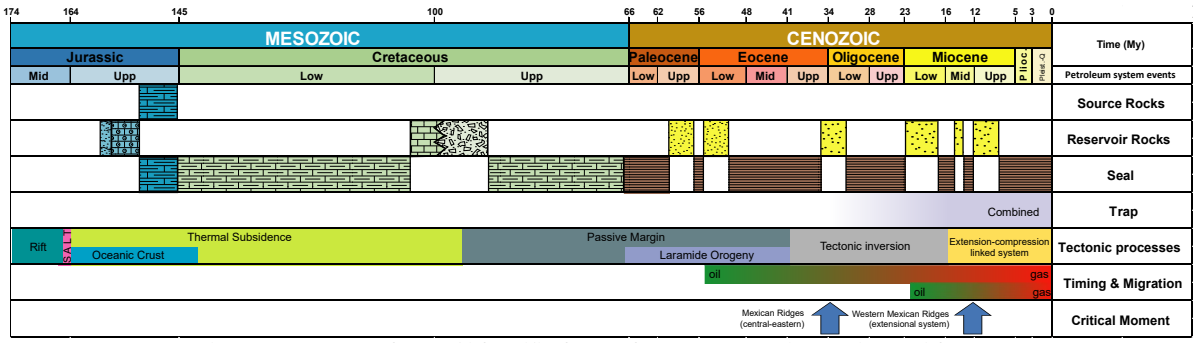


Figure 31. Events chart of identified petroleum systems in Mexican Ridges.

6.3.5. Plays

Plays in the northern Mexican Ridges assessed area are postulated based on current knowledge and the integration and analysis of seismic information, regional studies, well information and analogs. Plays defined within the Mexican Ridges, have a composite nomenclature associated with the Petroleum Province (GP = Deepwater Gulf of Mexico), the assessed area name (CM = Mexican Ridges), its category according to its state in the exploration (E = Established; H = Hypothetical) and finally the chronostratigraphic interval associated with the main age of the potential reservoir rocks.

For the defined plays in Mexican Ridges, the Upper Jurassic Tithonian rocks are considered as the main hydrocarbon source, despite other potential source rocks have been identified (Upper Cretaceous Cenomanian-Turonian and Eocene), its hydrocarbon generator potential in the area has not been confirmed. The Neogene play is the only one currently proven in the area, while the rest of the plays remain hypothetical.

According to the above, Table 11 shows a summary of the main characteristics of the assessed plays in northern Mexican Ridges.

Table 11. Summary of the main characteristics of assessed plays in northern Mexican Ridges.

Play	Trap style	Lithology and depositional environment of reservoir rocks	Porosity (%)	Main wells that have investigated the play
GP CM E Neogene	Anticlinal detachment and fault propagation folds; stratigraphic traps and traps related to salt and shale tectonics	Sandstones and siltstones in turbiditic facies of submarine fans, channels and crevasse splays in slope and basin environments.	7-35% intergranular, intragranular	Catamat-1 (Lower Miocene), Piklis-1, Ahawbil-1 (Upper Miocene), Deepwater analogs, e.g. Vespa-1 (Middle Miocene)
GP CM H Oligocene	Anticlinal detachment and fault propagation folds; stratigraphic traps and traps related to salt and shale tectonics	Sandstones and siltstones in facies of channels, crevasse splays, lobes and basin floor fans.	10-15% intergranular, intragranular	Deepwater analogs, e.g. Supremus-1, Exploratus-1 and Nobilis-101
GP CM H Eocene-Paleocene	Anticlinal fault propagation folds, low relief detachment folds by structural basement reactivation; stratigraphic traps	Sandstones in facies of channels, crevasse splays, lobes and basin floor fans.	5-35% intergranular, intragranular	Deepwater analogs, e.g. Maximino-1, Cratos-1 (Paleocene-Eocene) and Bukma-1 (Middle Eocene)
GP CM H Mesozoic	Upper Jurassic: Combined traps related to basement highs and tectonic basement reactivation. Cretaceous: Structural traps in folds related to tectonic basement reactivation and stratigraphic traps related to debris flows, breccias and turbidites.	Upper Jurassic: Dolomites, fractured limestones and oolitic limestones in ramp and shelf facies. Cretaceous: Slope breccias, calcareous debris flows and turbidites, fractured basin carbonates.	12-40% Oolitic banks, calcareous debris flows; intergranular porosity and intragranular dissolution secondary porosity. 2-20% Slope breccias, fractured carbonates, dolomites; intergranular porosity, intragranular and secondary fracture and dissolution porosity.	Onshore and shallow water analog fields, e.g. Poza Rica and Tamaulipas-Constituciones (Upper Jurassic, Lower and Middle Cretaceous), Arenque, Lobina (Upper Jurassic and Lower Cretaceous) and Náyade (Middle Cretaceous)

6.3.5.1. Play GP CM H Mesozoic

The Mesozoic play is represented by limestones deposited in internal and external shelf environments (oolitic banks), slope (slope breccias) and basin (fractured and/or dolomitized limestones). The most important traps are those associated with a series of basement highs alignments and wedges in a strip that runs along the western edge of the Mexican Ridges area, corresponding to the thinned continental crust zone.

Within the Jurassic sequences there are oolitic banks facies, proximal fan systems and distal shelf edge fan systems. Based on analog fields in shallow water, these facies correspond to basement highs interactions that directly influenced the development of oolitic banks, tidal channels and presence of internal lagoons in areas with internal neritic bathymetry and shallow environments of high energy.

Regarding the Cretaceous, it corresponds to carbonate fans facies, distal turbiditic lobes, canyons and submarine channels which can carry through them debris flows and evolve as deepwater fans to the basin, as well as slope collapse deposits or aprons.

Based on of seismic facies analysis and well correlation, a geological model for the Cretaceous is visualized considering the presence of channels or possible canyons, that could transport carbonated sediment flows and debris flows to deep parts of the basin, evolving to submarine fans with facies that could act as reservoir rocks.

The main seal elements for this play are the thick regional shale sequences, consisting of shaley mudstone deposits alternated with bituminous shale horizons of Jurassic, Cretaceous and Paleogene age, corresponding to thick shale packages, which are sometimes associated with mass transport complexes.

The main identified risks related to this play, are the presence and quality of reservoir rocks, as well as preservation, due to the severe conditions of temperature and burial of the sedimentary column.

6.3.5.2. Play GP CM H Eocene-Paleocene

The potential reservoir rocks of this play consist of turbiditic sandstones deposited in slope and basin environments, in submarine fans facies, channels and crevasse splays. This play has been drilled by Catamat-1, Caxa-1, Talipau-1 (Eocene) and Puskon-1 wells; the latter reaching Upper Paleocene levels.

During the Puskon-1 well drilling through the Paleocene levels, a series of important wet gas shows were logged. In addition, well log evaluations and petrophysical analyses allowed to identify intervals of interest in the Upper Paleocene under conditions of high pressure and high temperature.

The main seal for the Eocene-Paleocene play, are the thick shale sequences with regional distribution within the same Eocene-Paleocene and the Oligocene-Miocene levels, formed mainly by fine sediments deposited in suspension and muddy mass transport complexes.

The main risks for this play are the reservoir rock quality and the trap formation regarding to processes of timing and migration, as well as the existence of hydrocarbon charge, especially for Eocene levels.

6.3.5.3. Play GP CM H Oligocene

This play has been drilled by Catamat-1, Talipau-1, Puskon-1, Lakach-1, Piklis-1, Labay-1 and Caxa-1 wells; in the latter, the best evidence of reservoir rock presence was estimated in the Lower Oligocene and production tests were conducted, resulting in a water flood.

Based on wells in Mexican Ridges, the Oligocene column presents mostly shale lithologies, where the potential reservoir rocks are composed of sandstones interstratified with siltstones and shales with a high bentonite content.

Similar to the Eocene-Paleocene play, the main seal elements are the thick shale sequences with regional distribution of Oligocene-Miocene age, formed mainly by fine-grained suspension sediments and muddy mass transport complexes, corresponding to turbiditic systems in facies of channels and crevasse splays, as well as middle and distal submarine fan lobes.

The main risks for this play is reservoir rock quality and trap formation regarding processes of timing and migration, as well as the existence of hydrocarbon charge.

6.3.5.4. Play GP CM E Neogene

The Neogene play covers the Lower, Middle and Upper Miocene stratigraphic levels, consisting of sequence alternations of sandstones, siltstones and shales in turbiditic facies of submarine fans and distributary channels, deposited in slope to basin environments. This play has been proved by Catamat-1, Lakach-1 and Labay-1 wells in the Lower Miocene and by Piklis-1 and Ahawbil-1 wells in the Lower and Upper Miocene.

The abundance of shale sediments around submarine fan systems is what forms both the upper and lateral lithological seals to the possible reservoir sandstones. The Miocene intraformational shale bodies are considered as the upper seal for these fans, as well as the entire overlying column of shales of Lower Pliocene.

The main risks identified for this play are the reservoir rock quality and the timing and migration of hydrocarbons, related to the structures formation age (traps).

6.4. EXPLORATION PROGRESS

Historically, the Mexican Ridges were documented for the first time by Jones et al. (1967), who related their formation to salt tectonic processes. Later, Bryant et al. (1968) proposed a division for the Mexican Ridges foldbelt by zones, based on their structural style and characteristics, suggesting a contraction associated with gravity, through glidding on a detachment surface due to sedimentary load.

Since then, there are several works that have expanded the knowledge about the Mexican Ridges (e.g. Buffler et al., 1979; Pew, 1982; Salomón-Mora et al., 2004; among others) and identifying the petroleum potential of the province, characterized by contractional structures and their possibility of acting as hydrocarbon traps.

First oil and gas exploration activities in Mexico were concentrated in the onshore portion of Tampico-Misantla and Southeast Basins provinces, where the application of geophysical potential methods during the period of 1908 and 1938 was decisive in the geological analysis and discovery of fields in onshore Golden Lane (Rocha-Esquinca et al., 2013). Subsequently, the exploration extended to the western region of the Gulf of Mexico in shallow water beginning in 1957, with the first seismic reflection studies that culminated in the establishment and continuation of the Golden Lane in its marine portion by 1963, with the discovery of Isla de Lobos field (Cuevas-Leree, 2003).

Between 1964 and 1975, exploration increased on the continental shelf of the western Gulf of Mexico, 2D seismic acquisitions and several discoveries were made at Mesozoic levels in shallow waters, related to the Tuxpan platform edge such as the Arenque field in 1967 (Meneses de Gyves, 1999). Additionally in this period, the exploration drilling focused on Cenozoic objectives began at shelf extensional system (e.g. Neptuno-1 and Anegada-1 wells).

From 1996 the exploration activity in shallow waters is resumed, acquiring the first 3D seismic volumes. Until the beginning of the 2000, the exploration drilling is reactivated with the objective to assess the Cenozoic gas potential on the continental shelf of the western Gulf of Mexico and continuing with exploration of the Mesozoic Tuxpan platform edge in shallow water.

From 2001 to 2006, the exploration wells Lankahuasa-1, Ñu-1, Mercurio-1, Lobina-1, Kosni-1, Cañonero-1, Calipso-1, Caxui-1, among others, were drilled in shallow water, which information and results opened the way for the exploration expansion into deepwater, looking to assess the continuity of Cenozoic and Mesozoic plays related to the Tuxpan platform edge towards the Gulf of Mexico basin.

With the first 3D seismic volumes acquisition in deepwater since 2002 and the Lakach gas field discovery at the southeast limit of Mexican Ridges in 2007, deepwater exploration was triggered in the western Gulf of Mexico. By 2013, the 3D seismic volumes that currently exist in the Mexican Ridges were acquired and 9 more exploration wells (including 2 appraisal wells) were drilled, resulting in a total of 5 gas discoveries done by Pemex to date in Neogene sandstones (Lakach, Catamat, Labay, Piklis and Ahawbil).

For the Mexican Ridges, there are a total of 14 3D seismic volumes, which cover the deepwater zone and partially the extensional system in shallow water, covering a total surface area of 57,881 km^2. Also, 9 different 2D seismic studies acquired between 1973 and 2005 have been identified, with a linear coverage distributed throughout shallow and deepwater region (Table 12, Figure 32).

Table 12. Seismic studies acquired through 2015 in Mexican Ridges by Petroleos Mexicanos.

Seismic study	Year of acquisition	Surface coverage km^2	Acquisition technique	Processing
Faja de Oro A	1996	661	3D	PRESTM, POSTSTM
Faja de Oro B	1996	199	3D	PRESTM, POSTSTM
Lankahuasa	1999	1,755	3D	PRESDM, PRESTM, POSTSTM
Cañonero	1999	661	3D	PRESTM, POSTSTM
Lankahuasa Sur	2002	2,577	3D	POSTSTM
Nautla-Q Primera Etapa	2003	347	3D Q	PRESDM, PRESTM, POSTSTM
Lankahuasa Profundo	2003	3,438	3D	PRESTM, POSTSTM
Holok Alvarado	2003	9,836	3D	PRESTM, POSTSTM
Shanit Q	2004	2,237	3D Q	PRESTM, POSTSTM
Lankahuasa Norte	2002	2,624	3D	POSTSTM
Anegada Labay	2007	7,216	3D	PRESTM, POSTSTM
Aquila 3D Q*	2008	10,336	3D Q	PRESTM, POSTSTM
Tzumat /	2011	14,775	3D	POSTSTM
Centauro Sur 3D WAZ*	2013	6,770	3D WAZ	PRESTM, POSTSTM
Arenque Escualo	1973	-	2D	POSTSTM
Nayade/	1979	-	2D	STK, POSTSTM
Pampano Tuxpan	1983	-	2D	STK, STK-DMO, POSTSTM
Anegada Punta Delgada	1991	-	2D	POSTSTM
Matamoros Golfo de México A/	1994	-	2D	STK, STK-DMO, POSTSTM
Estudio Sísmico Interregional Litoral Golfo de México/	2000	-	2D	STK, POSTSTM
Regional Golfo de México/	2003	-	2D	POSTSTM
Isla de Lobos	2003	-	2D	STK-DMO, POSTSTM
Regional Sur 2D	2005	-	2D Q	STK, PRESTM, POSTSTM

* Within the assessed area
/ Partially within the assessed area

Until 2013, Pemex has drilled 10 exploration wells in deepwater Mexican Ridges, which have established the Neogene play so far (Table 13), from which gas discoveries have been made in this play and a volume of important information was obtained. Based on this exploration progress in the Mexican Ridges, the previous prospective resources assessment grouped the analysis in 3 plays of the Neogene, Paleogene and Mesozoic, divided into two administrative areas (Golfo de Mexico Profundo Sur y Golfo de Mexico Profundo B); for the northern Mexican Ridges assessment, the updated plays correspond to the administrative area of Golfo de Mexico Profundo Sur.

Within the assessed area, there are 3 3D seismic volumes (1 with partial coverage), 4 2D seismic studies and 1 well; however, all the available information was used in the

assessment updating of the northern Mexican Ridges. Tables 12 and 13 indicate the seismic studies and wells contained within the assessed area, respectively; and the map in Figure 32 shows the exploration information generated through 2015 around the Mexican Ridges, in terms of seismic and well information.

Table 13. Wells drilled through 2015 in Mexican Ridges by Petroleos Mexicanos.

Well name	Drilling completion year	Result	Investigated play
Lakach-1	2007	Dry gas producer	Lower Miocene
Catamat-1	2009	Non-commercial wet gas producer	Lower Miocene
Lakach-2DL	2010	Wet gas producer	Lower Miocene
Labay-1	2010	Dry gas producer	Lower Miocene
Puskon-1	2011	Plugged by unexpected geological column	-
Piklis-1	2011	Wet gas producer	Lower and Middle Miocene
Caxa-1*	2012	Dry	-
Talipau-1	2012	Water flooded	Lower Miocene
Piklis-1DL	2013	Wet gas producer	Lower Miocene
Ahawbil-1	2013	Non-commercial wet gas producer	Lower and Upper Miocene

*Wells within the assessed area

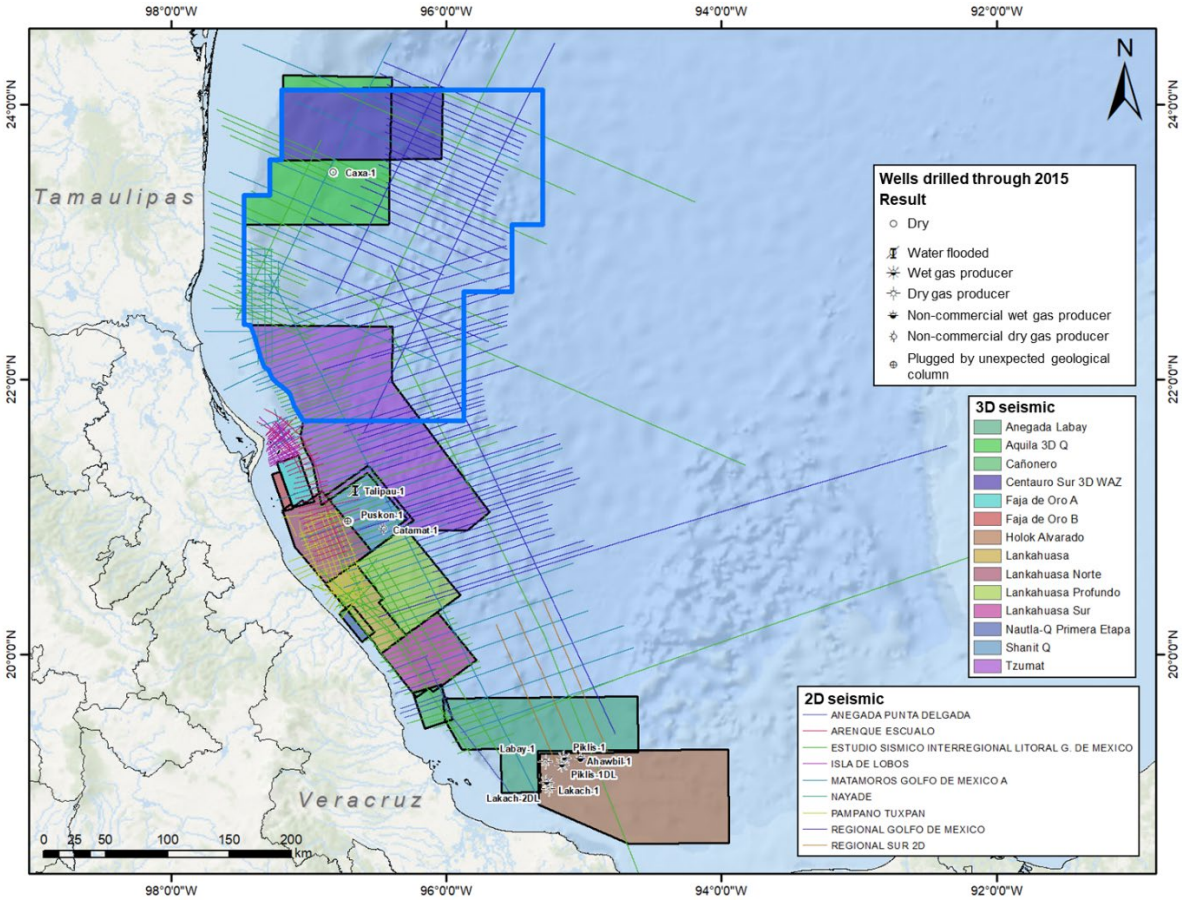


Figure 32. Map showing the exploration information generated through 2015 around the Mexican Ridges by Petroleos Mexicanos, in terms of seismic information and wells.

From 2013 to date within the northern Mexican Ridges assessed area, Pemex has not conducted activities since it does not currently have entitlements. However, with ARES program implementation, new exploration information has been generated; therefore, there is new information for prospective resources assessment updating in the northern Mexican Ridges.

6.4.1. Exploration information used for northern Mexican Ridges assessment updating

In the period from 2007 to 2013, Pemex drilled 10 exploration wells in deepwater Mexican Ridges, without any exploration drilling in the province since then (Table 13).

With the implementation of ARES program as at January 2015, new exploration information has been generated, which includes new 2D seismic information acquisition and the improvement of previously existing information, where the new 2D acquisition densely covers areas with a lack of 3D seismic. In addition to new 2D acquisition, most of the information generated through ARES, has focused on the improvement of the seismic imaging through the application of latest technology processing algorithms, especially towards the area with high geological-structural complexity due to salt and shale tectonic processes; as well as the union of previously existing volumes (merge).

The main ARES studies in deepwater Mexican Ridges done by 2018, include 7 different projects for new 2D seismic acquisition, 1 reprocessing of previously existing 2D seismic information, 5 reprocesses of previously existing 3D seismic information and a new geochemical biomarkers study from seabed piston cores samples, which are important in the analysis of petroleum systems. Table 14 shows the main ARES studies located in the Mexican Ridges.

The information set used for the northern Mexican Ridges assessment, mainly includes the information of the 10 exploration wells, including a large inventory of well logs and reports of core and core samples analysis, as well as the 3D and 2D seismic information acquired through 2013 by Pemex and the new 2D, 3D seismic and geochemical information from ARES since 2015 (Figure 33).

In addition to seismic information and wells, a series of previous regional studies on basin analysis, petroleum systems, plays and geochemical analyzes conducted by Pemex and the Mexican Petroleum Institute (IMP) in the Mexican Ridges are available through the National Hydrocarbons Information Center (CNIH).

Finally, an important component of the available information, are the historical databases of prospective resource assessments, in accordance with the Guidelines for the Analysis and Assessment of the Prospective and Contingent Resources of the Nation, published in DOF in december 2013.

All this set of information was analyzed and updated according to wells results and the new seismic information, through the integration, selection and combination of relevant information, as well as the analysis, interpretation and studies performed by the Commission.

Tabla 14. Characteristics of the main ARES projects located in the Mexican Ridges.

ARES permit	Project	Company	Type of study	Modality	Authorization year	Deliverables
ARES-TGS-NO-15-6P1.0417	Geoquimico Golfo de México	TGS AP Investments AS.	Geochemistry	Data acquisition	2015	Geochemical data from raw cores with biomarkers and isotopes
ARES-GXT-EU-15-2Q1.0336	MéxicoSPAN Sísmica 2D	GX Geoscience Corporation, S. de R.L. de C.V.	2D seismic	Data acquisition	2015	Kirchhoff PSTM stack filtered and scaled Kirchhoff PSTM stack RAW
ARES-PGS-MX-15-4R6.0183	México MC2D para el Amarre de Pozos	PGS Geophysical AS-Sucursal México.	2D seismic, Gravimetry and Magnetometry	Data acquisition	2015	Kirchhoff PreSTM RTM PreSDM Kirchhoff PreSDM
ARES-TGS-NO-15-6P1.0195	Gigante 2D	TGS AP Investments AS.	2D seismic, Gravimetry and Magnetometry	Data acquisition	2015	Stack PSTM and PSDM Velocidades
ARES-PGS-MX-15-4R6.0214	Cordilleras Mexicanas MC2D	PGS Geophysical AS-Sucursal México.	2D seismic, Gravimetry and Magnetometry	Data acquisition	2015	Kirchhoff PreSTM RTM PreSDM Kirchhoff PreSDM
ARES-PGS-MX-15-4R6.1076	Ampliación Cordilleras	PGS Geophysical AS-Sucursal México.	2D seismic, Gravimetry and Magnetometry	Data acquisition	2015	Kirchhoff PreSTM RTM PreSDM Kirchhoff PreSDM
ARES-SRC-AU-15-3B1.0521	Buscador Near-Shore 2D	Searcher Seismic, PTY, LTD.	2D seismic	Data acquisition	2016	Stack PSTM Stack PSDM
ARES-SSM-MX-15-9X3.780	Reproceso 2D Burgos Marino	Seismic Enterprises México, S. de R.L. de C.V.	2D seismic	Without data acquisition	2017	Stack PSTM raw with noise attenuation and filters Velocity model
ARES-DSM-MX-15-3P2.0684	Reprocesado Perdido 3D	Dowell Schlumberger de México, S.A. de C.V.	2D seismic	Without data acquisition	2015	Velocity model Kirchhoff PreSDM RTM PreSDM
ARES-CGG-MX-15-3G7.0187	Perdido 3D WAZ	CGG México S.A. de C.V.	3D seismic WAZ	Without data acquisition	2015	RTM PreSDM TTI and Kirchhoff PreSDM TTI
ARES-DSM-MX-15-3P2.3149	Reproceso 3D Cordilleras Mexicanas	Dowell Schlumberger de México, S.A. de C.V.	3D seismic	Without data acquisition	2016	Kirchhoff PreSDM Velocity model
ARES-GXG-MX-15-6T6.3674	Azteca Mexican Ridges 3D	GX Geoscience Corporation, S. de R.L. de C.V.	3D seismic	Without data acquisition	2017	Velocity model RTM PSTM RTM PSDM Stack PSDM (with Beam algorithm)
ARES-DSM-MX-15-3P2.11297	Proyecto Reprocesamiento Área Perdido Sur	Dowell Schlumberger de México, S.A. de C.V.	3D seismic	Without data acquisition	2018	Pre-SDM

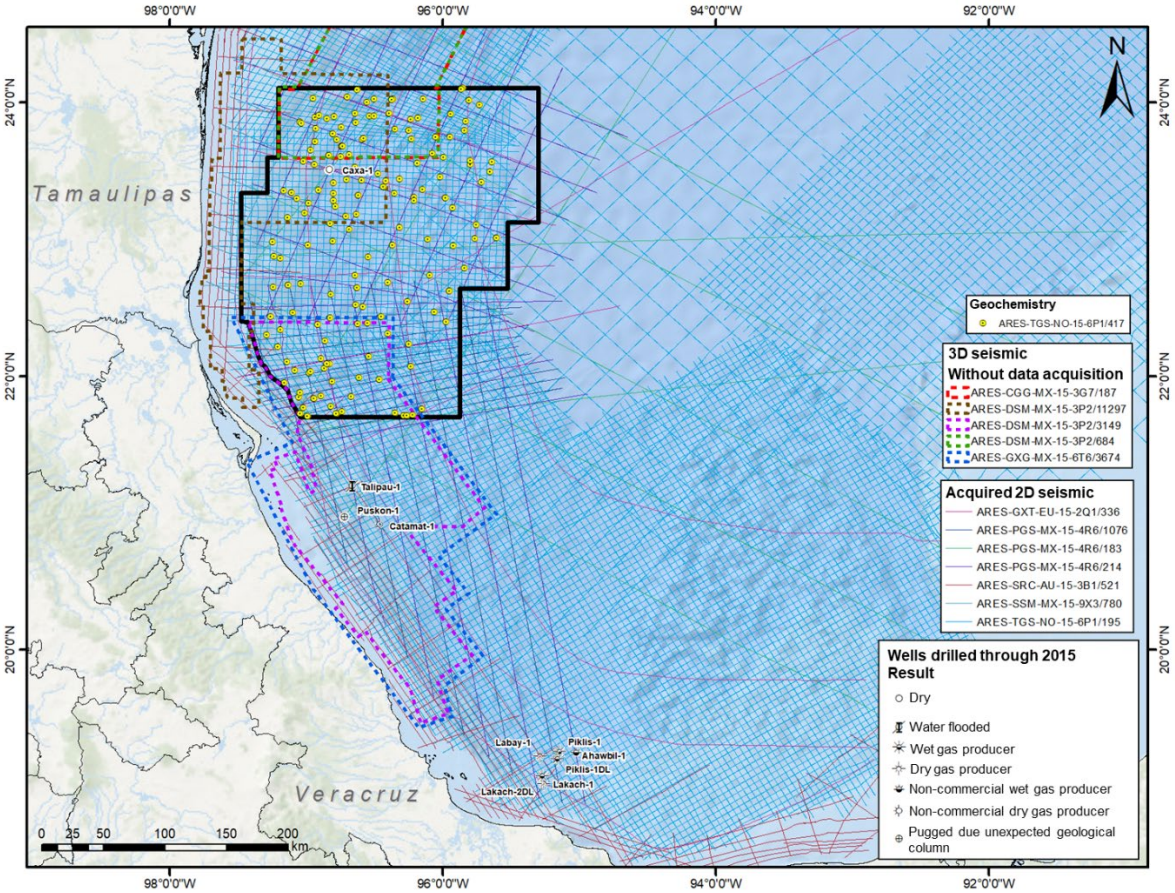


Figure 33. Map showing the main exploration information used in the northern Mexican Ridges assessment, in terms of geochemical, seismic and well information.

6.5. ASSESSMENT AND INTERPRETATION OF EXPLORATION INFORMATION

6.5.1. Seismic interpretation

The information assessment and interpretation stage consisted of collecting, validating and analyzing all the available information for the northern Mexican Ridges area, considering the geological-structural complexity, starting with regional seismic interpretation of the area, calibrating the interpretations with biostratigraphic data and well stratigraphic markers. The general process of horizons interpretation began in areas with high confidence where there is the highest density of well information, generating tying sections and alternating correlations between inline and crossline sections in time or depth.

The selection of the most suitable seismic version for interpretation, considered the acquisition method and the processing type mainly, since those parameters control the seismic image quality, taking into account the fact that certain types of acquisition and processing, attenuate certain misleading patterns that are easily confused as real geology (seismic artifacts), as others can also be highlighted. When assessing exploration prospects, a detailed seismic interpretation is required, so the selection of the best available seismic information version is very important to obtain better results.

Since Mexican Ridges present to the north, at the limit with Perdido Area, a complex salt and shale tectonics zone, the time-migrated seismic versions present significant image limitations around and below the salt bodies, since they cannot apply special velocities to salt and seismic energy is not positioned correctly when refracting through salt. For this reason, the most appropriate seismic version to obtain adequate imaging towards this area generally requires a depth migration before stacking or pre-stack depth migration seismic (PreSDM).

In PreSDM seismic, velocities of salt and of all geological horizons are assigned during processing (velocity model), for which it is necessary to determine salt bodies geometries of and boundaries between horizons, so when working with prestack-depth-migrated data, is needed to be aware that an interpretation of a previous interpretation it will be taking place (Jackson and Hudec, 2017). In that sense, it is very important to corroborate with the help of well information, that each geological horizon in the velocity model is in its correct position in depth and also, consider the algorithm used for migration, one of the most critical aspects in seismic data processing.

The set of 2D and 3D seismic information available in northern Mexican Ridges mainly covers PreSDM migrations through Kirchhoff and RTM (Reverse Time Migration) algorithms (Tables 12 and 14), which have advantages and disadvantages in regard to the process of seismic interpretation in areas with salt and shale tectonics.

The Kirchhoff PreSDM migration typically preserves the seismic texture and amplitudes, allowing to generate high-quality images towards the top of salt bodies and sometimes also allows to map the base of the salt bodies; this, as long as the geometry of these bodies is simple, it does not allow handling of complicated velocity models and does not generate good image quality in complex salt tectonics areas.

On the other hand, PreSDM RTM migration allows handling the wave equation in multiple paths, increasing the possibility of visualizing complex salt structures and visualizing the geological characteristics of areas around and below salt bodies. However, the seismic image generated by RTM migration is more sensitive to the used velocity model than in the Kirchhoff migration.

With that in mind, the regional seismic and exploration prospects interpretation in northern Mexican Ridges was conducted preferably on 2D and 3D PreSDM RTM seismic versions, prior review and validation of the corresponding velocity model. In certain areas without 3D seismic coverage but linear 2D seismic coverage, the same velocity model was generated and used to convert and adjust migrated versions in time to depth.

6.5.2. Petrophysical evaluation

Based on well logs, geological reports and documentation on core and core samples analysis from exploration wells in Mexican Ridges, petrophysical evaluations were carried out with conventional techniques to determine the main characteristics of the plays assessed in the area. This analysis included the identification and evaluation of different lithologies throughout the logs, as well as the determination of cutoff petrophysical range values that are key in volumetric assessment of exploration prospects, such as porosity, water saturation, net thickness, etc.

Figure 34 shows an example of the petrophysical evaluations conducted in wells of Mexican Ridges, from the well logs and core and core samples analysis.

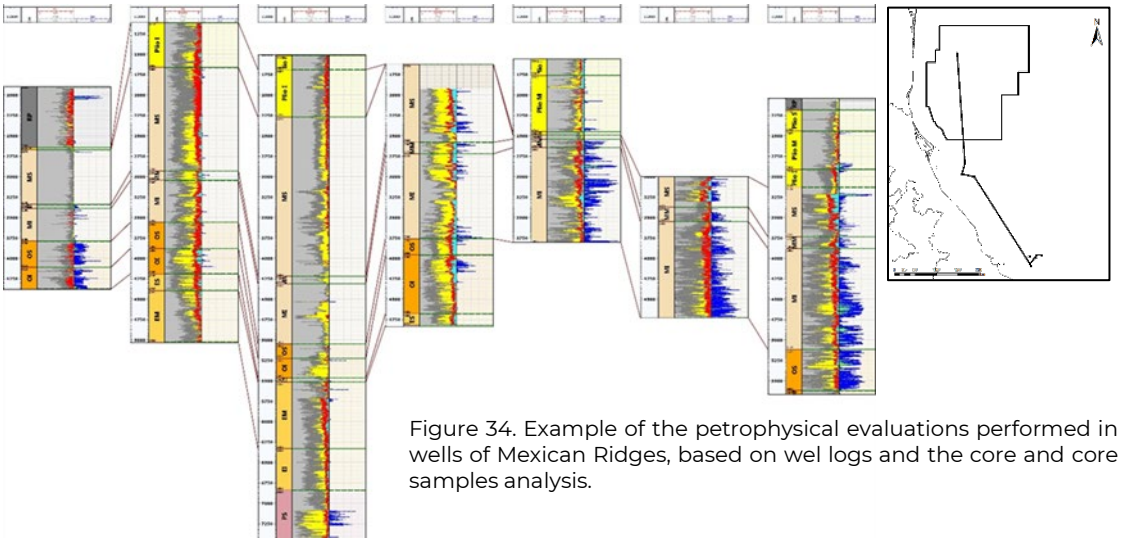


Figure 34. Example of the petrophysical evaluations performed in wells of Mexican Ridges, based on wel logs and the core and core samples analysis.

6.5.3. Seismic attributes and sedimentary facies interpretation

Seismic attributes (including those considered as direct hydrocarbons indicators) were applied as a tool for interpretation of seismic data (section 3.2.3), seeking to highlight variations in amplitude, phase and frequency of the acoustic signals, independently or in an integrated manner. These variations may have a correlation with geological, sedimentary and structural characteristics, which cannot be observed with the naked eye in conventional seismic images. In general, three types of seismic attributes were mainly applied: instantaneous (mainly RMS or Root Mean Square, phase, frequency), geometric (dip/azimuth, coherence, curvature) and spectral (decomposition in frequency ranges).

Among the most used attributes in the analysis, RMS stands out to try to identify potential fluid content in reservoir rocks that can be hydrocarbons, of coherence to highlight discontinuities such as faults, channel edges and chaotic areas such as mass transport deposits and spectral decomposition to detect lithological changes by frequency content. The combination and use of seismic attributes in the area was a key factor in the identification and delimitation of exploration prospects, in the identification of seismic facies and in GDE sedimentary maps construction (Gross Depositional Environment).

The stratigraphic interpretation of seismic profiles, well information calibration, geological horizons interpretation and the analogs documented for the Mexican Ridges, allowed to generate the sedimentary facies interpretation for the assessed plays from seismic information.

6.5.4. Estimation of expected hydrocarbon type

This analysis consisted of compilation, integration and updating of the available information through the National Hydrocarbons Information Center (CNIH), which includes several of previous regional studies of basin analysis, petroleum systems, plays

and geochemical analyzes done by Pemex and the Mexican Petroleum Institute (IMP) in Mexican Ridges.

Additionally, the new geochemical information derived from ARES, served to make updates of the expected hydrocarbon type; in this case, for the Upper Jurassic Tithonian source rocks and its situation as the main source rock interval of the area.

6.5.5. Identification and assessment of exploration prospects

The historical databases of prospective resources served as a key reference for exploration prospects identification in the northern Mexican Ridges area. Similarly, the information from the exploration plans of the 5 awarded contracts to date within the assessed area (Figure 28), served as a reference for the analysis performed by the Commission for the identification of exploration prospects.

Although the historical prospective resources databases and exploration plans serve as valuable references to know the vision about the potential of resources around the identified prospects, the assessment done by the Commission does not necessarily coincide to the reported assessment by the operators that are developing exploration activities in the area, especially in terms of the applied methodology, seismic interpretation around the prospects, number identified geological objectives, petrophysical and volumetric parameters, the expected hydrocarbon type, risk analysis for the estimation of the probability of geological success, estimation of the amount of prospective resources, among other factors.

The assessment of exploration prospects carried out by the Commission was done according to the methodology described in section 3.2, using homologous criteria and adopting the fundamental principles of evaluation and classification of resources of PRMS (Petroleum Resource Management System). For this reason, many of the prospects or leads and even geological objectives reported by the operators were not considered by the Commission for the prospective resources assessment in exploration prospects.

Based on the analysis and interpretation of new seismic information available, on the 10 wells drilled to date, calibrations and adjustments made to determine the petrophysics and adjustments in the expected hydrocarbon type, as well as models and studies carried out by the Commission, a total of 93 exploration prospects with up to 4 geological objectives were identified and evaluated, where 27 correspond with new prospects identified, which are part of the prospect inventory assessed by the Commission in northern Mexican Ridges.

In this way, the identified exploration prospects portfolio of in northern Mexican Ridges, is an estimated total risked mean of 1,916 MMboe, a variation of -16% respect to the previous estimates.

Table 15 shows the exploration prospects prospective resources assessment update carried out by the Commission, in comparison to the estimate as of 2018. The graph in Figure 35 shows the distribution by main expected hydrocarbon type, according to the assessment update carried out by the Commission, regarding the identified exploration prospects.

Table 15. Update of exploration prospects prospective resources assessment carried out by the Commission, compared to the estimate as of 2018

Prospective resources update of identified exploration prospects					
Category	**Prospective Resources P90 (MMboe)**	**Prospective Resources P50 (MMboe)**	**Prospective Resources mean (MMboe)**	**Prospective Resources P10 (MMboe)**	**Prospective Resources risked mean (MMboe)**
Estimation as of 2018	1,103	5,987	11,586	29,948	2,293
Update	**2,135**	**7,419**	**11,960**	**28,215**	**1,916**
Difference	1,033	1,432	375	-1,732	-377
Difference (%)	94%	24%	3%	-6%	-16%

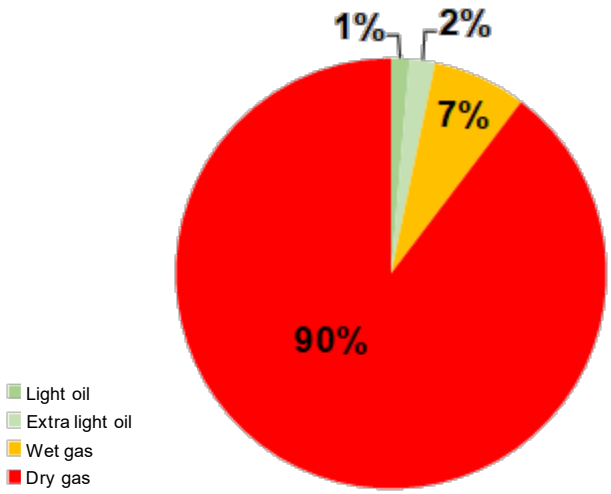


Figure 35. Distribution by main expected hydrocarbon type, according to the assessment update carried out by the Commission, regarding the identified exploration prospects.

6.6. NORTHERN MEXICAN RIDGES PLAY ASSESSMENT

Northern Mexican Ridges plays are postulated based on current knowledge and the integration and analysis of seismic information, regional studies, well information and analogs. Section 6.3.5 describes the main characteristics of the delimited and defined plays within northern Mexican Ridges area and Table 11 of section 6.3.5 shows the summary of their main characteristics.

The prospective resource assessment at the play level is based on probabilistic methods, considering the mapped and unmapped prospects as a total in a play, where the input information for the estimate is a distribution of the volume of identified prospects, a number of additional prospects that could occur in the play and an average probability of success. The volumetric assessment at the play level, comes from the construction of a probability density function derived from all of the geological objectives of exploration prospects that belong to the corresponding play, considering recoverable volumes and the discoveries characteristics within a play at a certain date.

The applied methodology for the assessment at play level is described in section 3.3. According to the play fairway analysis done in northern Mexican Ridges, 4 plays represented by the stratigraphic horizon containing the potential reservoir rocks were defined and based on this analysis, generalized play maps were developed to interpret the extension of the 4 assessed plays.

Figures 36 to 39 show schematically the interpreted extension for Mesozoic, Eocene-Paleocene, Oligocene and Neogene plays; respectively in northern Mexican Ridges, identifying in an illustrative way the areas where it is inferred that the play may exist but it is not possible to visualize prospects, mainly due to the geological complexity of the area, related to salt (at northern of the area) and shale tectonics or due to poor quality of seismic image. Also, allochthonous salt extent is indicated schematically and where the absence of the play is interpreted.

The graph in each figure shows the estimation curves of prospective resource volumes for the assessed plays, representing the identified and unidentified prospects (total prospective resource) estimates. The estimated total prospective resources in each assessed play, reflect the exploration potential related to the current knowledge and the available information at a certain date, so that the progress in exploration activities that provide new information, will generate adjustments in the estimates and in the total prospective resources assessment.

In the case of the Mesozoic and Eocene-Paleocene plays, to date, there are no wells that have proved these plays in the deepwater Mexican Ridges. However, they are postulated as hypothetical based on analogs wells from onshore and shallow water of Tampico-Misantla and from deepwater of the Perdido Area and Saline Basin.

For the Oligocene and Neogene plays, to date, 8 exploration wells have probed these plays; which include the most important Miocene discoveries made in deepwater Mexican Ridges, where 1 of those wells (Catamat-1) investigate the Lower Oligocene interval, resulting in a water flood at that stratigraphic level.

Regarding northern Mexican Ridges area, only one well is found within the assessed area (Caxa-1), which was declared dry without any production test. However, at the respective interpreted play extension maps, the result of this well at the original geological objectives (Oligocene and Miocene) is indicated as dry, based on well logs evaluations.

Table 16 shows the total prospective resources assessment update in plays done by the Commission, in comparison with estimates as of 2018.

Table 16. Prospective resources assessment update in plays done by the Commission, compared to the estimates as of 2018

Prospective resources assessment in plays				
Assessed plays as of 2018	**Prospective resources P90 (MMboe)**	**Prospective resources P50 (MMboe)**	**Prospective resources mean (MMboe)**	**Prospective resources P10 (MMboe)**
RN GPGMS H Neogene	311	758	1,007	2,128
RN GPGMS H Paleogene	305	832	1,157	2,753
RN GPGMS H Mesozoic	198	464	559	1,068
TOTAL	**815**	**2,054**	**2,724**	**5,949**
2019 Update				
GP CMN H Neogene	228	864	1,380	3,297
GP CMN H Oligocene	137	524	838	2,005
GP CMN H Eocene-Paleocene	23	95	163	402
GP CMN H Mesozoic	33	86	110	227
TOTAL	**420**	**1,569**	**2,491**	**5,931**
DIFFERENCE	-395	-485	-233	-18
DIFFERENCE (%)	-48%	-24%	-9%	0%

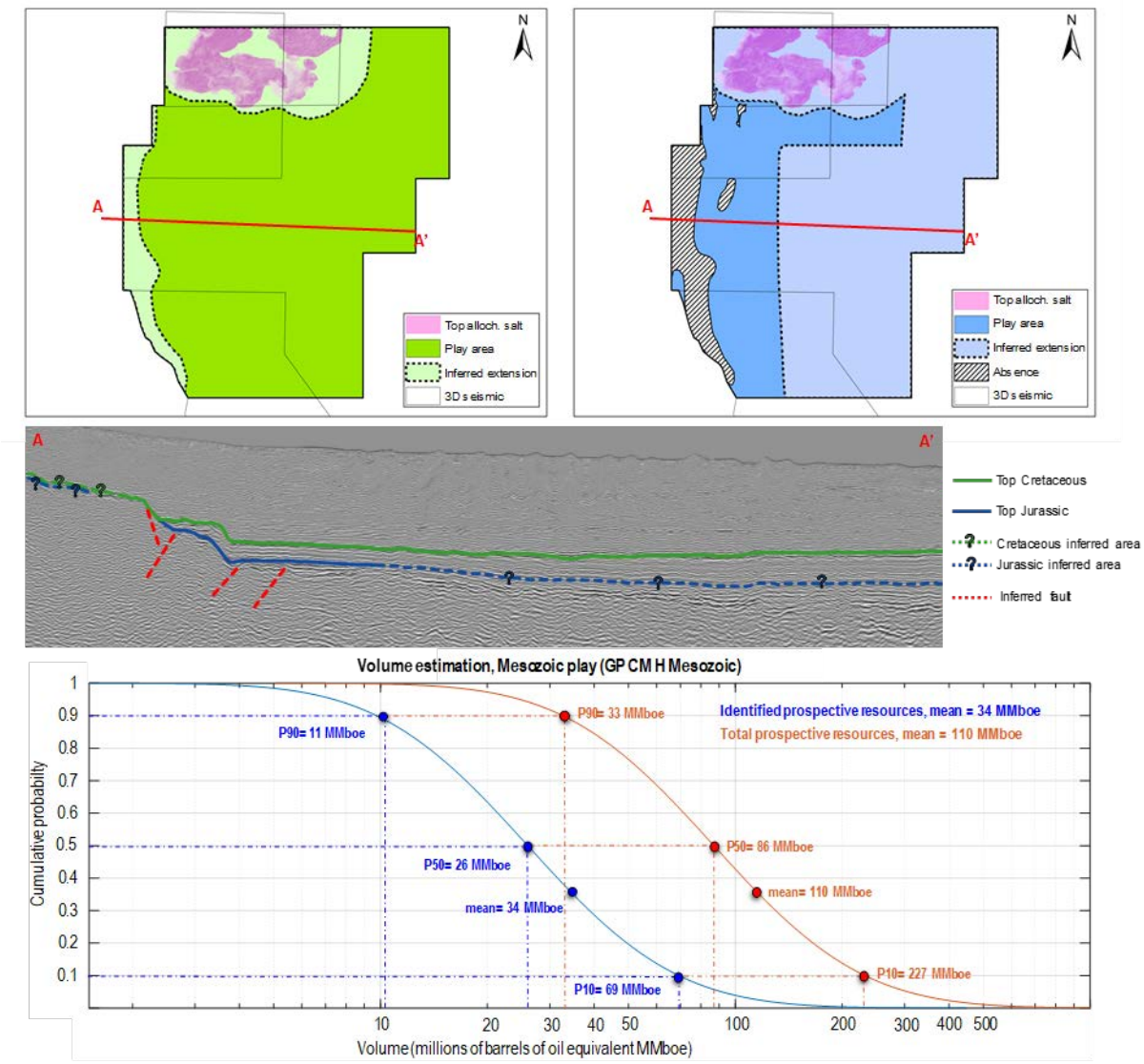


Figure 36. Map that schematically shows Mesozoic play distribution (Upper Jurassic and Cretaceous) in northern Mexican Ridges area, the seismic section exemplifies the areas where the play is inferred but it is not possible to visualize prospects and where the absence of the play is interpreted; in this case, mainly due to pre-existing basement highs, erosion towards shelf edge extensional margin or fault displacement. The graph shows the probabilistic prospective resource assessment, in terms of identified prospects volume and the total play volume.

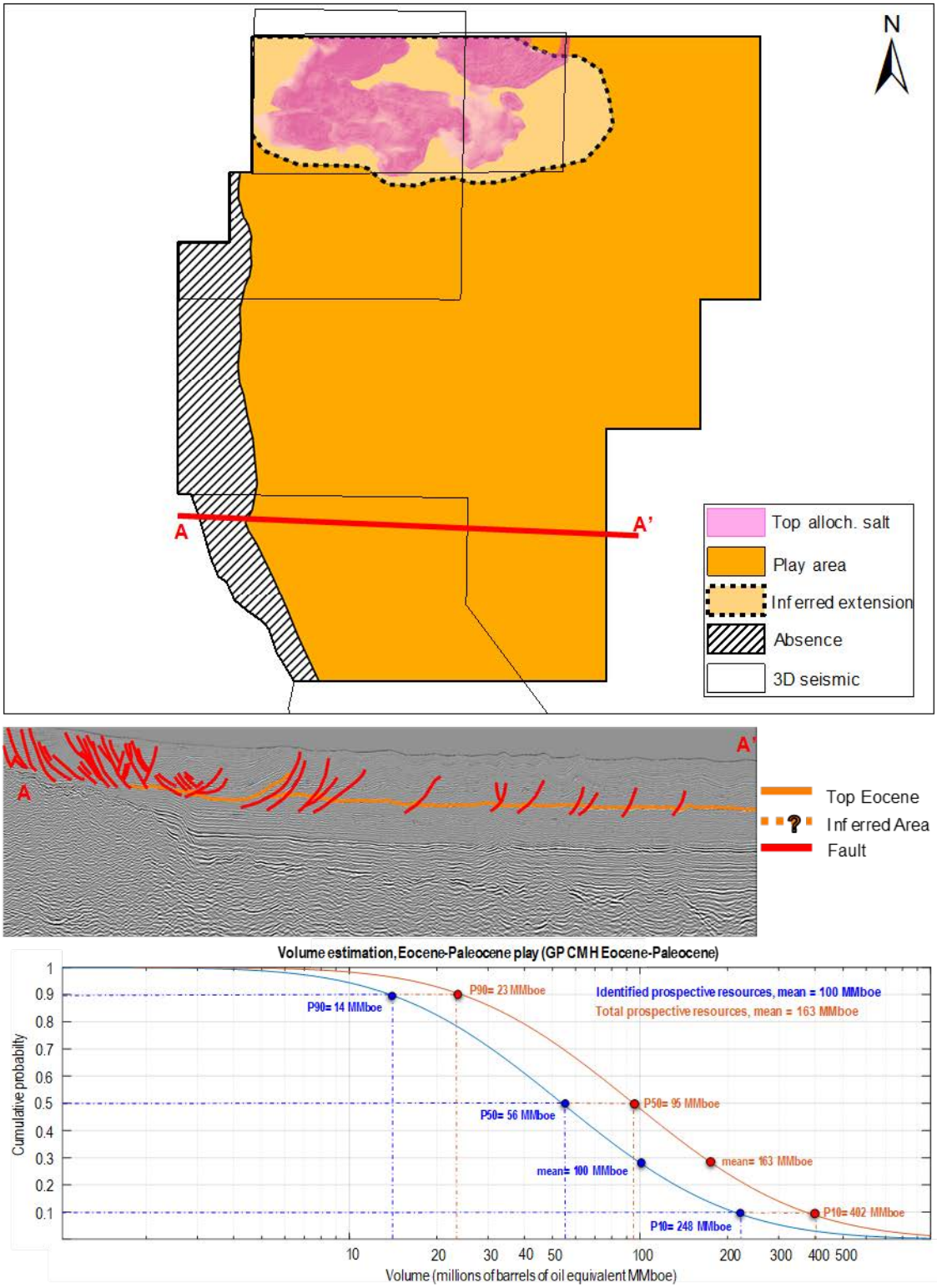


Figure 37. Map that schematically shows Eocene-Paleocene play distribution in northern Mexican Ridges area, the seismic section exemplifies the areas where the play is inferred but it is not possible to visualize prospects and where the absence of the play is interpreted; in this case, mainly due to erosion towards the shelf edge extensional margin or fault displacement. The graph shows the probabilistic prospective resource assessment, in terms of identified prospects volume and the total play volume.

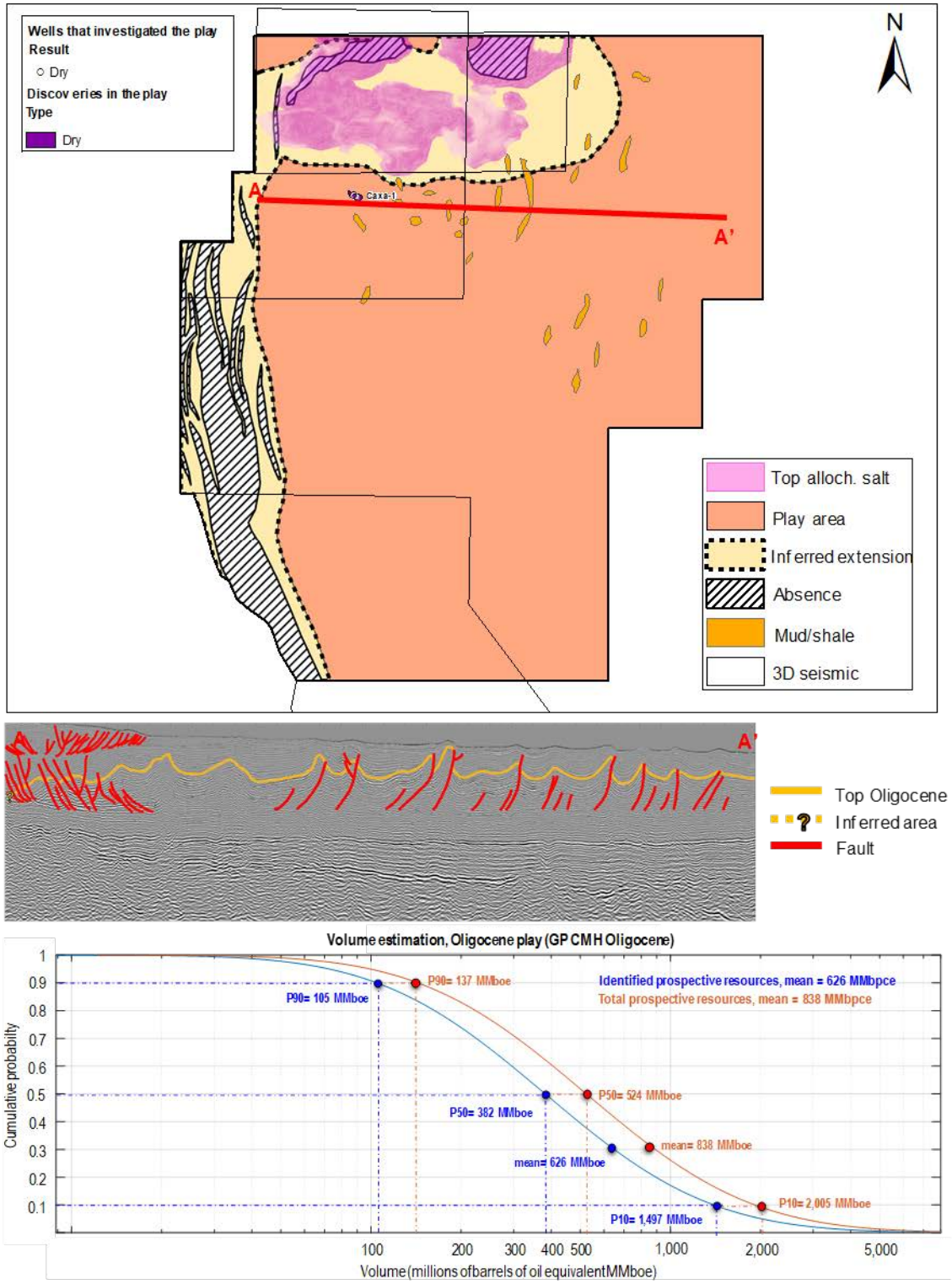


Figure 38. Map that schematically shows Oligocene play distribution in northern Mexican Ridges area, the seismic section exemplifies the areas where the play is inferred but it is not possible to visualize prospects and where the absence of the play is interpreted; in this case, mainly due to salt intrusions, erosion towards the shelf edge extensional margin or fault displacement. The graph shows the probabilistic prospective resource assessment, in terms of identified prospects volume and the total play volume.

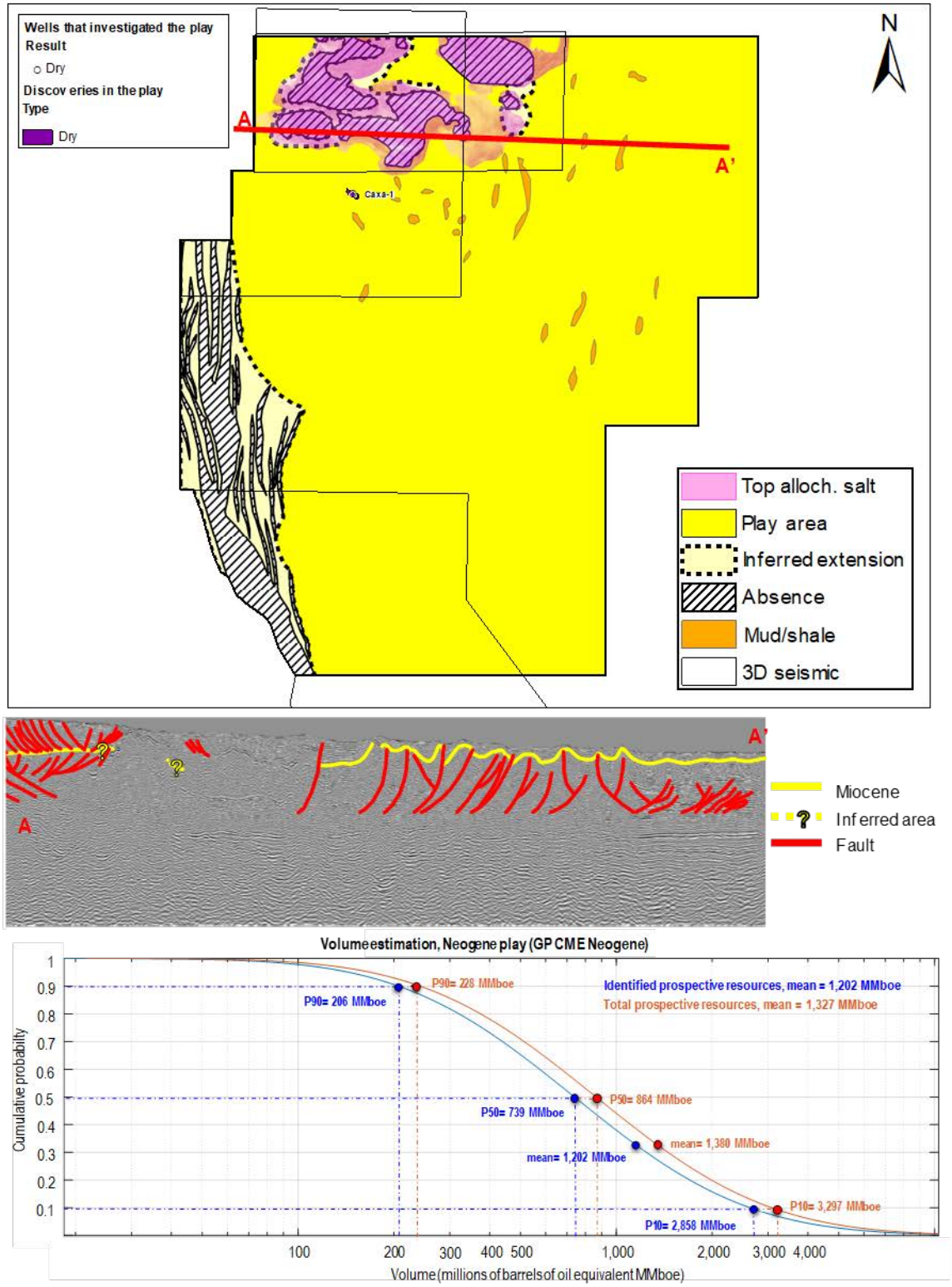


Figure 39. Map that schematically shows Neogene play distribution in northern Mexican Ridges area, the seismic section exemplifies the areas where the play is inferred but it is not possible to visualize prospects and where the absence of the play is interpreted; in this case, mainly due to salt intrusions, erosion towards the shelf edge extensional margin or fault displacement. The graph shows the probabilistic prospective resource assessment, in terms of identified prospects volume and the total play volume.

7. CENTRAL SALINE BASIN

7.1. STUDY AREA CHARACTERISTICS

The central Saline Basin area is located towards the central-eastern portion of the Gulf of Mexico, off the coast of the states of Veracruz, Tabasco and Campeche, in water depths that vary from 1,000 m to 3,500 m. The assessed area covers a surface of approximately 46,080 km^2 (Figure 40).

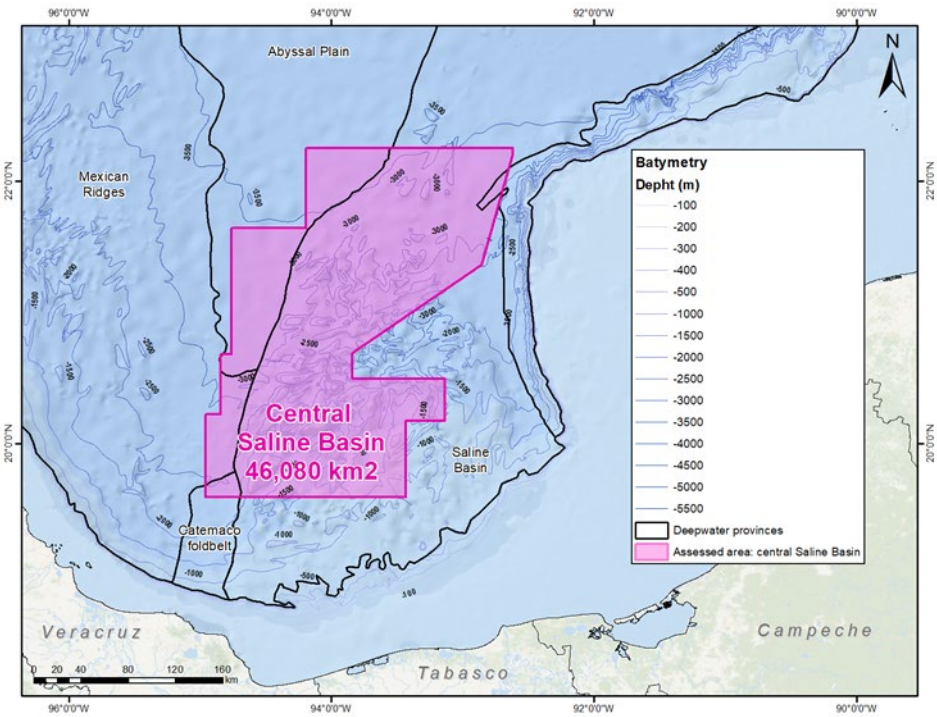


Figure 40. Geographic delimitation of the Central Saline Basin area.

Its geographic delimitation corresponds basically to the surface extension of Sayab, Ixic, Yoka-Butub and Temoa 3D seismic volumes, covering part of the abyssal plain towards the northwest corner of the area. The central Saline Basin area partially encompasses the Geological Province of the Catemaco foldbelt.

The deepwater Saline Basin is the result of the interaction of various tectonic events that acted at different times and with different strain directions, generating overlapped structural styles that comprise the complex tectonic structural framework that characterizes this portion of the Gulf of Mexico. The tectonic events' interaction in the area generated a continuous deformation beginning in the Paleogene, having its main structuring phase from the Middle Miocene (Chiapanecan orogeny) to the present (Angeles-Aquino et al., 1994; Pindell and Miranda, 2011).

The central Saline Basin area is characterized by the abundant presence of both autochthonous and allochthonous salt bodies, taking the form of pillows, diapirs, walls, tongues and canopies, where it is common to find syncline-type structures formed by the sediment accumulation in mini-basins around the evacuated salt. The processes of salt tectonics that prevail in the area give rise to potential hydrocarbon traps that include pinch-outs on and against salt, mini-basins, turtle-like structures and subsaline folds, with

potential reservoir rocks in Cenozoic turbiditic sandstones, as well as in Mesozoic limestones (Escalera and Hernández, 2010).

Currently, 3% of central Saline Basin surface area corresponds to Petroleos Mexicanos (Pemex) entitlements and 41% to contracts awarded during the fourth call of the first and second bidding rounds (Rounds 1.4 and 2.4, respectively), remaining 56% of central Saline Basin area unawarded (Figure 41).

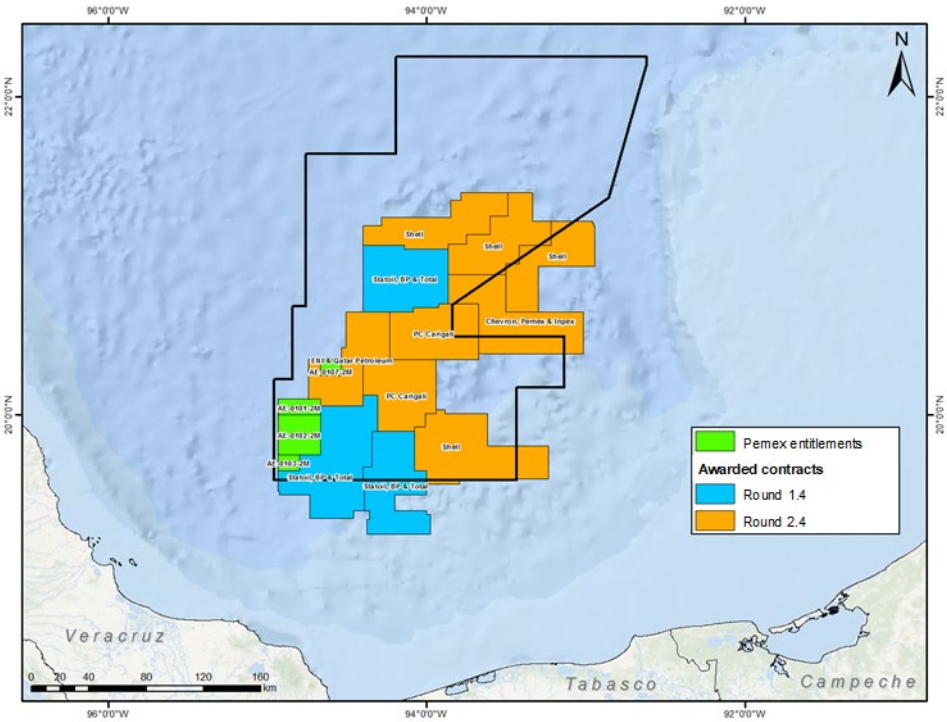


Figure 41. Current status of central Saline Basin area, regarding areas entitled to Pemex and awarded contracts.

8.1. GEOLOGICAL FRAMEWORK

Structurally, five main deformation events have been recognized in the Saline Basin, where the first two are regionally related to the Gulf of Mexico opening and the passive margin establishment, the next two are related to the regional interaction of Pacific margin tectonic plate limits (subduction and strike-slip faulting) and the last corresponds to local gravitational processes due to sedimentary loading and autochthonous and allochthonous salt evacuation (Cruz-Mercado et al., 2011).

The first two deformation events occurred from Triassic to Middle Jurassic, since Gulf of Mexico opening processes (rift) gave rise to horst-graben basement structures, which controlled the Upper Jurassic Callovian salt deposition due to marine invasion from the Pacific Ocean (Galloway, 2008; Nguyen and Mann et al., 2016) and possibly from the Atlantic Ocean (Snedden et al., 2014). According to Bird et al. (2015) and Nguyen and Mann (2016), the Gulf of Mexico continental rift processes and salt deposition, ended with the beginning of oceanic crust generation from the Oxfordian time.

As oceanic crust generation processes progress at the central part of the Gulf of Mexico, the large initial sag basin was split into a northern part (Louann) and a southern part (Saline Basin or Campeche Salt Basin) as conjugated margins, due to the beginning of sinistral rotation of the Yucatan block as the oceanic crust was generated (Steier and

Mann, 2019). Hudec et al. (2013), suggests that salt probably began to accumulate preferentially in pre-existing tectonic depressions, accommodating its deposition due to continental crust isostatic subsidence and giving place to the first synsedimentary structures that subsequently influenced Jurassic sedimentation.

Based on well information from the Campeche Sound and analogs from the United States sector of the Gulf of Mexico, the Oxfordian and even Kimmerigdian period is characterized by repeated marine regressions and transgressions (Ángeles-Aquino et al., 1994; Steier and Mann, 2019), resulting in sedimentary deposits with thickness and lateral and vertical facies changes, in environments that vary from coastal to ramp, whose distribution was mainly controlled by the basement topography and early salt deformations at the most part of paleo Gulf of Mexico; excepting Yucatan Platform, that apparently remained as an emerged element (Salvador, 1991; Hudec et al., 2013).

During Upper Jurassic and until the end of oceanic crust generation processes due to the Gulf of Mexico opening at the beginning of Cretaceous (Pindell and Kennan, 2009; Snedden et al., 2014), the basin entered in a thermal subsidence stage. Tilting or inclination caused by thermal subsidence, caused salt deposits to flow towards deepest parts of the basin, creating structures related to these movements, such as some stratigraphic unconformities (at Barremian-Campanian levels) and whose duration could extend until the end of Cretaceous (Meneses-Rocha, 2001; Hudec et al., 2013; Cruz-Mercado et al., 2011).

The tilting towards the basin generated a gravitational linked system with normal faults towards the periphery of Yucatan Platform, giving place to half-graben structures and salt rollers (Steier and Mann, 2019). While towards the north and the central part of the basin, salt pillows, passive and reactive diapirs were developed, as well as structures with low-angle folding in response to the extension generated at the shelf margin (Sánchez-Rivera et al., 2011).

At the end of Mesozoic and early Cenozoic periods, the Gulf of Mexico basin underwent a change in the sedimentary regime from carbonates to siliciclastics, due to uplift and exhumation of the Sierra Madre Oriental (Fitz-Díaz et al., 2018).

However, this orogeny has no regional extension to the southeast of Mexico and according to Meneses-Rocha (2011), there is no structural or stratigraphic evidence of its influence towards the marine area of southeast Gulf of Mexico. So, Paleocene-Eocene sequences deposition is continuous and related to the progressive uplift and erosion of granitic intrusives from Chiapas massif, metamorphic terrains (Chacus group) and pre-Eocene sedimentary rocks located along the Chiapas southern margin.

From Middle Eocene, compressive deformation in southern Mexico caused by the progressive continuation towards the south of the Laramide orogeny and the influence of the beginning of rupture and separation of the Chortis block (Ratschbacher et al., 2009), generated high-angle reverse faults and stike-slip faults that caused exhumations and regional erosion, which coincide with a period of clastic sedimentation from this area to the shelf and into deepwater through fluvial systems and turbiditic flows, respectively.

From Eocene-Oligocene and even to Early Miocene, Pindell and Miranda (2011) and Witt et al. (2012) agree that corresponds to a period of relative tectonic inactivity in southern Mexico, subsequent to the most severe deformation of the Laramide orogeny and prior to the deformation event associated with the Chiapanecan orogeny (Sánchez, 1979).

In contrast to the Middle Eocene, the sedimentation and exhumation rate of clastic sources at southeast Mexico was lower, combining deposition of shallow marine limestones (e.g. Macuspana limestone) on the previous clastic platform (Pindell and Miranda, 2011) and intermittent pulses of terrigenous sedimentation from the remaining positive elements, possibly with a main sediment source input from central Guatemala (Meneses-Rocha, 2001; Abdullin et al., 2016). Some of these pulses reached the deepwater zone as predominantly fine-grained sediments, represented by thick shales sequences, siltstones and some turbiditic flows.

In the deepwater and shallow water zone of Saline Basin, irregular depositional surfaces at Oligocene and Lower Miocene have been identified based on seismic information, which have been interpreted as a product of salt bodies movements (Ángeles -Aquino et al., 1994). The identified thickness variations at Lower Miocene levels and thinning of Oligocene sequences towards the top of salt-related structures, suggest that the salt could begin to move from Oligocene to Lower Miocene because of the sedimentary load.

In the southeast margin of the Gulf of Mexico, the period from Middle Miocene to Upper Miocene corresponds to a tectonic deformation stage and sedimentation related to the Chiapas massif rapid exhumation (Abdullin et al., 2018), the Chiapanecan orogeny (active until Late Miocene) and the Chiapas Foldbelt or Sierra de Chiapas deformation (Witt et al., 2012b).

Eastward displacement of the Chortis block and the development of a strike-slip tectonic boundary, with transtension and transpression alternating zones that includes the Polochic-Motagua and Tuxtla-Malpaso fault systems, are the major components in the Chiapas Foldbelt (Guzmán-Speziale and Meneses-Rocha, 2000). Contemporaneously, with the beginning of subduction of the Cocos plate below the North American plate, shortening was transferred to the north creating a wide foldbelt, which covers from the Catemaco Foldbelt (with main detachment level in Eocene-Oligocene shales), passing through the Saline Basin and up to the Pilar Reforma-Akal (with main detachment level in the Callovian salt).

Chiapas massif exhumation, the Chiapanecan orogeny and the development of the Chiapas Foldbelt, caused extensive erosion and abundant sandy terrigenous sediments supply to the shelf and to deepwater areas of Gulf of Mexico, forcing the coastline to advance northward. By the end of Middle Miocene, the sediment supply began to accumulate towards the shelf at Comalcalco and Macuspana regions, possibly in deltaic environments and with sediment supply from the Yucatan platform (Meneses-Rocha, 2001).

Finally, at the beginning of Late Miocene, the shelf area became gravitationally unstable, triggering extensional processes (product of gravitational tectonics) that perpendicularly deformed the structures generated during the Chiapanecan orogeny; at the same time as shortening towards northeast continued, generating a transtensional regime (Pindell and Miranda, 2011).

The combination of gravitational and strike-slip tectonics generated an extensional-contractional linked system in a southeast-northwest direction, which resulted in the Macuspana sub-basin formation (Upper Miocene-Pliocene), displacing the allochthonous and autochthonous salt bodies, as well as the Paleogene shales (Ambrose et al., 2003; Pindell and Miranda, 2011).

At the beginning of Pliocene the Comalcalco sub-basin is developed, coevally with an additional extension in the Macuspana sub-basin; according to Meneses-Rocha (2001) and Sánchez-Rivera et al. (2011), the Miocene-Pliocene stage corresponds to the main phase of halokinesis throughout the Saline Basin area. The main structures present in the marine portion of Saline Basin evolved in a southeast-northwest direction, giving place to a diversity of structures associated with salt diapirs (some collapsed, others still connected with the autochthonous salt), allochthonous salt canopies located near the seabed, contractional structures by salt inflation, as well as minibasins formation (Figure 42).

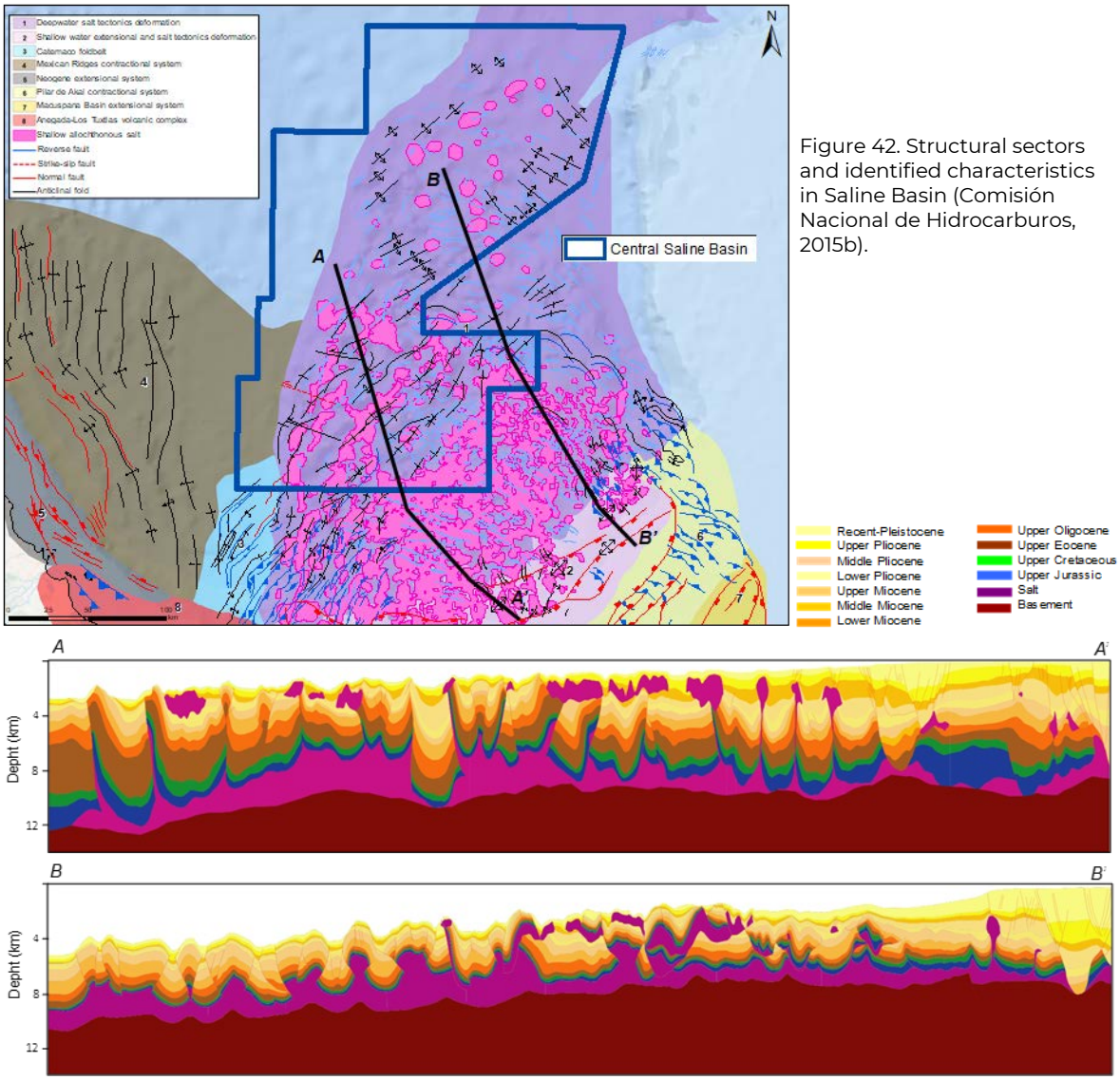


Figure 42. Structural sectors and identified characteristics in Saline Basin (Comisión Nacional de Hidrocarburos, 2015b).

The tectonic evolution of the area has controlled the development of environments and sedimentary column of deepwater Saline Basin (Figure 43). The oldest rocks that have been drilled in the area (Tamha-1 well), consist of Callovian salt deposited during Late Jurassic.

The early salt deformation had an important impact on paleoenvironments distribution during Jurassic. The Upper Jurassic is characterized by the development of low-angle

carbonate ramp environments, where changes in sea level influenced depositional environments.

Based on information from the Tamha-1 well, the Oxfordian in the Saline Basin is composed of siltstones and shales with an anhydrite package as a lower unit and towards the top, it is characterized of mudstone and intraclast wackestone deposited in shallow water environments (tidal flat).

Also, based on shallow water well correlations, Kimmerigdian is mainly characterized by deposits related to the development of high-energy oolitic banks, with southwest-northeast alignments parallel to the coast paleogeography, with lateral facies changes related to a transgressive stage in ramp environments.

According to Sánchez-Rivera et al. (2011), the basement highs paleogeography together with structures generated by early salt movements, controlled facies distribution. These sedimentary patterns are expected to extend into the deepwater zone, so the Kimmerigdian is constituted as one of the most important geological objectives in the Saline Basin.

Tithonian rocks are the most important hydrocarbon source and are composed of organic rich carbonate shales that were deposited in this period throughout the basin, product of a decrease in subsidence and sedimentation rate, and consistent with a maximum marine transgression period. Tectonically the basin was so stable, that the Tithonian rocks preserved similar lithological features throughout the basin.

During Lower Cretaceous, the marine transgression period that began from Upper Jurassic continues, covering the Yucatan platform and giving place to a marked depositional environment differentiation between the shelf, slope and basin. The shelf margin that was established at the beginning of Cretaceous, remained practically in the same position throughout all the period.

In the Upper Cretaceous, one of the main reservoir rocks of the Gulf of Mexico southeast region was deposited, derived from the erosion and karstification processes at the edge of the Yucatan platform. This reservoir rock is composed by dolomitized calcareous breccias with exoclasts of dolomitized mudstone-wackestone, microdolomite and bioclastic packstone in a dolomite matrix.

Based on seismic-stratigraphic interpretation of northeastern portion of the assessed area, reflectors with a chaotic internal configuration have been identified, with variations in width and thickness; besides to some erosive features within the Cretaceous, which can sometimes reach the Jurassic level. These features suggest the presence of proximal facies to the Yucatan platform edge (calcareous breccias), which could have good characteristics as reservoir rocks, similar to the main reservoir rocks in Campeche sound.

Additionally, seismic facies are identified and interpreted as carbonated turbiditic flows (possible calcarenites) from the Yucatan platform, as well as halokinetic breccias with lenticular patterns, product of the erosion of folds crests formed by saline domes, due to the ascending salt movements.

For the Paleogene stratigraphic column (Eocene-Oligocene), based on seismic attributes and interpretations of seismic information, sedimentary facies related to deposits of turbiditic systems have been defined, such as amalgamated channels, channel overflows and channeled submarine fan lobes. These systems have a preferential orientation from

southwest to northeast; however, channels are also observed that come from southeastern and western portions of the Gulf of Mexico basin, which converge into deepwater.

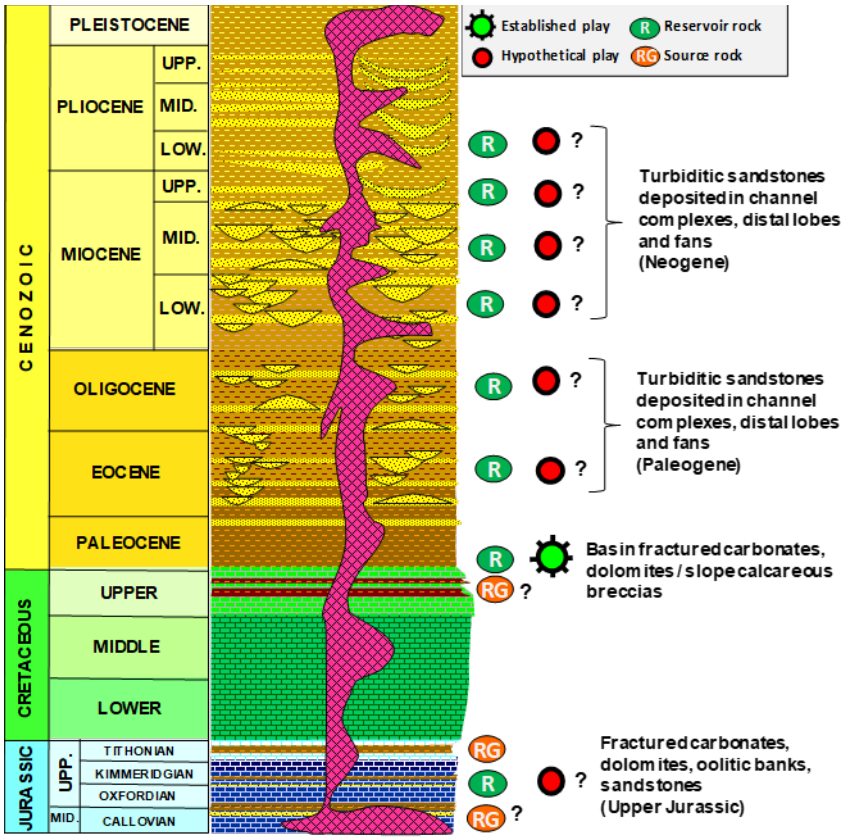


Figure 43. Schematic sedimentary column of Saline Basin, indicating identified levels as reservoir and source rocks.

For Eocene and Oligocene, mainly shale lithologies are expected, interstratified with fine-grained laminar sandstones, as well as medium-grained sandstones towards the areas where amalgamated channels and channelized lobes are interpreted. Additionally, towards the northeast portion of the area, the probable presence of carbonated turbiditic systems in Lower-Middle Eocene levels is inferred, which seems to come from the Yucatan platform.

Similarly, Neogene is characterized by sedimentary facies related to turbiditic systems deposits, like amalgamated channels, crevasse spalys and channelized lobes, with the same preferential orientation pattern from southwest to northeast, which converge into deepwater. Since Middle Miocene, as the maximum deformation stage that folded and back-thrusted the Chiapas-Reforma-Akal belt, the Chiapas massif exhumation and the formation of Sierra de Chiapas, contributed to large volumes of clastics from the south-southeast Mexico, that were deposited through high-density turbiditic currents in submarine fans, where channel complexes and lobes to deepwater are identified.

Considering that from Middle Miocene the main stage of tectonic and saline structuring took place, the distribution of sedimentary systems was influenced by the relief generated by salt intrusions, where thickness variations are identified towards the structural highs, wedges or pinch-outs and minibasins conformation.

For the Upper Miocene and Pliocene, sedimentary systems are observed confined, composed of fine-grained sandstones interstratified with very thin layers of siltstones and shales where thickness variation is observed, due to coeval movements of allochthonous salt. The seafloor relief due to salt tectonics effects, has a direct influence on sediments distribution for the Lower Pliocene; based on seismic interpretation, depositional systems confined to minibasins were identified, with local variations in the direction of sedimentation.

8.2. PETROLEUM SYSTEMS AND PLAYS

In the Saline Basin, as part of the Petroleum Province of deepwater Gulf of Mexico, five petroleum systems have been defined (Comisión Nacional de Hidrocarburos, 2015) supported by geochemical analyses from seabed hydrocarbon seepages samples and oil samples recovered through wells. According to Magoon and Dow (1994) and Magoon and Beaumont (1999) classification, four of these systems are considered as known (!) and one still remains speculative (?), postulated from nearby wells and analog fields in the shallow water region (Table 17).

Regionally, the Upper Jurassic Tithonian source rocks constitute the main hydrocarbon source stratigraphic level and are widely distributed throughout the Gulf of Mexico basin.

The petroleum systems defined for the Saline Basin do not consider other identified potential hydrocarbon source subsystems, corresponding to Upper Jurassic Oxfordian and Upper Cretaceous Cenomanian-Turonian stratigraphic levels, since their capacity as hydrocarbon source rocks and characteristics have not been confirmed in the deepwater zone of Saline Basin.

Table 17. Summary of the identified petroleum systems in the Saline Basin, including examples of exploration wells that have proved them and examples of nearby analog wells and fields located in shallow water to postulate speculative petroleum systems.

Source rock	Reservoir rock	**Level of certainty** (Magoon and Dow, 1994; Magoon and Beaumont, 1999)	Example
Upper Jurassic Tithonian	Pliocene-Miocene	Known (!)	Tabscoob-1 (Shallow water analog in Middle Pliocene), Alaw-1 (Upper Miocene), Hem-1, Nat-1 (Middle Miocene), Yoka-1, Kunah-1 (Lower Miocene)
Upper Jurassic Tithonian	Paleogene	Known (!)	Bukma-1 (Middle Eocene)
Upper Jurassic Tithonian	Upper Cretaceous Breccia	Known (!)	Nab-1 (Upper Cretaceous)
Upper Jurassic Tithonian	Cretaceous fractured	Known (!)	Tamil-1 (Upper Cretaceous)
Upper Jurassic Tithonian	Upper Jurassic	Speculative (?)	Etbakel-1 (Tithonian), Shallow water analogs, e.g. Alak-1, Lum-1 (Oxfordian), Esah-1, Ayin-1 (Kimmeridgian)

In the shallow water region of the Campeche Sound, an Oxfordian-Oxfordian confined petroleum system classified as known (!) has been established, by the positive geochemical correlation between biomarkers of oil reservoirs in Lower Oxfordian aeolian sandstones and hydrocarbons extracted from Upper Oxfordian source rocks sampled by wells (Pemex, 2010). However, it has not been defined if these rocks have the potential for hydrocarbon generation at a regional level, since multiple facies changes have been interpreted at a local level and their geographical extension has not been determined with certainty, as well as their continuity towards deepwater.

According to previous petroleum systems studies and modeling, the Oxfordian potential source rocks have practically the same burial histories as the Tithonian source rocks,

given their close stratigraphic position. However, a higher level of thermal maturity is expected in Oxfordian rocks than in Tithonian, since they have been subjected to higher temperatures and longer burial, entering before to the hydrocarbon generation window.

Besides of the Oxfordian-Oxfordian(!) confined system, the presence of oil from Oxfordian source rocks in some Kimmerigdian carbonate oolitic banks reservoirs has been interpreted, at the Campeche sound region in shallow water (Guzmán-Vega et al., 2001; Clara-Valdés et al., 2009). However, for most of the Kimmeridgian aged reservoirs, the presence of oil from Tithonian source rocks affinity has been interpreted (Gonzalez and Holguin, 1992; Guzmán-Vega and Mello, 1999; Guzmán-Vega et al., 2001; Clara-Valdés et al., 2009; Escalera and Hernández, 2009).

Since Kimmerigdian reservoir rocks are in a lower stratigraphic position regarding the Tithonian source rocks, which are considered the most important at regional level given their proven capability to generate hydrocarbons, various migration mechanisms have been interpreted to the hydrocarbons charge from Tithonian source rocks to Kimmerigdian aged reservoirs.

In general, vertical and/or horizontal migration processes have been determined within short distances, due to the effect of structural relief of traps and/or stratigraphic units juxtaposition; that is, migration occurs through faults or fractures. However, several authors (e.g. England et al., 1987; Gonzalez and Holguin, 1992; Birkle, 2006) suggest the possibility that migration can occur through the porous rocks matrix since both are in contact, provided that hydrocarbons find lower pressures on their way to go to reservoir rocks where they accumulate, suggesting downward migration with some horizontal component.

The vast majority of identified potential hydrocarbons trap structures with Kimmeridgian geological objectives in the assessed area, have been interpreted as structural and combined traps related to early salt movements; where processes of vertical and/or horizontal migration within short distances are inferred, related to the structural relief and through faults or fractures from Tithonian levels. Likewise, in some cases where possible Kimmeridgian-Oxfordian geological objectives were identified, are observed as salt-cored traps, with seismic monticular patterns and which are associated with possible high-energy facies (oolitic banks) or could also be associated with organic growths.

In the latter type of objectives and based on seismic information, it is difficult to interpret the faults or fractures that act as migration routes. However, horizontal migration processes are assumed from Titonian source rocks, which in turn are sealed laterally and vertically by the same Titonian shales or by anhydrite rocks within the Upper Jurassic.

The petroleum system elements include source rocks, reservoir rocks, seal elements and the processes of trap formation, timing and migration of hydrocarbons. Next, the elements of the identified petroleum systems in the assessed area of the Saline Basin are described in a general way.

8.2.1. Source rocks

The Upper Jurassic Tithonian rocks, constitute the main hydrocarbon source stratigraphic level for the entire Saline Basin. In the deepwater region, there are wells that drilled the Tithonian source rocks (Hux-1, Bok-1, Chuktah-201, Nab-1, Etbakel-1, Tamil-1 and Tamha-1) and together with fields and wells information from the shallow water region

of the Southeast Basins, have allowed to determine their lithological characteristics, distribution and hydrocarbon generating potential towards deepwater.

Within the assessed area, Tamha-1 drilled 25 m of Tithonian rocks, composed of mudstone-wackestone intraclasts and bioclasts carbonates, with bituminous aspect and slightly recrystallized and dolomitized. From geochemical analysis of core samples extracts made in this well, total organic carbon values of around 5.5% to 6% were obtained and with a mixture of type I and II kerogens, established by high hydrogen index values (IH = 654).

Based on basin and petroleum systems modeling made previously, the deepwater portion of Saline Basin is in different stages of hydrocarbon generation regarding Tithonian rocks, and where thermal maturity is mainly controlled by depth.

These stages range from high thermal maturity conditions to the north and west, where the presence of gases and condensates is expected; passing through areas where thermal maturity decreases towards the central part, opening the possibility of finding liquid hydrocarbons and finally, reaching an area where the expected hydrocarbons goes from gases to heavy oil towards the east and south ends.

As mentioned previously, other identified potential hydrocarbon source subsystems are not considered, corresponding to the Upper Jurassic Oxfordian and Upper Cretaceous Cenomanian-Turonian, since their hydrocarbon generating potential has not been confirmed regionally in deepwater of the Saline Basin.

8.2.2. Reservoir rocks

In the stratigraphic column of the Saline Basin, five potential stratigraphic reservoir rock intervals have been identified (Figure 43):

- **Pliocene.** The rocks considered as reservoir in the Pliocene are related to turbiditic systems deposits, such as amalgamated channels, crevasse splays and channeled lobes. Pliocene rocks have not been proved by deepwater wells. However, the Tabscoob-1 well located at the shallow and deepwater limit, south of the assessed area, was a gas and condensate producer in Middle Pliocene sandstones.

- **Miocene.** Similar to the Pliocene, the Miocene reservoir rocks are considered to be turbiditic sandstones deposited in channel complexes, lobes and distal deepwater fans in the Lower, Middle and Upper Miocene. The Miocene has been proved by wells Yoka-1, Nat-1 and Hem-1 within the assessed area and by Kunah-1 and Alaw-1 to the southwest of the assessed area.

- **Oligocene-Eocene**. The Oligocene is represented by deepwater turbiditic systems sandstones, while Eocene consists of deepwater turbiditic systems sandstones, as well as calcarenite flows from shelf edges and deposited in slope environments; both probably associated with channelized facies and slope aprons. Recently, Bukma-1 well discovered gas and condensate in Middle Eocene reservoir sandstones.

- **Cretaceous**. For the Cretaceous, fractured basin limestones have been identified, consisting mainly of micritic limestones and marls, where fracturing may be associated with salt tectonics and Cenozoic compressional events, which include

some bodies interpreted as halokinetic breccias with local extension. Additionally, the presence of calcareous breccias of slope environments is postulated, which correspond to deposits formed by calcareous debris flows and carbonated turbiditic flows from Yucatan platform.

Within the assesed area, Tamha-1 well drilled fractured basin carbonates (mudstone-wackestone) and some halokinetic breccia lenses related to salt intrusions. In deepwater, Tamil-1 and Nab-1 wells located southeast from the assessed area, established extra heavy oil production in Upper Cretaceous fractured basin carbonates and in slope breccias, respectively.

- **Upper Jurassic.** For the Upper Jurassic, mainly carbonate reservoir rocks deposited in mixed environments of Oxfordian age are expected, as well as carbonates of internal ramp with development of dolomites and oolitic banks for the Kimmeridgian level. According to the information of analog wells drilled in the shallow water region of the Campeche Sound, carbonates are mainly mudstone, wackestone and packestone-grainstone of oolites and intraclasts, diagenetically and tectonically fractured.

8.2.3. Traps and seal elements

According to the tectonic events that affected the southeastern portion of the Gulf of Mexico and the depositional environments, different types of traps have been identified, generated by the combination of compressional, extensional events and salt movements. The most important are traps generated by salt tectonics, related to salt-cored folds with reverse faults at their flanks and other structural traps, wedges or pinch-outs against salt diapirs and salt feeders, as well as salt domes and turtle-like structures, formed by salt evacuation

Also, stratigraphic traps with confined sandstones in shale or pinch-outs against salt diapirs have been identified, associated with channels and basin floor fans facies deposited from Eocene to Miocene. Finally, combined traps correspond to submarine fan facies structured by salt tectonics or by the compressive component of gravitational tectonics that mainly affected Middle Miocene to Pliocene stratigraphic levels; process that continues today, deforming the seabed surface.

According to the stratigraphy reported by wells and their seismic correlation, traps are additionally protected by lithological seals formed by shale sequences.

For the Cenozoic, the seal rock are shales that are arranged interstratified or alternated vertically and laterally with sandstones reservoir rocks, these shales were formed mainly by fine-grained material deposited in a pelagic way and in suspension as part of the turbiditic systems. While for the potential Mesozoic reservoir rocks, seal rocks are dominated by Paleocene pelagic sediments, by intraformational horizons of shaley limestone from Cretaceous and by calcareous shales of Tithonian levels.

In the southern part of the assessed area, which has an intense influence of salt tectonics, the seal is conformed by allochthonous salt bodies, which is considered efficient for potential subsaline structures; however, surface hydrocarbons seepages on the seabed are also indicators of leaks in the seals, which may be associated with movements due to rearrangement of saline bodies and/or faulting.

8.2.4. Timing and migration

Through petroleum systems simulations and basing modeling previously conducted, in addition to new ARES information and recent wells, it has been determined that thermal maturity for Jurassic source rocks is highly variable throughout the entire deepwater region of Saline Basin.

This variation ranges from thermally immature areas to the southeast, to overmature towards the west end. So, it is expected that in some regions of the central portion of deepwater Saline Basin, the Tithonian source rocks are within a liquid hydrocarbon generation window.

For example, in Tamil-1 and Nab-1 wells located at the southeastern end of deepwater Saline Basin region, extra heavy oils of 14 ° API were discovered, which is indicative of low thermal maturity for Tithonian source rocks. While in Tamha-1 well located at the south-central portion, Tithonian rocks also present immature conditions (Ro <0.5%).

On the other hand, the west of the area is characterized by high thermal maturity conditions, causing that towards these areas, the expected hydrocarbons are predominantly gas (wet gas and dry gas), as has been proven in reservoirs discovered by the wells Nat-1, Hem-1, Bukma-1, among others.

Based on these evidences and on the models made, it has been estimated that towards the Yucatan platform, the Tithonian source rocks have a low lithostatic load, since they are buried by lower thicknesses of sedimentary rocks; so, towards this area hydrocarbon generation started recently or has not yet started. In the specific areas where it has been identified that hydrocarbon generation conditions have already been reached, this occurred at the beginning of Lower Pliocene, initiating its expulsion from Upper Pliocene and continuing until today.

In the central portion of the Saline Basin, liquid hydrocarbon generation areas have been identified. However, modeling analyzes suggest that expulsion is limited to areas where Tithonian rocks reach deepest levels, where hydrocarbon generation processes started at the beginning of Upper Miocene and migration towards more recent periods, as the source rock was buried by thicker intervals of sedimentary column.

Towards the west end of deepwater Saline Basin region, at the limit with the Mexican Ridges, Tithonian source rocks are at greater depths and is possibly in a metagenetic stage. The hydrocarbons generation is estimated that occurred from the beginning of Eocene and until the beginning of Lower Oligocene; expulsion and migration begins from Lower Oligocene until the beginning of Lower Miocene, where its generating potential could be exhausted.

According to previous studies, a tendency to find high-pressure conditions at Paleocene levels has been identified, as a result of the high sedimentation rates and the relatively rapid sedimentation pulses that occurred mainly during the Neogene.

From these studies, it has been observed that hydrocarbons expelled from Tithonian source rocks tend to be distributed preferentially to Cretaceous reservoir rocks. This condition implies that for migration of hydrocarbons to Cenozoic reservoirs occurs, there must be discontinuities such as faults and fractures that act as migration pathways; or, through the interface between salt bodies and the stratigraphic levels with potential reservoir rocks.

Figure 44 shows a petroleum system events chart for the deepwater zone of Saline Basin, which summarizes the mechanisms and their temporal relationship with the elements and processes of the identified petroleum systems (Table 17), including the geological age of the events and the critical moment (Magoon and Dow, 1994), as the moment in time that best represents the generation, migration and accumulation of most hydrocarbons in petroleum systems.

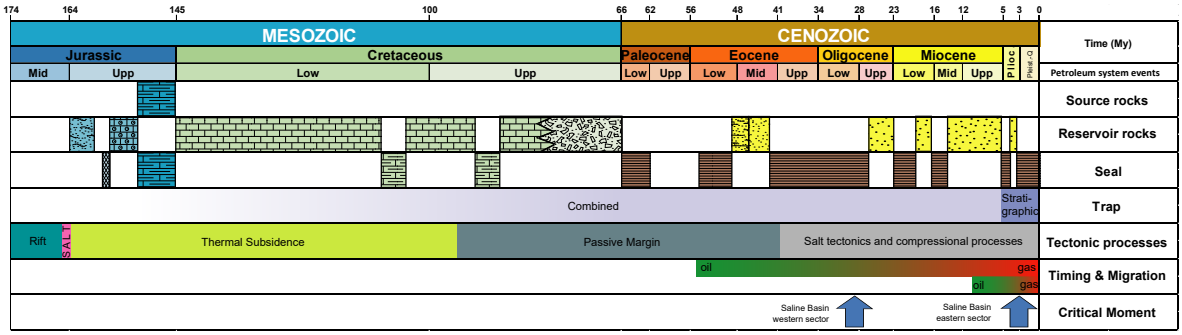


Figure 44. Events chart of identified petroleum systems in deepwater Saline Basin.

8.2.5. Plays

Plays of deepwater zone of the central Saline Basin, are postulated based on current knowledge and the integration and analysis of seismic information, regional studies, well information and analogs. Plays defined within Saline Basin, have a composite nomenclature, associated with the Petroleum Province (GP = deepwater Gulf of Mexico), the assessed area name (CS = Saline Basin), its category according to its exploration status (E = Established; H = Hypothetical) and finally the chronostratigraphic interval associated with the main age of the potential reservoir rocks.

In accordance with the above, Table 18 shows the summary of the main characteristics of the assessed plays in the deepwater zone of the central Saline Basin.

For the defined plays in Saline Basin, the Upper Jurassic Tithonian rocks are considered as the main hydrocarbon source, despite other potential source rocks have been identified (Upper Jurassic Oxfordian and Upper Cretaceous Cenomanian-Turonian), its hydrocarbon generating potential in the area has not been confirmed. The Upper Jurassic play has an hypothetical status until today, while the rest of the plays have been established (proved) gradually by exploration drilling in the area.

Table 18. Summary of the main characteristics of assessed plays in central Saline Basin.

Play	Trap style	Lithology and depositional environment of reservoir rocks	Porosity (%)	Main wells that have investigated the play
GP CS E Neogene	Stratigraphic and combined traps, related to folds and salt intrusions	Turbiditic sandstones deposited in channel complexes, lobes and distal submarine fans	10-32 % Intergranular, intragranular	Noxal-1 (Lower Pliocene), Alaw-1 (Upper Miocene), Hem-1, Nat-1 (Middle Miocene), Yoka-1, Kunah-1 (Lower Miocene)
GP CS E Paleogene	Stratigraphic and combined traps, related to folds and salt intrusions	Turbiditic sandstones deposited in channel complexes, lobes and distal submarine fans	12-20 % Intergranular, intragranular	Bukma-1 (Middle Eocene)
GP CS E Cretaceous fractured	Compressional structures	Fractured basin limestones	11-20 % fracture secondary porosity	Tamil-1 (Upper Cretaceous)
GP CS E Upper Cretaceous breccia	Stratigraphic and combined traps, related to compressional structures	Slope breccias	7-11% Intergranular, Intragranular, dissolution secondary porosity	Nab-1 (Upper Cretaceous)
GP CS H Upper Jurassic	Stratigraphic and combined traps, related to salt movements	Dolomites, oolitic banks, fractured carbonates	4-10% Intergranular, intragranular, fracture and dissolution secondary porosity	Shallow water analogs, e.g. Alak-1, Lum-1 (Oxfordian), Esah-1, Ayin-1 (Kimmeridgian)

7.3.5.1. Play GP CS H Upper Jurassic

The Upper Jurassic play is mainly represented by shallow water carbonates of mixed environments of Oxfordian age, as well as internal ramp carbonates with development of dolomites and oolitic banks for the Kimmeridgian, which are sealed laterally and vertically by Tithonian shales, by other shale packages and by anhydrites within the same Upper Jurassic level.

The Oxfordian carbonates and clastics of mixed shallow water environments underlie anhydrite deposits within the same Oxfordian level, which could act as seal rocks for this level; while the upper seal for the Kimmeridgian reservoir rocks, are shaley limestones and shales of Upper Jurassic Tithonian. For fault related traps, the lateral seal is constituted by shale fractions from the upper stratigraphic column and locally, the lateral seal can be formed by salt bodies.

The knowledge of Jurassic rocks in deepwater region is scarce; however, it is visualized as an hypothetical play based on analogs wells and discovered fields from the shallow water region of the Southeast Basins.

The play consists mainly of traps associated with structures generated during the early movements of salt, forming salt-cored monticular structures, which were subsequently affected by the regional compressive events of Middle-Upper Miocene time. At the northeast zone of the assessed area, the compressional effects of Middle-Upper Miocene time are not clearly seen; however, extensional structures linked to the basement were identified, which affect the Upper Jurassic-Lower Cretaceous rocks, forming structural traps related to salt rollers.

7.3.5.2. Play GP CS E Upper Cretaceous Breccia

The potential reservoir rocks of this play are constituted by calcareous breccias of slope environments, which correspond to deposits formed by calcareous debris flows and turbiditic flows from the platform edge erosion. These breccias were drilled by Etbakel-1 and Nab-1 wells in deepwater, consisting of subangulous to sub-rounded mudstone, wackestone and dolomite clasts, with dissolution cavities (vugs) and numerous fractures.

This play is restricted to the northeastern end of the assessed area, where the edge of the Yucatan platform is relatively close, so that together with seismic interpretations, it is possible that sedimentary breccias flows exists, with similar characteristics than reservoir breccias in the shallow water region of Southeast Basins.

The upper and lateral seal elements are constituted by the Paleogene pelagic sediments units, while in the case of traps with closure against fault, the lateral seal is constituted by the adjacent shale fractions. Additionally, for many of the potential hydrocarbon traps that involve this play, a side seal related to salt bodies was interpreted.

7.3.5.3. Play GP CS E Cretaceous fractured

Based on wells within the assessed area and from southeast of deepwater Saline Basin, reservoir rocks of this play correspond to limestones composed of marls and micrites, which include some bodies of locally identified halokinetic breccias.

Since this play is mainly related to structural traps produced by Middle-Upper Miocene compressional events and to salt tectonic processes, in addition to diagenetic processes involved on carbonate rocks, it is expected that a greater fracture degree exists towards anticline crests, as well as around salt intrusions.

The upper and lateral seal elements are constituted by the Paleogene pelagic sediment units, while in the case of traps with closure against fault, the lateral seal is constituted by the adjacent shale fractions.

7.3.5.4. Play GP CS E Paleogene

The main chronostratigraphic level of interest in this play is represented by the Eocene, with potential reservoir rocks composed of turbiditic systems sandstones and shelf edge calcarenite flows deposited in slope environments. The potential Oligocene reservoir rocks are represented by sandstones of deepwater turbidite systems.

Although Eocene-Oligocene sequences are mainly muddy, the analysis and interpretation of seismic information allowed the identification of sedimentary facies related to turbiditic systems deposits, such as amalgamated channels, channel overflows or crevasse splays and channelized lobes. These systems have a preferential orientation from southwest to northeast, delineating channels that come from the southeastern part and the western portion of the Gulf of Mexico basin, which converge into deepwater.

To the west edge of the deepwater region of Saline Basin there is unconfined sedimentation, where a pronounced slope has been interpreted, developing a large number of straight, amalgamated and/or anastomosed channels. While for the eastern region, depositional systems associated with channelized lobes are interpreted, controlled by an incipient salt tectonic activity at that time.

For the Paleogene play, more sandy sediments are expected as deposition are distributed down slope to the abyssal plain, so channelized deposits represent the areas of lower risk. Also, it is expected that there will be calcarenite flows from Yucatan platform, which are identified as rocks where hydrocarbons are produced in the shallow water zone of Southeast Basins.

In addition to the presence of lateral seals due to sal intrusions, the lateral and upper seal elements are composed of shaley facies dominated by pelagic sediments within the same Eocene-Oligocene units. In the case of closures against fault traps, the lateral seal is constituted by shale fractions of the upper stratigraphic column.

Recently, Bukma-1 well discovered a gas and condensate reservoir in Middle Eocene fine-grained sandstones, interpreted as channels and deepwater lobes.

7.3.5.5. Play GP CS E Neogene

The Neogene play is mainly represented by the Lower and Middle Miocene, characterized by sandstones of deepwater turbiditic systems as reservoir rocks, with traps sealed laterally and vertically by intraformational shales. This play is considered the most prospective in the deepwater region of Saline Basin and has been investigated by most of the wells drilled to date.

For Lower Miocene, massive coarse-grained sandstones of batial environments have been identified, deposited by high-density turbidity currents, which formed submarine fans and channels, whose distribution is controlled by salt tectonics in minibasins. Based on well logs electrofacies analysis, upward-fining stacking patterns of sandstone, siltstone and shale packages have been interpreted; in addition, in some core samples, channel erosive bases with massive sandstones, as well as some basal infill conglomerates can be observed.

For Middle Miocene, confined fan systems and channels are interpreted, which extend to the central part of the assessed area. Middle Miocene thicknesses that have been drilled so far are very small, because wells have been located at the top of anticline structures and because deposits of this age coincide with an important stage of deformation, thicknessess become thinner towards structural highs.

Middle Miocene rocks are distributed mainly in minibasins towards the central-east zone of the assessed area and towards the west, turbiditic systems are predominantly in confined fans and channels. The movements of allochthonous salt and the anticlinal structures of Catemaco foldbelt played an important role in sedimentation, as they confined some deposits and locally modified the sedimentation direction.

For the Upper Miocene, fine-grained sandstones are interstratified with siltstones and shales in very thin layers, deposited in confined environments. Upper Miocene gross thicknesses in wells are thin and even absent towards the top of some anticlinal structures, so greatest thicknesses are found in minibasins areas formed by allochthonous salt.

Finally, the Pliocene is expected to contain medium to coarse grained sandstone facies, whose continuity and distribution is controlled by the bathymetric relief during the Lower Pliocene. Based on the seismic analysis, it is interpreted as a confined depositional system

to minibasins developed by salt activity, which locally modified the sedimentation direction related to submarine fans.

From the petrology point of view, Neogene is composed of feldspathic litharenites with abundant volcanic lithics, feldspar, quartz, metamorphic and sedimentary rock fragments, with poorly clastic grain sorting and mineralogically immature, which have a good to very good quality as reservoir rock, due to grain dissolution secondary porosity.

In a large number of Neogene core samples from deepwater wells of Saline Basin, as well as in shallow water wells (e.g. Chuktah-1, Chuktah-201, Tibil-1, Lakmay-1 , Lakach-1, among others), sandstone units have been identified that contain abundant volcanic glass shards and/or layers with abundant bentonite content, which are described as hybrid tuffs due to the coexistence of sedimentary rock clastics and clayley-silty volcano-sedimentary material.

These rocks present anomalous volcanic glass content, exceptionally well preserved, without alteration or devitrification traces (petrographic characteristics observable in thin-section rock samples), which makes the difference between those vitreous or vitro-crystalline tuffs resulting from erosion and alteration of volcanic material sedimentary deposited.

The amount of volcanic rocks fragments reported in these sandstones, indicate an important calc-alkaline volcanic source for the Neogene, which may be related to effusive volcanic events of Miocene and Pliocene of Chiapas volcanic arc (Manea and Manea, 2006; Mora et al., 2007; Torres-Vargas et al., 2011) or, come from different relatively nearby volcanic sources with documented calc-alkaline effusive volcanic activity for the Neogene, such as Los Tuxtlas Volcanic Complex (Nelson et al., 1995; Ferrari et al., 2005).

The play consists mainly of combined traps associated with the Middle-Upper Miocene compression and salt tectonics, which create complex traps and some stratigraphic traps associated with salt intrusions. Towards Upper Miocene-Pliocene, the stratigraphic trap component becomes more important, with sedimentary wedging at structural highs and against salt bodies, related to salt tectonics that acted during Pliocene to nowdays.

8.3. EXPLORATION PROGRESS

First hydrocarbon discoveries in southeastern Mexico, were made in the early 20th century at onshore Saline Basin, associated with traps in salt domes and diapirs. With the onshore discoveries development during the mid-20th century, exploration in shallow water began to investigate the province continuity, gravimetrically configuring salt domes and defining their geometry with seismic continuous reflection techniques (Camargo and Quezada, 1991).

By the 1960s, fields had already been discovered on the continental shelf of Saline Basin, intensifying the amount of geological and geophysical studies in the shallow water region during the 1970s and 1980s, which allowed for the major structural systems to be identified and for the stratigraphic column in the shallow water zone to be defined. Since 1979, with 3D seismic information acquisition, the application of sequence stratigraphy concepts and the information from wells has allowed for the first tectono-sedimentary interpretations of the Saline Basin evolution to be performed (Aguayo-Camargo, 2004).

With the development of Southeast Basins shallow water exploration, several important discoveries were made, including the Akal (1976) and Sihil (1999) fields, so that for almost 30 years, exploration was focused on Mesozoic rocks of this region. These discoveries lead to deepwater exploration, and by 1990s, 2D and 3D seismic information acquisition began in the southeastern portion of Saline Basin, at the adjacent area to the Mesozoic rocks discoveries.

Between 1996 and 2012, the 11 deepwater Saline Basin 3D seismic studies were acquired, which together cover a total surface area of 70,755 km^2; while in the case of 2D seismic, the 6 different identified studies were acquired between 1997 and 2009 with linear coverage distributed throughout the deepwater region of Saline Basin (Table 19).

The first exploration wells in deepwater Saline Basin were drilled with Mesozoic geological objectives, which were looking to find commercial hydrocarbons accumulations similar to their shallow water analogs from Southeast Basins (Chuktah-201, Nab-1 and Bok- 1). It was not until the drilling of the Noxal-1 well in 2006 that the Cenozoic geological column exploration was triggered towards the deepwater zone.

Within the 2004 to 2015 period, Pemex drilled 22 exploration wells in the deepwater Saline Basin, which mainly established the Neogene play (Table 20) and from which gas discoveries were made and an important volume of information was obtained. Based on this exploration progress in the Saline Basin, the previous prospective resources' assessment grouped the analysis into 7 plays of the Neogene, Paleogene and Mesozoic; divided into two administrative areas (Golfo de Mexico Profundo Sur and Golfo de Mexico Profundo B).

Table 19. Seismic studies acquired through 2015 in the Saline Basin by Petroleos Mexicanos.

Seismic study	Year of acquisition	Surface coverage km^2	Acquisition technique	Processing
Chuktah	1996	690	3D	PRESTM, POSTSTM
Tamil	1997	655	3D	PRESTM, POSTSTM
Kayab	2002	848	3D	POSTSTM
Holok Alvarado	2003	9,836	3D	PRESTM, POSTSTM
Nox Hux	2003	2,140	3D	PRESDM, PRESTM, POSTSTM
Temoa*	2007	7,005	3D Q	PRESDM, POSTSTM
Anegada Labay/	2008	7,216	3D	PRESTM, POSTSTM
Han Sur Oeste de Tamil/	2010	12,214	3D	PRESDM, POSTSTM
Yoka Butub*	2011	5,585	3D	PRESDM, POSTSTM
Ixic*	2011	4,948	3D	PRESTM, POSTSTM
Sayab*	2012	21,963	3D	PRESTM, POSTSTM
Chuktah	1997	-	2D	POSTSTM
Golfo de México Profundo/	1997	-	2D	PRESTM, POSTSTM
Estudio Sísmico Interregional Litoral Golfo de México/	2000	-	2D	STK
Regional Golfo de México/	2003	-	2D	POSTSTM
Regional Sur 2D/	2005	-	2D Q	PRESTM, POSTSTM
Golfo de México Regional 2D-2009/	2009	-	2D	PRESTM

* Within the assessed area
/ Partially within the assessed area

Within the assessed area, there are 4 3D seismic volumes, coinciding with 5 2D seismic studies and 5 wells; however, all the information was used in the central Saline Basin area assessment updating. Tables 19 and 20 indicate the seismic studies and wells contained within the assessed area, respectively; and the map in Figure 45 shows the exploration

information generated by 2015 around the Saline Basin, in terms of seismic and well information.

Table 20. Wells drilled through 2015 in Saline Basin by Petroleos Mexicanos

Well name	Drilling completion year	Result	Investigated play
Chuktah-201	2004	Dry	-
Nab-1	2004	Heavy oil producer	Upper Cretaceous
Bok-1	2005	Water flooded	Upper Cretaceous
Noxal-1	2006	Dry gas producer	Upper Miocene
Lalail-1	2007	Gas and condensate producer	Middle Miocene
Chelem-1	2008	Dry	-
Tamha-1*	2008	Water flooded	Upper Cretaceous and Upper Jurassic
Tamil-1	2008	Heavy oil producer	Upper Cretaceous
Etbakel-1	2009	Dry	-
Holok-1	2009	Dry	-
Kabilil-1	2009	Dry	-
Leek-1	2009	Wet gas producer	Lower Miocene
Kunah-1	2011	Wet gas producer	Lower Miocene
Nen-1	2011	Dry gas producer	Upper Miocene
Hux-1	2012	Dry	-
Kunah-1DL	2012	Wet gas producer	Lower Miocene
Lakmay-1	2014	Dry	-
Yoka-1*	2014	Non-commercial wet gas producer	Lower Miocene
Nat-1*	2014	Wet gas producer	Middle Miocene
Alaw-1	2015	Dry gas producer	Upper Miocene
Hem-1*	2015	Wet gas producer	Upper Miocene and Middle Miocene
Nat-1DL*	2015	Wet gas producer	Middle Miocene

*Wells within the assessed area

During the last three years from 2016 to the end of 2018, Pemex within its entitlement areas has made new progress in exploration in Saline Basin. In addition, with the implementation of the ARES program, new exploration information has been generated by companies other than Pemex; therefore, there is new information for prospective resources assessment updating in the central Saline Basin.

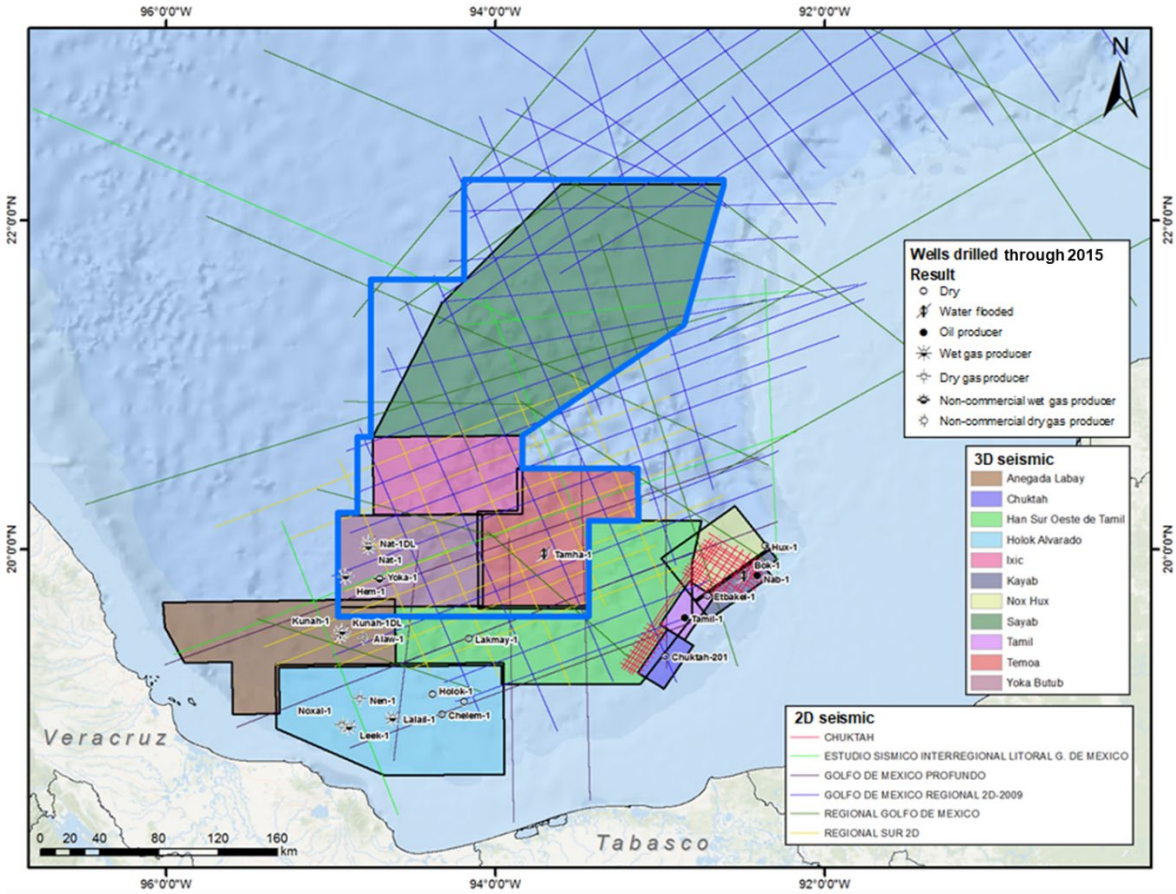


Figure 45. Map showing the exploration information generated through 2015 in the deepwater Saline Basin by Pemex, in terms of seismic information and wells.

8.3.1. Exploration information used for central Saline Basin assessment updating

From 2004 to 2015, Pemex drilled 22 exploration wells in deepwater Saline Basin, while in the 2016 to 2018 period, 1 exploration well has been drilled (Table 21). The Bukma-1 well was drilled in 2018, and allowed the Paleogene play to be established by confirming the presence of hydrocarbon accumulations at Middle Eocene levels.

Table 21. Wells drilled from 2016 to 2018 by Petroleos Mexicanos in deepwater Saline Basin.

Well name	Drilling completion year	Result	Investigated play
Bukma-1*	2018	Non-commercial gas and condensate producer	Middle Eocene

*Well within the assessed area

Additionally, with the ARES program implementation, a significant volume of new exploration information has been generated, including improvement of previously existing information, especially with regards to seismic studies in the deepwater Saline Basin. Most of the information generated through ARES has focused on the improvement of the seismic imaging by ultimate acquisition techniques and processing algorithms technology, given the geological-structural complexity of the area due to salt tectonics' processes.

The main ARES studies in deepwater Saline Basin carried out by 2018 include one new project for 3D WAz seismic acquisition, seven different projects for new 2D seismic acquisition, reprocessing of previously existing 3D seismic information and a new geochemical biomarkers study from seabed piston cores samples, which are important in the analysis of petroleum systems. Table 22 shows the main ARES studies located in Saline Basin.

Table 22. Characteristics of the main ARES projects located in the Saline Basin.

ARES permit	Project	Company	Type of study	Modality	Authorization year	Deliverables
ARES-TGS-NO-15-6P1.0417	Geoquímico Golfo de México	TGS AP Investments AS.	Geochemistry	Data acquisition	2015	Geochemical data from raw cores with biomarkers and isotopes
ARES-SPC-NO-15-1G2.0180	Regional Yucatan 2D	Spectrum ASA	2D seismic	Data acquisition	2015	Kirchhoff PSTM stack filtered and scaled Kirchhoff PSTM stack RAW Kirchhoff PreSDM
ARES-SPC-NO-15-1G2.0181	Deep Offshore 2D	Spectrum ASA	2D seismic	Data acquisition	2015	Kirchhoff PSTM filtered and scaled Kirchhoff PSTM stack RAW
ARES-DLP-MX-15-3O4.0229	Multicliente 2D Campeche	Dolphin Geophysical de México, S.A. de C.V.	2D seismic	Data acquisition	2015	Kirchhoff PreSTM Kirchhoff PoSTM Kirchhoff PreSDM
ARES-GXT-EU-15-2Q1.0336	México SPAN Sísmica 2D	GX Geoscience Corporation, S. de R.L. de C.V.	2D seismic	Data acquisition	2015	Kirchhoff PSTM filtered and scaled Kirchhoff PSTM stack RAW
ARES-PGS-MX-15-4R6.0183	México MC2D para el Amarre de Pozos	PGS Geophysical AS-Sucursal México.	2D seismic, Gravimetry and Magnetometry	Data acquisition	2015	Kirchhoff PreSTM RTM PreSDM Kirchhoff PreSTM
ARES-TGS-NO-15-6P1.0195	Gigante 2D	TGS AP Investments AS.	2D seismic, Gravimetry and Magnetometry	Data acquisition	2015	Stack PSTM and PSDM
ARES-MCG-NO-15-5G4.0372	Maximus	Multiclient Geophysical ASA.	2D seismic, Gravimetry and Magnetometry	Data acquisition	2015	Stack PSTM and PSDM
ARES-DSM-MX-15-3P2.0441	Campeche 3D WAZ	Dowell Schlumberger de México, S.A. de C.V.	3D seismic WAZ	Data acquisition	2015	RTM PreSDM (partial deliverables)
ARES-DSM-MX-15-3P2.0451	Reprocesado Campeche 3D	Dowell Schlumberger de México, S.A. de C.V.	3D seismic	Without data acquisition	2015	RTM PreSDM (partial deliverables) TTI RTM PreSDM (partial deliverables)

The information set used for prospective resources assessment updating in central Saline Basin mainly includes the information of the 23 exploration wells, including a large inventory of well logs and the reports of core analysis and core samples, as well as the 3D and 2D seismic information acquired through 2012 by Pemex and the new 2D, 3D seismic and geochemical information from ARES since 2015 (Figure 46).

In addition to seismic information and wells, a series of previous regional studies on basin analysis, petroleum systems, plays and geochemical analyzes conducted by Pemex and the Mexican Petroleum Institute (IMP) in the Saline Basin are available through the National Hydrocarbons Information Center (CNIH).

Finally, an important component of the available information are the historical databases of prospective resource assessments, in accordance with the Guidelines for the Analysis and Assessment of the Prospective and Contingent Resources of the Nation, published in DOF in December 2013.

This information set was analyzed and updated according to well results and the new seismic information through the integration, selection and combination of relevant information, as well as the analysis, interpretation and studies performed by the Commission.

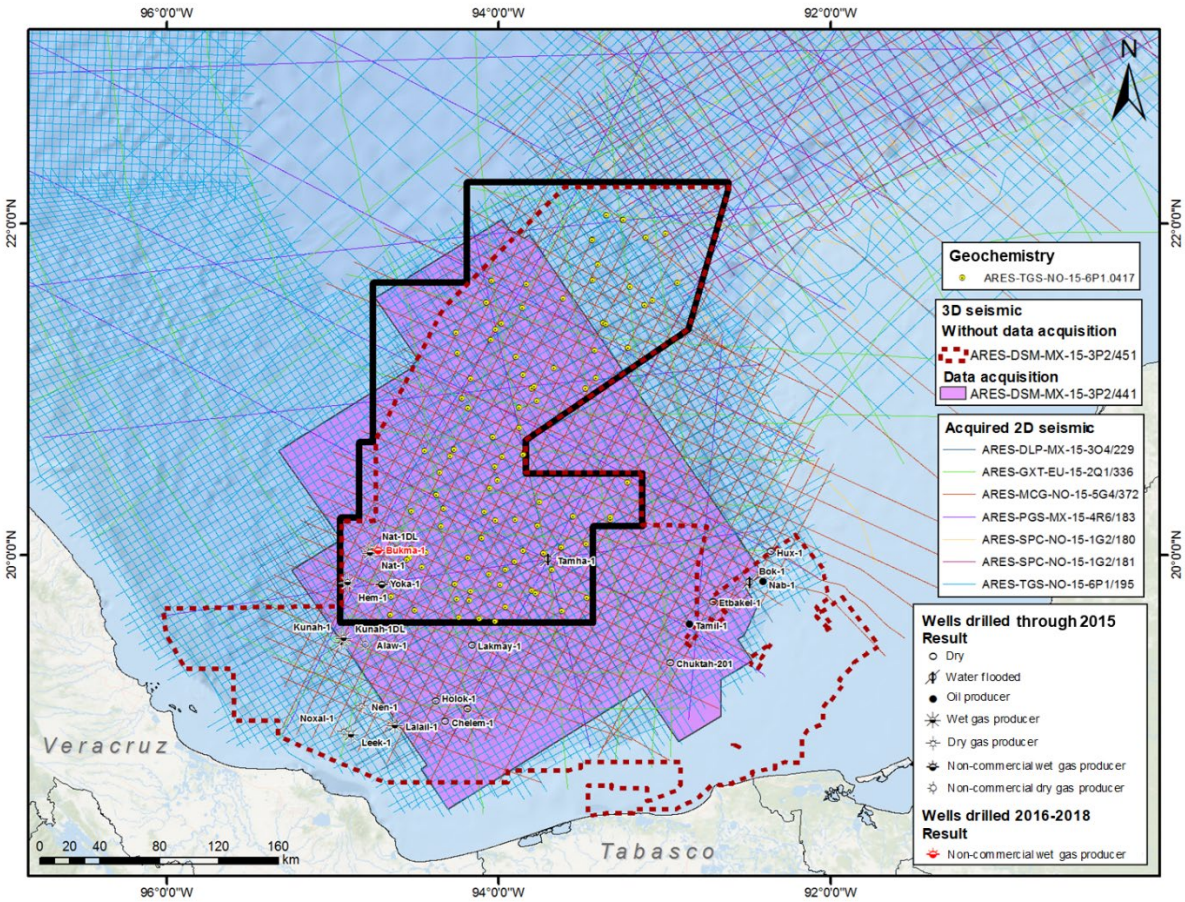


Figure 46. Map showing the main exploration information used in the central Saline Basin assessment, in terms of geochemical, seismic and well information.

8.4. ASSESSMENT AND INTERPRETATION OF EXPLORATION INFORMATION

8.4.1. Seismic interpretation

The information assessment and interpretation stage consisted of collecting, validating and analyzing all the available information for the central Saline Basin area, considering the geological-structural complexity in each sector and starting with regional seismic interpretation of the area, calibrating the interpretations with biostratigraphic data and well stratigraphic markers. The general process of horizons' interpretation began in areas with high confidence where there is the highest density of well information, generating tying sections and alternating correlations between inline and crossline sections in time or depth.

The selection of the most suitable seismic version for interpretation, considered the acquisition method and the processing type mainly, since those parameters control the seismic image quality, taking into account the fact that certain types of acquisition and processing, attenuate certain misleading patterns that are easily confused with real geology (seismic artifacts), as others can also be highlighted. When assessing exploration prospects, a detailed seismic interpretation is required, so the selection of the best available seismic information version is very important to obtain better results.

Since the deepwater Saline Basin is considered a complex salt tectonics area, time-migrated seismic versions have significant imaging limitations around and below salt bodies, since special velocities cannot be applied to salt bodies and seismic reflections do not locate correctly when refracting through salt. For this reason, the most appropriate seismic version to obtain an adequate image in areas with salt tectonics generally requires a depth migration before stacking or pre-stack depth migration seismic (PreSDM).

In PreSDM seismic, velocities of salt and of all geological horizons are assigned during processing (velocity model), for which it is necessary to determine salt bodies geometries of and boundaries between horizons. When working with prestack-depth-migrated data, one must be aware that an interpretation of a previous interpretation will be taking its place (Jackson and Hudec, 2017). In that sense, it is very important to corroborate with the help of well information, that each geological horizon in the velocity model is in its correct position in depth and also, consider the algorithm used for migration, one of the most critical aspects in seismic data processing.

The set of available seismic information in the deepwater Saline Basin consist mainly in PreSDM migrations through Kirchhoff and RTM (Reverse Time Migration) algorithms (Tables 19 and 22), which have advantages and disadvantages with regards to the process of seismic interpretation in areas with salt tectonics.

The Kirchhoff PreSDM migration typically preserves the seismic texture and amplitudes, allowing to generate high-quality images towards the top of salt bodies and sometimes also allows for the mapping of the base of salt bodies; this, as long as the geometry of these bodies is simple, as the technique does not allow handling of complicated velocity models and does not generate good image quality in complex salt tectonics areas.

On the other hand, PreSDM RTM migration allows the user to handle the wave equation in multiple paths, increasing the possibility of visualizing complex salt structures and visualizing the geological characteristics of areas around and below salt bodies. However, the seismic image generated by RTM migration is more sensitive to the used velocity model than in the Kirchhoff migration.

With that in mind, the regional seismic and exploration prospects interpretation in Perdido Area was conducted preferably on 2D and 3D PreSDM RTM seismic versions, prior review and validation of the corresponding velocity model. In certain areas without 3D seismic coverage but linear 2D seismic coverage, the same velocity model was generated and used to convert and adjust migrated versions in time to depth.

8.4.2. Petrophysical evaluation

Based on well logs, geological reports and documentation on core and core samples analysis from exploration wells in the deepwater Saline Basin, petrophysical evaluations were carried out with conventional techniques to determine the main characteristics of the plays assessed in the area. This analysis included the identification and evaluation of different lithologies throughout the logs, as well as the determination of cutoff petrophysical range values that are key in volumetric assessment of exploration prospects, such as porosity, water saturation, net thickness, etc.

Figure 47 shows an example of the petrophysical evaluations conducted in wells of deepwater Saline Basin, from well logs and core and core samples analysis.

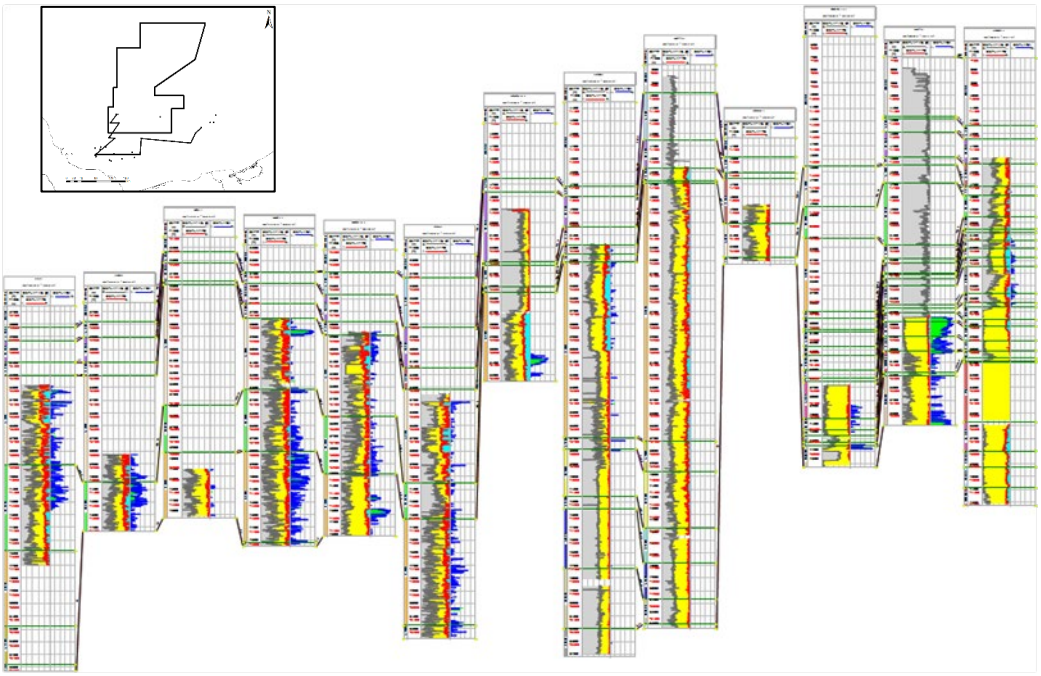


Figure 47. Example of the petrophysical evaluations performed in wells of deepwater Saline Basin, based on well logs,cores and core samples analysis.

8.4.3. Seismic attributes and sedimentary facies interpretation

Seismic attributes (including those considered as direct hydrocarbons indicators) were applied as a tool for interpretation of seismic data (section 3.2.3), looking to highlight variations in amplitude, phase and frequency of the acoustic signals, independently or in an integrated manner. These variations may have a correlation with geological, sedimentary and structural characteristics, which cannot be observed with the naked eye in conventional seismic images. In general, three types of seismic attributes were applied: instantaneous (mainly RMS or Root Mean Square, phase, frequency), geometric (dip/azimuth, coherence, curvature) and spectral (decomposition in frequency ranges).

Among the most used attributes in the analysis, RMS stands out with regards to trying to identify potential fluid content in reservoir rocks that can be hydrocarbons, of coherence to highlight discontinuities such as faults, channel edges and chaotic areas such as mass transport deposits and spectral decomposition to detect lithological changes by frequency content. The combination and use of seismic attributes in the area were key factors in the identification and delimitation of exploration prospects, in the identification of seismic facies and in GDE sedimentary maps construction (Gross Depositional Environment).

The stratigraphic interpretation of seismic profiles, well information calibration, geological horizons interpretation and the analogs documented for deepwater Saline Basin, allowed to generate the sedimentary facies interpretation for the assessed plays from seismic information.

8.4.4. Estimation of expected hydrocarbon type

This analysis consisted of compilation, integration and updating of the available information through the National Hydrocarbons Information Center (CNIH), which includes several of previous regional studies of basin analysis, petroleum systems, plays and geochemical analyzes done by Pemex and the Mexican Petroleum Institute (IMP) in the deepwater Saline Basin.

Additionally, the new geochemical information derived from ARES served to make updates of the expected hydrocarbon type; in this case, for the Upper Jurassic Tithonian source rocks and its situation as the main source rock interval of the area.

8.4.5. Identification and assessment of exploration prospects

As discussed in section 7.4.1, an important component of the available information are the historical databases of prospective resources, which served as an important reference for exploration prospects identification in the central Saline Basin area. Similarly, the information from the exploration plans of four Pemex entitlements and 11 awarded contracts to date within the assessed area (Figure 41), served as a reference for the analysis performed by the Commission for the identification of exploration prospects.

It is important to clarify that although the historical prospective resources databases and exploration plans serve as important references to know the vision about the potential of resources around the identified prospects, the assessment done by the Commission does not necessarily coincide to the reported assessment by the operators that are developing exploration activities in the area, especially in terms of the applied methodology, seismic interpretation around the prospects, number identified geological objectives, petrophysical and volumetric parameters, the expected hydrocarbon type, risk analysis for the estimation of the probability of geological success, estimation of the amount of prospective resources, among other factors.

The assessment of exploration prospects carried out by the Commission was done according to the methodology described in section 3.2, using homologous criteria and adopting the fundamental principles of evaluation and classification of resources of PRMS (Petroleum Resource Management System). For this reason, many of the prospects or leads and even geological objectives reported by the operators, were not considered by the Commission for the prospective resources assessment in exploration prospects.

Based on the analysis and interpretation of new seismic information available, on the 23 wells drilled to date, calibrations and adjustments made to determine the petrophysics and adjustments in the expected hydrocarbon type, as well as models and studies carried out by the Commission, a total of 104 exploration prospects with up to four geological objectives were identified and evaluated, where 19 correspond with new prospects identified, which are part of the prospect inventory assessed by the Commission in central Saline Basin.

In this way, the identified exploration prospects portfolio of in central Saline Basin, is an estimated total risked mean of 2,883 MMboe, a variation of -9% respect to the previous estimates.

Table 23 shows the exploration prospects prospective resources assessment update carried out by the Commission, in comparison to the estimate as of 2018. The graph in Figure 48 shows the distribution by main expected hydrocarbon type, according to the assessment update carried out by the Commission, regarding the identified exploration prospects.

Table 23. Update of exploration prospects prospective resources assessment carried out by the Commission, compared to the estimate as of 2018

Prospective resources update of identified exploration prospects					
Category	**Prospective Resources P90 (MMboe)**	**Prospective Resources P50 (MMboe)**	**Prospective Resources mean (MMboe)**	**Prospective Resources P10 (MMboe)**	**Prospective Resources risked mean (MMboe)**
Estimate as of 2018	2,552	9,277	**13,551**	31,093	**3,184**
Update	**3,107**	**10,229**	**11,587**	**21,668**	**2,883**
Difference	555	952	**-1,964**	-9,425	**-301**
Difference (%)	22%	10%	**-14%**	-30%	**-9%**

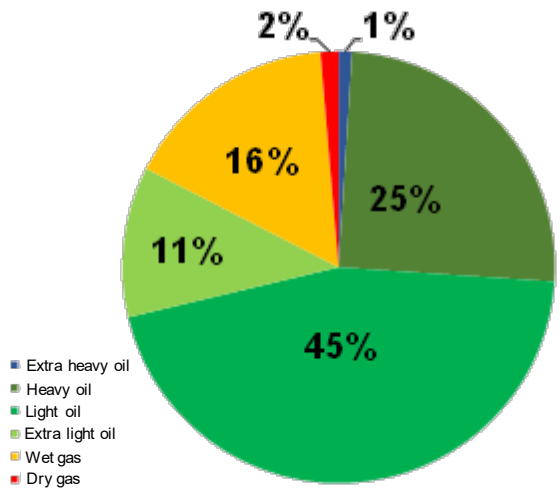


Figure 48. Distribution by main expected hydrocarbon type, according to the assessment update carried out by the Commission, regarding the identified exploration prospects.

8.5. CENTRAL SALINE BASIN PLAYS ASSESSMENT

Central Saline Basin plays are postulated based on current knowledge and the integration and analysis of seismic information, regional studies, well information and analogs. Section 7.3.5 describes the main characteristics of the delimited and defined plays within the assessed area and Table 18 of section 7.3.5 shows the summary of their main characteristics.

The prospective resource assessment at the play level is based on probabilistic methods, considering the mapped and unmapped prospects as a total in a play, where the input information for the estimate is a distribution of the volume of identified prospects, a number of additional prospects that could occur in the play and an average probability of success. The volumetric assessment at the play level, comes from the construction of a probability density function derived from all of the geological objectives of exploration prospects that belong to the corresponding play, considering recoverable volumes and the discoveries characteristics within a play at a certain date.

The applied methodology for the assessment at play level is described in section 3.3. According to the play fairway analysis done in central Saline Basin, five plays represented by the stratigraphic horizon containing the potential reservoir rocks were defined, and

based on this analysis, generalized play maps were developed to interpret the extension of the five assessed plays.

Figures 49 to 53 show schematically the interpreted extension for Upper Jurassic, Cretaceous fractured, Upper Cretaceous breccia, Paleocene and Neogene plays; respectively in central Saline Basin, identifying in an illustrative way the areas where it is inferred that the play may exist but it is not possible to visualize prospects, mainly due to the geological complexity of the area associated with salt tectonics and poor quality of seismic image. Also, allochthonous salt extent is indicated schematically and where the absence of the play is interpreted.

The graph in each figure shows the estimation curves of prospective resource volumes for the assessed plays, representing the identified and unidentified prospects (total prospective resource) estimates. The estimated total prospective resources in each assessed play reflect the exploration potential related to the current knowledge and the available information at a certain date, so that the progress in exploration activities that provide new information, will generate adjustments in the estimates and in the total prospective resources assessment.

In the case of Upper Jurassic play, to date there are no wells that have established the play in the deepwater Saline Basin; however, it is postulated as hypothetical based on several analog wells from Southeast Basins in shallow water.

In the case of Cretaceous and Cenozoic plays, to date, 11 exploration wells have established the Neogene; which include the most important Miocene discoveries made in Saline Basin, one in the Paleogene, one in the Upper Cretaceous breccia and one in Cretaceous fractured. Each indicative map of the interpreted play extension within the assessed area, shows the result of these wells within their corresponding play and the schematic extension of discoveries, including non-commercial accumulations or in which case, exploration wells that were water flooded or dry.

Table 24 shows the total prospective resources assessment update in plays done by the Commission, in comparison with estimates as of 2018.

Table 24. Prospective resources assessment update in plays done by the Commission, compared to the estimates as of 2018

Prospective resources assessment in plays				
Assessed plays as of 2018	**Prospective resources P90 (MMboe)**	**Prospective resources P50 (MMboe)**	**Prospective resources mean (MMboe)**	**Prospective resources P10 (MMboe)**
RM GPGMB E Neogene	580	1,354	1,475	2,542
RM GPGMB H Paleogene	124	370	415	899
RM GPGMB E Upper Cretaceous breccia	34	127	183	421
RM GPGMB E Cretaceous fractured	270	688	745	1,298
RM GPGMB H Upper Jurassic	259	705	809	1,504
RN GPGMS H Neogene	253	628	733	1,423
RN GPGMS H Paleogene	125	209	147	236
RN GPGMS H Mesozoic	282	623	651	1,087
TOTAL	**1,928**	**4,703**	**5,158**	**9,411**
2019 Update				
GP CS E Neogene	460	1,351	1,553	3,901
GP CS E Paleogene	246	860	1,021	2,998
GP CS E Cretaceous fractured	298	1,040	1,243	3,627
GP CS E Upper Cretaceous breccia	28	110	133	431
GP CS H Upper Jurassic	50	232	287	1,073
TOTAL	**1,082**	**3,593**	**4,237**	**12,030**
DIFFERENCE	-846	-1,110	-921	2,619
DIFFERENCE (%)	-44%	-24%	-18%	28%

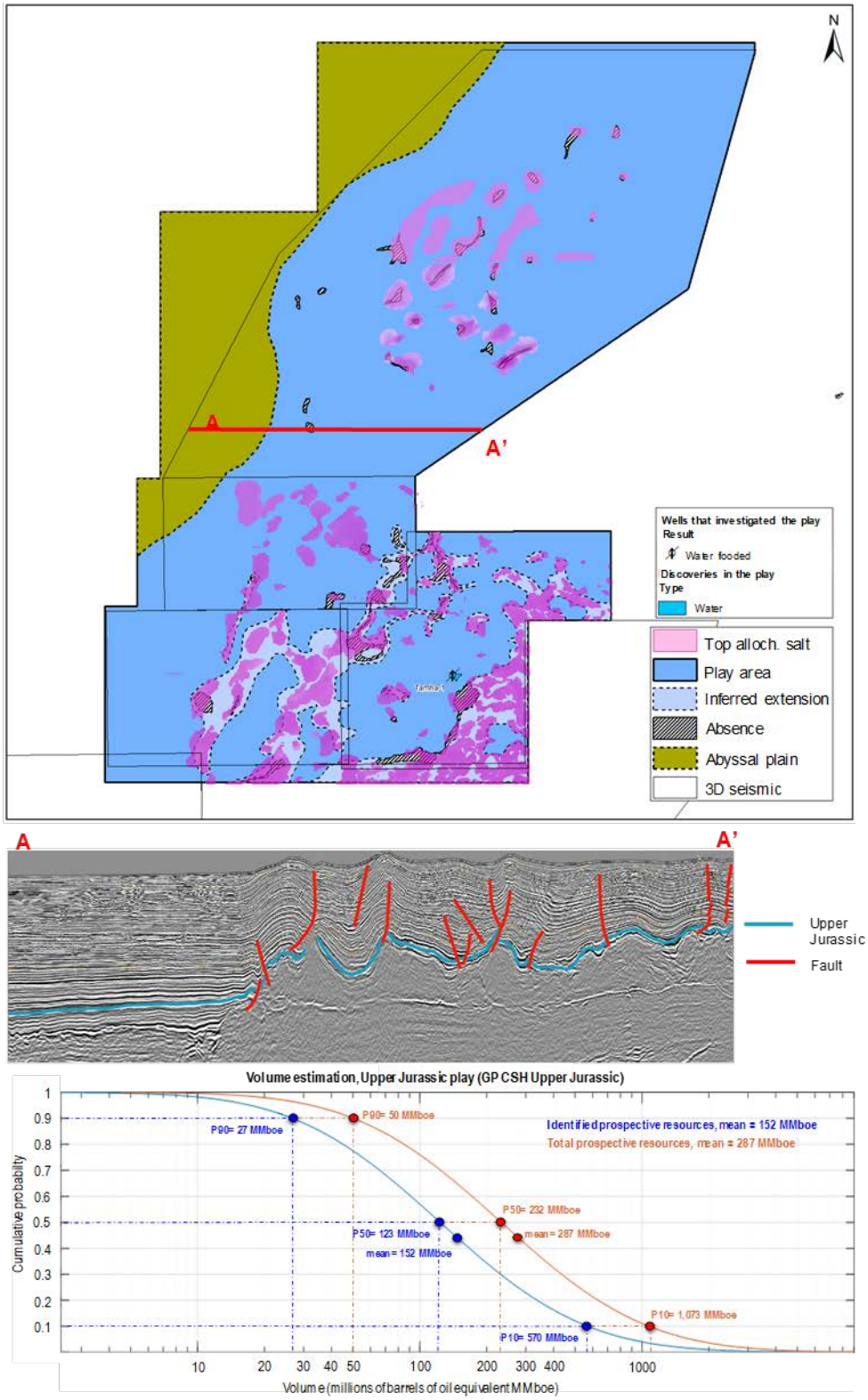


Figure 49. Map that schematically shows Upper Jurassic play distribution in the central Saline Basin, the seismic section exemplifies the areas where the play is inferred but it is not possible to visualize prospects and where the absence of the play is interpreted, in this case, mainly due to salt intrusions. The graph shows the probabilistic prospective resource assessment in terms of identified prospects volume and the total play volume.

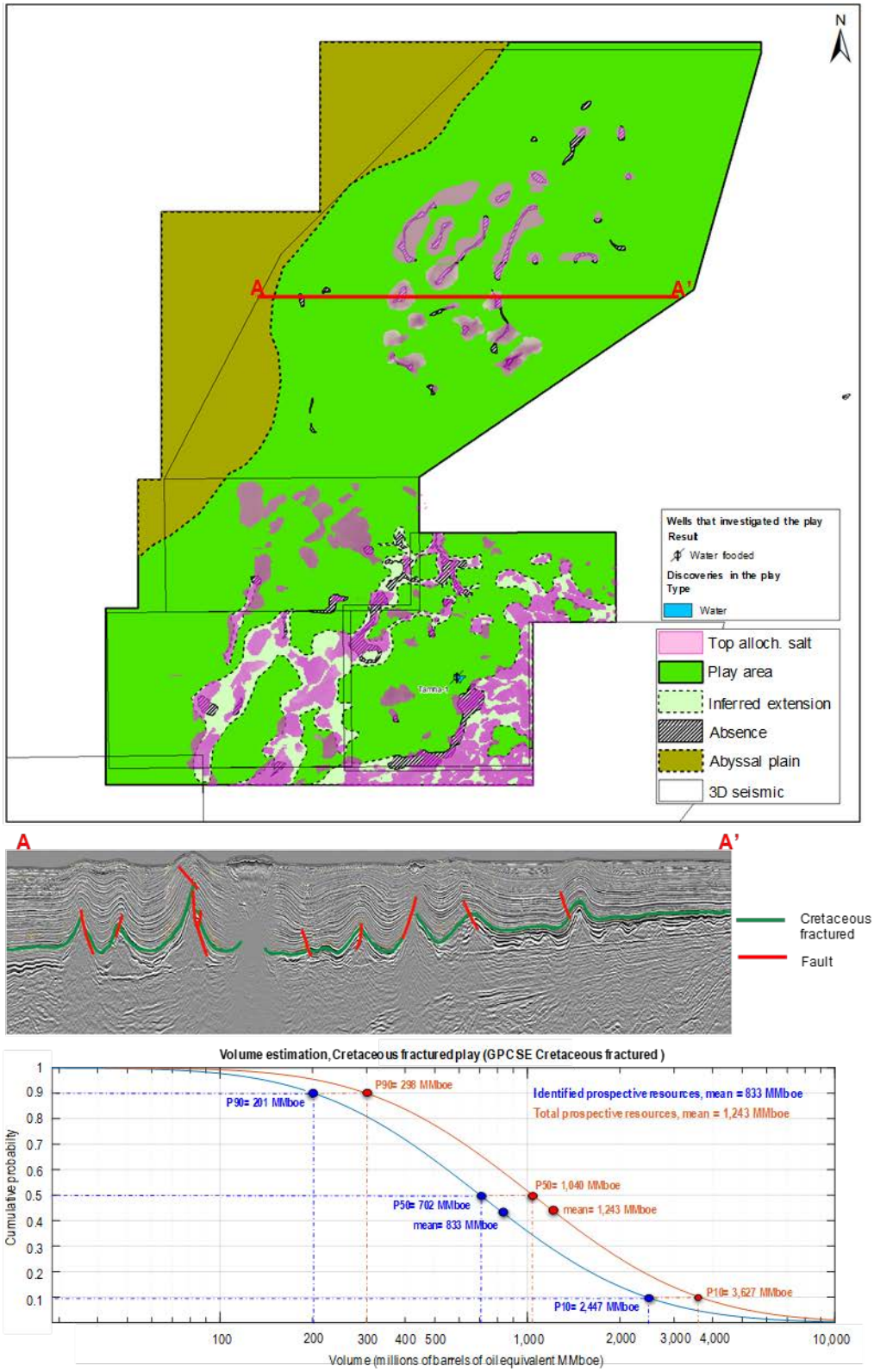


Figure 50. Map that schematically shows Cretaceous fractured play distribution in the central Saline Basin, the seismic section exemplifies the areas where the play is inferred but it is not possible to visualize prospects and where the absence of the play is interpreted, in this case, mainly due to salt intrusions and faults displacement. The graph shows the probabilistic prospective resource assessment, in terms of identified prospects volume and the total play volume.

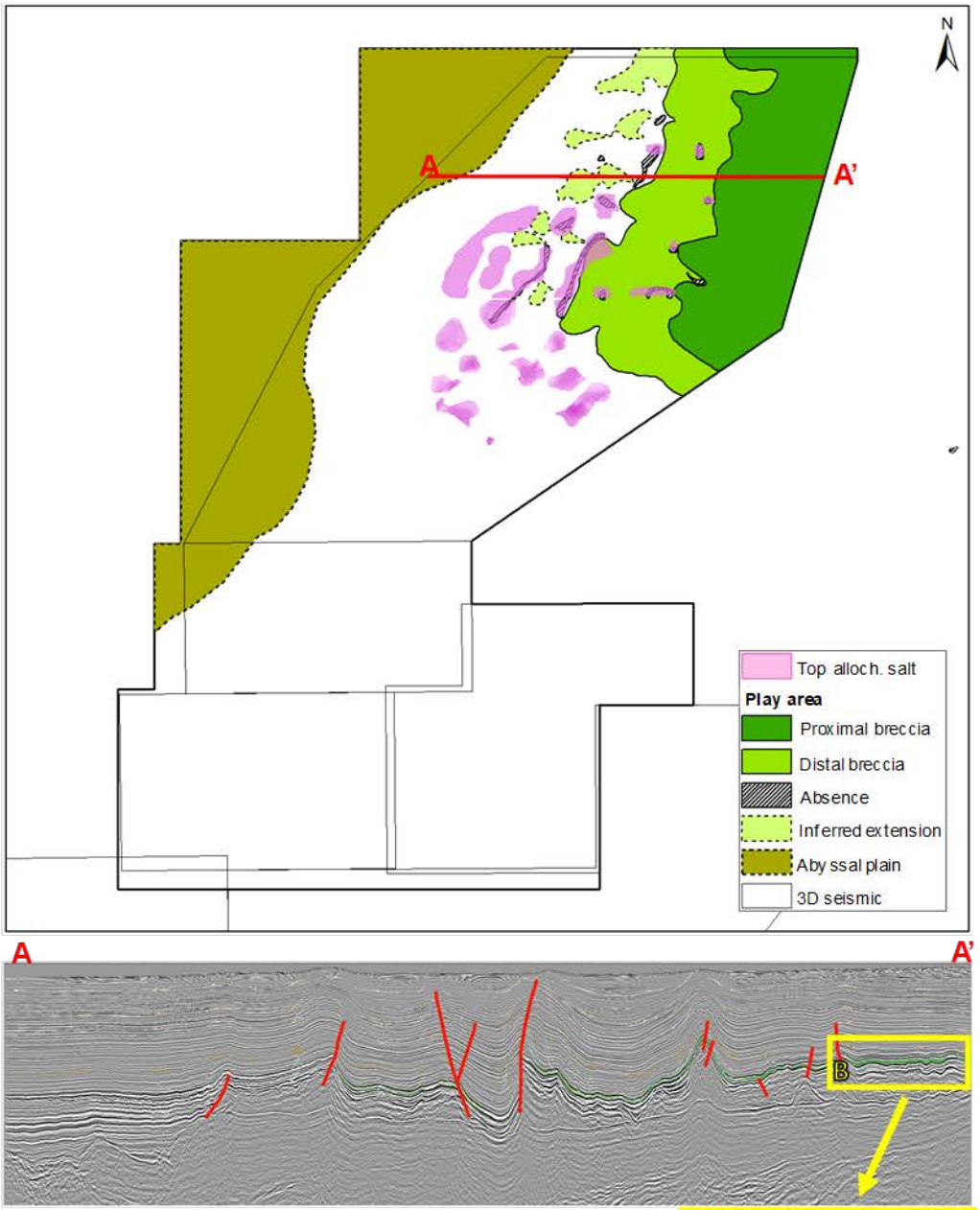
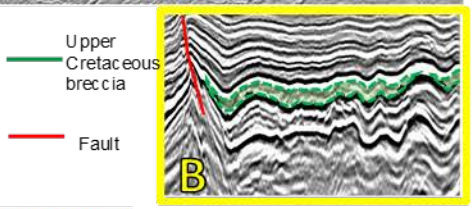
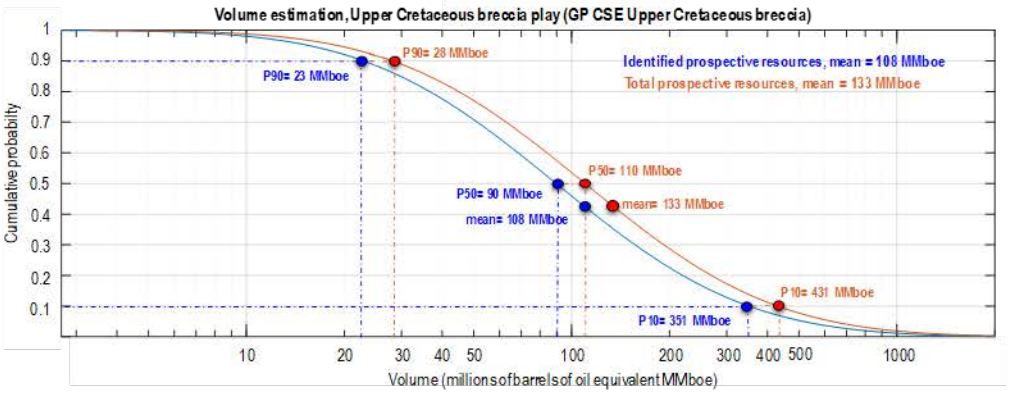


Figure 51. Map that schematically shows Upper Cretaceous breccia play distribution in the central Saline Basin, the seismic section exemplifies the areas where the play is inferred but it is not possible to visualize prospects and where the absence of the play is interpreted, in this case, mainly due to salt intrusions and faults displacement. The graph shows the probabilistic prospective resource assessment, in terms of identified prospects volume and the total play volume.





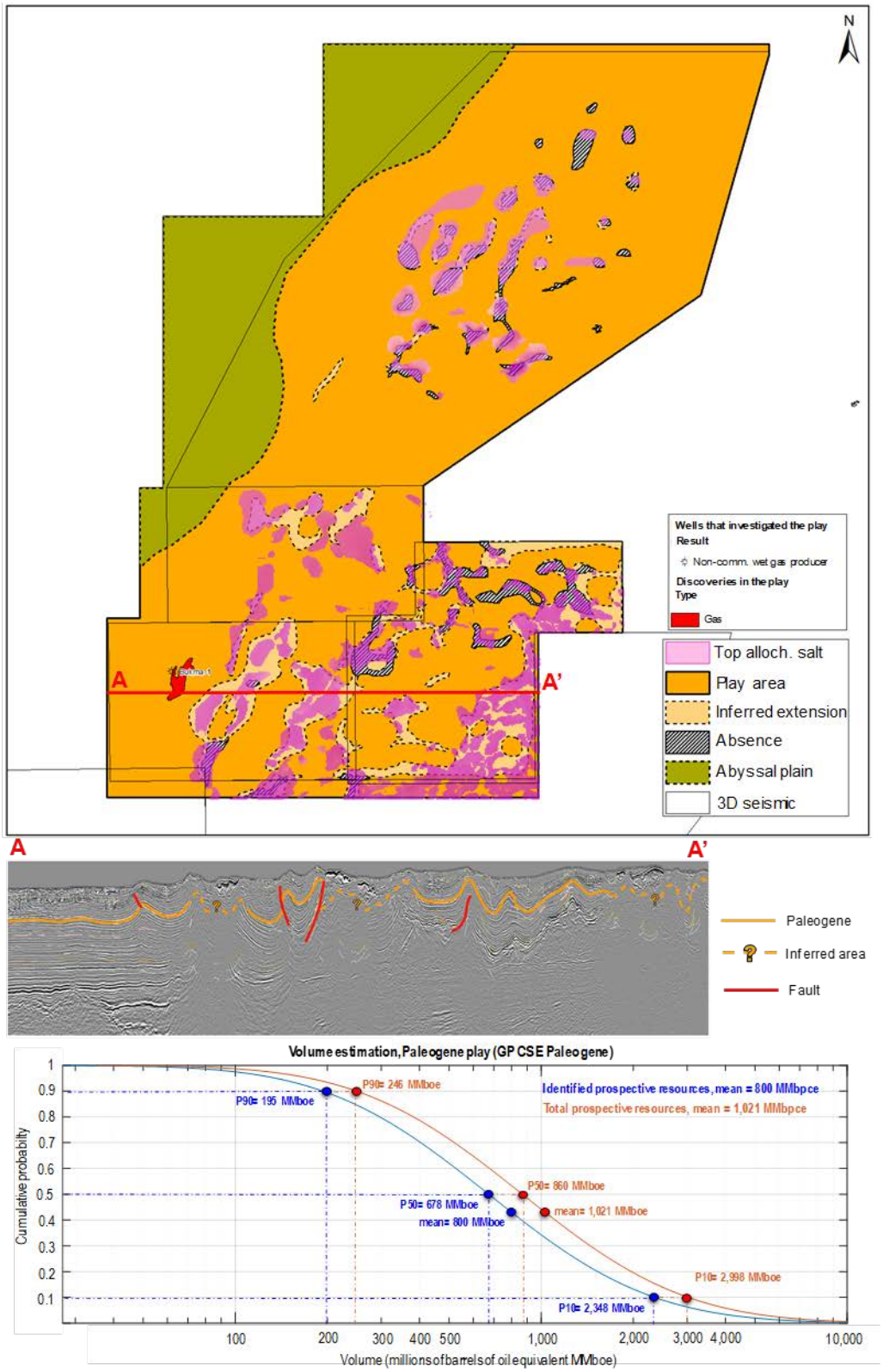


Figure 52. Map that schematically shows Paleocene play distribution in the central Saline Basin, the seismic section exemplifies the areas where the play is inferred but it is not possible to visualize prospects and where the absence of the play is interpreted, in this case, mainly due to salt intrusions. The graph shows the probabilistic prospective resource assessment, in terms of identified prospects volume and the total play volume.

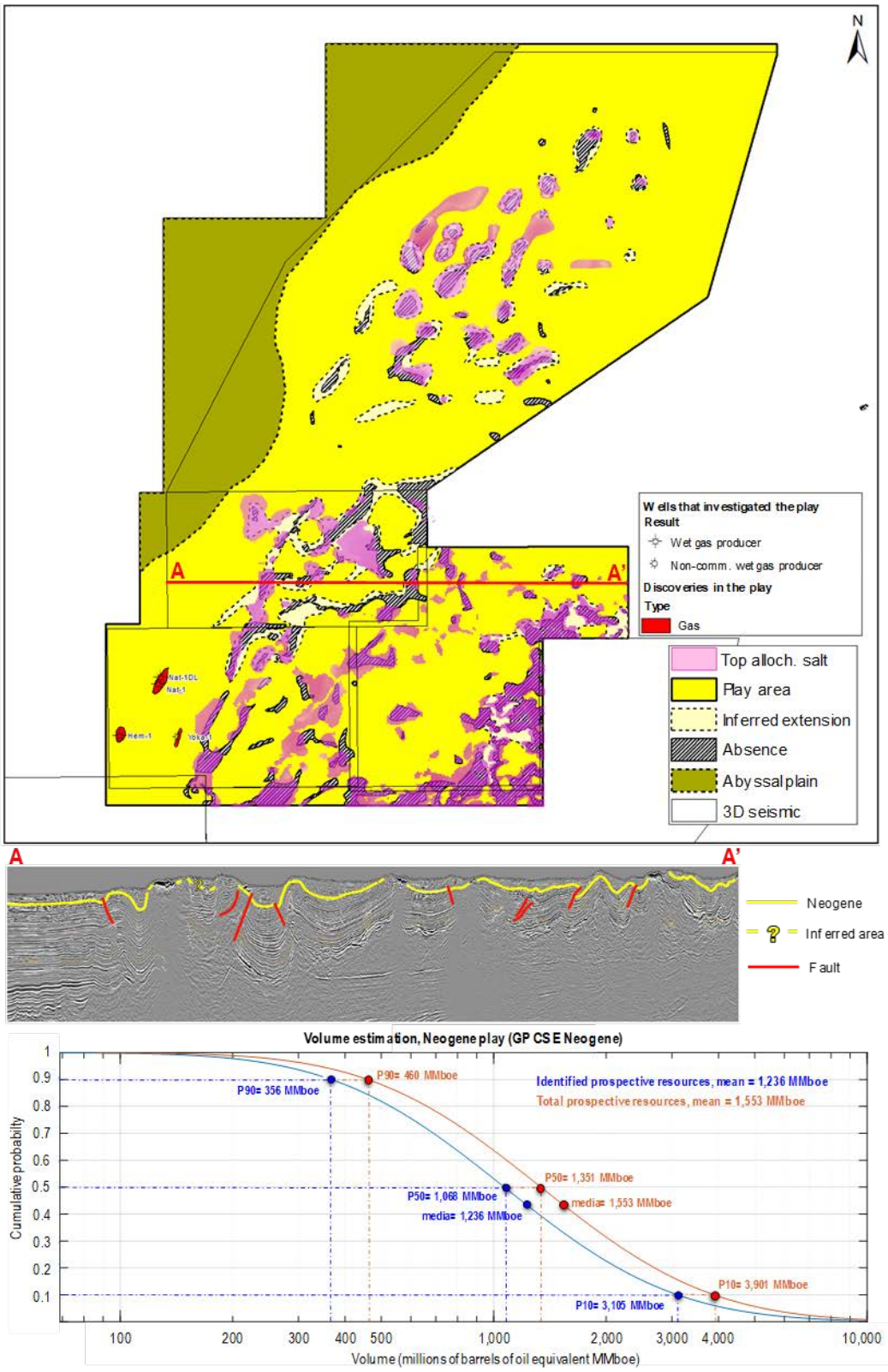


Figure 53. Map that schematically shows Neogene play distribution in the central Saline Basin, the seismic section exemplifies the areas where the play is inferred but it is not possible to visualize prospects and where the absence of the play is interpreted, in this case, mainly due to salt intrusions. The graph shows the probabilistic prospective resource assessment, in terms of identified prospects volume and the total play volume.

9. PROSPECTIVE RESOURCES UPDATE

The sum of prospective resources of each of the 14 plays identified within the assessment polygons in the Perdido Area, northern Mexican Ridges and central Saline Basin, results in the total prospective resource in these areas, considering the mean value as the best estimate. Quantification update of prospective resources done in this first stage is a risked estimate of the potential remaining quantity of recoverable hydrocarbons not yet discovered within the surface of the assessed areas.

Plays' delimitation in the surface of the three assessed areas corresponds to portions of a geological play that has been subdivided, due to convenience issues for the updating and due to the combination of administrative factors regarding water depth, international border limits and to technical factors related to exploration information coverage and morpho-structural styles.

The applied methodology for prospective resources assessment updating (section 3) is compatible with that used for the previous assessment, so the estimated prospective resources volumes in the areas where the assessment updating were performed are comparable both with the previous evaluation, as well as with the areas to be assessed in subsequent stages and in the context of the total conventional prospective resources.

The prospective resources assessment updating of the countrycarried out by the National Hydrocarbons Commission will be developed at different stages. In this first stage, the assessment and quantification of prospective resources of the Perdido Area, the northern portion of Mexican Ridges and the central portion of Saline Basin are updated, all located in deepwater Gulf of Mexico.

In that sense, consolidation of prospective resources quantification of the country will consist of updates conducted by the National Hydrocarbons Commission and those made by operators including their own updates, in compliance with the applicable regulations.

8.1. DEEPWATER PROSPECTIVE RESOURCES UPDATE

As discussed in section 4, as of 2018 deepwater conventional prospective resources in the Gulf of Mexico mean 27,835 million barrels of oil equivalent (MMboe); that is, approximately 53% of the total conventional prospective resources of the country. This quantification corresponds to 11 different plays previously defined in deepwater.

In this first stage of prospective resources assessment updating carried out by the Commission in a total area of approximately 126,830 km^2, the assessment has been regrouped in 14 plays corresponding to the Perdido Area, the northern portion of Mexican Ridges and the central portion of deepwater Saline Basin. The progress of exploration activities, mainly in terms of drilling new deepwater exploration wells, the new information derived from ARES program and the conducted analysis, allows for the updating of estimates of prospective resources in deepwater Gulf of Mexico.

According to the prospective resources balance done in the three assessed areas, the update of prospective resources estimates amounts to a total of 12,922 MMboe as the mean value, representing an adjustment of -23% respect to the 2018 estimate. Table 25

shows the comparison of the 2018 prospective resources estimate and the update made in this first stage.

Table 25. Comparison of 2018 prospective resources estimate and the update made in the three assessed areas, in terms of prospective resources identified through exploration prospects and the total estimate at play level.

Prospective resources assessment as of 2018									
Assessed areas in deepwater Gulf of Mexico	Identified prospective resources (MMboe)					Total prospective resources (MMboe)			
	P90	P50	Mean	P10	Risked mean	P90	P50	Mean	P10
Perdido Area	3,420	11,104	15,502	34,430	4,902	4,130	8,373	8,946	16,588
northern Mexican Ridges	1,103	5,987	11,586	29,948	2,293	815	2,054	2,724	5,949
central Saline Basin	2,552	9,277	13,551	31,093	3,184	1,928	4,703	5,158	9,411
Total	**7,075**	**26,368**	**40,639**	**95,471**	**10,379**	**6,873**	**15,130**	**16,828**	**31,948**
2019 Update									
Assessed areas in deepwater Gulf of Mexico	Identified prospective resources (MMboe)					Total prospective resources (MMboe)			
	P90	P50	Mean	P10	Risked mean	P90	P50	Mean	P10
Perdido Area	3,962	11,827	13,583	25,436	4,063	2,339	5,261	6,194	12,132
northern Mexican Ridges	2,135	7,419	11,960	28,215	1,916	420	1,569	2,491	5,931
central Saline Basin	3,107	10,229	11,587	21,668	2,883	1,082	3,593	4,237	12,030
Total	**9,204**	**29,475**	**37,130**	**75,319**	**8,862**	**3,841**	**10,423**	**12,922**	**30,093**

This update represents an adjustment of prospective resources estimates in the entire Gulf of Mexico deepwater region. According to the update made in this first stage for the three assessed areas, the total consolidation of prospective resources in deepwater, which is complemented by the previous estimate for the rest of the deepwater area, amounts to 23,929 MMboe as the mean value, which represents -14% variation respect to the 2018 estimate (Table 26).

Table 26. Total prospective resources estimates in deepwater Gulf of Mexico comparison, as of 2018 estimate and the 2019 update.

Prospective resources estimates in deepwater Gulf of Mexico	Prospective resources P90 (MMboe)	Prospective resources P50 (MMboe)	Prospective resources mean (MMboe)	Prospective resources P10 (MMboe)
Estimate as of 2018	11,462	25,393	27,835	47,452
2019 Update	8,430	20,686	23,929	45,596
Variation	-26%	-19%	-14%	-4%

8.2. MEXICO PROSPECTIVE RESOURCES UPDATE

As of 2018, total conventional prospective resources of the country amount to 52.6 billion barrels of oil equivalent (Bboe); that is, approximately 45% of the total prospective resources of the country.

In this first updating stage of prospective resources estimate carried out by the Commission, in a total surface area of 126,830 km^2 in deepwater Gulf of Mexico and as a complement to the previous estimate, the total conventional prospective resources of the country amount to 48,723 MMboe, where the deepwater region of Gulf of Mexico now represents 49% of total conventional resources of the country. Table 27 shows the balance of total conventional prospective resources of the country, in the context of the Petroleum Provinces of Mexico.

Considering the mean value as the best estimate and the technically recoverable resources for unconventional plays, the 2018 assessment was distributed in the Upper Jurassic Tithonian and Upper Cretaceous Turonian plays, whose prospective resources estimates of amounted to a total of 60,204 MMboe.

Within Pemex entitlement areas, an update has been made in the unconventional prospective resources estimation due to the development of hydrocarbons exploration and extraction activities, through the regional assessment of a new unconventional play corresponding to the Upper Jurassic Oxfordian in the Tampico-Misantla province. According to the information submitted to the Commission regarding the assessment of this play and its resources estimate, the play is mainly prospective for oil with mean prospective resources of 4,020 MMboe.

Based on this update, the unconventional prospective resources of the country are now related to Upper Jurassic Oxfordian, Upper Jurassic Tithonian and Upper Cretaceous Turonian plays, which result in a total of 64,224 MMboe.

Table 28 shows the conventional and unconventional prospective resources estimates according to the Petroleum Province, considering the mean value as the best estimate, while Figure 54 shows its distribution by main expected hydrocarbon type.

Table 27. Update of the total conventional prospective resources estimate of Mexico

Petroleum Province	Prospective resources P90 (MMboe)	Prospective resources P50 (MMboe)	Prospective resources mean (MMboe)	Prospective resources P10 (MMboe)	Percentage with respect to the mean value
Deepwater Gulf of Mexico	8,430	20,686	23,929	45,596	49%
Southeast Basins	8,227	13,710	14,466	21,697	30%
Burgos	1,436	2,916	3,204	5,400	7%
Tampico-Misantla	881	2,077	2,347	4,167	5%
Yucatan Platform	408	1,431	1,778	3,607	4%
Veracruz	726	1,337	1,432	2,261	3%
Chiapas foldbelt	428	1,045	1,172	2,079	2%
Sabinas-Burro Picachos	130	344	395	733	1%
Total Conventional Prospective Resources	**20,666**	**43,547**	**48,723**	**85,539**	**100%**

Table 28. Update of the total conventional and unconventional prospective resources estimates of Mexico, considering the mean value as the best estimate.

Petroleum Province	Total Conventional Prospective Resources, Mean (MMboe)	Total Unconventional Technically Recoverable Prospective Resources, Mean (MMboe)
Deepwater Gulf of Mexico	23,929	-
Southeast Basins	14,466	-
Burgos	3,204	10,770
Tampico-Misantla	2,347	38,942
Yucatan Platform	1,778	-
Veracruz	1,432	563
Chiapas foldbelt	1,172	-
Sabinas-Burro Picachos	395	13,950
Total Prospective Resources	**48,723**	**64,224**

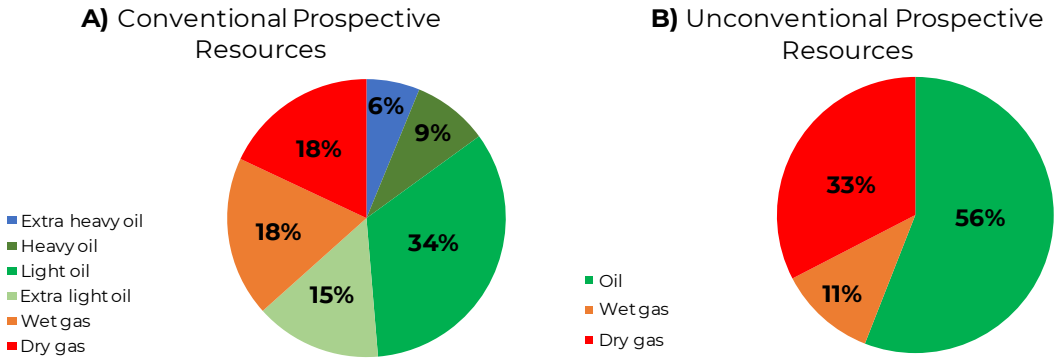


Figure 54. Distribution of conventional (A) and unconventional (B) prospective resources by main expected hydrocarbon type.

10. FINAL REMARKS AND NEXT STAGES

The assessment and quantification of prospective resources; that is, the volumetric estimation of the amounts of undiscovered hydrocarbons and their risk and uncertainty analysis, requires knowledge and understanding of petroleum systems in a sedimentary basin, where a reference framework implementation based on plays analysis allows one to assess, quantify and classify areas with petroleum potential, as well as distribution of the associated volumes, their risk level and uncertainty.

Explorers select basins, specific areas or certain geological trends to focus hydrocarbon exploration, where the development of oil and gas exploration activities and associated investment are characterized by high risk and uncertainty, which can be reduced but not eliminated through different technologies, studies, models and analysis of predictive nature. Considering that prospective resources are the amounts of potentially recoverable hydrocarbons at a certain date from undiscovered accumulations (SPE, 2018), there is no certainty that hydrocarbons will be discovered, when drilling is determined of exploration wells and if some accumulation is discovered, there is no guarantee that its development and production will be commercially viable at any moment in the quantitative estimation of these resources.

In that sense, the update of prospective resources estimates conducted in this first stage, in complement the previous estimate of prospective resources, is a risked estimate of the potential amount of remaining recoverable hydrocarbons not yet discovered within the three assessed areas which is highly uncertain, as the previous estimate is. Any quantitative estimation of prospective resources has limitations and its updating is necessary as new information is generated from the progress in exploration and production activities, by the emergence of new plays or by mature plays' revitalization, through technological advance and new concepts' application.

However, despite risk and uncertainty, the quantitative estimation of prospective resources is a fundamental guide for investment opportunities evaluation, in designing medium- and long-term energy policy strategies for the development of the hydrocarbons industry in a region, in the technological and capital needs' assessment, as well as for planning hydrocarbons' future supply. For this reason, several government agencies and institutions, as well as hydrocarbons exploration and production operators, tend to develop and implement their own methodologies, criteria and protocols to assess and estimate prospective resources.

There are different methodologies and techniques used for estimating prospective resources (e.g. Table 1 of section 3.3), whose main differences consist of the amount of available information for the assessment, the level of analysis, the different assumptions on which methods are based, the available tools and the goal to be achieved with the assessment; so, it cannot be judged if any particular methodology stands out above the others. However, something in common among the most used methods, is to quantitatively communicate the assessment results through a range of values with occurrence probabilities (probability of geological success) and in this case, using the PRMS (Petroleum Resource Management System) resources' classification as an international standard reference.

In this first stage of prospective resources' estimation update in three deepwater areas, the main components of the assessment are the information from 198 documented

exploration prospects (Tables 9, 15 and 24) and the analysis of 14 plays (Tables 10, 16 and 25) distributed over a total area of approximately 126,830 km^2.

Exploration prospects were interpreted and assessed internally according to the methodology described in section 3.2, using homogeneous criteria and adopting the fundamental principles for resource evaluation and classification of PRMS. Additionally, plays were assessed under the Total Petroleum System concept (Magoon and Schmocker, 2000) to include within a defined geographical extension, discovered accumulations, accumulations not yet discovered but potentially identified by exploration prospects, and remaining accumulations that are estimated to be still not identified and discovered.

The prospective resources assessment at play level was performed at lifetime; that is, without a timeframe limit based on exploration information and available studies, as well as the characteristics and recoverable volume of discovered reservoirs belonging to a play at a certain date. The results of the estimation of prospective resources constitute a comparative measure of the total amounts of estimated hydrocarbons that could exist in certain areas and do not imply a discovery or future production rate within a specific period of time.

The most important input for prospective resources' assessment at play level, in addition to identified exploration prospects, was the play fairway analysis, estimating a number of potential prospects that have not been visualized but are supported by the geological model of the play and a probability of geological success; where volume estimation related to a number of prospects not yet visualized, this was done through a stochastic simulation.

For the update of prospective resources' estimate, a significant volume of information was compiled, analyzed and interpreted, which included previous studies available at the National Hydrocarbons Information Center (CNIH), well information and the new exploration information generated by the ARES program, as well as the analysis, interpretation and studies conducted by the Commission.

Also, another important component of the available information are the historical prospective resources databases, which together with the information of exploration plans of Pemex entitlements and of the awarded contracts to date around the assessed areas, served as a reference for the analysis conducted by the Commission, especially in the exploration prospects identification.

In addition to the update of prospective resources estimate, this assessment and publication of the technical document is done with the following goals:

1. To make transparent and disclose the methodology used to assess and estimate the prospective resources of hydrocarbons in Mexico, aligned with methodologies and techniques that have been proved and applied internationally.

2. To promote knowledge of the Mexican subsoil, the petroleum potential assessment and contribute to the development of the hydrocarbons industry in Mexico, encouraging reserves incorporation and future production, based on prospective resources analysis.

3. By updating the prospective resources estimate, contribute to the medium- and long-term energy policy planning of the country, supporting the correct selection

of areas to develop hydrocarbons' exploration and production activities, as well as the value maximization of contractual areas for the Five-Year Plan, in benefit of the development of the hydrocarbons' sector and the economic growth of the country.

4. To promote the participation of oil and gas operators with different operating profiles, financial capabilities and tolerance to risk, focusing their interest in deepwater strategic areas that require technology and investment for their development.

5. To complement the technical-geological context of exploration activities currently under development in deepwater, as well as a reference framework for potential new participants, allowing them to have a quantitative view of the petroleum potential of the country.

Another important objective of the update of prospective resources estimate done in this first stage in deepwater, has to do with exploration prospects documentation and their eventual drilling within the framework of the corresponding exploration plans and authorizations for well drilling. Considering that exploration prospects documentation, constitutes a geological-geophysical support of prospective resources estimated volumes, the follow-up until drilling and results will allow calibrating volume and risk estimates, which will lead to prospective resources estimates with less uncertainty in the future.

To 2018, the geological success of deepwater exploration drilling in Mexico is 64% (Figure 55 A); that is, the well percentage with respect to the total wells drilled, where mobile hydrocarbons have been found in some of their geological objectives and independently of their commerciality. Also, considering recoverable volumes for those discoveries with available information (24 out of a total of 33), the total discovered volume is currently 58% respect to the total mean forecasted volume; where it seems that deepwater exploration has been dominated by oil expectation (Figure 55 B).

Generally speaking, considering volume mean values as the best estimate and independently of geological risk, there is a tendency to overestimate prospective resources volume especially for the oil case, where it was expected to find 65% more of the volume currently discovered. Those prospects with a mean volume greater than 200 MMboe, presented greater uncertainty in the estimates and with some exceptions, a discovered volume significantly lower than the initially forecasted (Figure 55 C).

It is difficult to establish a direct link between historical prospective resources estimates, geological risk and discovered hydrocarbon volumes as exploration drilling progress; since in fact, exploration is a dynamic activity of high risk and uncertainty.

The exploration prospects information together with discoveries size to estimate the total volume of prospective resources in a given area, has a direct impact on final volumetric estimates. The adjustment in exploration prospects assessment based on wells results and discovered volumes, together with new exploration information acquisition, led to adjustments in the total prospective resources estimate, in congruence with the result of recent exploration activity around the assessed areas in this first stage.

Any prospective resources estimate and the different methods to quantify them, represent an important effort to attempt to quantify a value that will not be known reliably until the resource is practically depleted. As such, estimates are just that:

estimates, so they should be used as general indicators and not as absolute volumetric predictions.

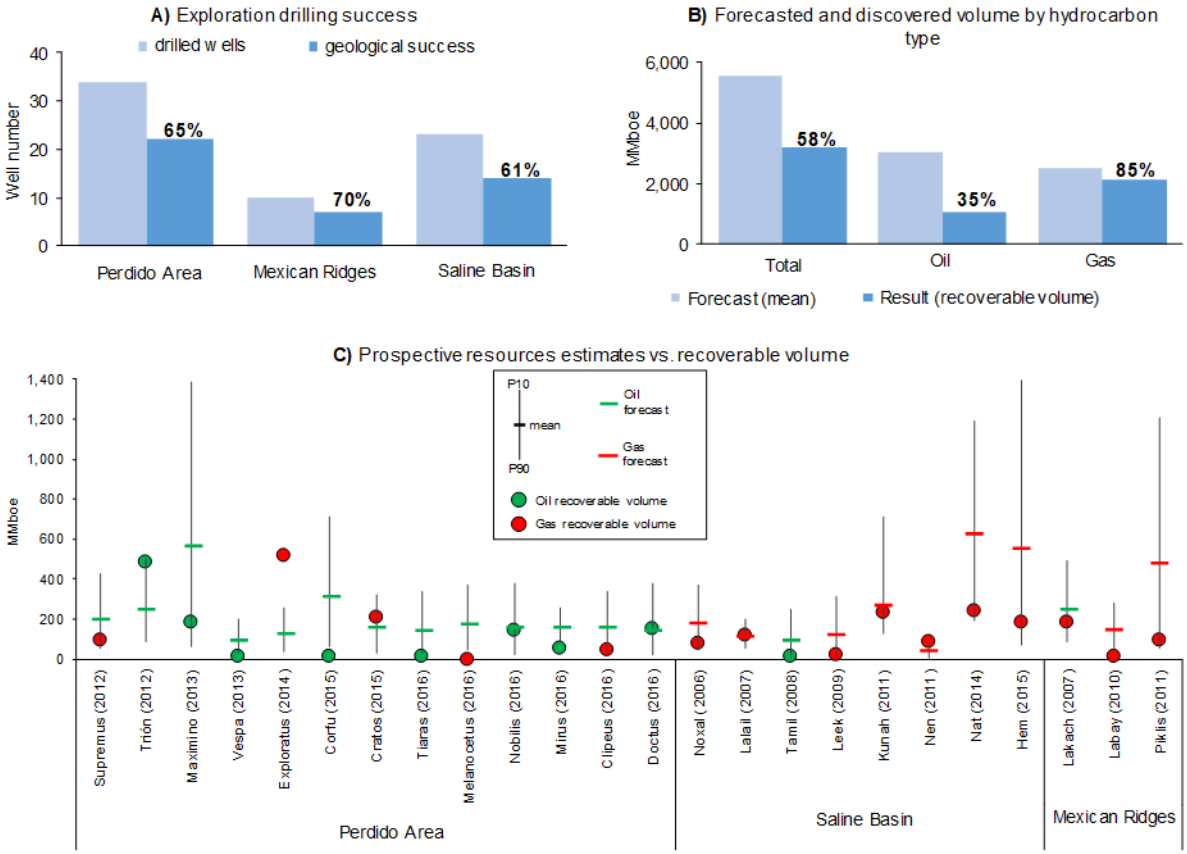


Figure 55. Graphs showing the current state of deepwater exploration in the Gulf of Mexico, showing comparatively exploration drilling success or the percentage of wells that found mobile hydrocarbons in any of their geological objectives with respect to the total drilled (A), the forecasted mean volume compared to the recoverable discovered volume reported by main hydrocarbon type (B) and a comparison of probabilistic estimates of prospective resources and volumes discovered by main type of hydrocarbon in wells (C). For B) and C), recoverable volumes of discoveries with available information are considered only.

In the next and second stage, prospective resources estimation will be updated in complementary deepwater areas to those assessed in this first stage, in the southern Mexican Ridges and in the southern Saline Basin, with an additional total surface area of approximately 76,930 km^2 (Figure 56). Likewise, the corresponding updates will be conducted in complement to the previous estimate, with the development of ongoing oil and gas exploration and production activities and their follow-up, mainly due to drilling and results of exploration wells, as well as new information derived from the ARES program.

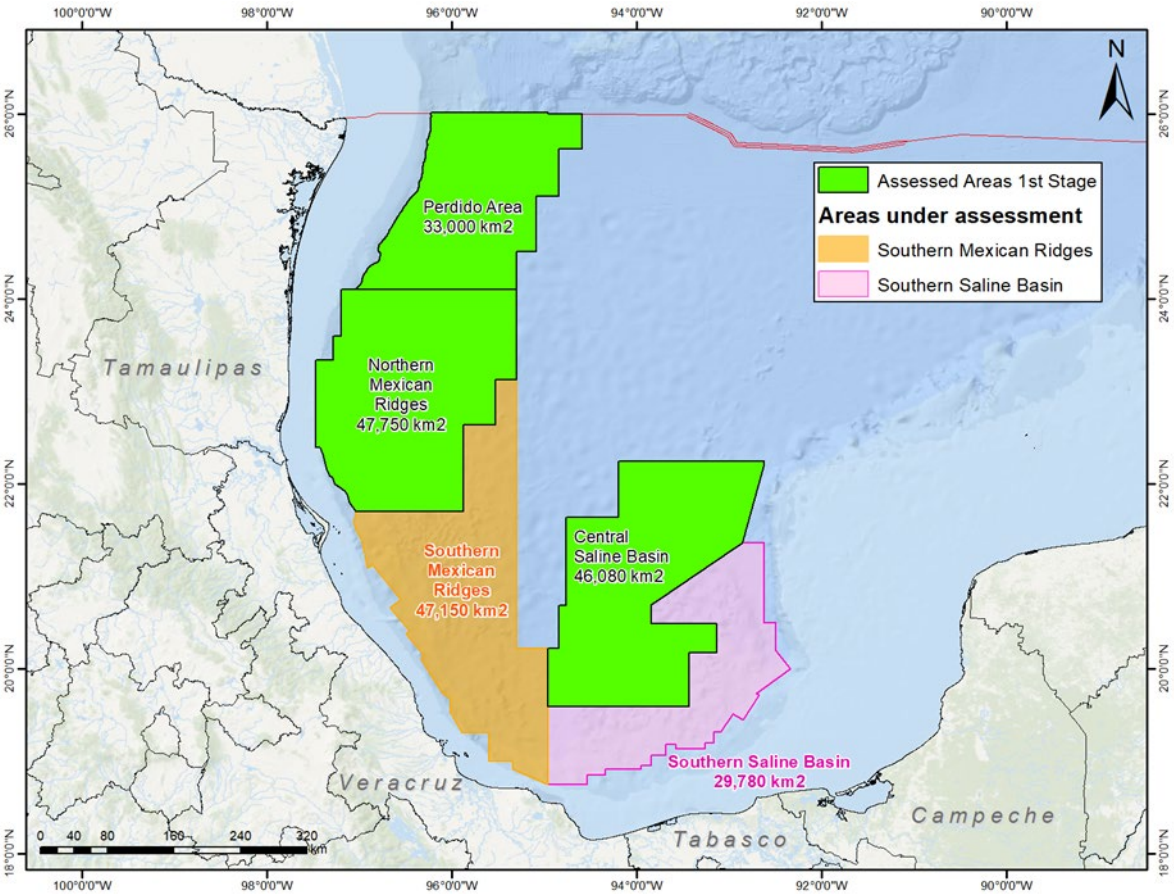


Figure 56. Map showing polygons delimitation of and surfaces in km^2 of the assessed areas in this first stage and areas under assessment, where prospective resources estimation will be updated in a next, second stage.

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GLOSSARY OF USED TERMS

Analog.- Method used in resources estimation in exploration, evaluation and early development stages when direct measurement of certain parameters of interest is limited or unknown. It is based on assessment of similarities of known reservoirs and their extrapolation to the potential reservoir or reservoir under evaluation.

Consolidated value of an exploration prospect.- In a prospect with multiple targets or geological objectives, it is the geological objective, the probability of geological success and the volume distribution representative of the prospect. These representative values come from an analytical procedure that allows to obtain estimates that involve concepts of conditional probability and stochastic simulation to model the dispersion of potential prospective volumes given multiple objectives. These representative values are different from the sum or average of the volumes and probabilities of geological success of each individual objective.

Contingent resources.- Volumes of hydrocarbons that are estimated to be potentially recoverable from known accumulations as of a given date, but where the applied project is still not considered commercial due to one or more contingencies.

Conventional resources.- Resources or volumes of hydrocarbons trapped in discrete and confined accumulations, which are found in porous and permeable rocks typically bounded by an aquifer and that are significantly affected by hydrodynamic influences, such as buoyancy of hydrocarbons in water. Under a geological approach, the volumes of conventional resources are related to structural and/or stratigraphic features, where the hydrocarbons accumulation or potential accumulation, come from a different source from the one that is contained, through processes of generation, migration and accumulation.

Direct hydrocarbons indicators (DHI).- Seismic amplitude anomalies, seismic events or seismic data characteristics, associated with the possible presence of hydrocarbon accumulations. They occur due to a change in the type of fluids in the rock pores, which produce a change in their elastic properties.

Discovery.- One or several hydrocarbon accumulations in the subsoil whose existence has been demonstrated by exploration drilling activities.

Estimated Ultimate Recovery (EUR).- It is an estimate at a given date of the volume amount of hydrocarbons that is potentially recoverable or that has already been recovered from a reservoir. In case that there is production, it is the potentially recoverable amount plus the amount that has already been produced.

Exploration plan.- Document in which the oil and gas operator describes sequentially or simultaneously the activities to be conducted aimed to petroleum potential assessment, reserves incorporation, as well as reservoir characterization and appraisal, as applicable within the Entitlement or Contractual area in question.

Exploration prospect.- Visualized undrilled geological condition of the subsoil, that has been studied with a certain level of detail and according to its technical attributes, likely to contain one or more hydrocarbon reservoirs in its geological objectives or drilling targets. According to the level of certainty about the presence of the elements of petroleum system and the project maturity to which it is associated, the exploration prospects can be subdivided into drilling locations with a viable drilling target (Localizations) and drilling opportunities or leads (Opportunities).

Exploration well.- A kind of well that is drilled based on a previously-identified exploration prospect, with the purpose of obtaining geological, geophysical and reservoir engineering information that allows for the checking of the postulated concepts and the presence of hydrocarbons in the subsoil.

Field.- Area consisting of one or multiple reservoirs, grouped or related according to the same structural geological aspects and stratigraphic conditions. There may be two or more reservoirs in a field, vertically and horizontally separated by impermeable rock layers, or both by geological barriers or discontinuities.

Frontier area.- In the context of hydrocarbon exploration and extraction, it refers to areas with known petroleum potential, where exploration activities have not been carried out or are limited, usually being classified as high risk.

Geological objective or target of an exploration prospect.- Theoretical stratigraphic, formational or specific depth interval in the subsoil, where the possible existence of hydrocarbon accumulations or other characteristics of interest has been identified and therefore, are considered in the planned wellbore trajectory for the eventual drilling of a prospect.

Geological Province.- Delimited and mappable geographic area, which is characterized by its rocks, its structure and a sequence of events such that it integrates a unique evolutionary history different from that of the adjacent areas, from which it is separated by stratigraphic, tectonic or both kind of limits.

Historical prospective resources datbases.- Integrated databases of exploration prospects and plays, according to the established templates and related to Resolution CNH.11.001/13 by which the National Hydrocarbons Commission established the Guidelines for the analysis and evaluation of prospective and contingent resources of the Nation and the exploration process oversee.

In place volume.- Total hydrocarbons amount that is estimated to exist originally in a field or reservoir at a certain date.

Monte Carlo simulation.- Statistical method of stochastic simulation, used to generate continuous random variables and use them to simulate a number of possible outcomes from a given mathematical model. The set of final values derived from the simulation, allows to calculate a distribution that represents the variability of possible results for the determined mathematical model.

Oil equivalent (oe).- Internationally used form to report total hydrocarbon inventory. Its value results from adding the volumes of liquid hydrocarbons (oil, condensates, and plant liquids) and dry gas equivalent to liquid according to its calorific value.

P90.- Statistical measurement of the confidence level for a series of ordered data, which indicates the point or moment in a distribution in which 10% of the occurrences are below the value and 90% are above. It is generally considered a reasonable minimum value, but not as small as the absolute minimum.

P50.- Statistical measurerement of the level of confidence for a series of ordered data, which indicates the point or moment in a distribution in which 50% of the occurrences are below the value and 50% is above. It corresponds to the statistical median of a set of ordered data.

P10.- Statistical measurement of the confidence level for a series of ordered data, which indicates the point or moment in a distribution in which 90% of the occurrences are

below the value and 10% is above. It is generally considered a reasonable maximum value, but not as large as the absolute maximum.

Petroleum Province.- Delimited geographical area where hydrocarbon accumulations have been identified or that there are favorable conditions for the accumulation of hydrocarbons, whose delimitation is generally due to administrative, geological, technical, economic or simply by convenience issues.

Petroleum system.- Natural system that includes an hydrocarbon generating focus from an active source rock, which includes all the essential geological elements and processes for an hydrocarbons accumulation to occur.

Petrophysical evaluation.- Characterization and quantitative determination of rock properties and the fluids present in their porous space, based on integration of information and methods that involve direct and indirect measurements of rocks in the subsoil, obtained through rock sampling and/or with specialized tools.

Play.- Set of hydrocarbons discovered accumulations and prospects within a geographically delimited area, which share a group of mutually related geological factors that give rise to an hydrocarbons accumulation; but at the same time, it requires more information and/or evaluation to define specific prospects.

Play established or proven.- Play where there is at least one discovery that, through exploration drilling, has proven the existence of hydrocarbon accumulations.

Play fairway.- Method for systematic mapping and assessment of petroleum system elements through geospatial analysis, to define and delineate geographic areas of interest where hydrocarbon accumulations can occur, which may correspond at least, to the maximum extent of the potential reservoir rocks associated to a play. It is also refered as play-based exploration.

Play hypothetical, speculative or unproven.- Conceptualized play based on geological, geophysical or analogs knowledge, where the existence of hydrocarbon accumulations through exploration drilling has not been proven.

PRMS.- The Petroleum Resources Management System is a document that provides a uniform methodology for the classification of resources and reserves, including their application guidelines and their reserve audit standards, as well as the set of principles, criteria , mathematical, technical and scientific methods, concepts and procedures used for the assessment, estimation and verification of hydrocarbon resources and reserves.

Probabilistic estimation.- Resource estimation method that is used to generate a continuous range of estimates and associated probabilities, using in turn geoscience and engineering data ranges.

Probability density function (PDF).- Set of values or density of a continuous random variable, which describes the relative probability according to which the random variable will take a certain value. In resource assessment, the PDF is a probability function that describes the uncertainty or range of possible values around some parameter of interest.

Probability of geological success (Pg or PoS).- Given the success, it is the probability of finding hydrocarbon accumulations capable of generating a stabilized and measurable flow in tests related to the minimum size of a potential resource volume or more, without specifying productivity, hydrocarbon type or associated market factors. In the context of prospective resources assessment, the probability of geological success estimation is based on the assessment of elements and processes of petroleum system, whose analysis involves the knowledge and study of historical information, models, extrapolations and

assumptions of geological phenomena, as well as a component of subjective judgments about local geological parameters.

Prospective resources.- It is the volume of hydrocarbons estimated at a certain date, that can be inferred is potentially recoverable from undiscovered accumulations through the application of future projects. Prospective resources are further subdivided according to the level of certainty, in resources associated with plays and exploration prospects.

Recoverable resources.- Quantities of hydrocarbons that are considered as producible given a project from discovered or undiscovered accumulations.

Recovery factor.- Numerical expression that indicates the amounts of the original in place hydrocarbons volume that are estimated to be recoverable in a reservoir, through specific processes or projects. It is typically represented as a percentage and referenced in time.

Reserves.- Quantities of hydrocarbons that are anticipated to be commercially recoverable through the application of development projects to known accumulations, as of a given date and under defined conditions. To be considered as reserves, hydrocarbons must meet four criteria: be discovered, recoverable, commercial and remaining (as of the evaluation date), based on the development project(s) applied. Additionally, reserves can be categorized according to the level of certainty related to the estimates.

Reservoir.- Natural hydrocarbons' accumulation that is in the subsoil and behaves like a hydraulically-interconnected system, where hydrocarbons are at high temperatures and pressures, occupying the porous space of the rocks that contain them.

Risk.- Probability of loss or failure. Risk = 1-probability of success.

Risked resources.- Product of the probability of geological success by the expected value of resources given the success. Risked volumes or prospective resources represent the value that is at least expected to obtain given a probability of geological success. Considering that the mean is the most representative value of a distribution of values, the mean risked volume will represent the minimum expected value of volume to be obtained given the success.

Salt tectonics.- Processes related to the evolution, geometry and deformation produced by the presence of thick evaporite sedimentary bodies, deposited in the stratigraphic column of a sedimentary basin. These bodies of evaporite deposits or salt tend to mobilize without necessarily having some external tectonic influence, due to differences in density and gravitational instability, among other factors; producing characteristic deformation patterns. It is also known as halokinesis.

Sedimentary facies.- Set of physical, chemical, biological and lithological characteristics of a body of sedimentary rock, which allows for differentiation from other adjacent rocks and whose set of characteristics permit the definition of an environment and depositional processes.

Seismic amplitude anomaly.- Abrupt increase or decrease in local seismic amplitude, produced by sudden changes in acoustic impedance. They can be produced by processing problems, geometric or velocity focusing, lithological changes and hydrocarbon accumulations.

Seismic attribute.- Specific measurable properties from seismic data, generally derived from measurements of time, amplitude, frequency and/or attenuation, which permit the description of geometric, kinematic, dynamic, statistical or geomechanical

characteristics, to finally infer lithological and petrophysical properties of rocks in the subsoil.

Seismic interpretation.- Analytical activities to infer the subsoil geology, structures, stratigraphy and lithologies from processed seismic information.

Seismic migration.- Process by which seismic waves or events are positioned geometrically in space or time according to the structure of geological events, generating a more accurate subsoil image by applying certain numerical convolution algorithms. In general, there are seismic wave or events migrations in time or depth.

Statistical mean.- It is the average value. It represents a measure that best describes the central tendency of a set or distribution of data. With the exception of low variance distributions, the mean is not the most likely value, but when the variance is small, the mean, median and mode are similar.

Stochastic simulation.- Statistical method where random variables are generated from a range of values with associated probabilities and whose result is a probability distribution of the potential results.

Uncertainty.- The range of possible results from a series of quantitative estimates. In resource assessment, uncertainty reflects a reasonable range of the potentially recoverable volume amount for a potential reservoir or project.

Unconventional resources.- Resources or volumes of hydrocarbons in accumulations over relatively large areas or pervasive that are not significantly affected by hydrodynamic conditions. Generally, such accumulations require the application of specialized extraction technology due to the high viscosity of fluids or due to low rock permeabilities that impede their mobility; for example, through fracking programs to extract oil or gas from shales, among others. Under a geological approach, unconventional resources volumes generally involve a confined petroleum system; that is, where the same source rock acts as reservoir and seal.

Volumetric formation factor.- Factor that describes the amount by which a given amount of hydrocarbons at reservoir conditions expands or contracts on its way to the surface. In the case of liquids (oil), this factor is expressed as B_{oi} and is always greater than 1; while in the case of gas it is expressed as B_{gi} and is less than 1.

Well log.- Measurements based on depth or time of some physical and/or chemical property of rocks in the subsoil, acquired through specialized tools that record the physical response of the rocks on the wall of the wellbore.

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