Sweet spot areas for shale oil and shale gas plays in the Upper Cretaceous rocks of the Middle Magdalena Valley, Colombia: insights from basin modeling

Andrés Pastor-Chacón[1]*, Roberto Aguilera[1], Jorge Luis Triana[1], Manuel Paez-Reyes[1], Maria Cantisano[1], Luis Bravo[1], Néstor Gamba[1], Miled Niño[1], Alexandra Delgado[1], Gabriel Mendoza[1], Juan David Rodriguez[1], Oscar Romero-Ballén[1], Maria Cecilia Ruiz[2], Hugo Buitrago[2] and Humberto Fuenzalida[1]

[1]Dirección de Hidrocarburos, Servicio Geológico Colombiano, Bogotá, Colombia, [2]Agencia Nacional de Hidrocarburos, Bogotá, Colombia

The Middle Magdalena Valley Basin (MMVB) in Colombia has a long history of conventional hydrocarbon exploration and production, with a cumulative production of 2.75 billion barrels of oil as of December 2021. Recent interest has been directed towards unconventional hydrocarbon plays within the basin due to the fine-grained nature of its Cretaceous source rocks and their mineralogy and mechanical properties. This study presents a three-dimensional basin model for three Upper Cretaceous source rocks, known as the "La Luna Formation," within the MMVB. The model was developed using new data from five outcrops, 7,640 km of 2D seismic lines, and forty-one boreholes, as well as additional data sets such as X-ray diffraction analyses, pyrolysis analyses, well-log correlations, facies analysis, fracture pattern prediction, pore pressure analysis, heat flow estimations, and petrophysical data. The model estimates total retained oil and gas volumes to be 7.95 billion barrels and 4.21 trillion cubic feet in most probable scenarios, after a 15% recovery factor. Seismic interpretation reveals pre-Eocene structures beneath Paleogene and Neogene sediments, and the thickness variation of the source rocks from south to north of the basin. Petrophysical modeling shows effective porosities ranging from 2%–12% and organic porosities lower than 0.1%, with parts of the succession that might correspond to a carrier bed play. From a geomechanical perspective, we identified several brittle strata based on the higher concentrations of carbonates and quartz, and the areas with a higher probability of occurrence of natural fractures. Pore pressure analysis of multiple wells shows that wells in which the Middle Eocene unconformity has beveled the source rocks have no sealing capacity, becoming a risk for the play. The results suggest potential for unconventional hydrocarbon plays in the MMVB, with sweet spot areas being primarily controlled by porosity, thermal maturity, gas-oil ratios, and retained oil and gas volumes, as well as to a lesser degree, the probability of natural fractures and pore pressure conditions. However, further exploration is needed to constrain uncertainties regarding facies and source rock quality, particularly within the depocenters of the basin, in order to prove the economic feasibility of these unconventional plays.

1 Introduction

The Middle Magdalena Valley Basin (MMVB) is located in Central Colombia and is the second most prolific hydrocarbons province of the country. Fine-grained Cretaceous rocks in northwestern South America and in the MMVB have been studied because of their importance as source rocks that feed conventional petroleum plays (e.g., Erlich et al., 2003; Rangel et al., 2017; Thompson-Butler et al., 2019). The chemistry, mineralogy, and mechanical properties of these rocks, however, have made them in more recent years the focus of attention as an unconventional play prospect (EIA, 2015). Yet-to find estimations of in-place and recoverable resources for the Cretaceous rocks within the MMVB as of December 2021 were 24.830 Tcf of gas and 7.787 Bbbl of oil (Mora et al., 2018; ANH-UPTC, 2021).

Despite the MMVB being an established hydrocarbon-producing basin, a thorough understanding of its full potential and the location of remaining undiscovered hydrocarbon resources requires a comprehensive evaluation of the petroleum system. Such an evaluation includes the determination of the total volume of hydrocarbons generated from each source rock, as well as the volumes of migrated and remaining hydrocarbons in or near the source beds for potential production. In the same way, previous interpretations of source-related biomarkers suggest the presence of an extensive petroleum system, although several questions to address around generation, migration, seal, and trap processes remain (e.g., Ramón et al., 1997; Rangel et al., 2017; Thompson-Butler et al., 2019).

The aim of this study is to analyze geological information from multiple sources, including outcrops, wells, wire-line logs, and source-rock geochemical data in order to: 1) determine rock properties; 2) develop a three-dimensional model depicting the regional basin architecture; and 3) use petroleum system analysis to evaluate the spatial distribution and petroleum potential of Upper Cretaceous source rocks across the MMVB, as unconventional reservoirs.

2 Basin geology and petroleum systems

The MMVB is an intermontane basin located in the central-northern part of the Andes in Colombia. It separates the Central and Eastern cordilleras of the country (Figure 1). The basin has a long history dating back to the Mesozoic, which was shaped by the tectonic interactions between the South American, Farallon, and Caribbean plates. During this period, the Central Cordillera was a magmatic arc, and rifted sub-basins filled with marine sediments formed to the east, each with their own subsidence history (Bayona, 2018; Sarmiento-Rojas, 2019). Compressional deformation of the Central Cordillera and the MMVB began in the Late Cretaceous, resulting in several time gaps, including the Late Campanian hiatus (Cooney & Lorente, 1997; Bayona, 2018; Etayo-Serna, 2019a). In the

Cenozoic, the basin began to fill with continental sedimentary rocks, which also partially covered the Central Cordillera with valley-fill deposits along an onlapping surface (Gomez et al., 2005; Caballero et al., 2013).

Figure 2 shows the sedimentary units which comprise the MMVB. The basal units of the Cretaceous include the continental-transitional strata of the Tambor and Cumbre formations (Berriasian-Valanginian), which are related to the rifting and opening stages of the basin. The so-called "Grupo Calcareo Basal" consists of the Rosa Blanca, La Paja, and Tablazo formations (Valanginian-Aptian) and shows the evolution of transitional to shallow marine calcareous environments. The Simiti Formation (Aptian-Albian) comprises shales and might correspond to a maximum base-level rise (Etayo-Serna, 2019b). The so-called "La Luna Formation" (Late Cenomanian-Campanian) consists of the Salada, Pujamana, Galembo, and La Renta formations related to thermal post-rift conditions. The Umir and Lisama formations (Maastrichtian-Early Paleocene) contain transitional and continental rocks corresponding to the Central Cordillera uplifting and basin closure. Finally, most of the Cenozoic fill consists of the La Paz, Esmeraldas, Mugrosa, Colorado formations, and the Real Group, related to the Eastern and Central Cordilleras uplifting.

At least two intrabasinal highs divide the MMVB (Figure 1), corresponding to the La Cira-Infantas and Cachira highs (Gomez et al., 2003; 2005; Cortes et al., 2022; Reyes et al., 2022). The related depocenters to the La Cira-Infantas high are generally deeper (e.g., Nuevo Mundo-La Salina Depocenter) and contain a thicker and more complete Cretaceous-Cenozoic succession than those near the Cachira high (e.g., Santa Lucia Depocenter), which appears positive during the Oligocene (Horton et al., 2015).

The MMVB is host to a petroleum system that is composed by several elements, including source rocks, reservoirs and seals. The source rocks are found primarily in the Cretaceous formations, with the La Luna Formation being the most significant. The oils found in most Cenozoic reservoirs of the MMVB are genetically linked to the Salada, Pujamana, Galembo, and the La Renta formations (Turonian-Campanian) (Mora et al., 1996; Ramón et al., 1997; García et al., 2001; Rangel et al., 2017). Two intervals that correspond to the Cenomanian-Turonian sequence or the Salada Formation and the Coniacian-Campanian sequence that lithologically corresponds to the Galembo and La Renta formations, were deposited under anoxic conditions allowing large amounts of organic carbon to be deposited during this time (Villamil et al., 1999; Erlich et al., 2003). These intervals contain total organic carbon (TOC) greater than 4% and contain the best-quality source rocks, likely type B organofacies of Pepper & Corvi (1995). The Pujamana Formation of middle-late Turonian age on the other hand corresponds to organic-lean rocks deposited under oxic to disoxyc conditions and likely type C/D organofacies of Pepper & Corvi (1995), suggesting that these rocks have a lower hydrocarbons generation potential. Additionally, the La Paja-Tablazo interval (Barremian-Lower Albian) serves as source rock as it is proved by rock-oil correlations of lower Cretaceous rock extracts and oils
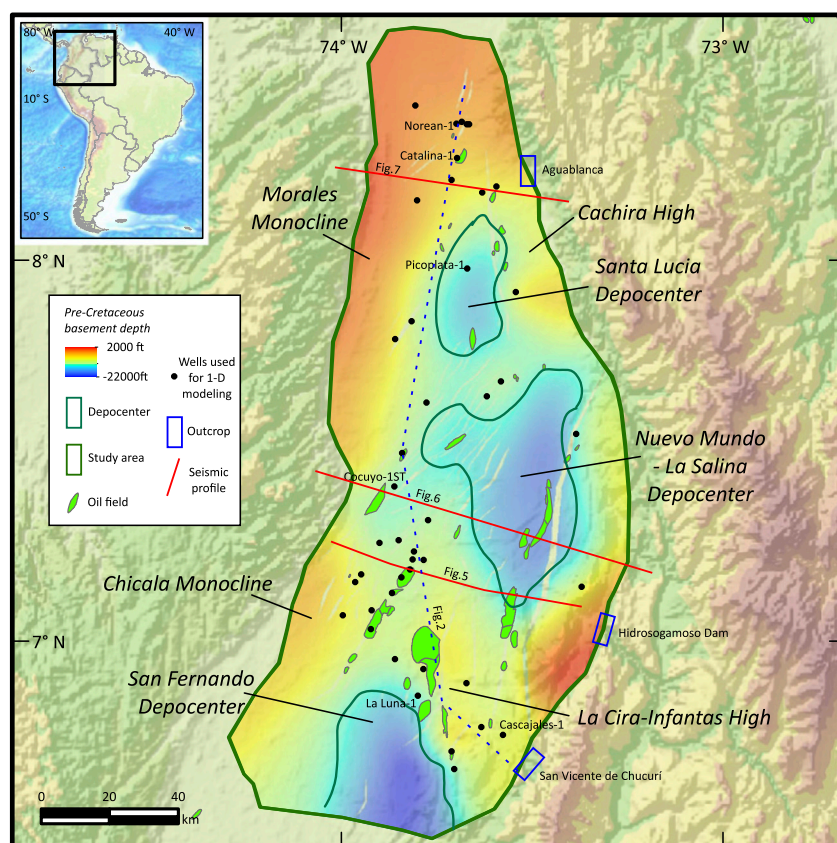
FIGURE 1
Location of the study area. Selected wells, composite seismic data, depocenters, and structural highs are also shown.

found in Cretaceous and Cenozoic rock reservoirs of the MMVB (Rangel et al., 2017; Thompson-Butler et al., 2019). This interval was also deposited under anoxic conditions enhancing organic carbon accumulation and preservation (Gaona-Narvaez et al., 2013; Jimenez et al., 2015).

Finally, the main reservoirs in the MMVB are the La Paz and Mugrosa formation and, to a lesser extent, the Lisama and Umir formations. Also, commercial reservoirs exist in the Galembo-La Renta, Salada, and Rosa Blanca formations. In the same way, the Simiti, Umir, and Colorado formations are considered regional seals, although internal local seals are also present within the reservoirs.
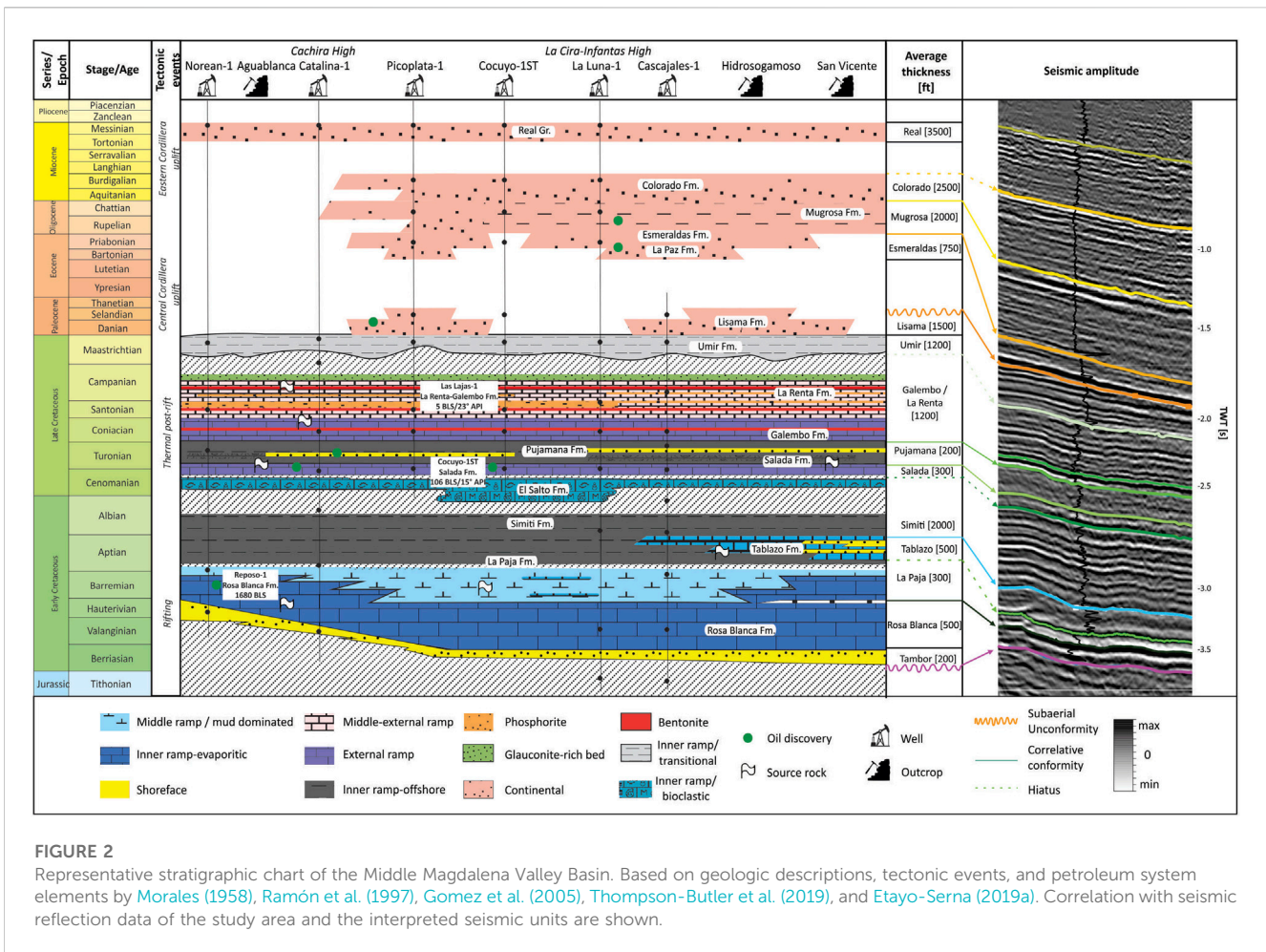
3 Materials and methods

This study presents an integration of a large-scale 2D seismic reflection dataset with borehole data, comprising of 7,640 km of 2D seismic data and forty-one wells, including lithological descriptions, biostratigraphic data, and velocity surveys, as well as electric logs and datasets of 1,500 X-Ray Diffraction samples (XRD), and 5,000 source rock geochemical data including vitrinite reflectance (%Ro), total organic matter (TOC), and pyrolysis. The subsurface data were primarily sourced from the Banco de Información Petrolera. The research follows a petroleum systems analysis workflow, comprising of seismic interpretation, petrophysical modeling, basin modeling, source-rock characterization, pore pressure analysis, and fracture systems characterization. The study aims to model hydrocarbon generation and predict the volumes of retained hydrocarbons, the Gas-Oil Ratio (GOR), porosity, thermal maturities in order to define sweetspots for unconventional exploration in the basin. The software used in this research include the Zetaware software suite, Techlog v2022, Petrel v2022, and Petromod v2022.

3.1 Seismic interpretation and curvature analysis

This study used three hundred 2D seismic-reflection lines in TWT to construct the regional structural framework, including the basement and key stratigraphic units. The data from thirty-five wells were tied using check-shot surveys, and data from neighboring wells were used to supplement any missing information.

The study also used lithological descriptions and stratigraphic ages from the boreholes to assign approximate ages to the marker horizons. Faults were also identified from seismic and well data. The time-to-depth conversion was done using interval velocities from check-shot surveys and synthetic seismograms. Quality control was

FIGURE 2
Representative stratigraphic chart of the Middle Magdalena Valley Basin. Based on geologic descriptions, tectonic events, and petroleum system elements by Morales (1958), Ramón et al. (1997), Gomez et al. (2005), Thompson-Butler et al. (2019), and Etayo-Serna (2019a). Correlation with seismic reflection data of the study area and the interpreted seismic units are shown.

performed by checking the seismic marker horizons against well tops from logs not initially involved in the interpretation, and isopach maps were created to provide a regional overview on the location of the depocenters and main structural features.

The depth structural maps obtained from the seismic interpretation were integrated into the basin modeling, and also for the analysis of strain and fractures on structural surfaces. This analysis employed the methodology proposed by Suo et al. (2012), which posits that the density and orientation of fractures are related to the curvature of a structural surface. Specifically, it states that as the curvature of a structure increases, the number of fractures also increases.

3.2 Petrophysics

Forty-one wells with triple-combo logs were evaluated to obtain petrophysical properties, including lithology, porosity, and permeability. Total organic carbon (TOC) content was estimated using mathematical models based on well-log measurements. For instance, TOC content was estimated from uranium concentrations as measured from spectral gamma ray, which involves a model based on the relationship between the uranium concentration and TOC (Fertl and Rieke, 1980). Correlations to bulk density measurements

were also used, using a model that relates the bulk density of the formation to TOC (Schmoker & Hester, 1983). In addition, the mathematical model which describes the correspondence of the compressional transit time with deep resistivity (Delta log R method), was also used as a related parameter to TOC (Passey et al., 1990). Finally, the validity of the values derived from petrophysical calculations was assessed by comparison to TOC contents determined via Rock-Eval pyrolysis or LECO carbon analyzer.

A probabilistic multimineral model was applied (i.e., Quanti-Elan ®) to determine rock mineralogy and clay volumes. The Quanti-Elan model uses well logs (e.g., density, photoelectric factor, sonic, neutron, gamma ray), XRD and TOC datasets to quantify the different minerals such as quartz, carbonates, phosphates, pyrite, and clays, applying multivariate statistical methods and providing a range of probabilities for each estimated mineral type rather than a deterministic answer (Ali et al., 2022). The multimineral model and the TOC estimation are necessary to calculate effective porosity, and organic porosity. We applied Galford et al. (2013) and Alfred & Vernik (2013) methods for organic porosity estimation, constrained with pyrolysis datasets, which measure the pore spaces created by thermal maturation and conversion of the organic matter into hydrocarbons within source-rock reservoirs.

The brittleness, or ability of a rock to fracture, is a valuable criterion in predicting enhanced productive intervals or areas. The Upper Cretaceous rocks were characterized based on a mineral-based brittleness index, proposed by Wang & Gale (2009), including borehole and outcrop data. Finally, evaluation of the geopressures on most of the wells were carried out establish the presence and distribution of overpressures in the basin, integrating drilling mud-weight data and well logs following Grauls' (1999) method, in order to evaluate the sealing risks for unconventionals prospectivity in the basin.

3.3 Basin modeling

We used one-dimensional (1D) and three-dimensional (3D) models to understand how rock properties in the basin changed over time and to identify the best areas for potential production from source-rock reservoirs (sweet spots). Forty-one 1D models in the MMVB were made to evaluate changes in source-rock properties, geohistory, and thermal maturity trends during the basin evolution. These results were combined and used to calibrate a 3D geological model of the Cretaceous-Cenozoic succession to create a 3D petroleum systems model.

Subsidence analysis helps to account for how the rocks in a basin have been buried or heated over time and how deformation has affected the basin structure (e.g., Hantschel and Kauerauf, 2009). We used subsidence analysis (backstripping) to reconstruct the basin's evolution from the Cretaceous to the present day, considering sediment compaction and variations in paleobathymetry or paleotopography (Allen & Allen, 2013). From seismic interpretation and subsidence curves, erosion maps were estimated to include the eroded thicknesses of the stratigraphic units in the basin modeling Stratigraphic names, ages, unconformities, and time gaps correspond to Morales (1958), Gomez et al. (2005), Caballero et al. (2013), Sarmiento-Rojas (2019), Bayona (2018) and Etayo et al. (2019a) proposals.

We applied inverse modeling to the regional burial history model, allowing for the reconstruction of the basin time-temperature history. Inverse modeling involves using observed data to infer the underlying parameters of a geological model. For example, the use of present-day surface temperatures, paleolatitude and paleoglobal mean surface datasets, and crustal models. Based on average yearly temperature observations from the IDEAM (2022), the calculations of present-day surface temperatures are around 26 °C. To estimate paleo-temperatures, as described by Beardsmore & Cull (2001), we included paleolatitude and paleoglobal mean surface temperature datasets (e.g., Scotese et al., 1988). Also, we used crustal models to estimate the lower thermal boundary conditions of the sedimentary basin at the present day and through time. The Pre-Cretaceous basement structure is based on the Barrera-Lopez et al. (2022) model, which proposed a crustal thickness map based on geophysical and geomorphological data for northern South America, allowing us to use an average total lithospheric thickness of 120 km (to the 1,330°C isotherm). In the same way, a transient heat flow was considered to estimate the heat flow in the study area, because heat flow affects thermal maturation of the source rocks and thus the generation of hydrocarbons (e.g., Beardsmore & Cull, 2001). We also considered the role of lithospheric extension in the basin's thermal history, which

only had a minor influence, since modeled crustal extension factors from wells were consistent with Early Cretaceous β values close 1.2 (Sarmiento-Rojas et al., 2001).

Forward modeling is a valuable method to address the physical properties of a basin involving the simulation of various scenarios to generate geological parameters (e.g., density, porosity, velocity) and iteratively adjusting the input parameters of the simulation until the simulated results match the observed data as closely as possible, also evaluating the reliability of the model. Lithologies for each formation were estimated based on individual wire-line log data analysis, cuttings, core descriptions, and well completion reports applying inverse modeling. Also, the lithologies and burial history were calibrated with density and/or sonic logs, and the effective porosity calculation from petrophysics. (Figure 3). The thermal histories of all 1-D models were calibrated using present-day corrected temperature data (e.g., Holgate and Gerner, 2010) and maturity indicators, including vitrinite reflectance (Ro) and Tmax. The %Ro suppression within MMVB sediments was not apparent in the available data as other authors previously mentioned (e.g., García-Gonzalez & Carvajal, 2006), and it is possible to have measurements in solid bitumen which require proper conversions to equivalent Ro (Juliao-Lemus et al., 2015), to calculate accurate paleotemperatures.

3.4 Source-rock properties

The 3D petroleum systems model for the Salada, Pujamana, Galembo and La Renta Formations also includes the estimation of the source-rock properties such as quantity and quality of the organic matter. These formations are formed up of a combination of lithologies, nomenclature broadly explained in Terraza-Melo (2019), including: phosphorites (TOC 2-3 wt%), mudstones (TOC 0.5–3 wt%), shales (TOC 0.5-1 wt%), and wackestones (TOC 0.5–3 wt%), which together create a continuum of possible source rocks with TOC values ranging from less than 1 to greater than 7 wt% (Figure 4). The hydrogen index (IH) of these rocks' ranges from 150 mg HC/g TOC to 700 mg HC/g TOC and its organofacies are described below (Section 3.4) (Figure 4).

As additional inputs to the petroleum systems model, we used an updated dataset for the MMVB, including open file TOC, rock-eval pyrolysis, and Ro data (e.g., Aguilera et al., 2010), the TOC and hydrogen index (HI) to determine properties for each source rock (Figure 4). Using measured maturity data and the suitable kinetics based on the kerogen type, as mentioned in the following section, the HIo values—which indicate the original HI of the source rock before the start of kerogen transformation—were approximated from current values.

3.5 Source rock kinetics

Modeling the kinetics of kerogen pyrolysis approximates the thermal decomposition of organic matter in source rocks, which is a key process in the generation of hydrocarbons (Pepper & Corvi, 1995). Using pyrolysis measurements, Aguilera (2022) created source-rock kinetics specific to the Cretaceous source rocks of the MMVB, using the non-linear regressions for different kerogens in Canadian basins proposed by Cheng & Jiang (2015). Most of the organic matter in the Galembo-La
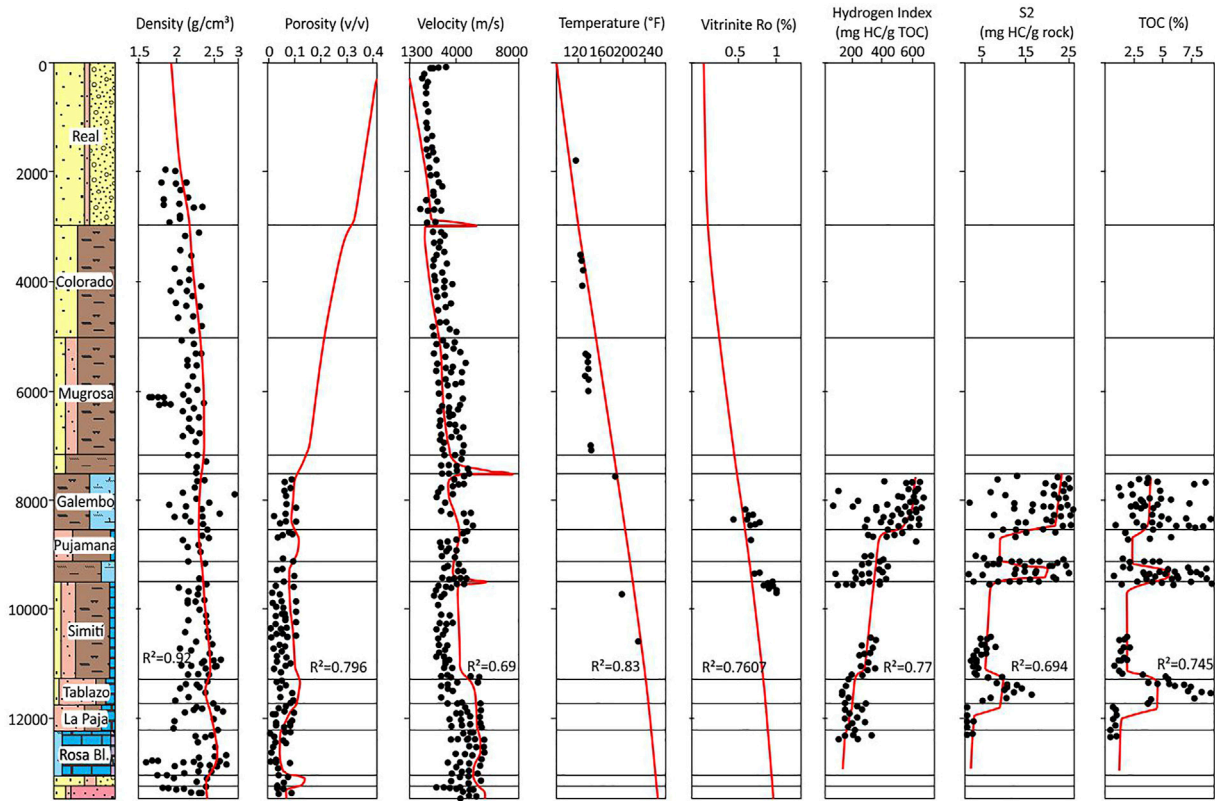
FIGURE 3
Example of forward modeling with well log data calibration for compaction, thermal and geochemical parameters for 1D models in the study area.
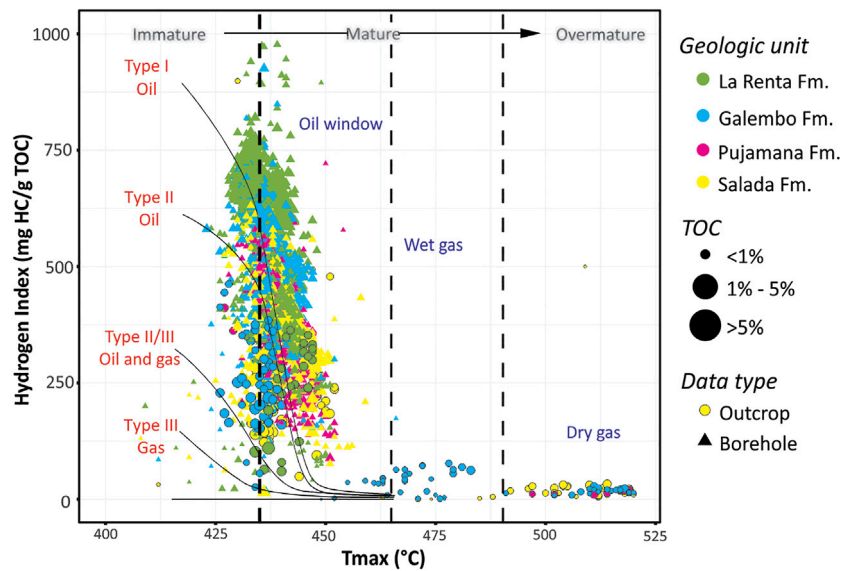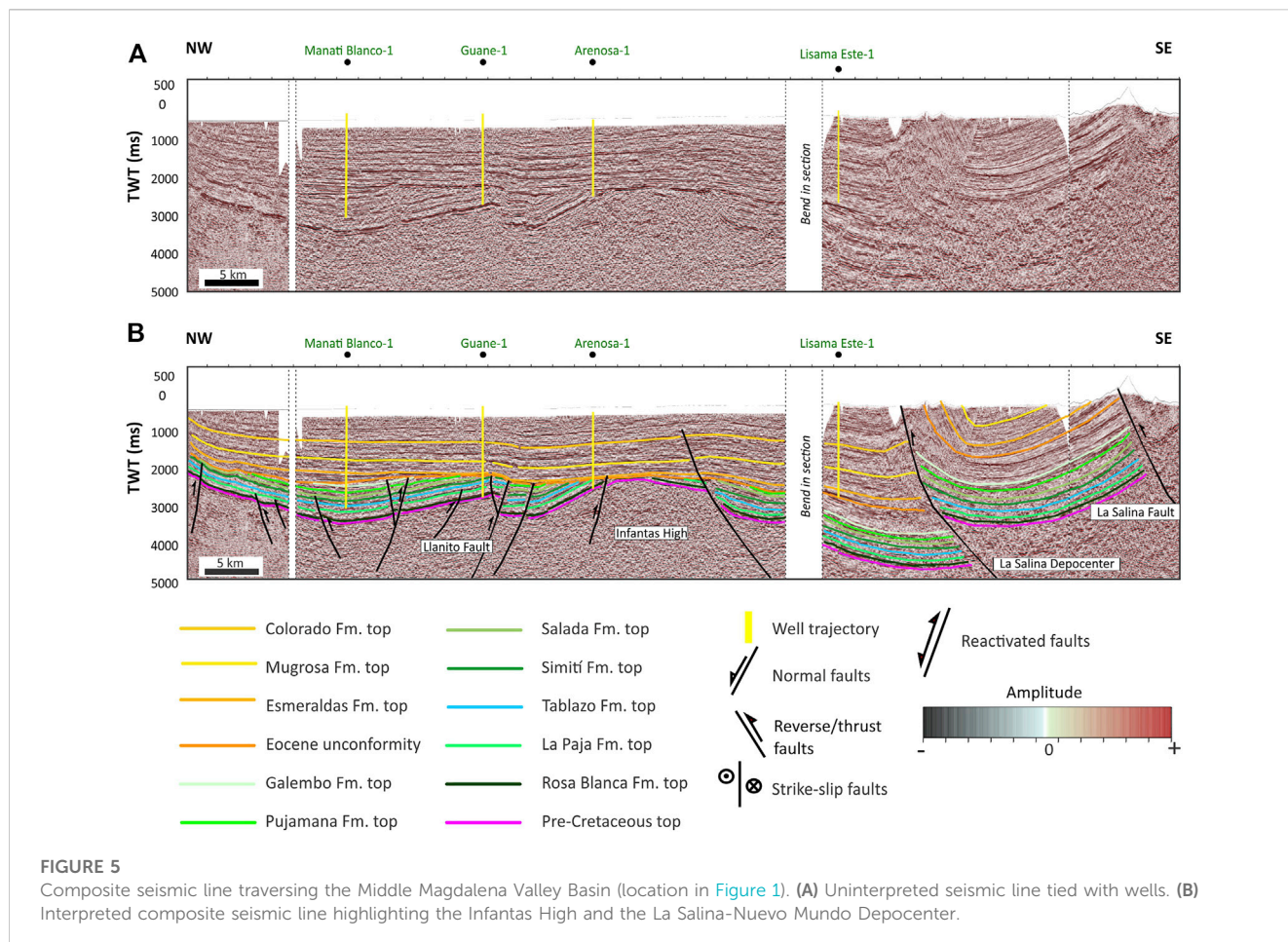

FIGURE 4
Plot of pyrolysis temperature (Tmax) versus hydrogen index (HI) and total organic content (TOC) for the Salada, Pujamana, Galembo and La Renta formations in the study area, that shows present-day kerogen quality and thermal maturity stages.

FIGURE 5
Composite seismic line traversing the Middle Magdalena Valley Basin (location in Figure 1). **(A)** Uninterpreted seismic line tied with wells. **(B)** Interpreted composite seismic line highlighting the Infantas High and the La Salina-Nuevo Mundo Depocenter.

Renta, Pujamana, and Salada is marine, following Pepper and Corvi's (1995) organofacies type B, and only a minor fraction is terrigenous non-marine, under Pepper & Corvi's (1995) organofacies types D and E.

3.6 Expulsion and retention

In order to model the volume of hydrocarbons expelled per unit area, additional data on rock density and sorption capacity were needed. The density of the inorganic rock matrix, the amount of organic matter, and the fluid contained in the pore spaces all influence bulk density, which in turn, depends on both organic and inorganic porosity. In this study, average values calculated from petrophysical estimations were applied for all three source rocks modeled. Also, adsorption models were used to describe the mass of hydrocarbons released into the free pore space of the source rock.
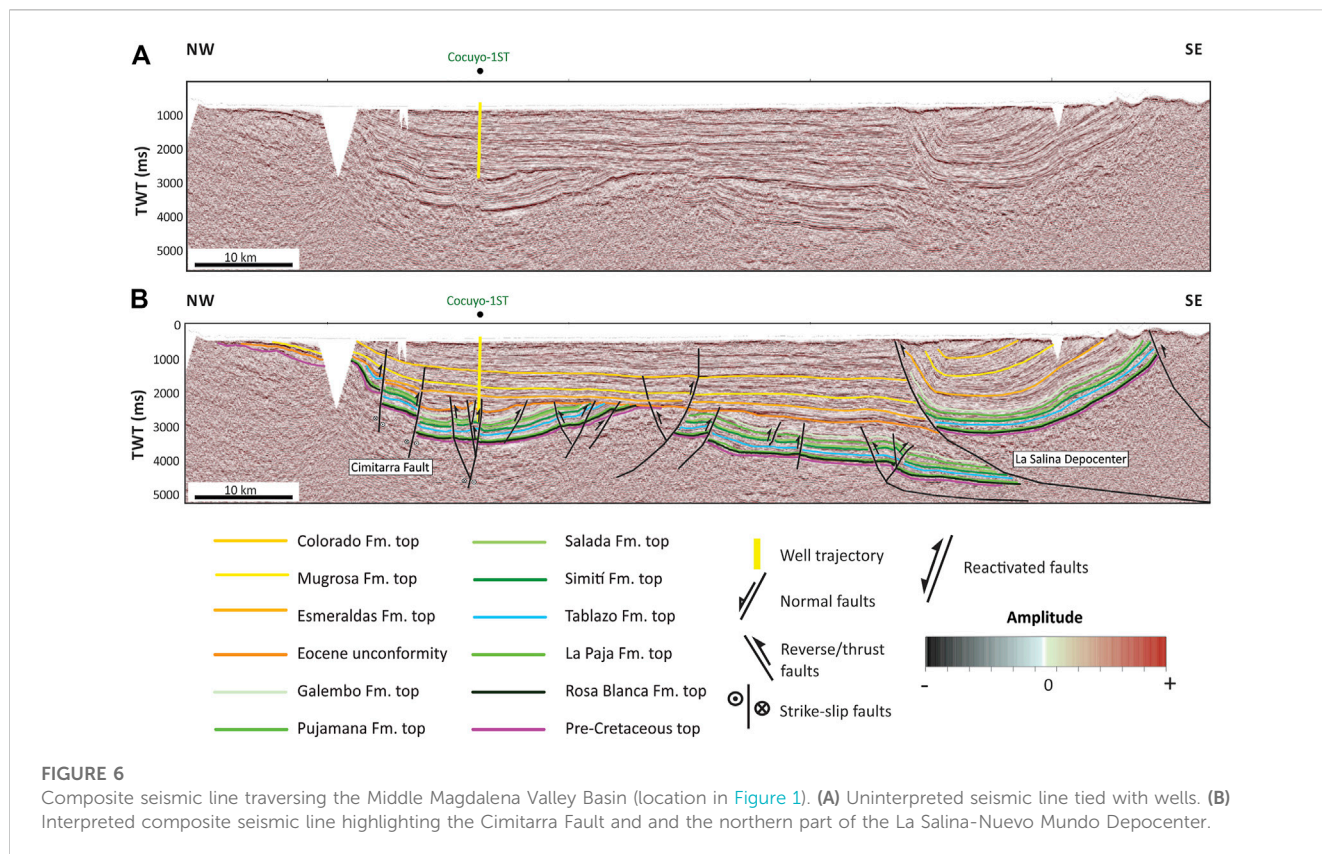
4 Results

4.1 Seismic interpretation and curvature analysis

The seismic succession was subdivided into eleven (11) seismic units, from the pre-Cretaceous basement to the Colorado Formation

(Figure 2). The succession above the pre-Cretaceous basement is thickening southward and eastward, reaching its maximum thickness of 5.0 s TWT (ca. 7,200 m) within the Nuevo Mundo–La Salina Depocenter (NM-LSD) and 4.5 s TWT (ca. 4,800 m) within the Santa Lucia Depocenter (SLD). Northward and westward, the succession thins to a minimum thickness of 0.5 s TWT (ca. 300 m), where the basement forms the so-called Chimichagua Platform (Reyes et al., 2004), which separates the Lower Magdalena Valley Basin. The seismic units are interpreted to be deposited between the Cretaceous and Neogene based on biostratigraphic data from outcrops and boreholes (Figure 2).

The 2D seismic profiles (e.g., Figures 5–7) show pre-Eocene structures beneath the Paleogene and Neogene sediments. Most of these structures appear to be beveled and eroded before the deposition of Eocene sediments (e.g., La Cira-Infantas High, Figure 5). Also, it preserves high-angle reverse faults and east-verging fault-propagation folds cored by the basement (e.g., Figure 6). The Salina Fault System forms the western boundary of the NM-LSD (e.g., Figure 5) and suggests pre-Andean deformation related to early phases of uplifting of the Eastern Cordillera (Sarmiento-Rojas et al., 2001). Also, the seismic profiles show a progressive onlap of Cenozoic units onto the Central Cordillera basement. The timing of the Central Cordillera's uplift is evidenced in the Morales Monocline (MM) and the Cachira High (CH), which appears to occur before the

FIGURE 6
Composite seismic line traversing the Middle Magdalena Valley Basin (location in Figure 1). **(A)** Uninterpreted seismic line tied with wells. **(B)** Interpreted composite seismic line highlighting the Cimitarra Fault and and the northern part of the La Salina-Nuevo Mundo Depocenter.

Paleocene, our observations are consistent with several proposals for the study area (e.g., Suarez et al., 2000; Gomez et al., 2003; Parra et al., 2012; Cortes et al., 2022).

Figure 8 shows selected structural and isopach maps of the Galembo, Pujamana, and Salada formations. This allows us to propose three structural domains in the MMVB. To the south, the structural domain is evidenced by the presence of reactivated north-south oriented inversion faults associated with the uplift of the Eastern Cordillera, which includes oil fields such as La Cira-Infantas, Lisama, and Provincia. In the central domain, there is evidence of northeast-southwest transpressive faults associated with structural inversion, including oil fields such as Casabe, Llanito, Cantagallo, Garzas, and Cristalina. Finally, in the northern domain, there is evidence of strike-slip faults associated with the uplift of the Central Cordillera, including oil fields such as Doña Maria, Totumal, Ayombero, and Crisol. The isopach maps reveal that the Pujamana and Salada Formations are thicker in the southern and central domains than in the northern domain. However, the thickness of the Galembo Formation increases in the northern domain and could be related to increasing accommodation space due to the uplifting of the Central Cordillera.

García-Delgado & Velandia (2020) studied the tectonic geomorphology of the northern part of the Central Cordillera, the San Lucas Range, proposing two regional domains related to the Palestina Fault. Our results agree with their model since interpreted seismic reveals that most of the faults in the Central Cordillera could be mapped on the subsurface of the MMVB and have right-lateral kinematics (e.g., Cimitarra and Las Brisas faults). Also, our model is an alternative to the proposal of Guerrero et al.

(2021), who considers the Cimitarra and Casabe faults as structures related to the Eastern Cordillera.

The best production values in several worldwide basins (e.g., Western Gulf Basin) are in areas with high natural fractures (Ramirez & Aguilera, 2014). Figure 9 presents the results of the curvature analysis for the Galembo, Pujamana, and Salada Formations. The maps reveal areas with higher and lower probability of the existence of natural fracture systems. The NM-LSD and the Cachira High have areas with a higher probability of natural fractures. For example, the Chuira field near the Cachira High has 16% porosity related to natural fracture systems (Acevedo et al., 2012a). On the other hand, the Morales Monocline, the San Fernando Depocenter, and the La Cira-Infantas High are areas with a lower probability of naturally induced fractures.

4.2 Petrophysics and pore pressure analysis

The petrophysical modeling allows us to suggest the Galembo, Pujamana, and Salada Formations' lithology based on quartz-feldspar-mica, carbonate, and clay content (Figure 10). We mapped these distributions to assess the lateral variations of the source rocks. Notably, the Salada Formation has carbonate contents in areas neighboring the SLD and the La Cira-Infantas High between 0.5 v/v and 1.0 v/v. This contrasts with the carbonate content of the Pujamana Formation, which in all study area is below 0.3 v/v, with small areas of the Chimichagua Platform containing values of 0.5 v/v. The Galembo Formation has carbonate contents ranging between 0.3 v/v and 0.5 v/v. For all three units, neighboring areas around the
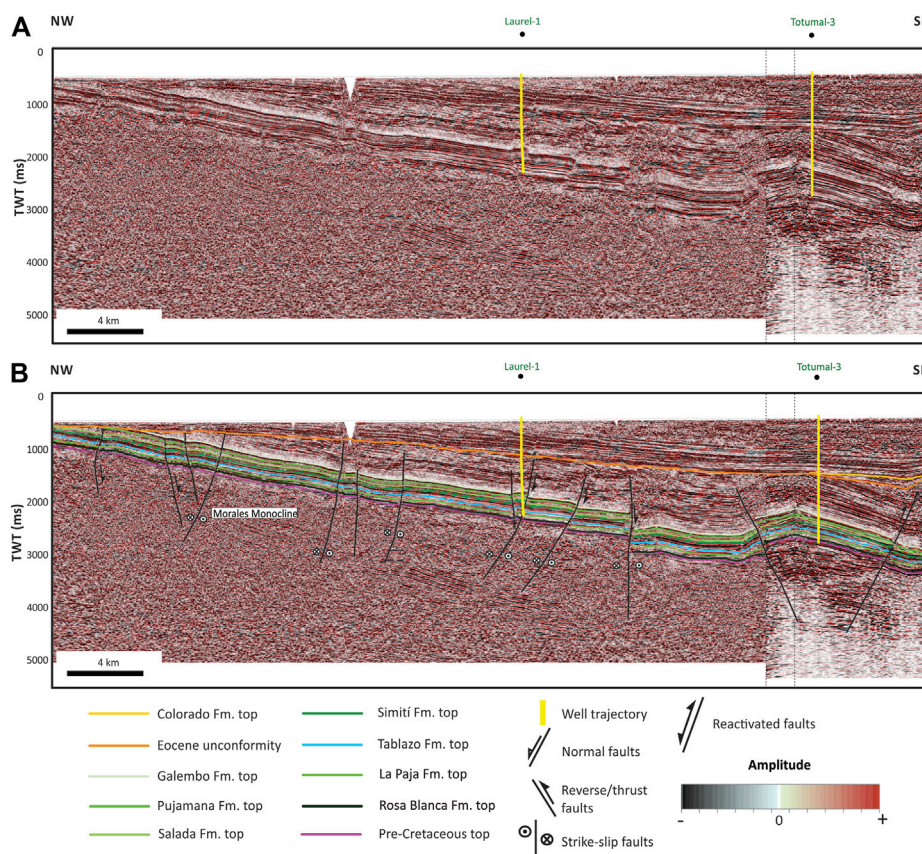
FIGURE 7
Composite seismic line traversing the Middle Magdalena Valley Basin (location in Figure 1). **(A)** Uninterpreted seismic line tied with wells. **(B)** Interpreted composite seismic line highlighting the Morales Monocline and the Totumal Field.

San Fernando Depocenter contain quartz-feldspar-mica contents between 0.4 v/v and 0.7 v/v. Also, the Galembo and Pujamana Formations have quartz-feldspar-mica contents between 0.4 v/v and 0.6 v/v in the SLD. Finally, the Pujamana Formation has the highest contents of clays, between 0.4 v/v and 0.7 v/v in most of the study area. As an alternate petrophysical mineral model, Rojas et al. (2013) applied conventional models, which include the apparent grain density (DGA), and the apparent volumetric photoelectric factor (UMA), obtaining results consistent with our proposal, despite having a limited well log and XRD dataset.

In the same way, Figure 11 presents XRD datasets plotted in a ternary diagram (Gamero-Diaz et al., 2013) of quartz-feldspar-mica, clay, and carbonates content, comparing the MMVB source rocks with worldwide shale plays from Bromhead et al. (2017) and Mews et al. (2019). Petrographic data suggest that most of the quartz in this source rocks is related to diagenetic processes rather than its depositional environment (e.g., Acevedo et al., 2012a; Galvis-Portilla et al., 2014). In all cases, clays content is lower than 40%, suggesting, that most of the units have an excellent brittleness quality which might help in future completion designs, also agreeing previously published petrophysical models which proposes at least two landing zones within the Salada and Galembo formations (e.g., Piedrahita and Aguilera, 2017a; Veiga et al., 2023). Perez et al. (2014) presented an XRD

dataset of the La Luna-1 well, showing the composition of clay minerals. Their results show that illite and interstratified species compose the bulk of the clay minerals and have lesser proportions of kaolinite. However, future research in other boreholes of the basin is required to understand the composition of clay minerals and unveil their depositional and diagenetic history.

The effective porosity in the studied source rocks ranges between 2% to 12%. The La Renta Formation has the higher porosities which range between 5% to 12%. Considering this, the La Renta Formation is a probable carrier bed, despite not being modeled as an independent source rock from the Galembo Formation. We estimated TOC and organic porosity from well logs, revealing that organic porosity values range from 0.0006 v/v to 0.002 v/v for all three formations, implying low levels of organic matter conversion (Jarvie, 2014). When compared to worldwide shale plays (e.g., Barnett Shale), the estimations for the MMVB are quite low, because organic porosity values range from 0.01 v/v to 0.04 v/v (Romero-Sarmiento et al., 2013). However, our results are comparable with those obtained by Piedrahita & Aguilera (2017a, 2017b) in the study area, who used different well log estimations to obtain kerogen density and organic porosity. Also, our results match those obtained by Aguilera (2022), who applied Chen & Jiang's (2016) methodology for organic porosity estimations from pyrolysis
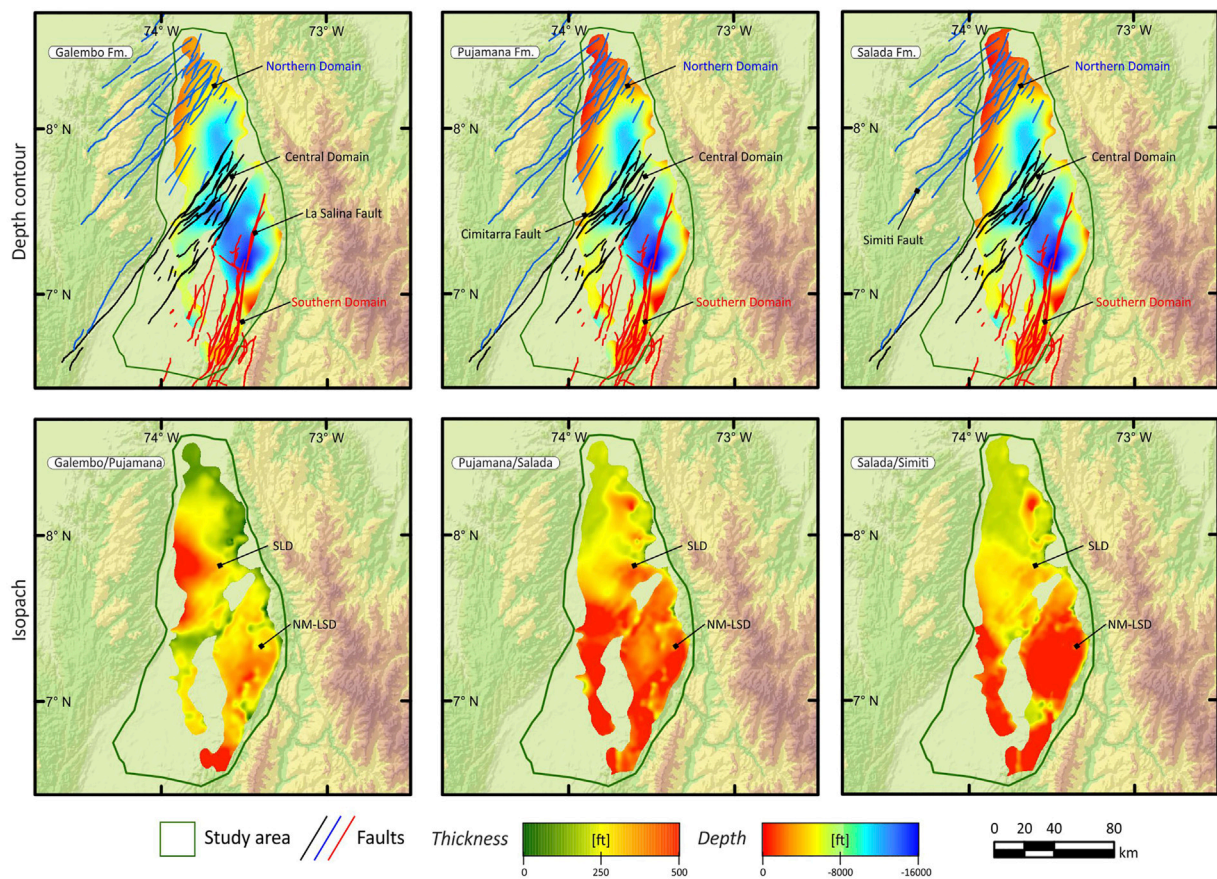
FIGURE 8
Depth contour and isopach maps (in feet) of the Salada, Pujamana and Galembo formations in the Middle Magdalena Valley Basin. The maps show the thickness trends of the source rocks from the seismic interpretation as well as the main depocenters in the study area.
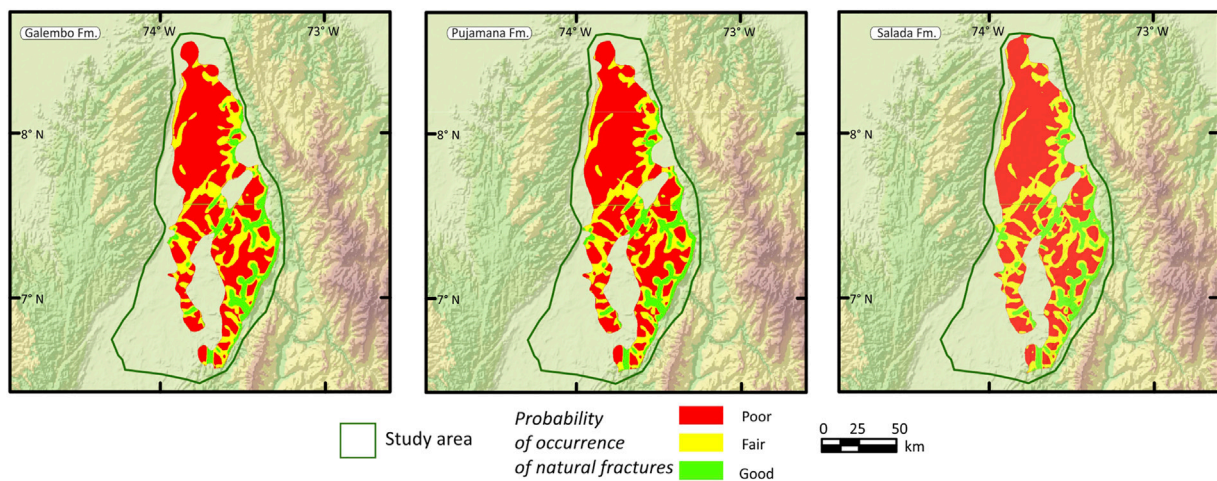

FIGURE 9
Probability of occurrence of natural fractures maps of the Salada, Pujamana, and Galembo formations in the Middle Magdalena Valley Basin.
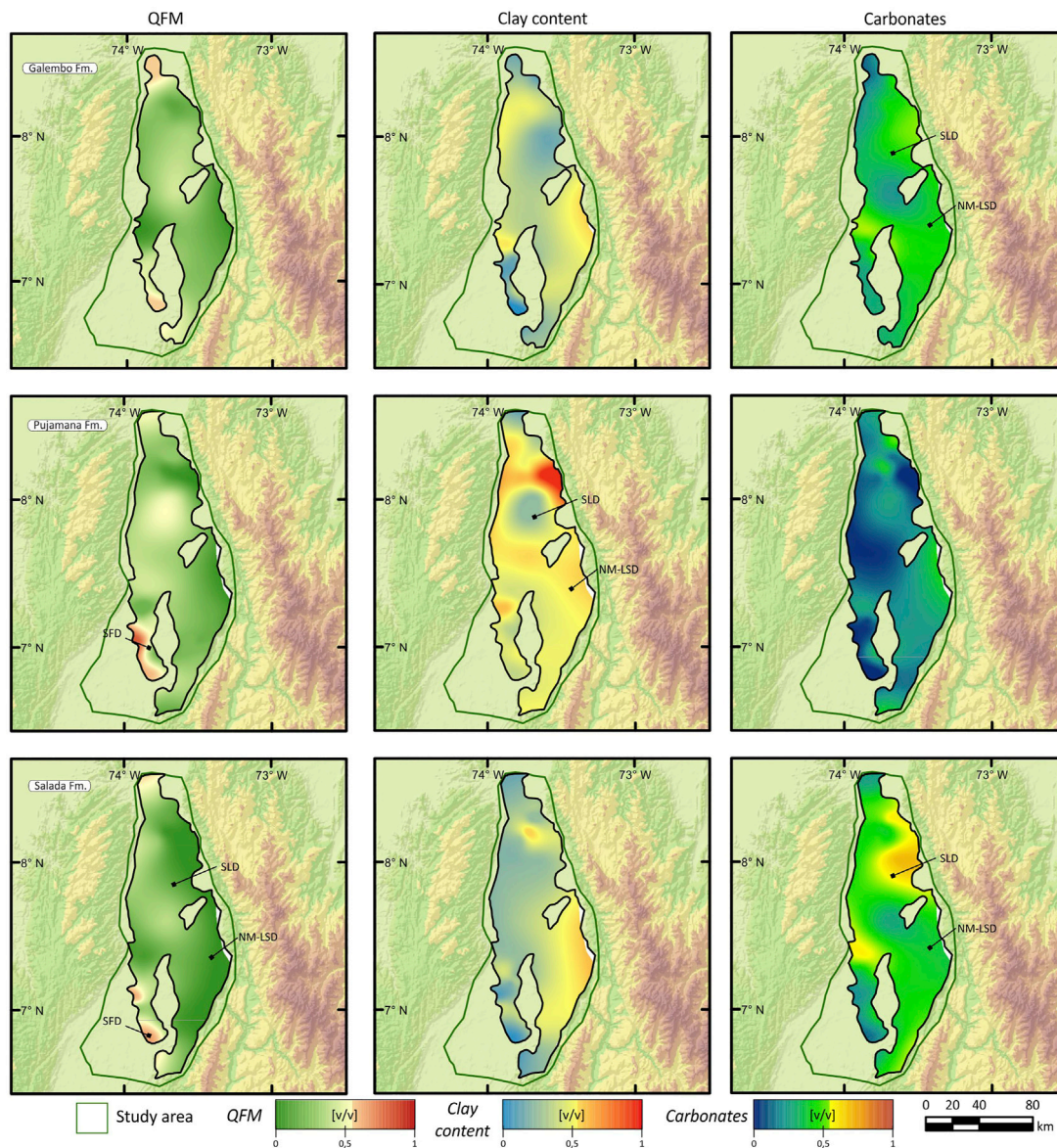
FIGURE 10
Quartz-Feldspar-Micas (QFM), clays and carbonates content maps from petrophysical modeling of the Salada, Pujamana, and Galembo formations in the Middle Magdalena Valley Basin.

datasets, and to Ceron et al. (2013) estimations using digital rock physics. Finally, should be expected higher organic porosity values in deeper parts of the study area.

The overpressure increases the production drive of liquid hydrocarbons and favors higher production rates (Gong & Rodriguez, 2017) but also is a sign of sealing integrity and capacity. As a first approach, the pore pressure analysis helps screen overpressure intervals and allows us to map the distribution of areas with low pore pressure, which might become a risk for the source-rock play (see Section 5.1). We observed two areas with low pore pressure conditions: First, areas with structures beveled by unconformities (e.g., La Cira-Infantas High), and second, areas with low overburden (e.g., Morales Monocline). Our results are consistent with those obtained by

Vargas-Silva et al. (2019), revealing that factors such as water expansion have a negligible effect on the pore pressure in the basin. Although thermal stress and oil and gas generation have limited influence on the pore pressure estimation at the wells, with most of the effect related to compaction pressure, its effects could increase overpressure in deeper areas and be observed in the predicted GOR (see Section 4.5).

4.3 Heat flow and burial modeling

Progressive burial of the strata during the basin infill process promotes physical changes in rock properties, reducing their porosity and permeabilities in contrast to increasing density,
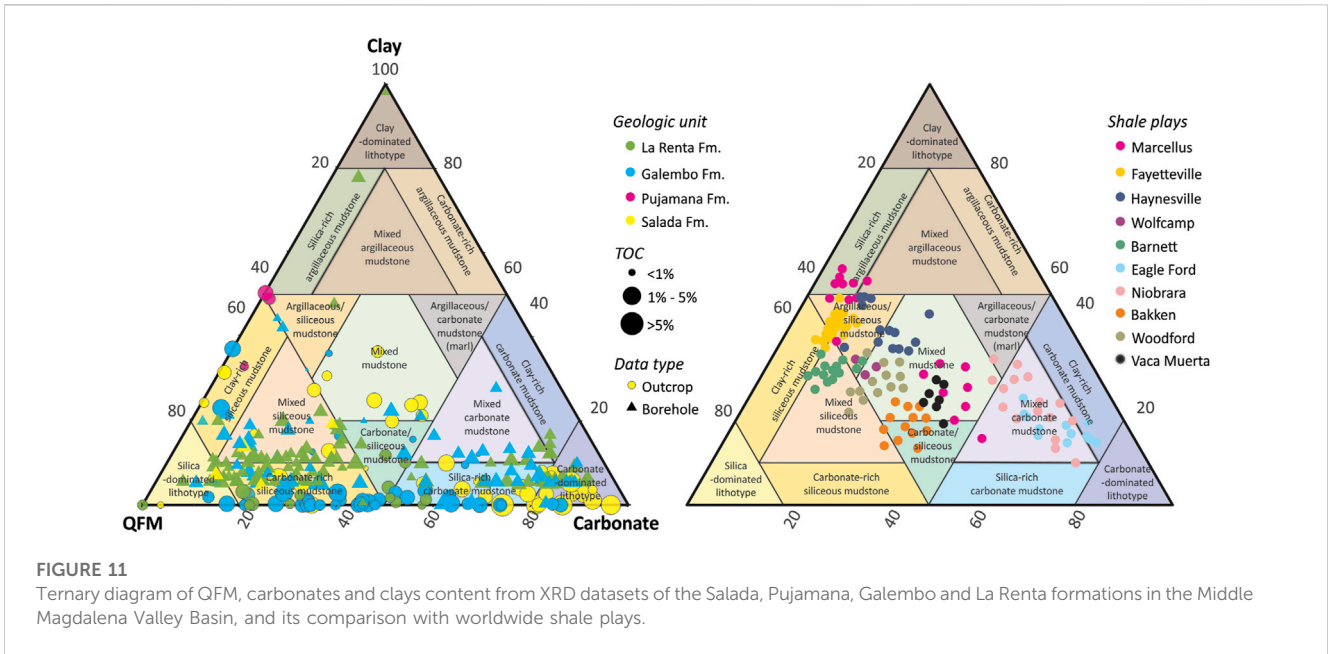
FIGURE 11
Ternary diagram of QFM, carbonates and clays content from XRD datasets of the Salada, Pujamana, Galembo and La Renta formations in the Middle Magdalena Valley Basin, and its comparison with worldwide shale plays.
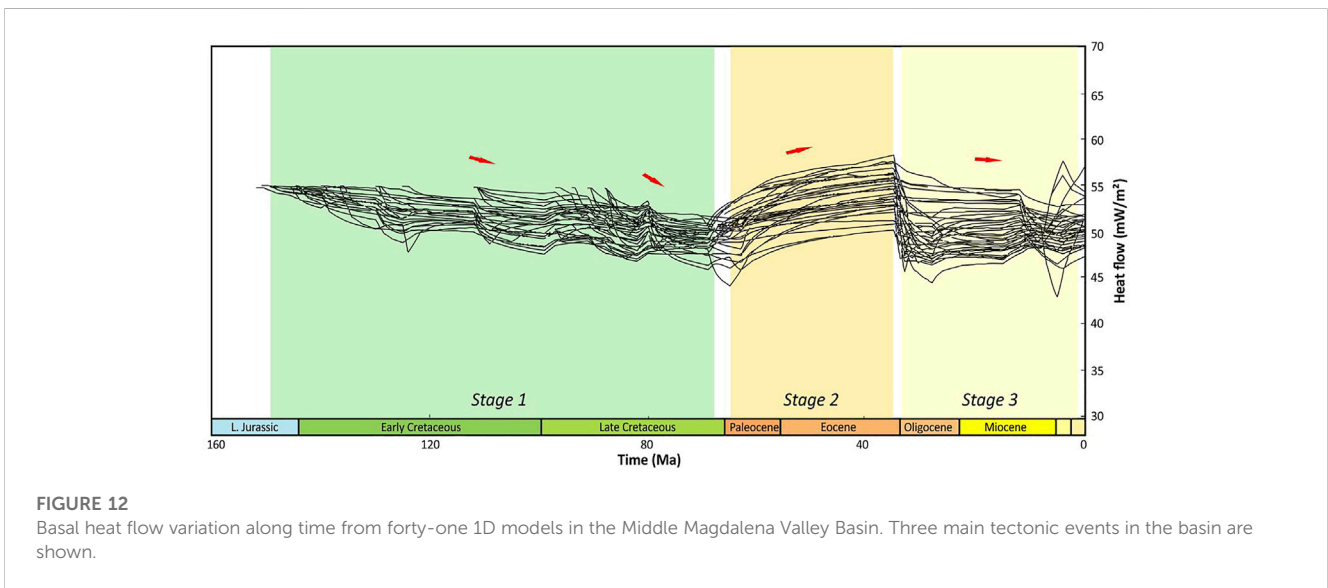

FIGURE 12
Basal heat flow variation along time from forty-one 1D models in the Middle Magdalena Valley Basin. Three main tectonic events in the basin are shown.

velocity, and heat capacity as the rock is buried and compacted by sediments. Athy's Law (Allen & Allen, 2013) explains these processes and allows empirical calculation based on porosity reduction as burial increases. In this way, the burial models of the wells were calibrated by comparing the porosity, velocity, and density profiles measured from well-logs and laboratory data to predicted data by modeling (Figure 3). As a result, burial modeling suggests at least two significant episodes of generation of accommodation space, which extend throughout the Cretaceous and from the Oligocene to the present day. In contrast, a major episode of erosion is recorded from the final part of the Late Cretaceous until the Eocene, widely observed using seismic lines and outcrop data (e.g., Section 4.1). From the Berriasian through the Hauterivian, the basin records an increased rate of tectonic

subsidence (Tambor and Rosa Blanca formations). The La Paja and Tablazo formations, which span the Barremian to Aptian, undergo a low tectonic subsidence rate. The Simiti, Salada, Pujamana, Galembo-La Renta, and Umir formations, which range from the Albian to the Maastrichtian, show an increase in the basin's tectonic subsidence rate. Although the highest subsidence rates are recorded in the southern province (e.g., La Salina-Nuevo Mundo Depocenter), the central and northern provinces have areas with high subsidence rates (e.g., Santa Lucia Depocenter).

The heat flow modeling allows us to identify three stages of the basal heat flow history consistent with the major tectonic episodes described above, reflecting burial history (Figure 12). As an alternative to the heat flow model published by Gonzalez et al. (2020), during the Early Cretaceous, the basin setting could be
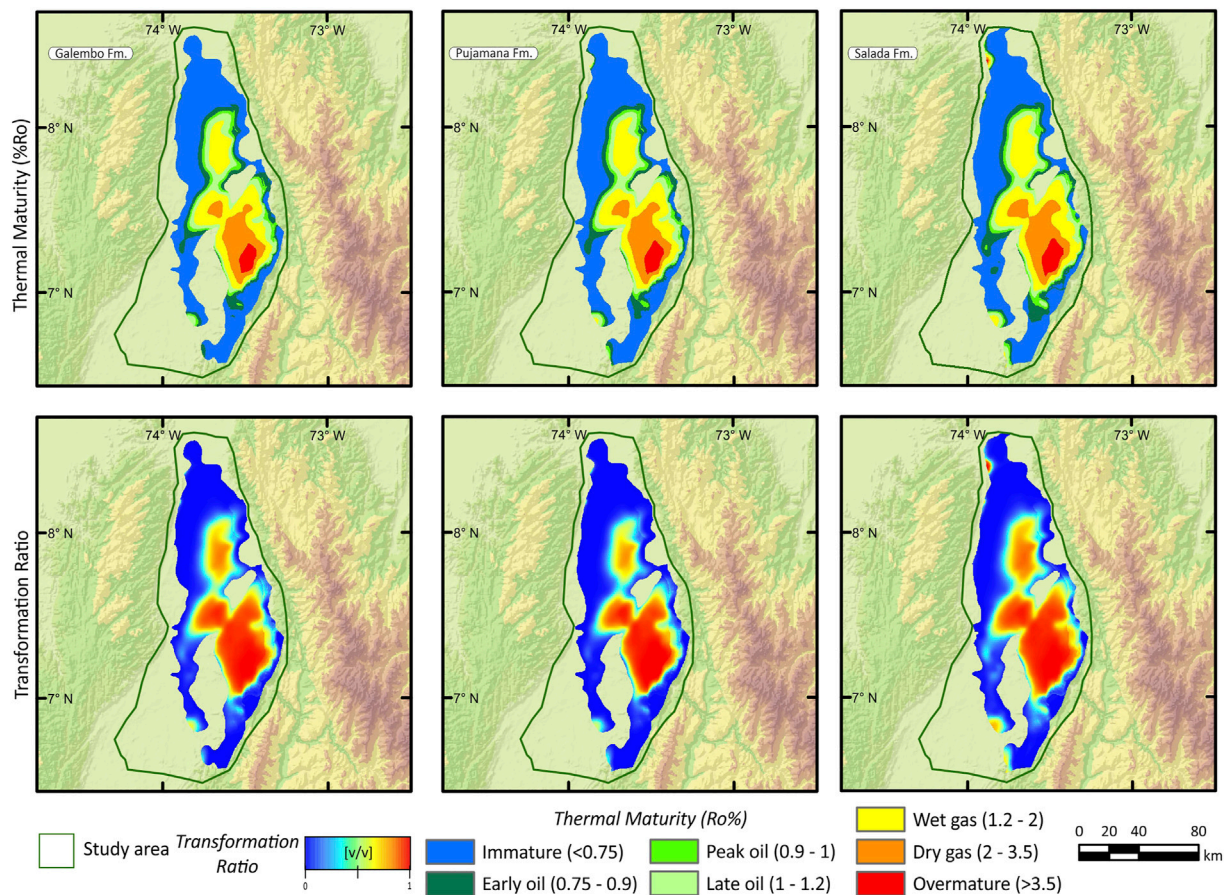
FIGURE 13
Thermal maturity (%Ro) and transformation ratio maps of the Salada, Pujamana and Galembo formations in the Middle Magdalena Valley Basin.

explained with basal heat flow values below 60 mW/m². Likewise, the history of basal heat flow is consistent with the subsidence history of the basin proposed by authors such as Sarmiento-Rojas et al. (2001), who suggest that the stretching factors (β) for the basin are very low (≈1.2).

4.4 Hydrocarbon generation

4.4.1 Transformation ratio

Figure 13 compares the transformation ratio and the modeled thermal maturity. The source-rock transformation ratios are quite different in the SLD and NM-LSD. The highest transformation ratios were reached in the NM-LSD, ranging between 70% to 100% (wet-gas window to overmature) for the Galembo, Pujamana, and Salada Formations. In the SLD, the highest transformation ratios range between 50% to 80% (peak-oil to the wet-gas window). The variation in the transformation ratio between depocenters is controlled by the maximum burial depth. However, the number of boreholes drilled in the depocenters is low to compare the transformation ratios' variations properly. In the same way, there is a need for more data to evaluate the effects of crustal radiogenic

heat production and the conductivity of coals within the Cenozoic succession, and we hope future research assesses it.

4.4.2 Total hydrocarbons generation

The estimation of generated and retained hydrocarbons from the different source rocks is based on a volumetric material balance controlled by the kinetics of the source rock model used, in this case Pepper and Corvi's (1995) organofacies models, according to its kerogen type and thermal maturity levels reached during the maturation process. From these models an estimation of the hydrocarbons, generated and expelled, is made and a retained volume of hydrocarbons is obtained (liquid and gas phases), volume that is controlled by the organic porosity wettability, adsorption and absorption of the rock matrix, and the progressive transformation of kerogen into hydrocarbons with increasing temperature.

The total generation potential of all modeled Upper Cretaceous rocks in the MMVB is approximately 163.63 billion BOE (Table 1). Critical factors affecting total generation potential include source-rock quality and thermal maturity. The extent of the Upper Cretaceous generation pod is consistent with the location of major conventional fields (Figure 14).

TABLE 1 Total retained and generated hydrocarbons of the Upper Cretaceous rocks in the MMVB.

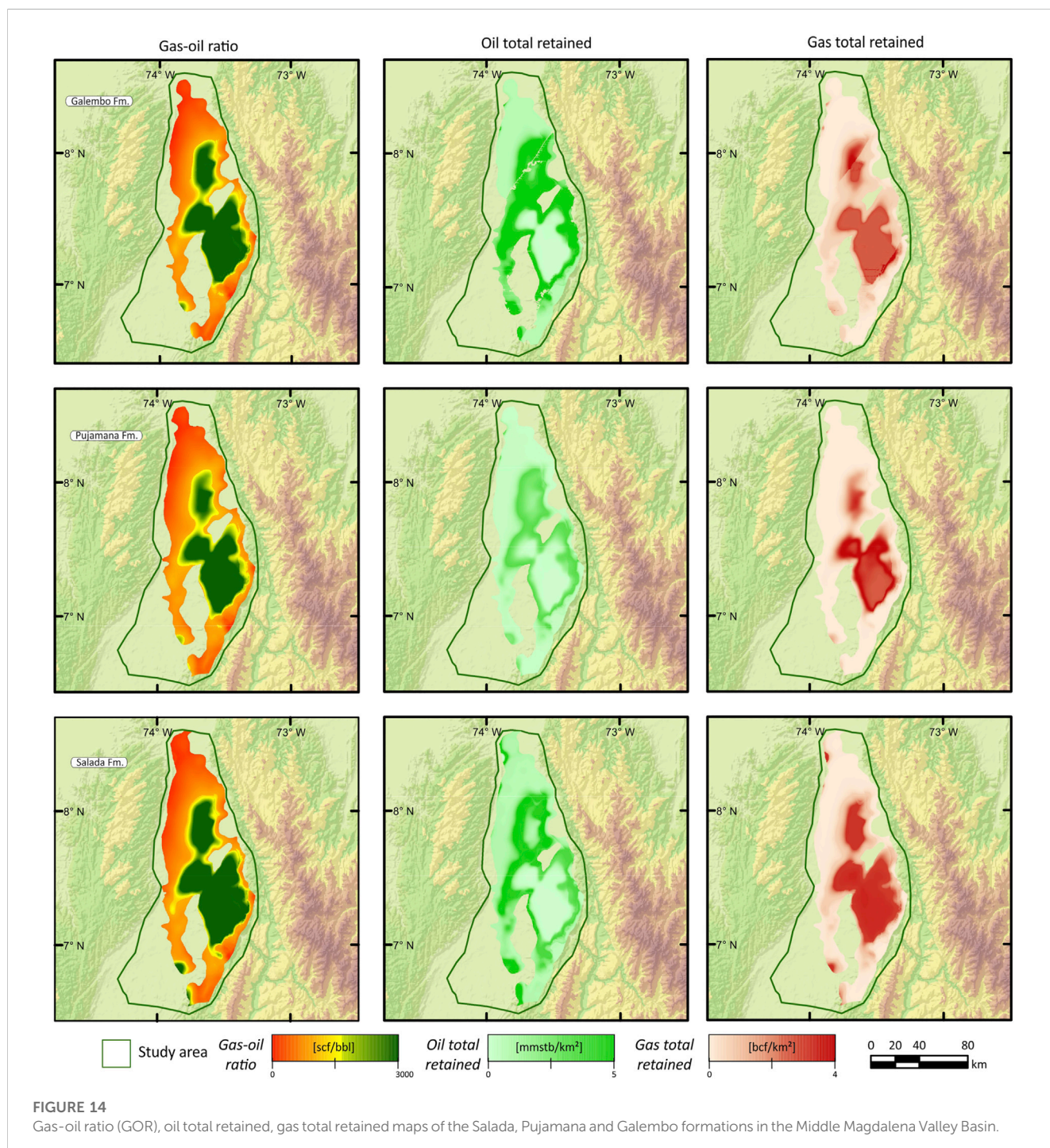| Source rock	Gas retained (Tcf)	Liquid retained (Bbbl)	Gas retained (Tcf)[a]	Liquid retained (Bbbl)[a]	Total HC generated (billion BOE)	Average GOR (scf/bbl)
Galembo Fm	8.30	23.53	1.24	3.52	48,77	1,508
Pujamana Fm	8.0	10.96	1.2	1.64	44,69	1,371
Salada Fm	11.82	18.6	1.77	2.79	70,16	1,577
Total	28.12	53.09	4.21	7.95	163,63	4,456

[a]After a 15% recovery factor.

FIGURE 14
Gas-oil ratio (GOR), oil total retained, gas total retained maps of the Salada, Pujamana and Galembo formations in the Middle Magdalena Valley Basin.

TABLE 2 Cut-off values to rank sweet spot areas in the MMVB.

Criteria	No *sweet spot*	Fair	Good
Effective porosity (%)	≤2%	2%–5%	≥5%
Transformation ratio (fraction)	≤0,2	0,2–0,5	≥0,5
GOR (scf/bbl)	≤1,000	≥1,000	
Liquid retained (Bbbl/km^2)	≤1,0	1,0–5,0	≥5,0
Gas retained (Bcf/km^2)	≤0,5	≥0,5	

Determining the relative hydrocarbon quantities expelled by each source rock depends on several other critical variables, including organofacies. For example, Aguilera (2022) observed similar HIo values between Lower and Upper Cretaceous rocks (HIo 600–750 mg HC/g TOC). However, Lower Cretaceous seem to have affinity with lower quality Pepper and Corvi' (1995) B/D/ E organofacies. The Upper Cretaceous rocks have a lower maturity trend and organofacies with a lesser proportion of terrigenous organic matter, which increases the volume of hydrocarbons expelled compared with the Lower Cretaceous source rocks.

The thermal maturity influences the total hydrocarbons generated because the Galembo, Pujamana, and Salada formations reached higher transformation ratios in the depocenters than in less mature margins of the basin. Although hydrocarbon generation began in the Late Cretaceous, most of the generation occurred in the Neogene, coincident with the maximum burial depth as earlier studies suggest (e.g., Gonzalez et al., 2020).

4.5 Retained hydrocarbons

The basin modeling total liquid and gas retained from the Upper Cretaceous source rocks of the MMVB are estimated at 7.95 Bbbl and 4.21 Tcf, after a 15% recovery factor respectively. Most liquids and gas retained are in the Galembo and Salada Formations rather than the Pujamana Formation (Figure 14). Although the results from this study are comparable with those from Mora et al. (2018), with modeled volumes of a similar order of magnitude, their proposal considers the Pujamana Formation with the higher total gas retained.

The predicted GOR values range between 10–3,780 scf/bbl, suggesting that the expelled products will be primarily light oil in areas below 75% transformation ratios and gas condensates in areas with higher transformation ratios (Figure 14). Despite no unconventional well test data, conventional production data help to check the consistency of the predicted GOR. For example, oil fields neighboring the Cachira High (e.g., Totumal field) produced 130 barrels from the Galembo Formation in initial tests, but its production quickly declined. Consistent with the GOR values of approximately 600 sfc/bbl predicted by the basin modeling for such interval in that part of the basin.

The volumes of hydrocarbons retained within the source rocks suggests good potential for shale oil and gas plays. Therefore, the predicted hydrocarbon type is light oil, with some gas condensate in areas of high thermal maturity. This result is consistent with the oil and gas shows reported during drilling in most wells.
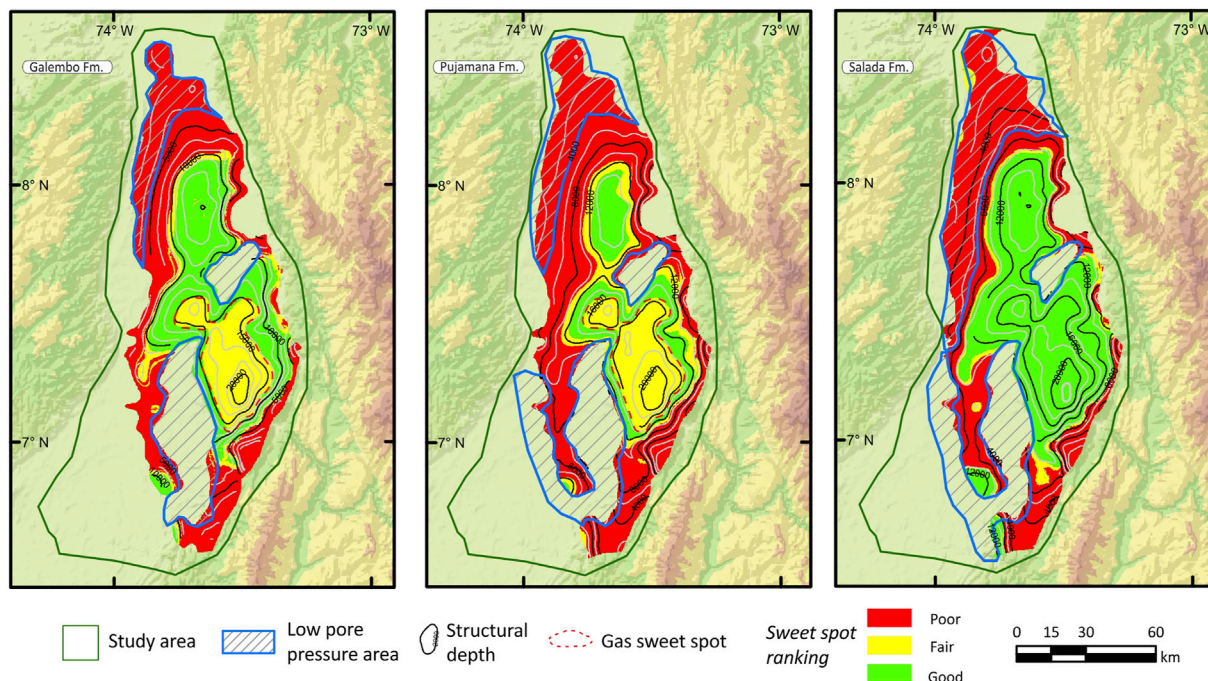

FIGURE 15
Sweet spot areas maps of the Salada, Pujamana, and Galembo formations in the Middle Magdalena Valley Basin. Low pore pressure areas and structural depth contours (in feet) are also shown.

Several authors mentioned solid bitumen remnants and extensive asphaltites within the Upper Cretaceous rocks' outcrops of the study area and boreholes drilled near the Cachira High (e.g., Acevedo et al., 2012b). A plausible explanation invokes the generation of solid bitumen in the early stages of hydrocarbon generation (Juliao-Lemus et al., 2015). However, future source-rock correlations should answer this question, although the possibility of asphaltite accumulations from hydrocarbons generated in the Lower Cretaceous source rocks cannot be ruled out.

5 Discussion

5.1 Geologic factors that control the sweet-spots areas

Each basin's geology is different, and its conditions should be evaluated to propose a *sweet spot*. In this context, we define a *sweet spot* as a geographic area with expected high production values surrounded by areas with lower production values, following Shurr & Ridgley (2002) definition. This proposal differs from the *sweet spot* considered from the net-pay at a reservoir scale (e.g., Slatt et al., 2015) or economically viable areas.

After data integration and interpretation, we suggest that the *sweet spot* areas in the MMVB for the Galembo, Pujamana and Salada Formations are driven by: 1. The effective porosity. 2. The transformation ratio. 3. The total retained gas and liquid hydrocarbons. 4. The gas-oil ratio. We propose the following cut-off values to rank and reclassify each map into good, fair, or low (Table 2).

As presented before (see Section 4.1, 4.2), the mineralogical brittleness is constrained by the facies distribution, considering that all source rocks were deposited under mixed-ramp conditions, with low deposition of clay minerals. On the other hand, the thickness variation of the source rocks along the basin remains quite constant, despite areas with higher thicknesses (see Section 4.1). The probability of natural fractures (see Section 4.1), considered a criterion that would account in combination with the *sweet spot* maps, helping to screen areas that could be produced under conventional conditions. These criteria are not deemed as factors for a definition of an unconventional *sweet spot* in the MMVB at a regional scale, because they are related to more local effects related to sedimentological heterogeneity and structural deformation within the basin. Organic porosity is another geologic criterion that does not drive the sweet spot definition and is included in the effective porosity. The basin modeling and petrophysical data show that thermal maturity in the areas outside the depocenters, where most of the wells have been drilled so far in the basin, is too low to develop significant organic porosity systems (see Section 4.2).

However, published results of mercury intrusion porosimetry reveal discrete intervals within the Salada and Galembo Formations, with pore volume constituted by 0.2–5.5 nm pore sizes (Juliao-Lemus et al., 2015; Casadiego-Quintero & Rios-Reyes, 2020), that could be produced under more conventional completions (Baek & Akkutlu, 2019).

5.2 Distribution of shale oil and shale gas sweet spots

Considering geologic constraints, we present three *sweet-spot* maps for the Galembo, Pujamana, and Salada formations (Figure 15). Contours in maps represent depth contours from each stratigraphic surface, and hatched polygons are areas with an additional risk due to low pore pressure conditions (see Section 4.2). Also, when combined with curvature analysis maps, the *sweet-spot* maps highlight areas that could be produced under unconventional completions and improve conventional completions. The green areas represent a good sweet-spot area, the yellow and red areas represent fair and no sweet-spot areas, respectively.

These maps help delineate areas representing shale oil and shale gas plays. Until now, only the Picoplata-1 well was drilled in the SLD reached the Salada Formation with promising results, but its tests were conventional. Although the La Renta Formation was not included in the sweet-spot maps, future research is required to confirm if it could be considered as a carrier bed play. Future drilling in the depocenters is required to confirm the modeling results and to address its uncertainties.

6 Conclusion

This study used petroleum systems analysis to provide a regional framework for understanding unconventional hydrocarbon prospectivity of the Upper Cretaceous source rocks in the MMVB. Results have allowed to assess the spatial distribution and petroleum generation potential of Upper Cretaceous source rocks across the basin, and the likely volumes of both expelled and retained hydrocarbons. The deterministic petroleum systems model estimated the volumes of retained hydrocarbons at 7.95 Bbls of oil and 4.21 Tcf of gas after a 15% recovery factor. The combined volumes of hydrocarbons generated from the Upper Cretaceous are mapped, highlighting the broad extent of the generation pods and their consistency with the location of major conventional fields across the basin. Source rocks within the Salada and Galembo formations are the biggest contributors to both expelled and retained hydrocarbons because these are the richest, thickest, and most extensive source facies, with good to excellent potential across the entire basin. In contrast, the hydrocarbon volumes generated by the Pujamana Formation are low because its shale facies have source rocks of lower quality.

The three sweet-spot maps for the Upper Cretaceous source rocks show areas with good potential for shale oil and shale gas to be tested. In addition, the development of these resources in such areas could contribute to the energy transition of the region. However, the distribution of the sweet-spot areas reveals that the depocenters are still to be drilled to better constrain uncertainties regarding the facies and source rock quality, and to prove the economic feasibility of the unconventional play in the MMVB.

Data availability statement

The raw data supporting the conclusion of this article will be made available by the authors, without undue reservation.

Author contributions

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Conflict of interest

The authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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