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Geochemistry of Petroleum Gases and Liquids from the Inhassoro, Pande and Temane Fields Onshore Mozambique

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Abstract: Although the first petroleum fields in the Mozambique basin were discovered more than 60 years ago, the composition and origin of petroleum fluids in this basin are largely unknown. We studied the geochemical composition of petroleum gases and liquids from the Inhassoro, Pande and Temane fields located onshore Mozambique. The gases are relatively dry (methane-dominated, average $C_1/(C_1–C_5)$ ratio is ~0.96), have pure thermogenic origin, originate predominantly from marine shale source organofacies and show no evidence of primary microbial gas or biodegradation. Most condensates have relatively high API gravity up to 76 degrees, are very mature and contain only traces of biomarkers, likely from migration contamination. However, biomarkers in the light oil from the Inhassoro field indicate that the oil derived from sub-oxic marine shales of the Late Cretaceous age. We suggest that the Aptian-Coniacian Domo Shale is the likely source rock for petroleum gases and liquids in the studied fields. Our geochemical data, including gas isotopes, as well as source-specific and age-specific biomarkers, exclude coals in the Late Carboniferous—Early Jurassic Karoo Supergroup as effective source rocks for the studied fields.

Keywords: petroleum; natural gas; oil; isotopes; Mozambique

1. Introduction

The Mozambique basin encompasses over 300,000 km^2 onshore and offshore Mozambique and is the largest sub-equatorial sedimentary basin in Africa [1,2]. The Mozambique basin was formed in the oceanic void created by the rifting of the African and Antarctic plates during the Gondwana break-up in the Late Jurassic period [3]. The steeply dipping volcanic hills of the Lebombo—Sabe Monocline, which form the western and northwestern margin of the basin, mark the onset of this rifting event and are tightly dated at 183 ± 1 Ma [4]. The lower part of the basin's sedimentary fill contains sedimentary and volcanogenic rocks of the Karoo Supergroup (Late Carboniferous—Early Jurassic Gondwana unit) and Middle-Upper Jurassic continental red beds [3]. The upper part of the sedimentary fill is divided into the Cretaceous "Limpopo" and the Tertiary "Zambezi" deltaic super-cycles [5].

Petroleum exploration in the Mozambique basin started in 1904 [6], and 85 onshore exploration wells have been drilled to date. These wells penetrated the Tertiary and Cretaceous section and resulted in the discovery of four fields (Pande, Temane, Inhassoro and Buzi). Exploration success is relatively low, as only 10% of exploration wells resulted in petroleum discoveries. There are several onshore oil and gas seeps reported in the basin [6,7].

Pande and Temane are the two fields currently producing petroleum fluids in Mozambique. Inhassoro is not yet producing but development wells are being drilled. These fields are located about 600 km northeast of Maputo near the coast in Inhamnabe province (Figure 1). The Pande, Temane and Inhassoro fields were discovered in 1950s–1960s by Gulf Oil [6]. These fields contain gas, condensate and light oil in sandstones of the Upper Cretaceous Lower Grudja formation. The traps are very subtle structures, and stratigraphic seals largely control the shape and size of accumulations [8]. The Pande field produces dry gas from the Lower Grudja G-6 reservoirs located at depths between 1050 and 1500 m below surface. Wells in the Temane field produce gas and condensate from the G-9 reservoir. Oil has been found in the Inhassoro field in the G-6 (thin oil rim with a gas cap) and G-10 (under-saturated oil) reservoirs.

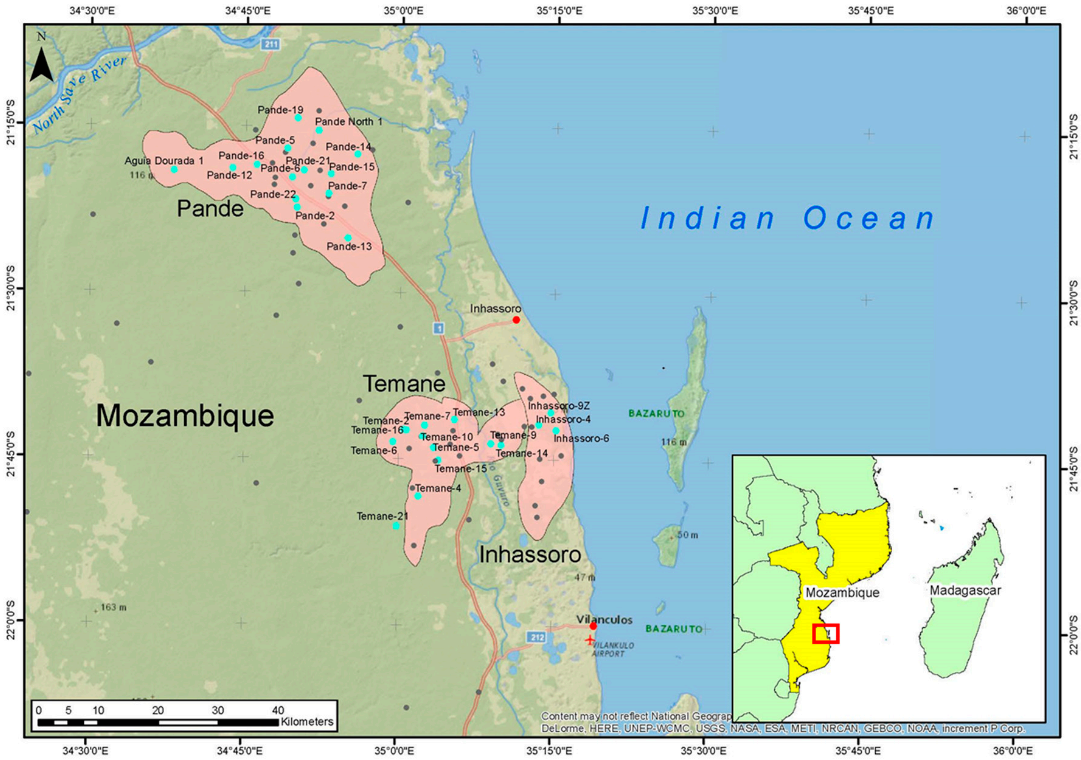

Figure 1. Location maps. The insert shows the country of Mozambique, and the red box indicates the boundaries of the larger map. The larger map shows the outlines of fields (based on IHS database) and the wells (grey dots). Wells with abbreviated labels are the wells used in this study and listed in Tables 1 and 2 (bright green dots).

Although the first gas field onshore Mozambique was discovered 60 years ago (Temane in 1956), no geochemical data has been published from this area before. As a result, there are many speculations about the effective source rocks in the Mozambique basin, and intervals as old as the Late Carboniferous—Early Jurassic Karoo Supergroop [2] and as young as the Paleogene Cherigoma Formation [9] have been suggested as source candidates. Here, we present and discuss geochemical data on natural gases, condensates and light oils sampled from the Inhassoro, Pande and Temane fields. Using molecular and isotopic composition of gases and biomarkers of liquids, we infer the age, organofacies, and thermal maturity of potential source rocks of these fluids. This study is an example of source rock re-assessment based on integrated gas and oil geochemical and biomarker analyses.

2. Materials and Methods

A total of 37 gas samples from 30 wells in the Inhassoro, Pande and Temane fields were collected and analyzed between 1990 and 2012. The locations of sampled wells are shown in Figure 1. An Inhassoro gas sample from well I-9z is associated with oil produced from an oil leg in the Gruja G-6 reservoir. All other gas samples come from wells producing mostly gas and condensate. The gases were collected during drill stem tests (DST), production tests and from well heads during production. Molecular and isotopic compositions of gases were analyzed at different laboratories (mostly at Isotech Laboratories (Champaign, IL, USA) and Fugro Robertson (UK)). Gas analyses were performed using regular methods of gas chromatography (GC) and mass spectrometry (MS) methods described, for example, in [10]. The authors did not find any inconsistencies between analytical results from different laboratories. The carbon isotope composition of gases is expressed in $\delta^{13}C$ values, which are reported as per mil (‰) relative to the Pee Dee Belemnite (PDB) standard. The hydrogen isotope composition of gases is expressed in $\delta^{2}H$ values, which are reported as per mil (‰) relative to standard mean ocean water.

A total of 20 condensate and light oil samples were collected, analyzed and studied. In this paper we present and discuss geochemical data for two representative samples: a condensate from well Temane-13 and a light oil from well Inhassoro-9z. Geochemical measurements (API, sulfur, metals, and saturates, aromatic, resins, asphaltenes (SARA)) on these liquids, whole oil gas chromatography (WOGC) and biomarker (GC-MS) analyses were performed at Weatherford (Shenandoah, TX, USA) using methods and equipment described in [10].

3. Results

3.1. Geochemistry and Origin of Gases

The molecular composition of sampled gases is presented in Table 1. Hydrocarbons dominate in gas samples and compose 88.1–99.4% (average 97.2%) of the total gas. Methane (C_1) is the dominant hydrocarbon gas and ranges from 79.6–95.9% (average 92.8%). Gases are generally dry with an average $C_1/(C_1-C_5)$ ratio of 0.957. Nitrogen is the dominant non-hydrocarbon gas and ranges from 0.1 to 11.9% (average 3%). Oil-associated gas in the I-9z well has very low CO_2 content (0.014%) while Pande and Temane gases do not contain any measurable CO_2.

The isotopic composition of sampled gases is presented in Table 2. $\delta^{13}C$ of C_1 varies from −45.2‰ to −34‰ (average −40.1‰). Interpretation based on the genetic relationships of $\delta^{13}C$ of C_1 vs. $C_1/(C_2+C_3)$ (Figure 2 [11–14]) and $\delta^{13}C$ of C_1 vs. $\delta^{2}H$ of C_1 (Figure 3) suggest that all studied gases have a thermogenic origin. A Chung's plot (Figure 4) confirms that the gases have a pure thermogenic origin and do not contain any microbial gas. It is likely that the gases originated mostly from a single source rock (likely shale but not coal). However, the gas lines plotted on the Chung's plot are not straight, which may imply some mixing of gases from different sources [15]. Although the gases are located at shallow depths (1154–1529 m measured depth below surface) and relatively low temperatures (between 30 and 60 °C), there is no evidence of biodegradation in these gases.

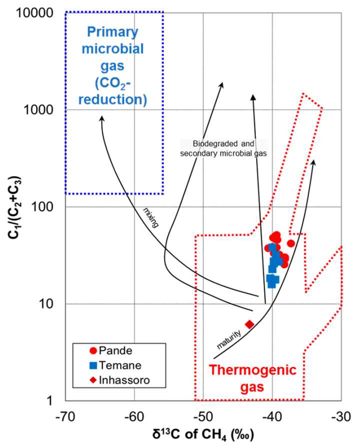

Figure 2. Gas genetic diagram using $\delta^{13}C$ of CH_4 vs. $CH_4/(C_2H_6 + C_3H_8)$ for selected gases from the Inhassoro, Pande and Temane fields. Genetic fields are defined according to [11–14].

Table 1. Molecular composition of gases from the Inhassoro, Pande and Temane fields. "DST" stands for drill-stem test, "PT" stands for production test, and "nd" stands for not detected.

Field	Well	Sample	Top Depth (m)	Base Depth (m)	Reservoir	Molecular Composition (mol %)														Ratios	
						C_1	C_2	C_3	iC_4	nC_4	iC_5	nC_5	C_{6+}	CO_2	N_2	O_2	Ar	He	H_2	$C_1/(C_2+C_3)$	$C_1/(C_1\text{-}C_5)$
Inhassoro	Inhassoro-4	DST-1			G-9																
Inhassoro	Inhassoro-4	DST-2			G-6																
Inhassoro	Inhassoro-6	DST-3	1162.1	1172.8	G-6																
Inhassoro	I-9z	Wellhead			G-6	79.57	9.29	3.70	0.91	0.91	0.30	0.22	0.40	0.014	4.56	0.10	0.0228	0.0028	nd	6	0.838
Pande	Aguia Dourada-1	DST-1	1053.5	1062.7	G-6																
Pande	Pande North				G-6	94.94	1.75	0.77	0.23	0.25	0.10	0.12	0.46		0.68				0.0269	38	0.967
Pande	Pande-14	DST-2	1521	1529	G-11	93.10	1.80	0.40		0.20		0.10		nd	4.40					42	0.974
Pande	Pande-14	DST-4	1150	1154	G-6	92.40	2.80	0.80		0.50		0.20		Trace	3.30					26	0.956
Pande	Pande-14	DST-4	1150	1154	G-6	93.60	2.40	0.80		0.40		0.10		nd	2.70					29	0.962
Pande	Pande-14	DST-4	1150	1154	G-6	84.70	2.10	0.70		0.40		0.20		nd	11.90					30	0.961
Pande	Pande-2				G-6	95.59	2.39	0.56	0.17	0.20	0.07	0.07	0.34		0.10				0.0269	32	0.965
Pande	Pande-5				G-6	95.69	1.42	0.64	0.21	0.22	0.08	0.08	0.33		0.74				0.0269	46	0.973
Pande	Pande-6				G-6	95.82	1.33	0.57	0.18	0.20	0.08	0.07	0.37		0.85				0.0269	50	0.975
Pande	Pande-7		1160	1180	G-6	93.66	2.08	0.83	0.21	0.22	0.07	0.05	0.23		2.62		0.02	0.02		32	0.964
Pande	Pande-7				G-6																
Pande	Pande-12	Wellhead			G-6	94.98	1.59	0.47	0.12	0.12	0.04	0.03	0.10	0.006	2.46	0.042	0.0173	0.0136	nd	46	0.976
Pande	Pande-16	Wellhead			G-6	95.88	1.47	0.40	0.08	0.08	0.02	0.02	0.04	nd	1.94	0.036	0.0147	0.0176	0.0052	51	0.979
Pande	Pande-19	Wellhead			G-6	94.62	1.84	0.59	0.14	0.15	0.05	0.04	0.18	nd	2.31	0.037	0.0162	0.0166	nd	39	0.971
Pande	Pande-21	Wellhead			G-6	95.54	1.52	0.45	0.10	0.11	0.03	0.03	0.13	0.006	2.01	0.041	0.0183	0.0146	0.0018	48	0.977
Pande	Pande-15	Wellhead			G-6	93.90	2.03	0.79	0.22	0.23	0.08	0.06	0.26	nd	2.38	0.030	0.0163	0.0176	nd	33	0.965
Pande	Pande-22	Wellhead			G-6	95.66	1.51	0.48	0.12	0.13	0.04	0.03	0.16	nd	1.80	0.038	0.0135	0.0151	nd	48	0.976
Pande	Pande-13	Wellhead			G-6	94.12	1.82	0.64	0.18	0.18	0.06	0.05	0.18	nd	2.68	0.046	0.0186	0.0169	nd	38	0.970
Temane	Temane-14	PT-1			G-12																
Temane	Temane-14	PT-2			G-11																
Temane	Temane-2		1295	1297	G-7	93.39	2.32	1.10	0.26	0.33	0.10	0.08	0.39		2.01		0.01	0.02		27	0.957
Temane	Temane-2				G-9	93.07	2.05	1.32	0.38	0.46	0.16	0.12	0.40		11.90				0.0269	28	0.954
Temane	Temane-21	PT-1			G-8																
Temane	Temane-7	Production test	1283.5	1307.5	G-9																

Table 1. *Cont.*

Field	Well	Sample	Top Depth (m)	Base Depth (m)	Reservoir	Molecular Composition (mol %)														Ratios	
						C_1	C_2	C_3	iC_4	nC_4	iC_5	nC_5	C_{6+}	CO_2	N_2	O_2	Ar	He	H_2	$C_1/(C_2+C_3)$	$C_1/(C_1\text{-}C_5)$
Temane	Temane-9	DST-2			G-9																
Temane	Temane-15	Wellhead			G-9A	90.51	3.34	1.84	0.48	0.53	0.15	0.11	0.22	nd	2.75	0.038	0.0158	0.0159	nd	17	0.933
Temane	Temane-4	Wellhead			G-9A	90.06	3.26	1.78	0.46	0.50	0.14	0.10	0.20	nd	3.42	0.042	0.0180	0.0167	0.0081	18	0.935
Temane	Temane-5	Wellhead			G-9A	92.87	2.82	1.22	0.28	0.31	0.09	0.07	0.21	nd	2.05	0.043	0.0149	0.0163	0.0047	23	0.951
Temane	Temane-10	Wellhead				94.30	2.05	0.89	0.21	0.25	0.07	0.06	0.18	nd	1.91	0.040	0.0137	0.0159	0.0078	32	0.964
Temane	Temane-7	Wellhead			G-9B	94.51	1.77	0.70	0.17	0.21	0.07	0.06	0.20	nd	2.22	0.050	0.0151	0.0178	0.0147	38	0.969
Temane	Temane-6	Wellhead			G-9B	89.79	3.59	2.02	0.52	0.57	0.16	0.11	0.22	nd	2.94	0.045	0.0163	0.0160	0.0013	16	0.928
Temane	Temane-16	Wellhead			G-9B	93.09	2.37	1.19	0.35	0.38	0.13	0.10	0.21	nd	2.11	0.039	0.0144	0.0160	0.0028	26	0.954
Temane	Temane-13	Wellhead			G-9B	90.95	3.30	1.65	0.41	0.45	0.13	0.10	0.29	nd	2.64	0.042	0.0163	0.0146	0.0020	18	0.938

Table 2. Isotopic composition of gases from the Inhassoro, Pande and Temane fields.

Field	Well	Sample	Top Depth (m)	Base Depth (m)	Reservoir	Carbon Isotopic Composition $\delta^{13}C$ ‰)							Hydrogen Isotopic Composition $\delta^{2}H$ (‰)		
						C_1	C_2	C_3	iC_4	nC_4	iC_5	nC_5	C_1	C_2	C_3
Inhassoro	Inhassoro-4	DST-1			G-9	−45.2	−33.9	−28.6					−193		
Inhassoro	Inhassoro-4	DST-2			G-6	−43.0	−33.6	−28.8					−201		
Inhassoro	Inhassoro-6	DST-3	1162.1	1172.8	G-6	−45.1	−33.9	−29.0					−187		
Inhassoro	I-9z	Wellhead			G-6	−43.3	−30.9	−25.8	−25.2	−23.7	−24.6	−24.0	−156	−116	−109
Pande	Aguia Dourada-1	DST-1	1053.5	1062.7	G-6	−34.0	−25.5	−23.4					−169		
Pande	Pande North				G-6	−40.6							−138		
Pande	Pande-14	DST-2	1521	1529	G-11	−37.3	−26.8	−23.3							
Pande	Pande-14	DST-4	1150	1154	G-6	−38.3	−26.6	−23.0							
Pande	Pande-14	DST-4	1150	1154	G-6	−38.2	−27.1	−25.4							
Pande	Pande-14	DST-4	1150	1154	G-6	−38.2	−26.6	−24.0							
Pande	Pande-2				G-6	−39.0							−137		
Pande	Pande-5				G-6	−39.5							−137		
Pande	Pande-6				G-6	−39.6							−136		
Pande	Pande-7		1160	1180	G-6	−39.5	−28.6	−24.9	−22.9	−24.2			−146		
Pande	Pande-7				G-6	−38.8	−28.8	−25.5	−22.9	−24.5			−155		
Pande	Pande-12	Wellhead			G-6	−39.3	−27.1	−23.2	−21.9	−21.0	−22.0	−21.7	−143	−111	−111
Pande	Pande-16	Wellhead			G-6	−39.4	−26.7	−23.1	−21.8	−20.8	−26.7	−21.5	−143		
Pande	Pande-19	Wellhead			G-6	−40.0	−27.1	−23.1	−22.2	−21.0	−21.9	−21.7	−143		
Pande	Pande-21	Wellhead			G-6	−39.9	−27.3	−23.9	−22.5	−21.5	−24.0	−21.8	−143		
Pande	Pande-15	Wellhead			G-6	−39.8	−28.6	−25.0	−24.1	−22.5	−23.6	−22.6	−144	−112	−116
Pande	Pande-22	Wellhead			G-6	−39.6	−27.0	−23.4	−22.7	−21.4	−22.0	−21.5	−143		
Pande	Pande-13	Wellhead			G-6	−39.4	−27.3	−23.5	−22.8	−21.6	−22.9	−22.2	−140		

Table 2. *Cont.*

Field	Well	Sample	Top Depth (m)	Base Depth (m)	Reservoir	Carbon Isotopic Composition $\delta^{13}C$ ‰)							Hydrogen Isotopic Composition $\delta^{2}H$ (‰)		
						C_1	C_2	C_3	iC_4	nC_4	iC_5	nC_5	C_1	C_2	C_3
Temane	Temane-14	PT-1			G-12	−44.9	−35.3	−28.9					−198		
Temane	Temane-14	PT-2			G-11	−44.8	−35.3	−29.0					−201		
Temane	Temane-2		1295	1297	G-7	−39.0	−32.5	−27.6	−24.8	−26.8			−141		
Temane	Temane-2				G-9	−39.8							−138		
Temane	Temane-21	PT-1			G-8	−39.3	−33.6	−28.6					−188		
Temane	Temane-7	Production test	1283.5	1307.5	G-9	−39.2	−29.8	−26.0		−27.8			−144		
Temane	Temane-9	DST-2			G-9	−40.0	−33.8	−28.5					−187		
Temane	Temane-15	Wellhead			G-9A	−40.1	−32.7	−27.8	−26.5	−24.4	−25.5	−24.0	−139		
Temane	Temane-4	Wellhead			G-9A	−39.6	−32.5	−27.4	−26.4	−24.1	−25.1	−23.8	−141	−118	−109
Temane	Temane-5	Wellhead			G-9A	−40.0	−33.2	−27.9	−27.0	−24.5	−25.8	−24.2	−140	−115	−114
Temane	Temane-10	Wellhead				−39.5	−32.2	−27.6	−26.6	−24.5	−25.7	−24.2	−139		
Temane	Temane-7	Wellhead			G-9B	−40.0	−31.5	−27.1	−26.4	−24.4	−26.5	−24.2	−140		
Temane	Temane-6	Wellhead			G-9B	−40.1	−33.1	−28.1	−27.0	−24.8	−25.9	−24.1	−141		
Temane	Temane-16	Wellhead			G-9B	−39.8	−32.8	−28.0	−26.9	−24.9	−26.0	−24.2	−140		
Temane	Temane-13	Wellhead			G-9B	−40.3	−33.3	−28.4	−27.2	−25.1	−25.9	−24.3	−142	−117	−112

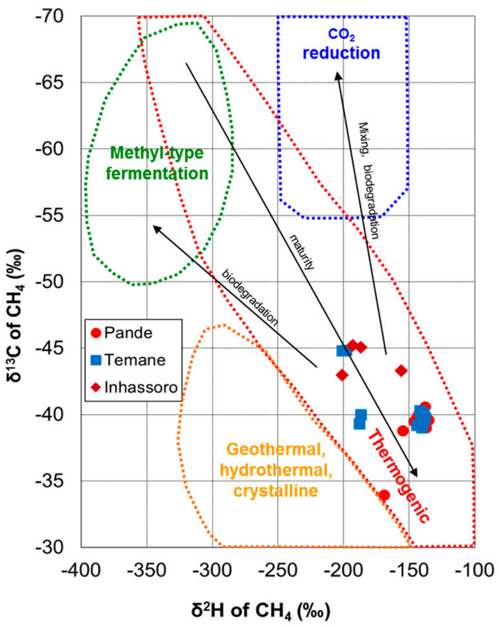

Figure 3. Gas genetic diagram using $\delta^{13}C$ of CH_4 vs. δ^2H of CH_4 for selected gases from the Inhassoro, Pande and Temane fields. Genetic fields are defined according to [12–14].

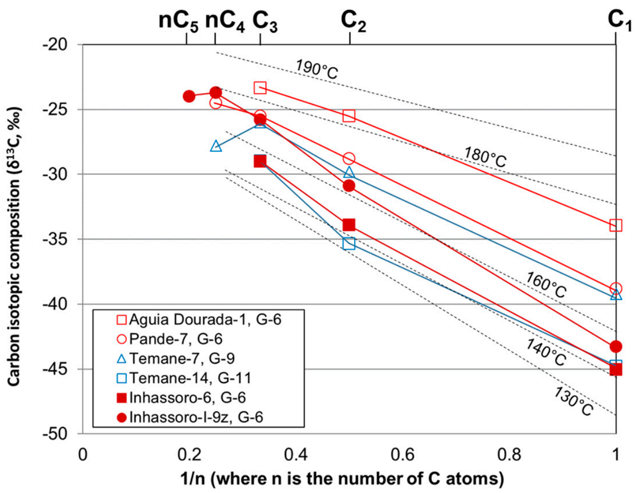

Figure 4. Carbon isotopic composition ($\delta^{13}C$) of C_1–C_5 in selected gases from the Inhassoro, Pande and Temane fields on the natural gas plot [15]. The isolines of standard thermal stress (STS, °C) are drawn after [16].

The studied gases display a clear maturity trend. Gases in the Pande field are the most mature, and its easternmost sample from the Aqua Dourada-1 well has the highest maturity. Most Pande gases formed in the gas window (R_o (or Vitrinite Reflectance, VR) from 1.2 to 1.6% (Figure 5), based on the models in [17], and they have a standard thermal stress of about 170–180 °C (Figure 4) based on the nomogram in [16]). Gases in the Temane field show intermediate maturity and gases in the Inhassoro field are the least mature. Gas from the Temane-14 well located close to the Inhassoro field has a maturity similar to gases in the Inhassoro field. Most Temane and Inhassoro gases apparently formed in the late oil-condensate window (R_o from 0.8 to 1.2% based on the models in [17], and they have a standard thermal stress of 150–160 °C based on the nomogram in [16]).

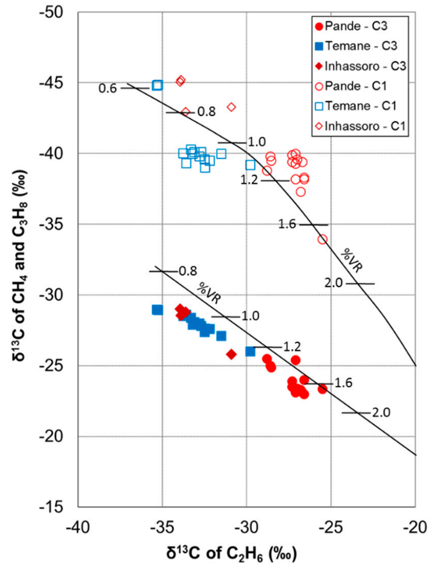

Figure 5. Carbon isotopic composition ($\delta^{13}C$) of CH_4, C_2H_6, and C_3H_8, of gases from the Inhassoro, Pande and Temane fields. Maturity of the gases can be inferred based on the relationship between $\delta^{13}C$ of gases and the vitrinite reflectance (VR (or R_o), %), as suggested in [17].

3.2. Geochemistry and Origin of Petroleum Liquids

There are two types of petroleum liquids observed in the Inhassoro, Pande and Temane fields. Most liquids in the Pande and Temane fields are white/colorless condensates in which only light hydrocarbons <nC_{15} are present (see Figure 6 for a typical condensate from the Temane-13 well). These condensates have API gravity up to 76 degrees and lack detectable sulfur and metals. Small amounts of biomarkers identified in these condensates suggest a wide range of sources and maturities. It is likely that these biomarkers were picked up by petroleum fluids along migration pathways ("migration contamination" in [18]) and therefore should not be used for source and maturity interpretation.

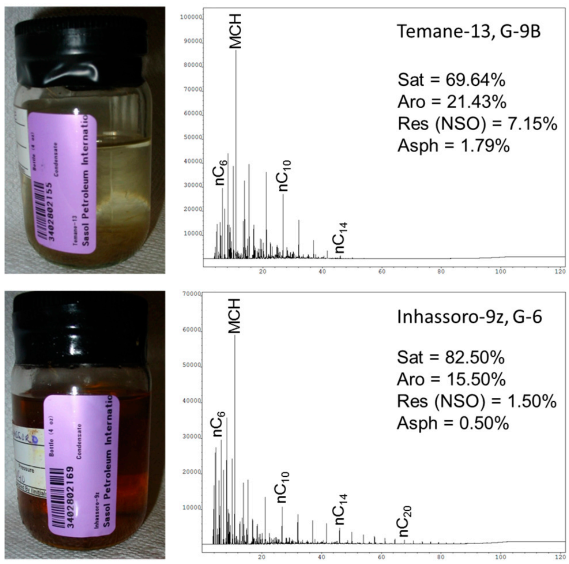

Figure 6. Pictures, whole oil gas chromatographic (WOGC) traces and SARA composition of condensate from Temane-13 well (reservoir G-9B) and light oil from Inhassoro-9z well (reservoir G-6).

The second group of liquids are yellow condensates and light oils from the Temane and Inhassoro fields. These samples, with a relatively higher content of alkanes >nC_{15} likely contain liquids from the effective source rock (i.e., not from migration contamination). As an example, well I-9z produces dark yellow light oil (API gravity 53.5 degrees) from the Grudja G-6 reservoir (Figure 6). This oil has alkanes up to nC_{35} present on WOGC and contains traces of sulfur (0.03%), vanadium (<1 ppm), and nickel (<1 ppm). Biomarkers in this sample (Figure 7) are present in sufficient amounts to be used for source typing and maturity interpretation. The Pristane/Phytane ratio is 2.88, which indicates that the liquid may have originated from marine shale source rocks deposited in the sub-oxic environment [19]. Isoprenoid/n-alkanes ratios (Pristane/nC_{17} = 0.30 and Phytane/nC_{18} = 0.13) also indicate that Inhassoro light oil likely originated from marine shale source rocks. Terpanes indicate that the oil was apparently sourced from shales [19]. Based on the relatively high concentration of gammacerane, these shales were deposited in stratified and possibly hypersaline waters [19]. The Canonical Variable (CV) 2.31 calculated from δ^{13}C of saturated fraction (−27‰) and aromatic fraction (−24.5‰) suggests significant terrigeneous input in the organic matter of the source rock [20]. An MDR value of 12 correlates to an R_o (VR) value around 1.4% and suggests that the light oil was expelled in the late oil-condensate window [21]. Other biomarker ratios, such as (DIA27S + DIA27R)/(C27S + C27R) = 0.73, C29S/(C29S + C29R) = 0.35, H32S/(H32R + H32S) = 0.59, and TAS/(MAS + TAS) = 0.19 support a somewhat lower maturity of the oil [19], perhaps around R_o 1.0%, which is consistent with the interpretation from associated gases. The light oil from I-9z well has oleanane at relatively low concentrations, suggestive of Late Cretaceous age of the source rocks [22]. The C_{28}/C_{29} $\alpha\beta\beta$ steranes ratio is 0.94, which suggests a Late Jurassic to Miocene (most likely Cretaceous) age of the source rocks [23].

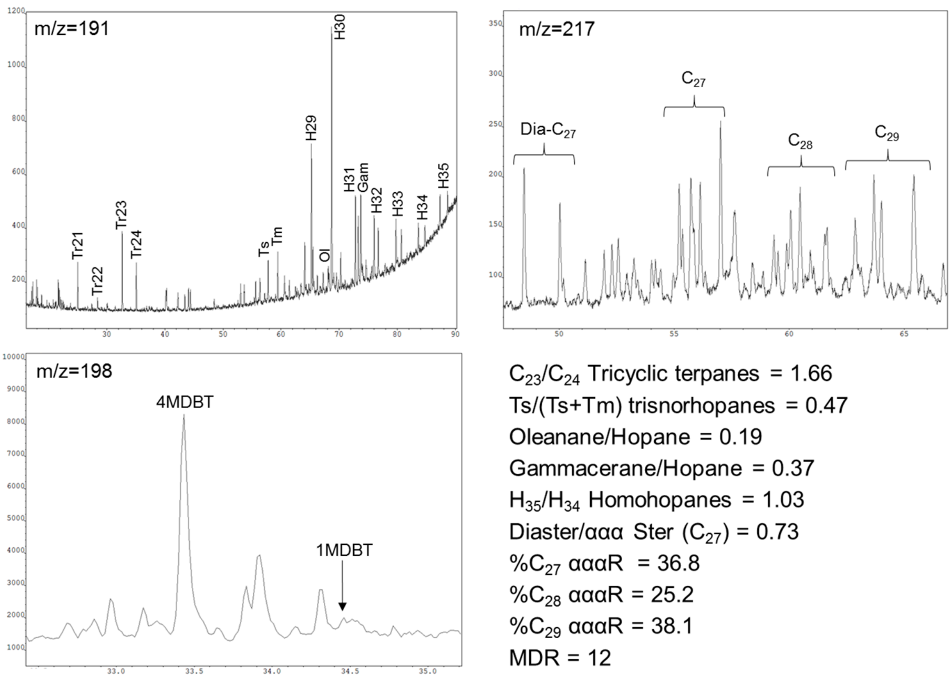

Figure 7. Mass fragmentograms of the saturated (m/z 191 and 217) and aromatic (m/z 198) fractions of light oil from Inhassoro-9z well (reservoir G-6). Key biomarker ratios and parameters are shown.

4. Discussion

The geochemical data presented above suggests that petroleum gases and liquids in the Inhassoro, Pande and Temane fields have a thermogenic origin (Figures 2, 3 and 6). It is likely that petroleum was expelled from one main source rock interval. That source rock is likely a marine shale deposited in a sub-oxic, stratified and potentially hypersaline and paralic (lagoonal, shallow neritic) environment. Age-specific biomarkers suggest that the source rock maybe of the Late Cretaceous age.

Although the Late Carboniferous—Early Jurassic Karoo Supergroup containing coal measures has been suggested as a potential source rock in the Mozambique basin [2], our data suggest that the petroleum fluids in the Inhassoro, Pande and Temane fields were not sourced from the Karoo for the following reasons. Firstly, the isotopic composition of natural gases and biomarkers in the liquids indicate that the fluids were sourced from marine shales and not from coals. Secondly, age-specific biomarkers in the oil from the Inhassoro field exclude the possibility of pre-Cretaceous source rocks. The lack of CO_2 in the natural gases also suggest that coals did not contribute to these accumulations.

Coster et al. [24] believed that the gas in the Pande field was microbial (they called it "immature") and sourced from the Lower Grudja mudstones. However, our isotope data indicate that the gas in the Pande field is a pure thermogenic gas and very mature. Lower Grudja mudstones are not a likely candidate for source rocks in the basin because they are not sufficiently mature.

Based on our geochemical data, we propose that Aptian-Coniacian Domo Shale is the most likely source rock for the petroleum in the Inhassoro, Pande and Temane fields. Where penetrated and sampled, Domo Shale usually contains relatively small amount of organic matter (TOC < 2%), and is relatively depleted in hydrogen (Hydrogen Index (HI) is < 200 mg/g TOC). Even when immature, this source rock deposited in sub-oxic environment likely has HI no higher than 400 mg/g TOC. This is clearly not a world-class source rock, which helps explain the relatively low exploration success rate and gas dominance in the Mozambique basin.

The maturity trend observed across the Inhassoro, Pande and Temane area, where the Pande fluids are the most mature and the Inhassoro fluids are less mature, suggests that the fluids migrated from the west or northwest. Although there is a gravity low northwest of the Pande area, the current regional dip is to the east, which makes recent migration from the west unlikely. Another possibility is that the fluids migrated from a very large kitchen located below the Zambezi Delta depression (northeast of the fields area) [24]. This would imply a very long-distance migration (hundreds of kilometers), which may explain the lack of CO_2 in the gases (as CO_2 can dissolve in water on long migration pathways) and the variety of migration-contamination biomarkers in the condensates. Further maturity and migration modelling is needed to locate and understand kitchens for the petroleum fluids in the Inhassoro, Pande and Temane fields.

5. Conclusions

We present here geochemical data and interpretations for petroleum gases and liquids in the Inhassoro, Pande and Temane fields onshore Mozambique. We conclude that:

(1) Studied petroleum gases have a pure thermogenic origin with no evidence of primary microbial gas (contrary to suggestions in [24]) or biodegradation. These gases were generated mostly by marine shale source rocks with little addition of gases from other source types. The gases are relatively dry (methane-dominated) and were generated in late oil—dry gas windows.

(2) Most condensates have relatively high API gravity, up to 76 degrees. They apparently were generated in the condensate-gas maturity windows. These condensates contain traces of biomarkers, which were likely picked up during migration from source rocks to reservoirs.

(3) Light oil in the Inhassoro field contains biomarkers likely related to the source rocks and likely originated from sub-oxic marine shales of the Late Cretaceous age.

(4) Aptian-Coniacian Domo Shale is the likely source rock for the petroleum gases and liquids in the studied fields. Based on source-specific and age-specific biomarkers, coals in the Late Carboniferous—Early Jurassic Karoo Supergroup do not appear to be effective source rocks for the studied fields (contrary to suggestions in [2]).

(5) Our interpretation of source rock age, organofacies and characteristics implies modest future exploration potential and gas dominance in the Mozambique basin.

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