Spatial Variations of Salinity, Temperature and Pressure on the Flank of a Salt Dome, Offshore Louisiana: Implications for Mechanisms of Fluid Flow

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SPATIAL VARIATIONS OF SALINITY, TEMPERATURE AND PRESSURE
ON THE FLANK OF A SALT DOME, OFFSHORE LOUISIANA:
IMPLICATIONS FOR MECHANISMS OF FLUID FLOW

A Thesis

Submitted to the Graduate Faculty of the
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Abstract

Salt dome dissolution in the Gulf of Mexico sedimentary basin is a primary cause for elevated pore water salinities in the subsurface. Temperature, pressure, salinity, lithology and fluid density are parameters often used to identify preferential conduits and driving forces for fluid migration. These parameters were calculated using 20 wireline logs covering 40 km² on the south flank of a salt dome on the continental shelf, offshore Louisiana. 3-D seismic has been utilized to determine location of faults, to aid in sand correlation, and to provide a structural overview of the dome. Vertical and lateral variations in lithology, salinity, temperature, pressure, and fluid density were documented. The shallowest beds investigated are Pleistocene, hydrostatically pressured, shale dominated, nearly horizontally oriented, and contain waters of approximately marine salinity (35 g/L). The deepest section contains Miocene, shale dominated, south dipping sediments with salinities slightly greater than marine. The middle regime contains Pliocene sediments with pore waters up to 5 times marine salinity. Over 90 percent of this section is gross sand. Salt dissolution has generated dense, hypersaline brines that appear to be migrating downdip through the thick Pliocene sandy section. Sands that come in contact with or near the salt/sediment interface tend to contain pore waters with relatively higher salinities. Reservoir continuity can be inferred from seismic data, but discontinuities that are not ascertained through seismic data can be validated by sharp salinity contrasts. Fluid compartmentalization across a normal supradomal fault is evident and the offset of salinity contours are consistent with the throw of the fault. This suggests that hypersaline brines were migrating before the formation of the fault and that salt dissolution could be contributing to extensional forces that lead to normal faulting.
Introduction

Subsurface brines in the Gulf of Mexico sedimentary basin are mainly sourced from the dissolution of salt (Hanor and Sassen, 1990; Hanor and McIntosh, 2007). Sediments present throughout the Gulf Coast were deposited in fluvial, deltaic or marine environments. The original pore water contained in these sediments was 35 g/L salinity, the approximate concentration of seawater, or less. However, these same sediments now buried at greater depths contain formation waters between seawater salinity and up to an order of magnitude higher concentration (350 g/L). Mixing of connate formation waters and highly concentrated brines, generated from the dissolution of salt deposits, leads to a large variety of salinities with a complex and continuously evolving spatial distribution (Workman and Hanor 1985).

The distribution of hypersaline brines is strongly controlled by lithology (Bruno and Hanor, 2003), as sand is much more permeable than shale, allowing for rapid migration of fluids. Sands that are in contact with salt act as pathways for solute transport and generally contain pore waters with elevated salinities (Hanor et al., 1986). In addition to migration along more permeable sands, brines have also been shown to move along fault planes. For instance, Lin and Nunn (1997) presented evidence for geopressured fluids of relatively lower salinity expulsing up along fault planes into overlying reservoirs in the Eugene Island Block 330, offshore Louisiana. Hanor and Sassen (1990) noted that onshore biodegraded hydrocarbons, which are often found in shallow Miocene to Plio-Pleistocene reservoirs, are likely the result of oxygenated waters migrating down growth faults associated with salt diapirism. A study by Leger (1988) on the Black Bayou dome in south Louisiana contends that downward migration of cooler, denser brines is occurring on a growth fault on the eastern flank of the dome, along with upward migration of lighter, warmer brines at greater depths. Leger (1988) also depicts displaced
downward isotherms near the salt/sediment interface at shallow depths and displaced upward isotherms at greater depths.

Fluid flow patterns around salt domes have been studied for many years but most previous studies investigated onshore Louisiana salt structures rather than offshore (Bruno and Hanor 2003). Onshore studies are still useful analogs for offshore studies because the forces inducing fluid migration and methods used to infer fluid flow are the same. Nikiel and Hanor (1999) compared an offshore study in the South Pelto, South Timbalier Bay areas with results from previous onshore studies and concluded that salinity variations with depth are essentially the same.

A variety of mechanisms and fluid flow patterns around onshore salt structures have been documented. For example, salt in the Welsh dome in Southwestern Louisiana is dissolving around the top of the dome, with hypersaline brines migrating vertically and laterally away from it (Cassidy and Ranganathan, 1992). The vertical component can be explained by geopressured fluids migrating up along the flanks of the dome (Cassidy and Ranganathan, 1992), which may be episodic in nature (Roberts and Nunn, 1995) and/or the high thermal conductivity of salt causing convective overturn of fluids (Evans et. al, 1991). These brines flow laterally away from the top of the dome along permeable sands beds due to variations in fluid density, which is a function of salinity, temperature and pressure (Phillips et. al, 1981; Ranganathan and Hanor, 1988). Another study at the Iberia dome (Hanor and Workman, 1985) documents the generation of dense brines moving down its flanks.

While different mechanisms and patterns have been identified, three major hydrogeologic regimes have been identified throughout the Gulf Coast in these studies (Fig. 1). The shallowest
regime is hydrostatically pressured with normal marine salinity water (about 35 g/L) and fluid movement is driven by topography. The deepest regime is overpressured and also contains normal or subnormal salinity waters. This is a shale dominated section, which is a primary cause for relatively low salinity, due to trapping of seawater during deposition (Hanor and Sassen, 1988) and/or smectite to illite transition accompanied by the release of interlayer fresh water (Szalkowski and Hanor, 2003). The middle regime is a sand dominated section, hydrostatically pressured, with hypersaline pore waters derived from the dissolution of salt. Fluid movement in the middle regime is driven by density variation or free convection.

**Figure 1:** Study from Bay Marchand shows salt dissolving at the top of the dome and migrating downdip through Pliocene sands due to a fluid density inversion (Bruno and Hanor 2003).

Fluid compartmentalization across faults, based on salinity contrasts, has been documented by Bruno and Hanor (2003) at the Bay Marchand field, offshore Louisiana (Fig. 2). The faults in the southernmost part of the section show sharp salinity differences on each side.
The fault that intersects the middle of the section may indicate fluid migration across the fault because the 100 g/L contours are offset in the opposite direction compared to the fault movement.

**Figure 2:** Fluid compartmentalization across faults at Bay Marchand (Bruno and Hanor, 2003)

The purpose of this study is to investigate fluid migration patterns and mechanisms on the south flank of a salt dome located offshore Louisiana on the continental shelf. The exact location cannot be identified due to the proprietary nature of the seismic data used. The field name, well identities, block numbers, shot point locations and survey description details are also proprietary. Spatial variations of lithology, temperature, pressure, salinity and fluid density were calculated and displayed. Major faults and horizons of interest were mapped using seismic data to provide a structural framework for the study area. This is the first study of salinity variations on the flank of a salt dome that includes the detailed use of seismic data.
Collectively, this information can be used to infer fluid migration pathways, assess reservoir connectivity and compartmentalization, and provide evidence to test previously established hypothesis regarding the hydrogeology of the Gulf of Mexico sedimentary basin.
**Study Area and Geologic Setting**

The study area encompasses 40 km² in the Gulf of Mexico sedimentary basin on the continental shelf offshore Louisiana (Fig. 3). Seismic and well data used range between 1000 m to 3925 m below sea level. The sediments within this depth range are Pleistocene to Upper Miocene in age, and overlie and/or adjoin the south flank of a large salt dome (Fig. 4).

The present distribution of sediments was formed by changes in sea level and sediment supply. The Mississippi River has deposited sediments in South Louisiana since the Miocene. Sediments were deposited in progradational, aggradational and retrogradational sequences, depending on seawater level fluctuations (Hentz et al., 1997). Upper Miocene sediments were deposited in progradational cycles and vary upsection from deepwater delta sediments to shallow fluvial sands (Sensi et al., 1997). Pliocene sediments reflect an aggradational period and consist of fluvial and deltaic sands (Hentz et al., 1997). There has been significant oil and gas production from Upper Miocene and Pliocene sands in the Gulf of Mexico (Hentz et al., 1997; Sensi et al., 1997). Average porosity for the sands is 29% and permeabilities range from <100-2000 mD (Hentz et al., 1997).

South Louisiana sediments generally dip to the south. Dips in the study area increase with depth due to the presence of diapiric salt. Dips range from nearly flat lying sediments at sea bottom (30 ft/mi), to the deepest mudstone facies which dip about 800 ft/mi, with an intermediate zone of intercalated sand and shale that dips approximately 300 ft/mi (Hentz et al., 1997). A more complete description of the structural regime will be provided in the results section.
Figure 3: 40² km study area showing the 20 wells used in this study, their spatial distribution and deviation paths. The symbols represent bottom hole location and the blue contours indicate depth to salt.
**Figure 4:** Generalized cross section through the Gulf of Mexico. Sediments in the study area range from Tertiary to Miocene and overlie middle Jurassic salt. (Galloway et al., 1991)
Data and Techniques

Data used in this study includes twenty wireline logs with subsurface offset values from directionally drilled wells, and a 3-D seismic survey in time. Well data depths were converted into time by applying a time-depth chart derived from one representative well. There is undoubtedly variation in velocities from well to well. Therefore, the time-depth chart only approximately aligns the wells with the seismic data, and there may be error in sand ties to reflectors.

Spontaneous potential (SP) curves allow identification of sand and shale beds. Shale baselines are established for each log. The SP values for shale baselines vary from well to well and also with depth in each well. Percent sand and shale was determined in 300 m intervals from top to bottom of each well. This was achieved using an excel spreadsheet developed specifically for this project. The algorithm in the calculator assumes the lithology encountered in each well is either sand or shale. Deflections more negative than the baseline are considered sand, while deflections more positive are considered shale. There are limitations to the program. Shale inclusions within sand beds sometimes are not thick enough to produce an SP response that crosses over to the positive side of the baseline and they are recorded as sand. The program is designed for digital SP logs with measurements every half foot. The baseline can only be altered in 300 m intervals. Despite these limitations, the calculator provides an approximation of gross sand/shale ratios with depth in each well, which is critical in understanding fluid flow pathways because lithology is a strong controlling factor of matrix permeability (Bruno and Hanor 2003).

Formation temperatures were determined from bottom hole temperatures (BHTs) found on the log headers, which are corrected for the cooling effects of the drilling mud using the Kehle (1971) correction curve. The BHTs were linearly interpolated to the seafloor assuming a
temperature of 20° C, which is an established mean value for the Texas-Louisiana continental shelf seafloor (Li et al., 1997). Pressure data were derived from the mud weight values on the log header. Pressure values were converted into geostatic ratios, which are pore fluid pressures/height of the fluid column. A geostatic ratio of 13.6 kPa/m or .60 psi/ft or greater is considered to be overpressured. 2 runs were collected on 3 of the wells, while the other 17 had only 1 run. This reduces the reliability of the temperature and pressure information calculated, and these data are only considered approximate.

Formation water salinities were determined for all clean, low resistivity sands with measured log thicknesses greater than 16 m in thickness. There are between 10-20 sands that fit the criteria per well with the exception of 2 wells that permitted only 2 and 7 measurements. The well with only 2 measurements had only 500 ft of logging. A salinity calculator developed by Hanor (personal communication) uses the SP log and mud resistivity values to estimate salinity, derived from the work of Bateman and Konen (1977). Funayama (1990) showed that salinity estimates from SP measurements are subject to error but still provide useful estimates. The maximum SP deflection from the shale baselines in each sand was used to represent the entire sand and therefore maximum salinity estimates are calculated. Pore water salinities from well head samples for 28 sands in 15 wells were used to confirm the accuracy of the calculated salinities and provide salinities for thin sands (<16 m). Fluid density was determined with corrections for temperature, pressure and salinity based on an equation of state for density of NaCl solutions (Philips et al.1981).

The 3-D seismic data was loaded into Petrel 2008 and was used to map faults and correlate sands. The area investigated included 451 crosslines and 304 inlines.
Results

Structure/Lithology

Three seismic lines are used to depict the structural features of the region. Key faults are shown in black and 4 horizons are mapped in different colors. These horizon have been arbitrarily named H1-H4, H1 being the shallowest and H4 being the deepest. The purpose of mapping these horizons was to show the vertical extent and relative offsets of the faults. Figure 5 is an interpreted line in the NW part of the study area and shows a major crestal growth fault which extends from the seafloor down to the salt-sediment interface. There is also an antithetic normal fault. H1 sits above the antithetic fault and extends from the SW part of the line, all the way to the crestal growth fault. H2 and H4 terminate at the antithetic fault, whereas H3 terminates before reaching it. Figure 6 is a SW-NE section through the middle of the study area. Depth to top of salt increases, the crestal growth fault is bifurcated and situated on the highest point of the salt structure. There are also three antithetic normal faults. H1 is continuous from the SW to the growth fault. H2 and H3 show similar offsets across the series of antithetic faults and are not mapped on the NE side of the bifurcated growth fault because there is no well control. H4 terminates after the first antithetic fault. This is the only part of the study area where both faults and well control are present and will be an area of focus in the compartmentalization section. The final section, farthest SE in the study area, also shows the bifurcated growth fault, along with a series of synthetic normal faults and a single antithetic normal fault (Fig. 7). H1 is coherent from the SW until it reaches the bifurcated growth fault. H2 and H3 are interpreted across the line from the SW to the growth faults, and show comparable displacements across the synthetic normal faults. H4 is present only SW of the 2 normal fault from the SE.
Figure 5: Crestal growth fault and antithetic normal fault. The dashed line indicates top of salt.

Figure 6: Bifurcated growth fault and a series of antithetic normal faults. The dashed line indicates top of salt

Figure 7: Bifurcated growth fault and a series of synthetic normal faults and an antithetic normal fault. The dashed line indicates top of salt.
Figure 8: Map of study area with cross section locations. See Figure 3 for symbol and contour information.

Figure 8 shows a series of cross sections used to show variations in salinity, temperature, pressure and fluid density. The middle Pliocene is the most sand-dominated part of the region and consists of over 90 percent sand beds (Fig. 9). Pleistocene and Miocene sediments are dominated by shale and in some areas contain less than 25 percent sand beds.
Salinity

Pore water salinities calculated from SP and determined by chemical analysis vary greatly within the region. There are three distinct salinity regimes salinity versus depth for the entire region. The shallowest 1000 m is shale-dominated and contains pore waters with salinities ranging from 21 g/L to 75 g/L. The sand-dominated middle section, from 1000 to 3100 m contains pore water with a wide range of salinities, ranging from 50 g/L up to 185 g/L. There is significant scatter in these data, but the water sample salinities are consistent with the salinities estimated from log data (Fig. 10). The deepest shale-dominated section from 3100-4000 m has somewhat lower salinities, which range from 50 g/L to 125 g/L.

Vertical variations in salinity can be seen in Figures 11 and 12. At shallow and deep depths, salinities are relatively low, and the middle of the sections contain higher salinities.
Salinity also varies laterally with proximity to salt and hypersaline brines are coincident with higher percentage of sand (Fig. 13). Near the top of the dome, salinity values are higher (>125 g/L) in the Pliocene section, compared to areas farther away from the dome where salinities drop to between 100-125 g/L.

**Figure 10:** Graph showing salinity (g/L) versus SSTVD (m). Gold represent values calculated from salinity calculator and blue represent values obtained from produced waters. Scatter at intermediate depths is evident both in calculated and produced water values.
Figure 11: Cross section B-B’ showing salinity variation. Vertical lines represent wells and the squares along the well paths are data points used to contour salinity. Location is shown in Figure 8.
Figure 12: Cross Section C-C’ showing salinity variation. Vertical lines represent wells and the squares along the well paths are data points used to contour salinity. Location is shown in Figure 8.
Figure 13: Cross section A-A' showing vertical and lateral variation in salinity. The dashed lines surround an area of over 90 percent gross sand (see Figure 9). The solid line represents a Pliocene horizon (H5) that was mapped on seismic and seen in figure 14. Location is shown in Figure 8.
A seismic horizon (H5) in the middle of the Pliocene section was mapped (Fig. 14) to visualize the salinity variations on that surface (Fig. 15). There were ten salinity measurements on wells that tied in closely with this horizon. Salinity values were not interpolated directly onto the surface due to vertical variations in salinity that could misrepresent this particular sand package. H5 terminates to the north and northeast as a result of its intersection with the major growth fault discussed earlier and there is no well control in this study on the other side of the fault, so it was not mapped in the other fault block. H5 dips to the south. Salinities are above 125 g/L to the north, near the top of the dome (Fig. 15). Salinities range between 100 g/L and 125 g/L to the south, with values at the southernmost part of the map at approximately 100 g/L. There is a point to the southwest that is 146 g/L, inconsistent with the lessening salinity away from the top of the dome. While the horizon appears to correlate between wells and data points, there could be stratigraphic discontinuities below seismic resolution.

Figure 14: Time map of H5 from the Pliocene section. Salinity data points are indicated by black dots. Bright colors represent shallow depths and dark colors represent deeper depths.
Figure 15: Salinity contour map on H5. Salinity data points are represented by the black squares.

**Temperature**

Figure 16 shows corrected bottom hole temperatures versus depth in the study area. Geothermal gradients vary with proximity to salt. The average gradient is approximately 25 °C/km. Gradients range from 28 °C/km closer to the top of salt versus 22 °C/km downdip. Isotherms rise slightly with closer proximity to salt (Fig. 17). Elevated temperatures above salt are expected as highly conductive salt wicks heat away from nearby sediments (Kumar, 1989).
Figure 16: Plot of Temperature (°C) versus SSTVD (m) from corrected bottom hole temperatures. The solid line is the average, 25 °C/km gradient, with $R^2 = .9557$.

Figure 17: Cross section A-A’ showing upwelling isotherms (°C) with closer proximity to salt. Vertical lines represent wells and the squares along the well paths are formation temperature data points used to contour temperature. Location is shown in Figure 8.
Pressure

Fluid pressures are hydrostatic above 3100 m (Fig. 18). There is an abrupt increase in geostatic ratio below 3100 m, where the values increase to greater than 13.6 kPa/m (.60 psi/ft), and signify overpressure. The overpressured zone occurs in the shale dominated (>50% shale) part of the study area.

Figure 18: Geostatic ratio (fluid pressure/depth) of formation waters. Values represent geostatic ratio at the bottom of each well estimated from mud weights. Line at 3100 m indicates top of overpressure.

Fluid Density

Variations in salinity are the strongest control on fluid density in the study area. Thus, the spatial distribution of fluid densities is similar to the salinity distribution (Figs. 13 and 19). Densities in section A-A' range from over 1050 kg/m³ to less than 1040 kg/m³, with higher
densities towards the top of salt (Fig. 12). Within the higher density middle Pliocene section, relatively denser fluids are present updip, closer to salt compared to downdip away from salt.

**Figure 19:** Cross section A-A’, showing vertical and lateral variation in fluid density (kg/m$^3$). Dashed lines surround area of over 90 percent gross sand.

**Fluid Compartmentalization**

Lateral discontinuities in salinity where seismic reflectors appear coherent can be explained by stratigraphic pinchouts or faults, which may or may not be resolvable with seismic data. Figure 20 shows a continuous reflector where there is a significant contrast in salinity, 121 g/L near salt and 54 g/L down dip, between two close wells. The slight dimming in the reflector may represent discontinuity in the sand. However, these seismic data alone cannot confirm the presence of a hydraulic disconnection. The sharp salinity contrast further supports that there is a discontinuity. Figure 21 shows one reflector that is continuous close to the salt sediment.
interface and another that clearly pinches out before reaching salt. The continuous sand has pore water with a salinity of 154 g/L, whereas the salinity in pinched out sand is much lower, 49 g/L.

Figure 20: Stratigraphic compartmentalization implied by seismic and salinity data. Vertical axis is two way travel time and each tick mark interval is 25 ms.

Figure 21: Vertical compartmentalization implied by seismic and salinity data. Vertical axis is two way travel time and each tick mark interval is 25 ms.
Evidence for fluid compartmentalization across a fault is shown in Figures 22, 23, 24. Figure 22 shows a seismic line and location. Figure 23 shows where the faults on the section have been interpreted and salinity contours, which are drawn based on the salinity data and reflectors as a guide. Amplitudes terminate at the fault, suggesting that the fault is sealing. Figure 24 is a cross section showing the compartmentalization without the seismic background so the contours can be seen more easily. The fault of interest is a normal fault, which is downthrown to the north. The 75 g/L and 100 g/L contours match the throw and direction of the fault, as seen on the seismic line (Fig. 23).

Figure 22: Uninterpreted seismic line showing well placement. White squares represent salinity data points. Vertical axis is two way travel time and each tick mark interval is 100 ms.
Figure 23: Interpreted seismic line with salinity contours. White squares represent salinity data. Vertical axis is two way travel time and each tick mark interval is 100 ms.

Figure 24: Fluid compartmentalization across a fault without seismic data background.
Discussion

The spatial variations in lithology, salinity, temperature, pressure, and fluid density allow classification of three unique hydrogeologic regimes within the study area. The shallowest regime is a Pleistocene and younger age section containing waters having salinities near or equal to seawater. This section is hydrostatically pressured and is shale-dominated. It is possible that these fluids are static as the data do not show an obvious driving force for fluid movement. The deepest regime is an Upper Miocene, shale-dominated, overpressured section, which also contains low salinities.

In between the shallow and deepest regime lies a middle section, dominated by Pliocene sands, which contains hypersaline brines. Waters in these sands are saltier and denser updip closer to the salt structure. These observations indicate that salt is dissolving near the top of the dome and migrating down dip through the predominantly sandy Pliocene section. Fluid density inversion appears to be the primary driving force for fluid flow.

It is clear that sands in contact or close to contact with salt tend to contain much higher salinity formation waters. The lower, shale dominated section contains some sands that pinchout or are sealed by shale and contain near seawater salinity. There are also instances where seismic data suggest possible reservoir connectivity as justified by continuous reflections. However, the salinity data suggest there are either stratigraphic or fault barriers that may be below seismic resolution and cause hydrologic compartmentalization. Amplitude dimming in between salinity data points is probably indicative of stratigraphic discontinuity, but the significant contrast in salinity supports the conclusion that the reservoirs are not hydrologically connected.
There exists a salinity distinction across the fault shown in Figure 24. The 75 g/L and 100 g/L contours, which conform with seismic reflectors, exhibit an offset consistent with the throw of the fault. This suggest that brines with elevated salinity derived from salt dissolution may have been migrating before the formation of the fault. It is possible that salt dissolution is in part a cause for extensional forces and the supradomal normal faulting seen on top of the dome. The downthrown side of the fault is closer to the top of salt compared to the upthrown side, which is consistent with the proposal that salt dissolution is a factor. There are a series of these antithetic normal faults (Fig. 6) but this study lacks well control in the other fault blocks so there is no salinity data available in this study. The fault in Figure 24 could also be acting as a barrier to fluid flow, which would explain the present compartmentalization across it. Previous work, at the Bay Marchand field (Bruno and Hanor, 2003), showed similar compartmentalization (Fig. 2), but without seismic data to validate interpretations of sand correlations and fault locations between well control. The seismic data in this study adds another level of confidence for the original argument for compartmentalization across faults.

Data provided to this study indicate that Pliocene hydrocarbons in this area have an average API gravity of 23, whereas Miocene hydrocarbons average an API of 28 (anonymous personal communication). Normal API gravity values for oil accumulations range from 25-40 API and gravities tend to increase with burial depth (Blanc and Connan, 1994). If there is evidence for oil degradation, it has usually occurred within the reservoir, as opposed to degradation at the source or during migration stages (Blanc and Connan, 1994). The contrast between Pliocene and Miocene oil gravities could merely be a function of the temperature and pressure conditions of the reservoirs or differences in source rock. However, assuming there is and/or has been brine migration through these Pliocene reservoirs, there could also be a
component of water washing, which refers to the process by which oils are exposed to flowing
water resulting in the removal of water soluble compounds and consequently degrading the oils
(Blanc and Connan, 1994).
Conclusions

Salt dome dissolution in the study area has created dense brines that appear to be migrating down dip away from salt through permeable Pliocene sands. Sands in the deepest shale dominated section contain lower salinities, thus the shales are likely acting as a partial barrier to fluid flow in the interbedded sands, which also may be discontinuous. There is a substantial lithologic control on fluid migration pathways. Overpressure occurs at approximately 3100 m and geothermal gradients increase with closer proximity to salt. These conclusions are consistent with the results found in Bruno and Hanor (2003), which was the primary analog for this study. It is possible that fluid flow due to density inversion has lead to water washing and caused degradation of hydrocarbons in the Pliocene, but additional work needs to be done to more fully support this idea. It would be of interest to obtain specific API gravity values for the field and investigate the relationship between hydrocarbon quality and formation water salinity. There may be a correlation between lower API values and elevated salinity. Another useful avenue would be to perform a similar study with better well control across faults or on a different flank of the dome for comparison.
References Cited


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Appendix: W-#: SP (mV), Salinity (g/L), Fluid Density (kg/m³), Temperature (°C), Pressure (MPa) versus SSTVD (ft)

A1: W-1: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
A2: W-2: SP (mV), salinity (g/L), temperature (°C), versus SSTVD (ft). No mud weight was available for this well, so pressure and fluid density were not calculated.
A3: W-3: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft)
A4: W-4: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
A5: W-5: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
A6: W-6: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
A7: W-7: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
A8: W-8: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
**A9**: W-9: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
A10: W-10: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
A11: W-11: SP (mV), salinity (g/L), fluid density (kg/m$^3$), temperature ($^\circ$C), pressure (MPa) versus SSTVD (ft).
A12: W-12: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
A13: W-13: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
A14: W-14: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
A15: W-15: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
A16: W-16: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
A17: W-17: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
**A18:** W-18: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
A19: W-19: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
A20: W-20: SP (mV), salinity (g/L), fluid density (kg/m³), temperature (°C), pressure (MPa) versus SSTVD (ft).
Vita

Andrew Kevin Steen was born in 1985 in Traverse City, Michigan. He graduated from Traverse City Central High School in 2003. After successfully completing the basic physics, calculus, chemistry and biology courses in college, he then discovered geology. Fascinated by the incorporation of all major sciences to solve practical problems, he continued taking geology courses with a particular interest in energy. He attended SAGE (Summer of Applied Geophysical Experience) in Santa Fe, New Mexico, during the summer of 2007. He received his Bachelor of Science degree in geological sciences with a geophysics option from Michigan State University in 2007. Louisiana State University invited him to enroll in the graduate program with a teaching assistant position and he accepted. He moved to Baton Rouge, Louisiana, and spent three years working towards a Master of Science degree. He also had an internship with Chevron in the summer of 2008. In May 2010, he graduated from LSU with a Master of Science in geology and subsequently began his career in oil and gas exploration, working for Chevron in Covington, Louisiana.