COMPARISON BETWEEN GULF OF MEXICO AND MEDITERRANEAN OFFSHORE RESERVOIRS

A Thesis

by

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ABSTRACT

Deepwater oil and gas are simply conventional reserves in an unconventional setting. They consist of a resource class of their own largely because they face a common set of challenges in the course of their identification, characterization, development and production. However, there have already been successful deepwater reservoir developments, in sedimentary environments such as the Gulf of Mexico, offshore Brazil and West Africa. Especially in Gulf of Mexico, the offshore reservoirs are analyzed and exploited on a large scale, rendering a good case for deepwater exploration. Recently there have been large deepwater reservoirs discovered in the Mediterranean Basin. Except for the main reservoir type, the two regions' situations are similar to each other including large water depth, great production potential and significance in the role played in their regions' energy industry, respectively.

Before the exploration starts, the analysis and forecast of the reservoir properties and quality are always the priority. This research is to characterize these reservoirs in a way that will be useful for further exploration. A previous study of US reservoirs including both terrestrial and offshore Gulf of Mexico reservoirs showed correlations of depth vs pressure, temperature, and mobility. Similar works are done for the newly discovered reservoirs in Gulf of Mexico, and the same approach is applied to the analysis of Mediterranean reservoirs. Basically, the study showed important trends related to water depth that explains why deepwater reservoirs may offer exceptional potential over terrestrial and shallow water reservoirs. The research done in this thesis is based on the following aspects: (1) previous analysis for Gulf of Mexico, (2) the new reservoir data analysis for both Gulf of Mexico and Mediterranean, (3) evaluation and comparison of the two regions.

The deepwater reservoirs in two regions are similarly impacted by the water depth. Both reservoir pressure and porosity are altered higher by water. Also, some reservoir properties like permeability can be possibly inferred under specific condition. Based on the study, it is obvious that offshore reservoirs of the two regions have the potential for high deliverability and deserve exploration.

DEDICATION

I would like to thank my committee members, Dr. Sun, Dr. Ayers for their guidance and support throughout the process of this research, especially my supervisor and committee chair, Dr. Economides. I really learned a lot and am impressed by her meticulous attitude toward doing things.

Thanks also go to my friends and colleagues and the department faculty and staff for making my time at Texas A&M University a great experience. I also want to extend my gratitude to the professors outside the department who have taught me classes and gave me much help on my study.

Finally, thanks go to my mother and father for their encouragement and support. It will be permanently appreciated.

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I wish to thank my supervisor, Dr. Economides for her great guidance and help on gathering and analyzing the data, and on the completion of the thesis.

NOMENCLATURE

A	reservoir age
bcm	billion cubic meter
D	total depth (in pressure and temperature figure), ft
H_R	depth from sea floor (mud line) to reservoir formation, ft
H_t	depth from sea level to reservoir formation, ft
P_R	reservoir pressure, psi
T_R	reservoir temperature, deg. F
α	Biot's poroelastic constant
ν	Poisson ratio
σ_H	absolute horizontal stress
σ_v	absolute vertical stress
Φ	porosity
μ	viscosity

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1. INTRODUCTION

As the conventional petroleum resources on land or onshore have already been largely explored and developed, deep to ultra-deep offshore ones have gradually become main targets for exploration and production in the future.

In the US, government economic incentives, such as the Deep-water Royalty Relief Act, have brought about renewed interest and more intense efforts in the development of hydrocarbon resources in the Gulf of Mexico. The extent to which this growth trend is expected to last depend largely on access to publicly owned offshore lands, economic incentive legislation and policies, as well as on continued increase of productivity and technological advances (National Petroleum Council, 2011). Deepwater reservoir appears already to be very large with reserves estimated for the world already in the hundreds of billions of barrels (Ehlig-Economides and Economides, 2002).

In the Gulf of Mexico, offshore petroleum resources provide the tantalizing possibility in the near future of not only surpassing the maximum modern production of about 3.2 billion barrels per year, accomplished in 1985 thanks to Alaskan production, but also to surpass the maximum annual production of about 3.6 billion barrels of oil per year, observed in the early 1970’s. (In the year of 2012 US production is about 2.36 billion barrels) (Ehlig-Economides and Economides, 2002)

When it comes to Mediterranean, Elandaloussiet al. (2010) divided the Mediterranean countries around the basin into two areas as figure 1 shows for the convenience of introduction:

- Northern Mediterranean countries (NMCs), composed of EU countries(Cyprus, France, Greece, Italy, Malta, Portugal, Slovenia and Spain) and non-EU Mediterranean countries(Albania, Bosnia and Herzegovina, Croatia, Macedonia and Serbia)
- 11 southern and eastern Mediterranean countries (MED-11), comprising Algeria, Egypt, Libya, Morocco, Tunisia and Turkey along with 5 other south-eastern Mediterranean countries, which are Israel, Jordan, Lebanon, Palestine and Syria.

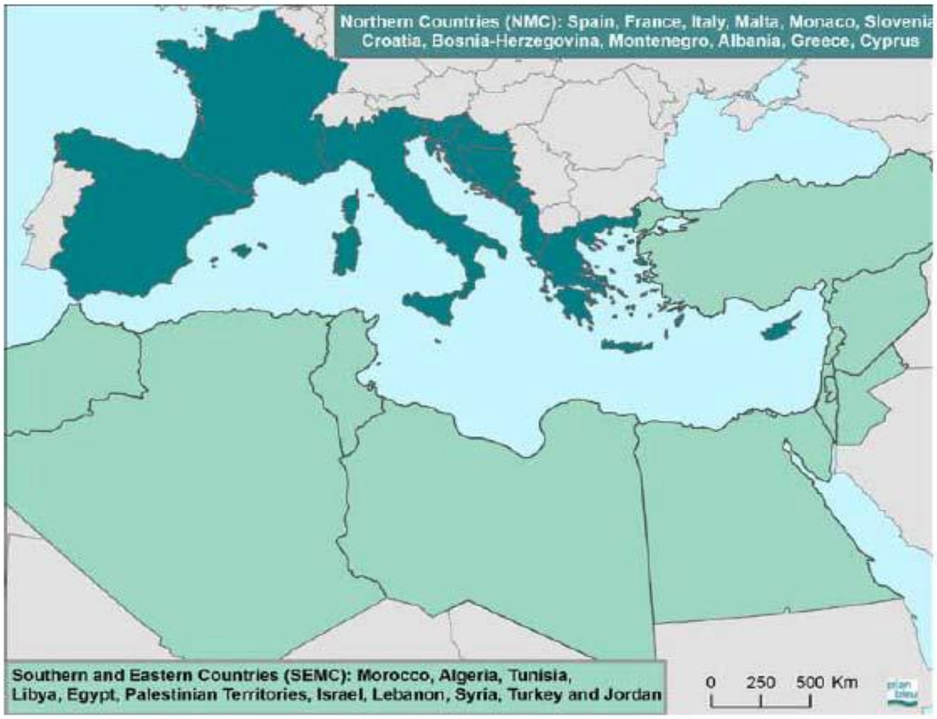

Figure 1. Mediterranean Basin (source: El Elandaloussi 2010)

The MED-11 area is the main petroleum resources reserve and production area around the basin. Estimates for MED-11 by BP (2011) and Cedigazalready top 5% of the world's proven oil reserves (about 6145 Mt) and 5% of the world's gas reserves (about 8500 bcm), accounting for most of the hydrocarbon reserves of the overall Mediterranean region. Most of these reserves are located in three North African countries: Lybia, Algeria and Egypt. Currently, the MED-11 area accounts for 31% of the Mediterranean region's overall energy demand. According to the MEDPRO Energy Reference Scenario by Manfred et al. (2012), the potential energy provided by this area is also very large, a level set to rise to 47% by 2030 – growing by an average annual rate of 3.3% between 2009 and 2030. These just make the Mediterranean Basin a prolific source of hydrocarbon.

Generally, for sandstone reservoirs, shallow sediments tend to be unconsolidated containing heavy oil, and deep deposits are likely to be hard rocks of low permeability containing gas. The result is an overall reflection of mobility, which relates directly to well potential. (Ehlig-Economides and Economides (2002)). However, different from Gulf of Mexico, the main reservoir type in Mediterranean are carbonate (including limestone and dolomite).

The analysis of physical properties of hydrocarbon mixture and formation is an important step in the design of various stages of oilfield operations, especially in the offshore reservoirs like Mediterranean and Gulf of Mexico. The fluid properties, which change with pressure and temperature, have been evaluated for both reservoir engineering and production design operations. For deep water reservoirs, since water depth accounts for a large portion of the total depth, high pressure and the overpressure circumstances could in turn change the properties of reservoir fluid.

Data from some of the largest ultra-deepwater accumulations of hydrocarbons shows correlation of depth vs mobility, which is contrasted with data from terrestrial reservoirs, and that may be due to overpressure. Overpressure has been observed in Mediterranean and Gulf of Mexico reservoirs and has been studied extensively in Gulf of Mexico. Osborne and Swarbrick (1997) introduced some explanations for overpressure. Generally they described three categories of mechanisms: (1) increase in compressive stress caused by disequilibrium compaction and tectonic compression; (2)

fluid volume change caused by temperature increase, diagenesis, hydrocarbon generation and cracking to gas; (3) fluid movement and processes related to density differences between fluids and gasses.

Ehlig-Economides and Economides (2002) provided some physical hypotheses for interpretation and listed some results. Some certain hypotheses guide the analysis for the deep water reservoirs. Figure 2 and 3 illustrate expected temperature and pressure behavior for both onshore and offshore reservoirs. As the figures show, temperature should follow a geothermal gradient, but will be shifted downward for deep-water reservoirs because of the low temperature at the mud line (ocean bottom), which approaches the standard freezing temperature for water. Pressure is expected to follow the hydrostatic pressure gradient, the weight of a column of water. Overpressured reservoirs exceed hydrostatic pressure. For a deep-water reservoir, the pressure gradient below the mud line may be quite extreme compared to that of a terrestrial reservoir of similar total depth.

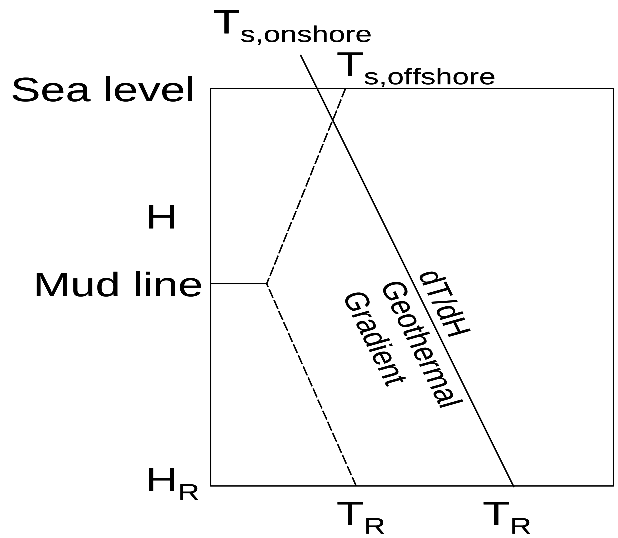

Figure 2. Expected reservoir temperature behavior

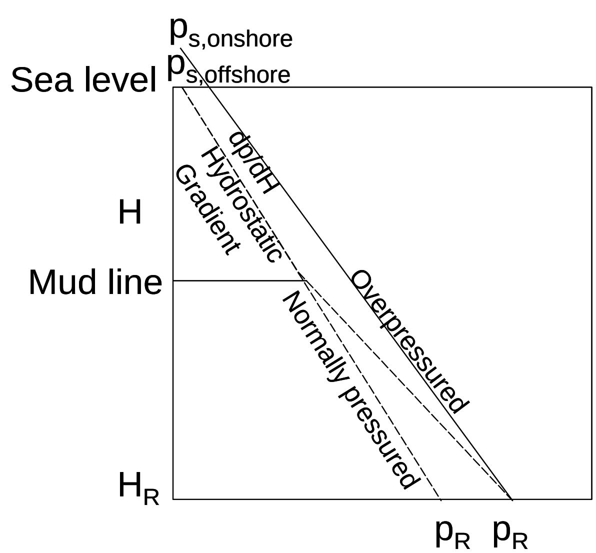

Figure 3. Expected reservoir pressure behavior

Permeability vs porosity behavior may be similar for onshore and offshore, but offshore porosity values measured from the mud line are greater than onshore porosity values at the same depth below the land surface. One justification for this is derived from the understanding of the vertical stress, often known as the lithostatic stress, σ_v and given by the weight of the overburden:

$$\sigma_v = g\int_0^H \rho dH \tag{1}$$

For the average value of $\bar{\rho}$ = 165 lb/ft^3, σ_v (psi) = 1.1 H (ft).

The vertical stress, which is the absolute stress in the porous medium, leads to an effective vertical stress,

$$\sigma_v{}' = \sigma_v - \alpha p \tag{2}$$

where α is Biot's poroelastic constant, ranging between 0.7 and 1 and p is the pore pressure.

The effective vertical stress translates through the Poisson relationship into an effective horizontal stress

$$\sigma_H{}' = \frac{\nu}{1-\nu}\sigma_v{}' \tag{3}$$

where ν is the Poisson ratio and is roughly equal to 0.25 for a sandstone; higher for a shale (e.g. 0.35).

In the absence of large tectonic stresses, as is the case for the Gulf of Mexico, the absolute horizontal stress, σ_H, can be obtained from Eqs. 2 and 3:

$$\sigma_H = \frac{\nu}{1-\nu}\sigma_v + \frac{1-2\nu}{1-\nu}\alpha p \tag{4}$$

Suppose one offshore reservoir is at a total depth of 15,000 ft under 5,000 ft of water. The absolute vertical stresses is13, 175 psi (1.1*10,000 + 0.435*5000). If the reservoir is normally pressured, the effective vertical stresses is about (assuming α =1) 6650 psi. If it is overpressured, e.g. by 3000 psi, the value is reduced 3350 psi. The absolute horizontal stresses (assuming ν =0.25) is about 9,000 psi for normally pressure reservoir, but about 11,000 psi for the overpressured formations.

Based on the database and those hypotheses, the results showed that offshore reservoirs of Gulf of Mexico are overpressured and the amount of overpressure increases with water depth. Also, the porosity trend with total depth increases with water depth, and permeability vs porosity trend is lower than the typical trend onshore. While for Mediterranean reservoirs, data is not as much as that of Gulf of Mexico. So this thesis is going to mainly focus on the newly updated data for Gulf of Mexico and try to make a comparison between the two regions.

2. DATA SOURCES

The data used in this work are provided from two sources: one is the Atlas of Gulf of Mexico gas and oil sands compiled in 2010 and updated in 2013 by the Bureau of Ocean Energy Management, and another is Atlas of Reservoirs, South Atlantic Margin & Mediterranean Region: (Set 2 – Mediterranean Region) from AAPG database. The database for Gulf of Mexico includes over ten thousand offshore reservoirs' information for Gulf of Mexico. The AAPG database contains nearly 100 oil and gas reservoirs' information for the Mediterranean region, with entries much fewer than Gulf of Mexico, but could also provide some basic understandings mainly for reservoir rock properties, formation age and physical properties.

3. GULF OF MEXICO

The previous work done for Gulf of Mexico has cast light upon the deepwater reservoir issues. However, the data of the previous work extended only to the year of 1994. Also, method is improved to better analyze the database with different water depth range.

Figure 4 shows all the offshore data entries from new database plotted in the graph of water depth vs subsea depth. The gas data are defined as those with API gravity equaling to 0. The gas data entries account for two thirds of the database, while the rest are for oil. Most of the reservoirs are beneath very shallow water. Gas reservoirs with large water depth usually have relatively small total depth, contrary to oil reservoirs. Also, in this work, most of the graphs are in the “Bubble” style, with bubble size indicating a third parameter (usually water depth in this work). The total depth is the depth measured from sea level to the formation and the subsea depth is the depth from mud line to reservoir (also for the whole thesis).

The formation age for the offshore Gulf of Mexico reservoirs is generally young, ranging from recent to about 180 million years, but most of the formations are younger than 40 million years. The oldest rocks in Gulf of Mexico formed in Jurassic. Some reservoirs took shape during a long time. For those, the mean value of their forming period are used for their ages. Galloway (2009) pointed out that Cenozoic fill is the most prolific host, then the Cretaceous and Jurassic units. This is consistent with the number of data entries of the reservoirs' own period. Based on this, the formation age vs total depth and water depth for gas and oil are plotted in Figure 5 respectively. In this graph, very few outlying points, only about 10, indicating those Mesozoic formations, are excluded. They are located in the block off the coastline of the border of Mississippi and Alabama. Both trends show increasing age with depth, which conforms to the law of superposition. Moreover, most of the large bubbles indicating large water depth are below the average trendline. This means for the same total depth, reservoirs with larger water depth are likely to have younger age.

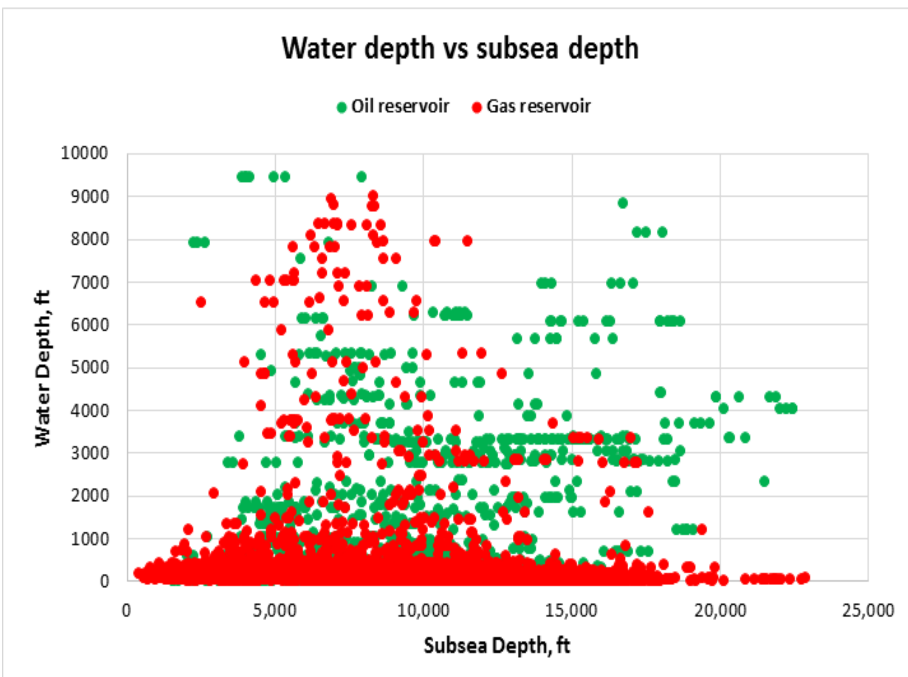

Figure 4. Water depth vs subsea depth

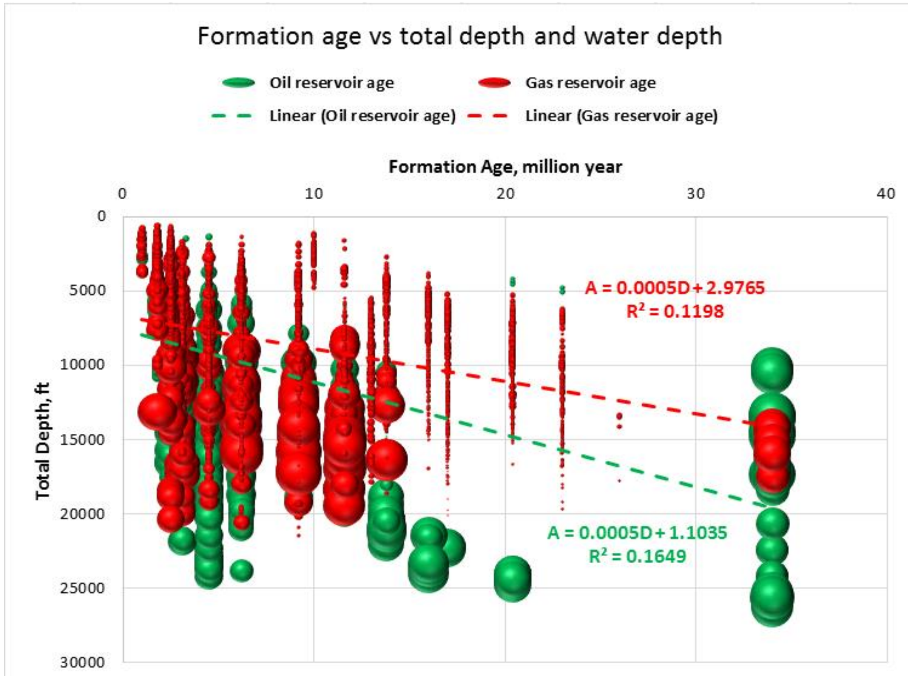

Figure 5. Formation age vs total depth and water depth

3.1 Pressure Observations

Generally, for normally pressured reservoirs, the initial pressures should be at approximately hydrostatic pressure levers, which is about 0.433 psi/ft. But for offshore reservoirs in Gulf of Mexico, the overpressure phenomena exist all over. Also, for the newly updated database, there is a problem that the pressure data may have the probability of being dominated by one same reservoir formation pressure gradient. Usually, different reservoir discovery year will represent different reservoir, so the sorting work is done by different discovery year. This has more or less reduced the impact of the domination issue. The after-sorting pressure against total depth and water depth has been graphed in a reverse order as shown in Figure 6. The bubble size represents the water depth. The larger the bubble is, the deeper the water is.

The fits for pressure in different water depth range are

$P_R = 0.886D_t - 2764.9$ for water depth < 50 ft (5)

$P_R = 0.7647D_t - 1766.6$ for water depth between 50 to 100 ft (6)

$P_R = 0.7278D_t - 1179.5$ for water depth between 100 to 500 ft (7)

$P_R = 0.7303D_t - 735.62$ for water depth between 500 to 1000 ft (8)

$P_R = 0.7774D_t - 1455.2$ for water depth between 1000 to 5000 ft (9)

$P_R = 0.8353D_t - 3346.9$ for water depth > 5000 ft (10)

These fits obviously show that the whole trend is shifted from the normal hydrostatic gradient to a more overpressured status. In this graph, different ranges of water depth are separately analyzed and are shown on the graph as the dashed line. Despite those shallow reservoirs, the slopes of dashed lines for different water depth on the graph increase with water depth.

The overpressure trend is shifted more when pressure is graphed against subsea depth with increasing water depth as in Figure 7. Most of the large bubbles are above the average trendline, indicating that the overpressure is exaggerated by the water depth.

Actually, sedimentation from the Mississippi River has caused large accumulations of sediment over past several million years. While most of the sedimental reservoirs are very young, the quick sedimentation has generated compaction-induced pore pressures, which could reach very high values at large depth. Zoback (2007) pointed out that the transition from hydrostatic gradient to overpressure is highly variable in different places but could be in small water depth. That is to say, there are areas where overpressure is found at very shallow depth and is responsible for shallow-water flow zones, which is consistent with the graph.

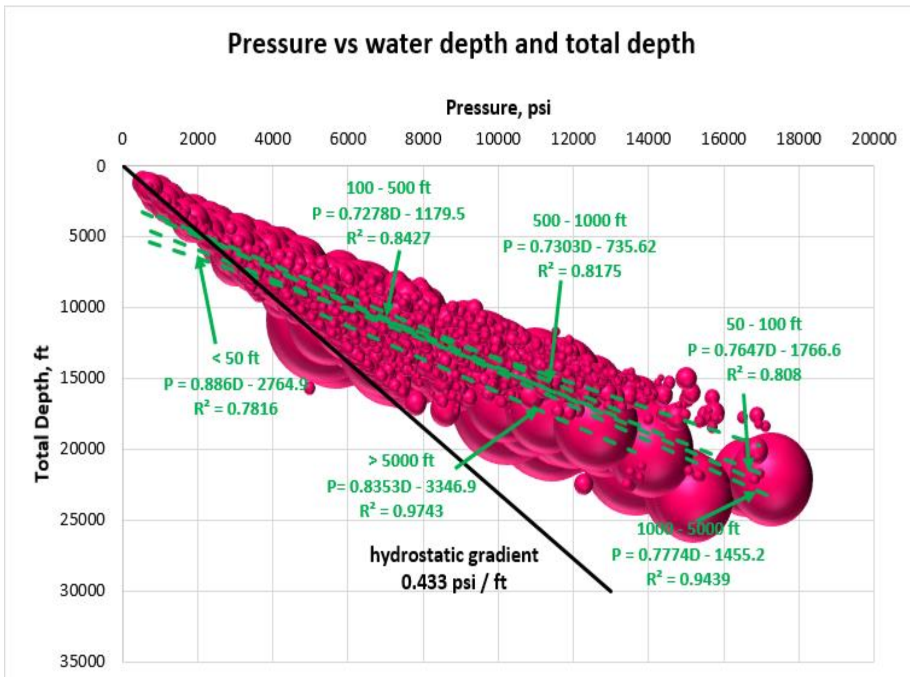

Figure 6. Pressure vs total depth and water depth

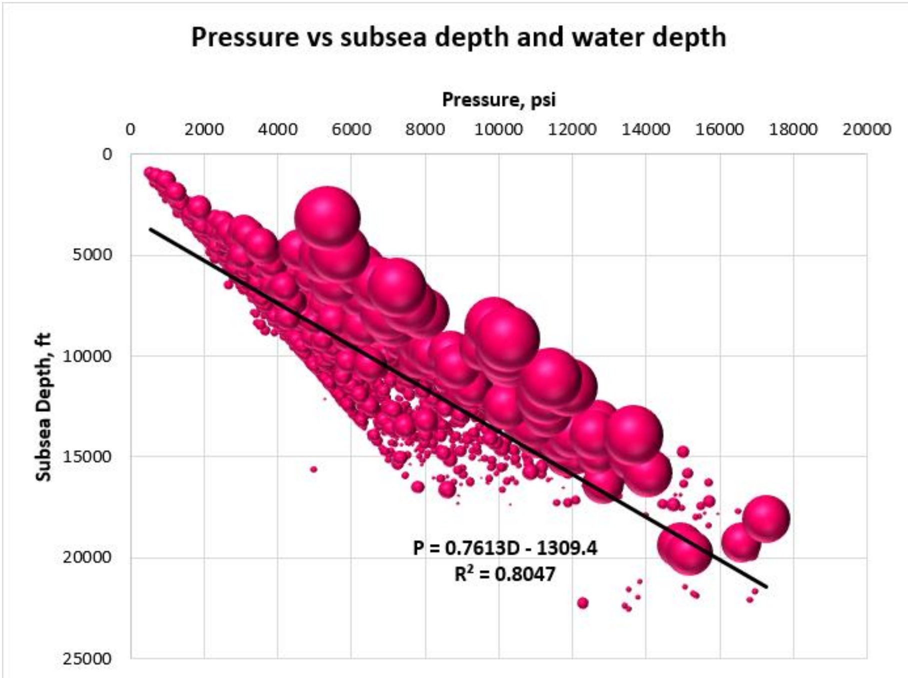

Figure 7. Pressure vs subsea depth and water depth

3.2 Temperature Observations

The temperature behavior is very close to the general geothermal gradient. Figure 8 shows temperature vs total depth and water depth in reverse order. Similarly, different ranges of water depth are analyzed separately as done for pressure.

The fits for temperature in different water depth range are

$T_R = 0.0138D_t + 68.133$ for water depth < 50 ft (11)

$T_R = 0.0128D_t + 73.433$ for water depth between 50 to 100 ft (12)

$T_R = 0.0126D_t + 74.266$ for water depth between 100 to 500 ft (13)

$T_R = 0.0112D_t + 65.91$ for water depth between 500 to 1000 ft (14)

$$T_R = 0.0056D_t + 85.337 \text{ for water depth between 1000 to 5000 ft} \quad (15)$$

$$T_R = 0.0094D_t - 3.9739 \text{ for water depth} > 5000 \text{ ft} \quad (16)$$

The slopes are generally decreasing with water depth. For a reservoir with large water depth, the cooling effect of water makes great sense so that the temperature could be very low, and this is embodied in the graph – for a same horizontal level, large bubbles are always on the left side.

Figure 9 shows the graph of reservoir temperature vs subsea depth and water depth. The trend for the overall offshore reservoir temperature (the green dashed line) gives a geothermal gradient of 1.27 deg. F per 100 ft and an ambient temperature of 74.87 deg. F, which may be somewhat higher than in the actual situation. This is likely caused by great numbers of shallow reservoir data entries, which implies that the average shallow reservoir ambient temperature is about 75 deg. F. The black straight line shows the general geothermal gradient with ambient temperature of 32 deg. F, the temperature at the sea floor in deep water, according to the work done by Ehlig-Economides and Economides (2002). The large bubbles are mostly below the average trendline, which means for the same subsea depth, reservoirs with larger water depth could have lower temperature. This also demonstrates the cooling effect brought by water.

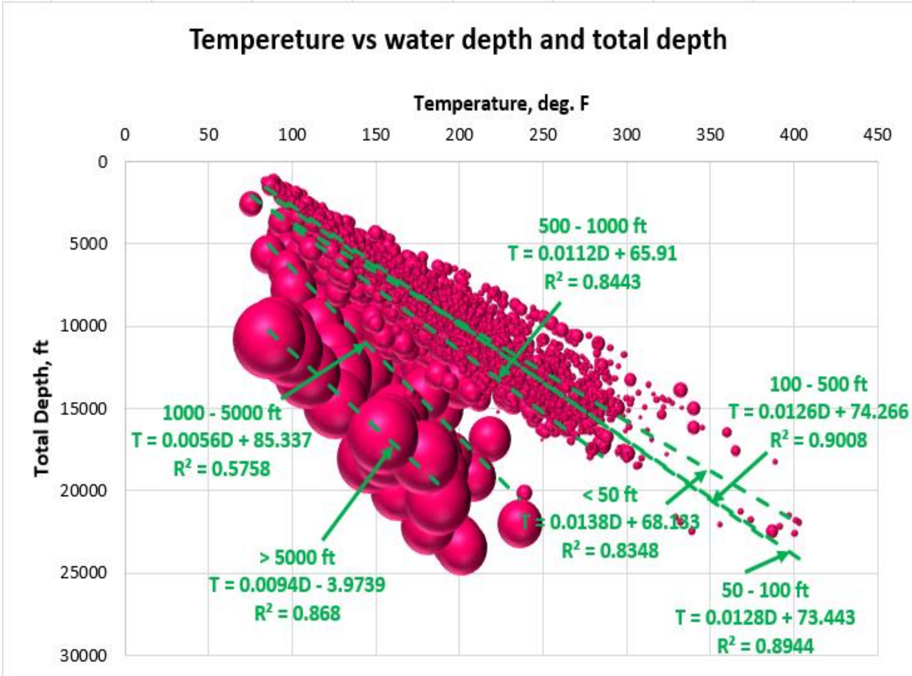

Figure 8. Temperature vs total depth and water depth

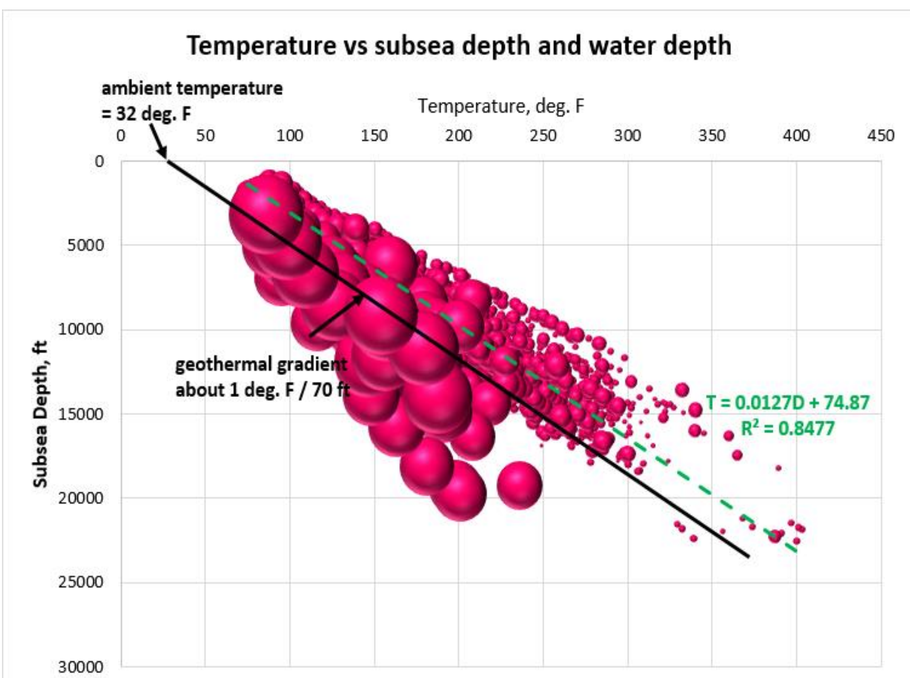

Figure 9. Temperature vs subsea depth and water depth

3.3 Porosity Observations

Porosity is a very significant factor to evaluate the reservoir quality. Figure 10 shows the plot of porosity vs total depth and water depth. The black straight line is the trend for all the offshore reservoir porosity data. This has depicted the overall declining trend for the porosity with increasing total depth. Most of the big bubbles are above the average trend. To understand more clearly about the influence of water depth, porosity data with water depth larger than 1000 ft are displayed separately with the green dashed line as the trend line. There is a shift from the overall trend. The trend becomes more flat, indicating that large water depth may result in increasing porosity with other conditions the same. Generally, the porosity decreases with increasing depth due to compaction by the overlying beds diagenesis. But when a portion of the overburden is water depth, the stress could be less, weakening the effect of compaction.

Figure 11 shows the porosity vs effective stress and formation age. The bubble size represents the formation age with large bubbles indicating older formation age. The porosity decreases with the effective stress as expected. Moreover, the largest bubbles are much below the average trend, which means the older formations have the lower porosity.

Porosity vs water depth and formation age is plotted in Figure 12. The bubble size also represents the formation age. Due to lots of shallow reservoir data, the porosity hasn’t shown direct relationship with water depth and formation age. The data points are very scattered in the graph. Actually, a reservoir with shallow water depth could be very old in age, having a low porosity after a long time of diagenesis and mechanical compaction. So, the porosity could be altered higher with the same total depth and larger water depth, but doesn't link to water depth merely.

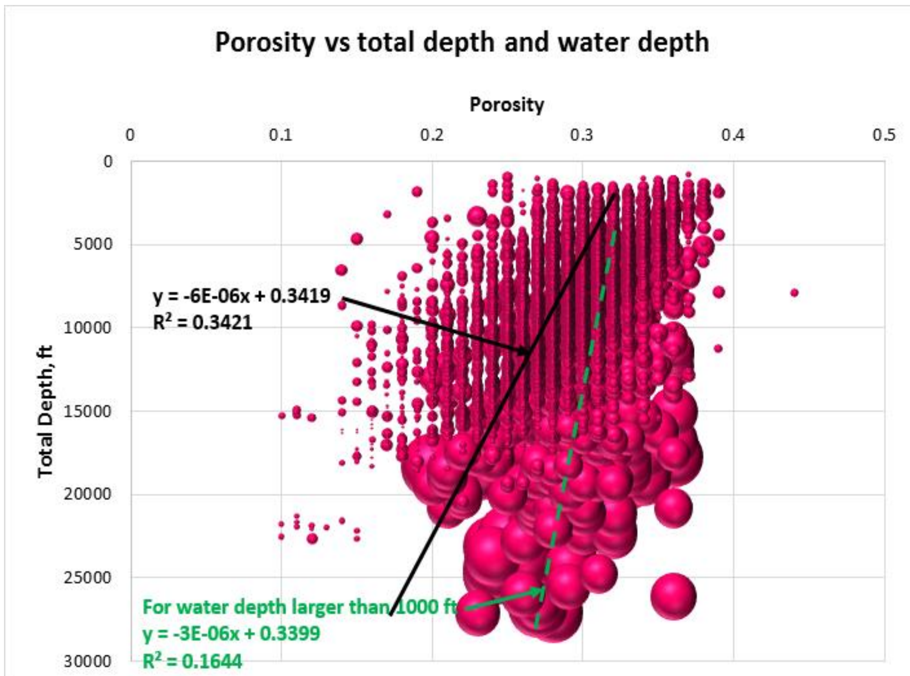

Figure 10. Porosity vs total depth and water depth

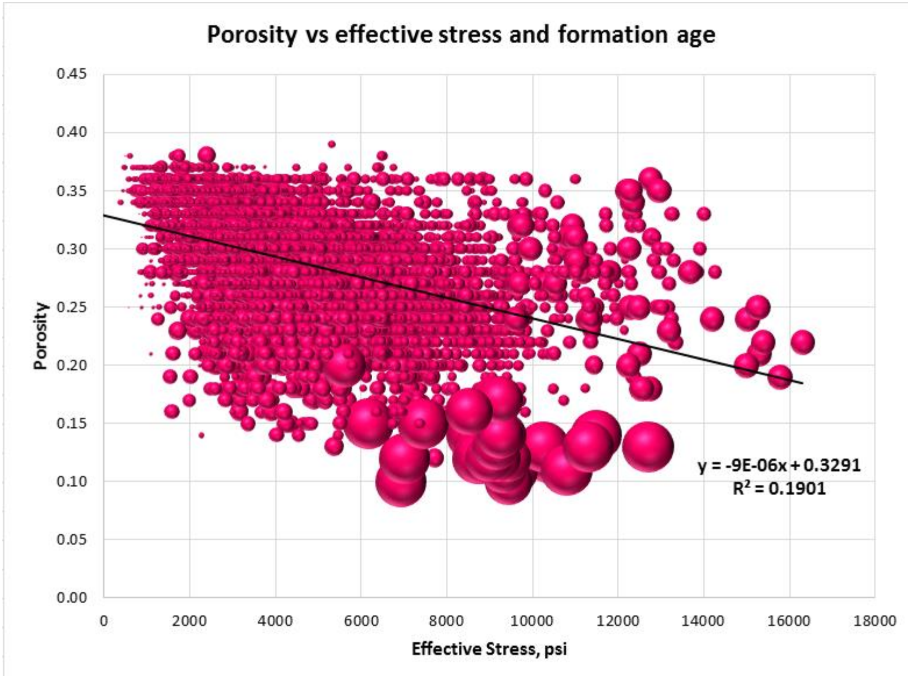

Figure 11. Porosity vs effective stress and formation age

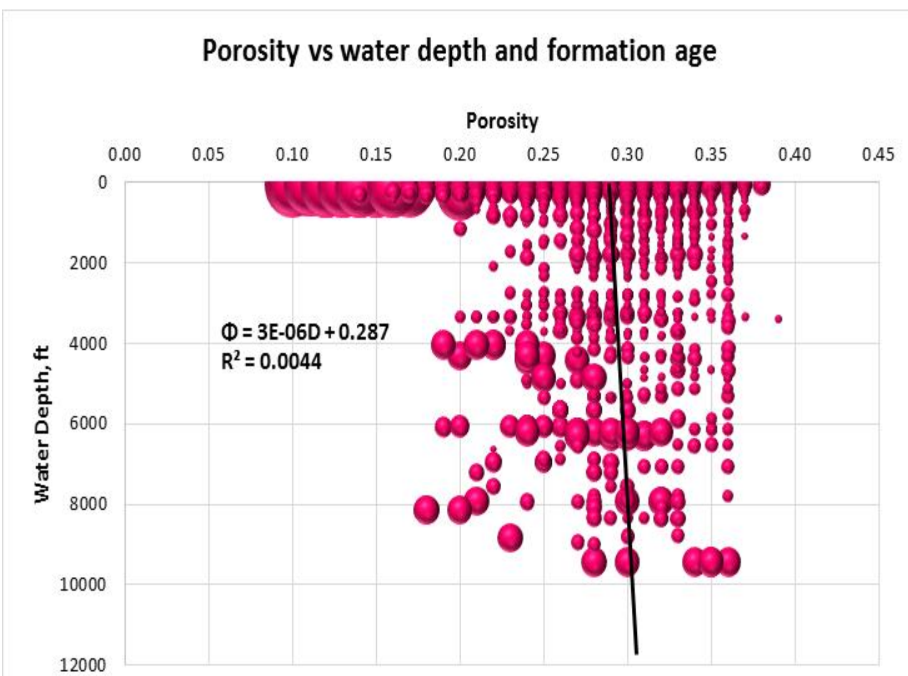

Figure 12 Porosity vs water depth and formation age

3.4 Permeability Observations

Permeability is plotted vs total depth and water depth in Figure 13, with the black straight line showing the overall trend. The permeability data is very scattered in the graph. The line fit for the permeability data gives a very small R square value, namely a large variance. This has suggested that the permeability is not sensitive to water depth.

Figure 14 is the graph of permeability vs porosity and water depth. The permeability increases slowly with porosity below 0.2 but gets a boost above that value. In this plot, there is a better fit showing that the permeability is proportional to porosity in general although the data points are still quite scattered.

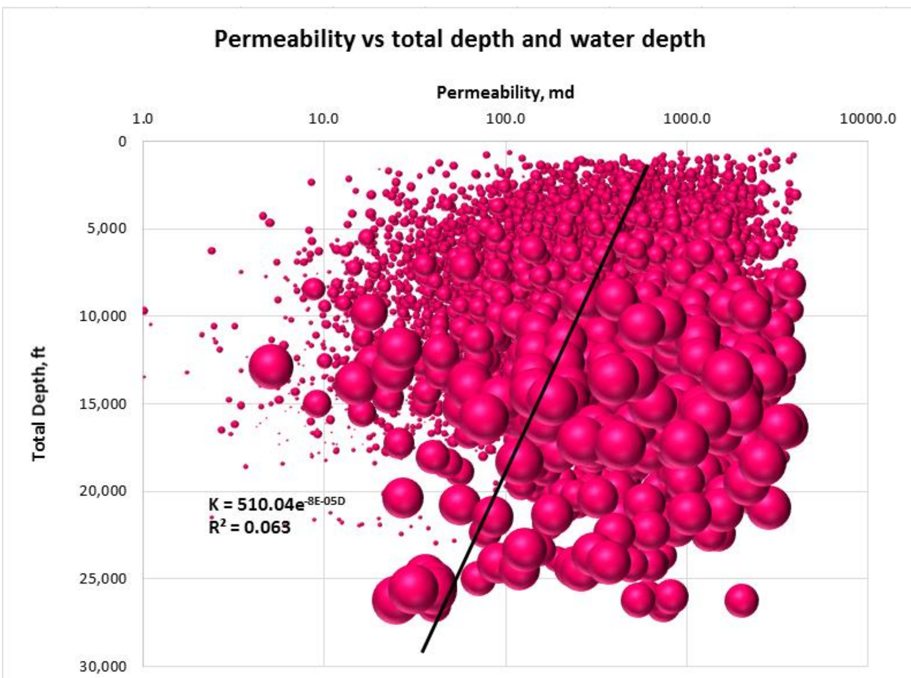

Figure 13. Permeability vs total depth and water depth

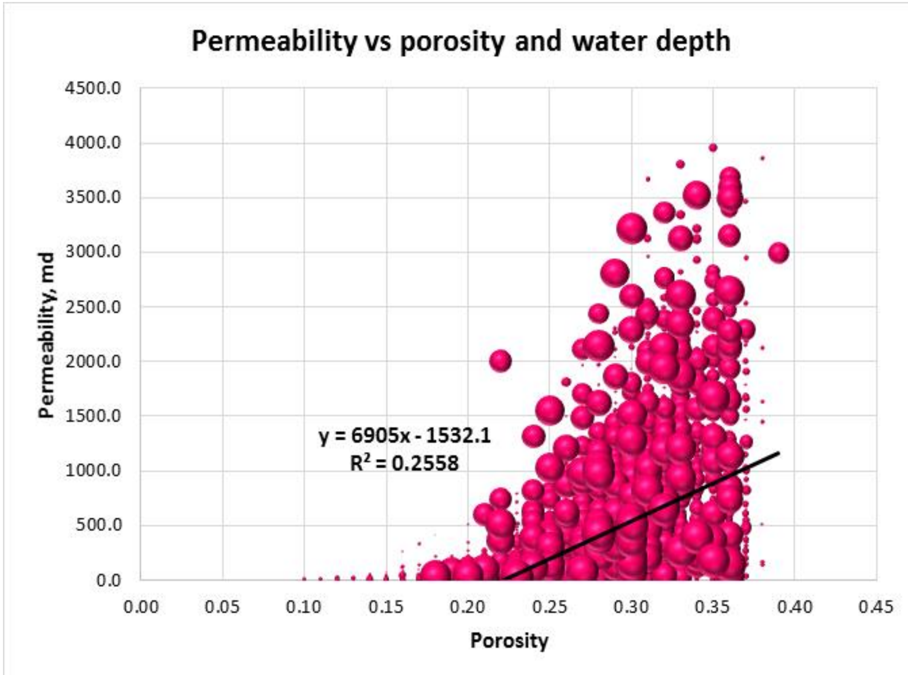

Figure 14. Permeability vs porosity and water depth

3.5 Oil Viscosity Observations

Viscosity is an important parameter for evaluating petroleum fluid property and is very sensitive to the hydrocarbon composition for varying pressure and varying temperature. As such, it is an integrator of many factors, which makes it somewhat complicated.

In the database, there is no viscosity data for any of those reservoirs. In this thesis, correlations of Beggs and Robinson (1975) and Vasquez and Beggs (1980) are used for calculating the oil viscosity. The correlations are considered precise and are often used for estimating the fluid property. For gas viscosity estimation, Lee, Gonzales and Eakin

(1966) correlation is used. The graph of viscosity vs subsea depth and water depth is shown in Figure 15 with y-axis displayed in logarithmic scale. The trend for oil is different from for gas. Most of the oil viscosity is in the range from 0.2 to 2, decreasing with total depth, but doesn't have an obvious reflection for water depth. While for gas viscosity, the data follows an increasing trend with depth. Differing from oil viscosity, the deeper the water is, the larger the gas viscosity is. The gas viscosity is kind of proportional to the pressure as the water depth varies. This is embodied in the graph as the big bubbles are generally above the small bubbles.

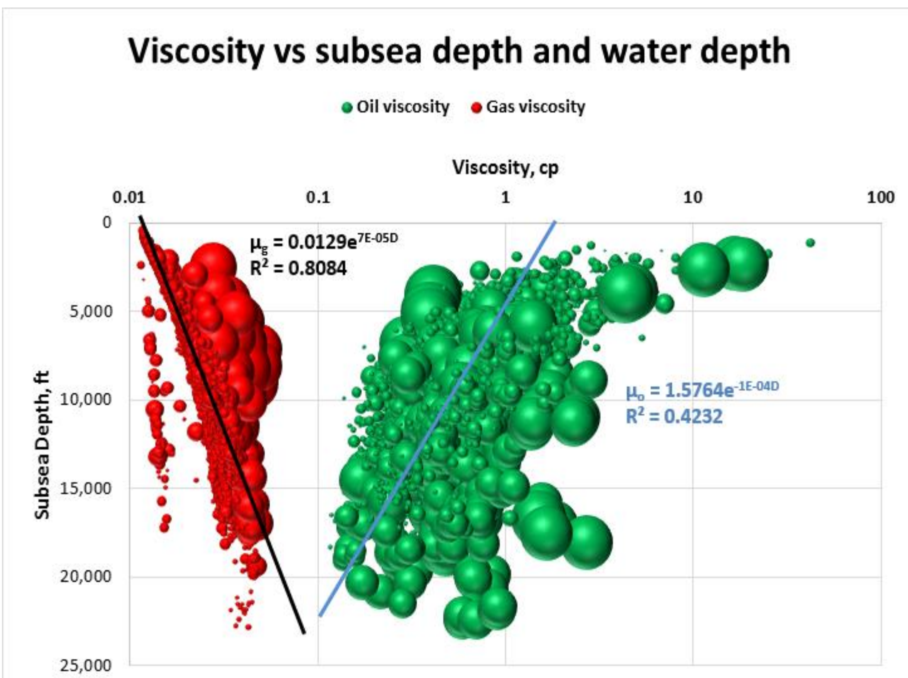

Figure 15. Viscosity vs subsea depth and water depth

3.6 Oil API Gravity Observations

API gravity is an indicator of the hydrocarbon composition. Figure 16 is the graph of oil API gravity vs subsea depth and water depth, and Figure 17 is API gravity vs temperature and water depth. The data points in both graphs haven't shown strong relationships between those required parameters. However, there are still something revealed. Wenger et al. (2001) indicated that increasing API gravity with temperature can be a sign of biodegradation, but the lack of variation in API gravity with subsea depth temperature in Figure 16 suggests this is not a strong effect. Also, most of the oil reservoirs have the oil API gravity between 20 to 40, which means the crude oil is mostly medium to light crude oil, a range commands the highest prices.

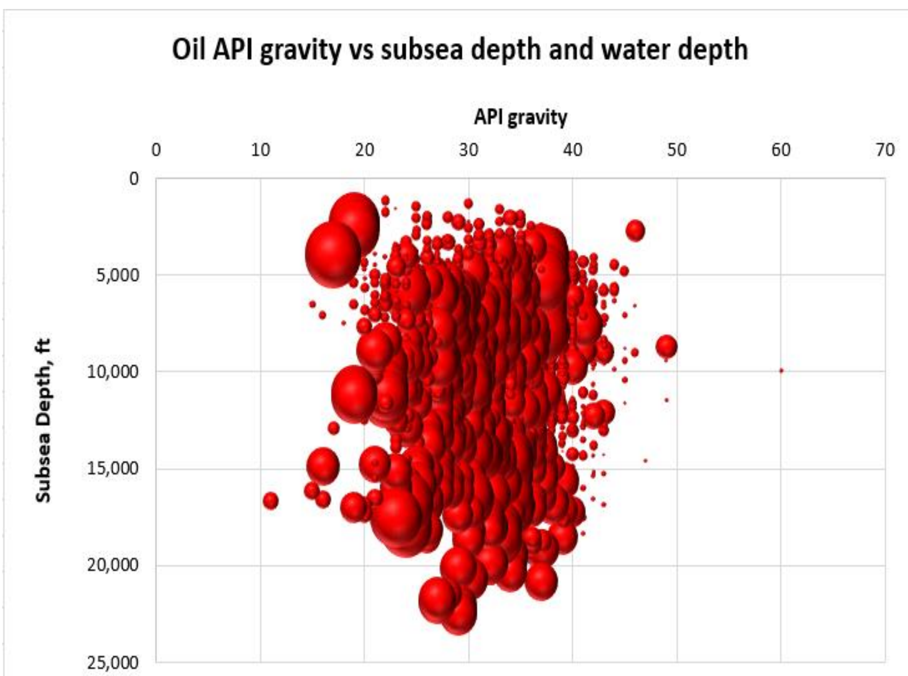

Figure 16. Oil API gravity vs subsea depth and water depth

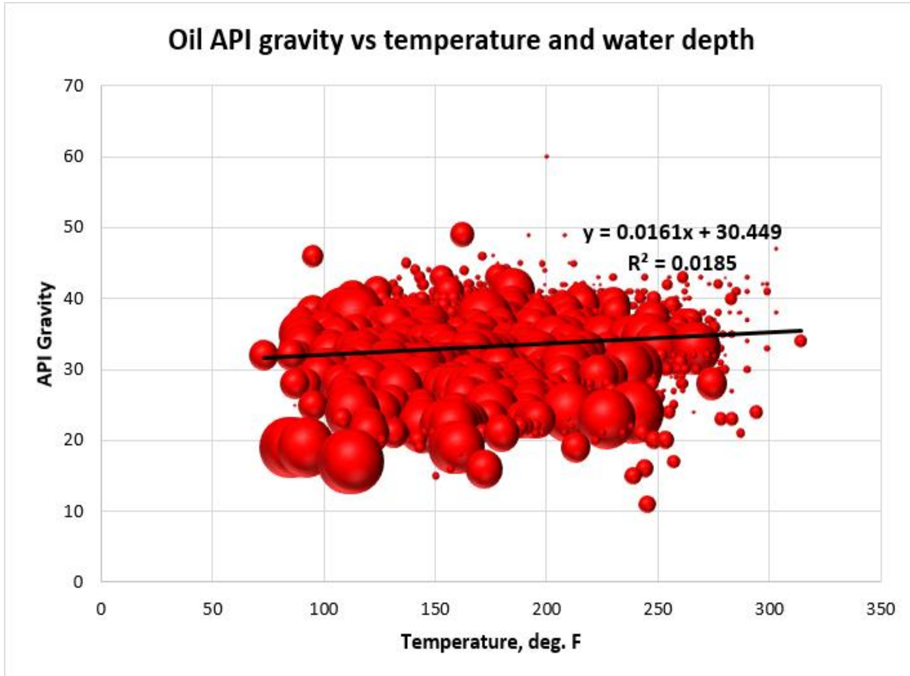

Figure 17. Oil API gravity vs temperature and water depth

3.7 Mobility Observations

Mobility is the ratio of permeability over viscosity. It is pivotal to evaluating the reservoir quality. The reservoirs with high mobility are always what explorers expect. Figure 18 is the graph of mobility vs subsea depth and water depth for both gas and oil. The mobility trends are scattered in general. The oil mobility is increasing with the depth while the gas mobility is decreasing. For gas, quite a few of the large bubbles are above the average trend, indicating that reservoirs with larger water depth will provide larger gas mobility. For oil, there is no strong relationship between mobility and water depth, but the upward trend for oil mobility indicates that deeper offshore reservoirs will have increasingly high mobility as the graph shows. For gas reservoirs with the same subsea depth, the one with larger water depth would be a better choice.

Figure 19 is the mobility plotted vs hydrocarbon volume, also with bubble size representing the water depth as above. Those reservoirs with high mobility and large hydrocarbon volume are the best to be expected, namely on the upper-right part of the graph. For oil, most of the offshore reserves are in the mobility range from 10 to 1000 md/cp, but with broad band of volume. For gas, the mobility is going upward with the volume increasing. Also, most large bubbles are with high hydrocarbon volum, suggesting deepwater gas reservoirs are more likely to have large quantity of hydrocarbon. And due to the small viscosity, the gas mobility is averagely 10 times larger than oil mobility.

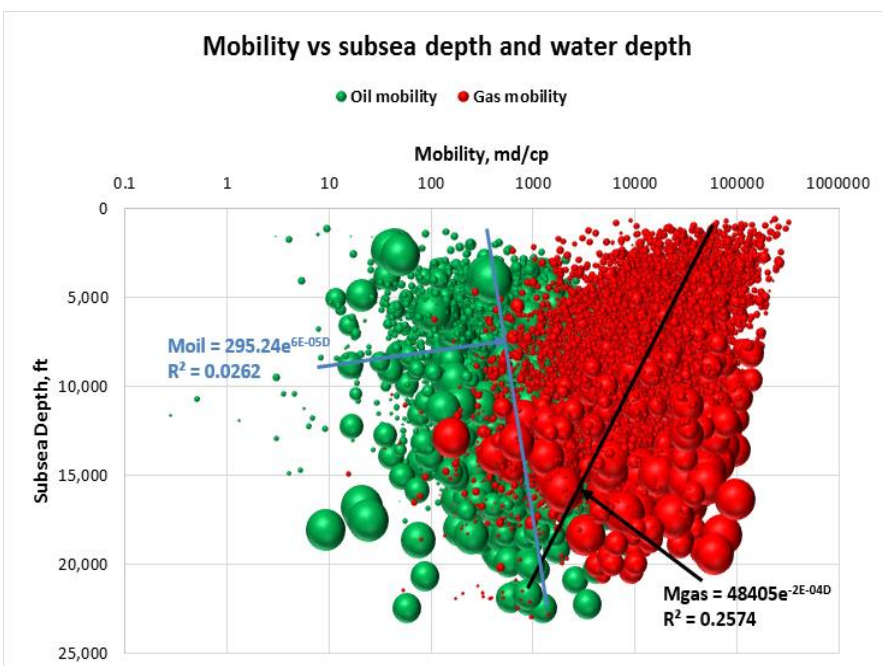

Figure 18. Mobility vs subsea depth and water depth

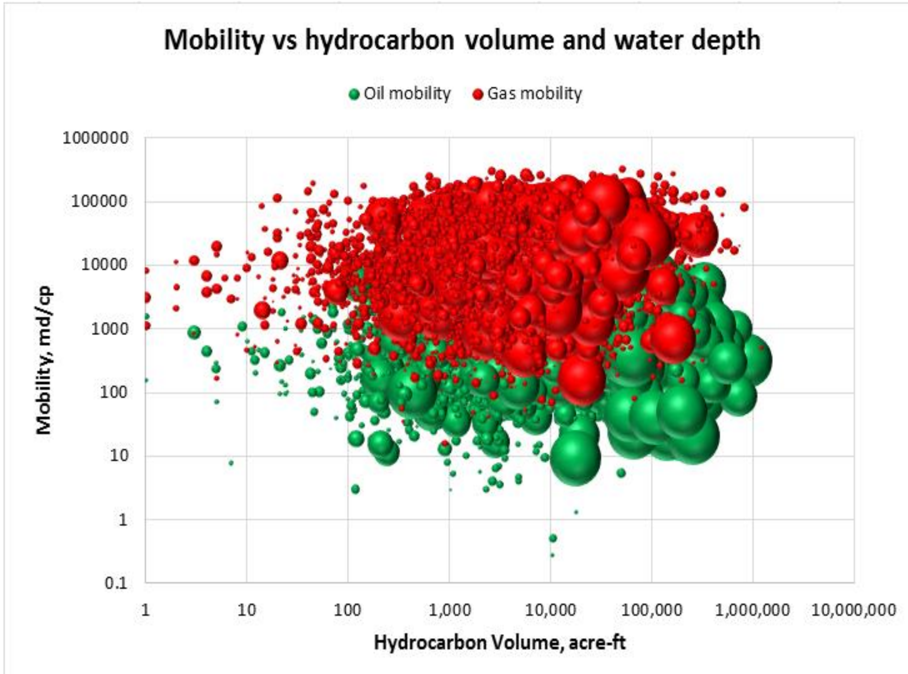

Figure 19. Mobility vs hydrocarbon volume and water depth

4. MEDITERRANEAN REGION

Mediterranean region is not like Gulf of Mexico, which has the biggest offshore reservoir database in the world. Its exploration history is not long, but the region has considerable potential. The known reservoirs are mainly in the southern and western part. This chapter considers nearly 100 data entries from the Mediterranean region.

Figure 20 is a graph of formation geologic age vs total depth. The reservoirs range in age from Triassic to Quaternary with only slight evidence of increasing age with depth. Compared to Gulf of Mexico reservoirs, Mediterranean reservoirs are older with more age variations. Actually, the Eastern, Central and Western Mediterranean basins formed in different paleogeologic times. Eastern Mediterranean reservoirs mainly developed from 23 million years ago, Central mainly 30 million years in age, and Western formed during Mesozoic and Cenozoic. The scattered data points in the graph have proved the varied reservoir age.

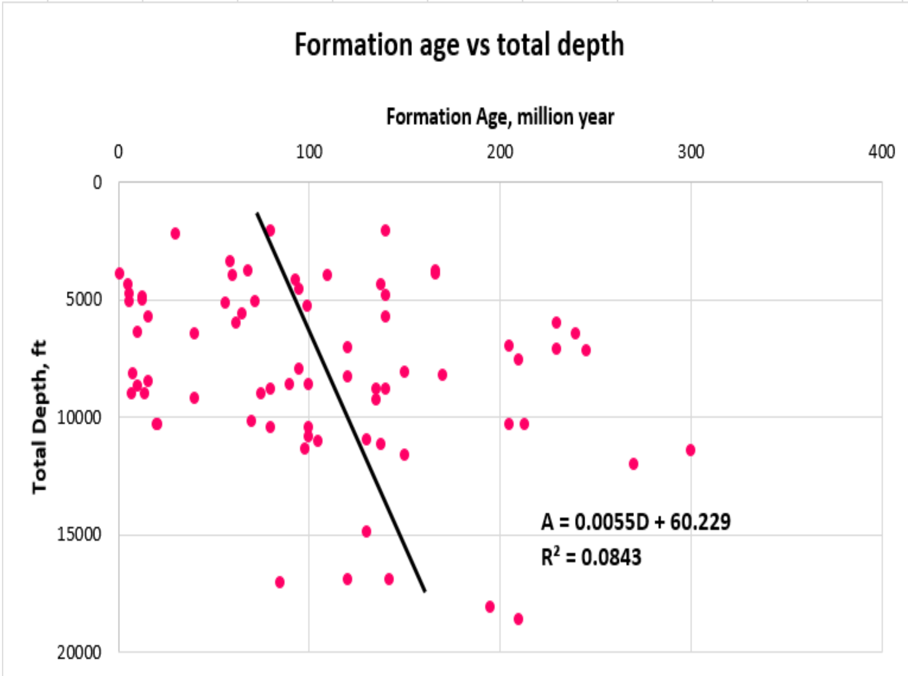

Figure 20. Formation age vs total depth

4.1 Pressure and Temperature Observations

Only few pressure and temperature data were found for the reservoirs for the Mediterranean region. To better see the contrast, these two properties are graphed together with data of Gulf of Mexico.

Figure 21 overlays the pressure vs total depth and water depth for few Mediterranean reservoirs on the trends previously shown for Gulf of Mexico reservoirs. The Mediterranean reservoirs are also overpressured, but not that much as Gulf of Mexico. Revil et al. (1999) suggested that reservoir fluid overpressures observed in the Mediterranean r are the result of disequilibrium compaction related to the presence of free methane and high sedimentation rates. In this situation, sediments are unable to expel the pore fluids in response to the overlying sediment loading, causing the fluid overpressure phenomenon (Magara, 1978).

Figure 22 shows the temperature vs total depth and water depth for both regions. The temperature gradient for Mediterranean is higher than that of GoM. Revil et al. (1999) indicated according to the work done by previous scholars that most of the methane was generated due to biodegradation from the organic matter present in the sediment. This would result in relatively low temperature. But due to the average shallower water (especially for the data found, the water depth is mostly smaller than 400 ft) in Mediterranean region, which brings less cooling effect to the reservoir, the reservoir temperature is generally somewhat higher than that in Gulf of Mexico.

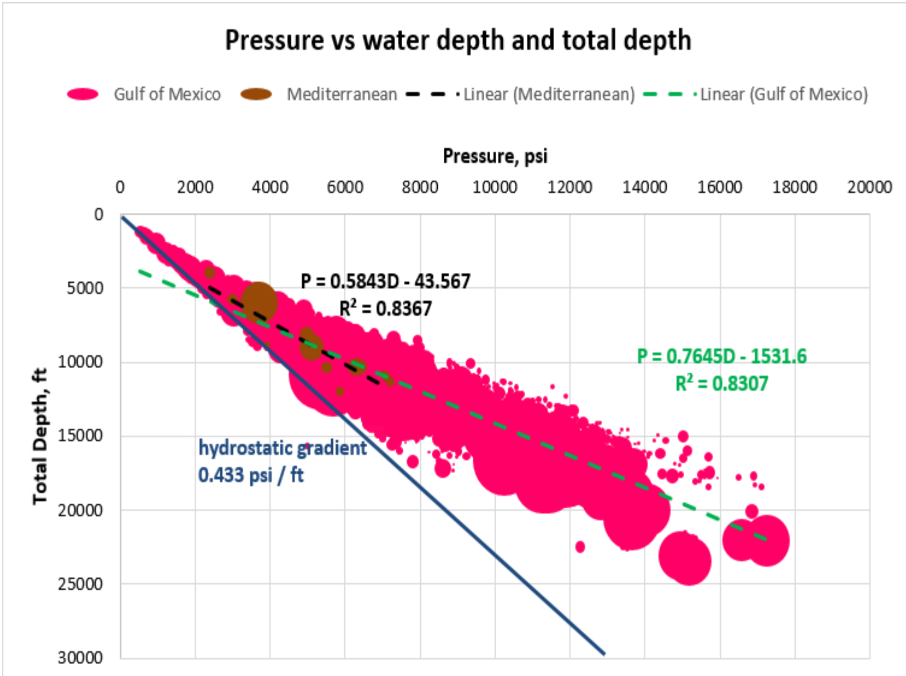

Figure 21. Pressure vs total depth and water depth comparison

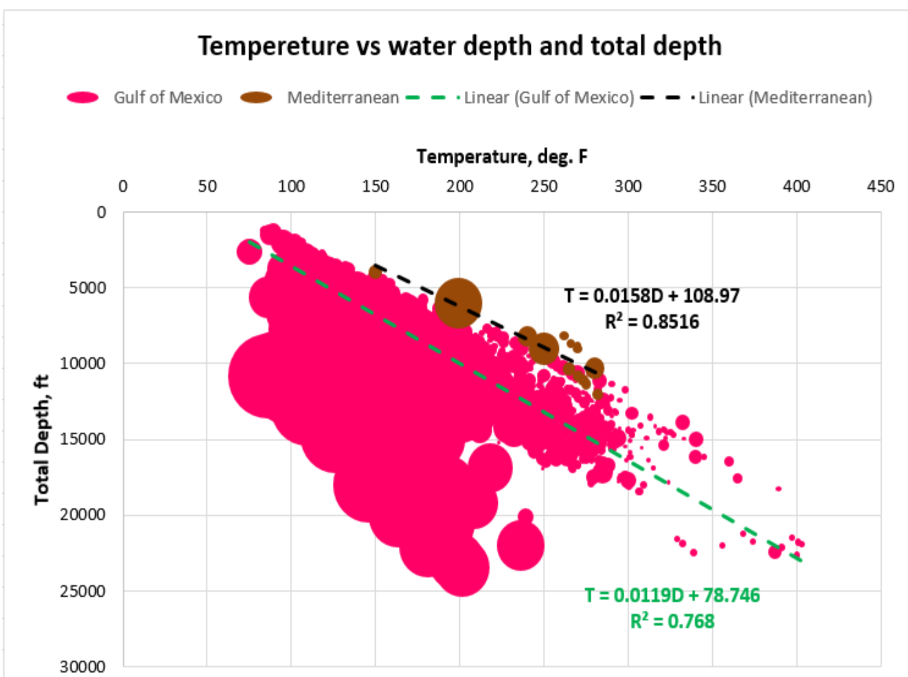

Figure 22. Temperature vs total depth and water depth comparison

4.2 Porosity Observations

Figure 23 is the graph of porosity vs total depth and water depth with bubble size proportional to the water depth. As expected, the porosity is decreasing with total depth, and most of the big bubbles are above the average trend. Similar to trends observed by Ehlig-Economides and Economides (2012) in the Gulf of Mexico, this may be a sign of lower stress resulting from a portion of the total depth being water depth.

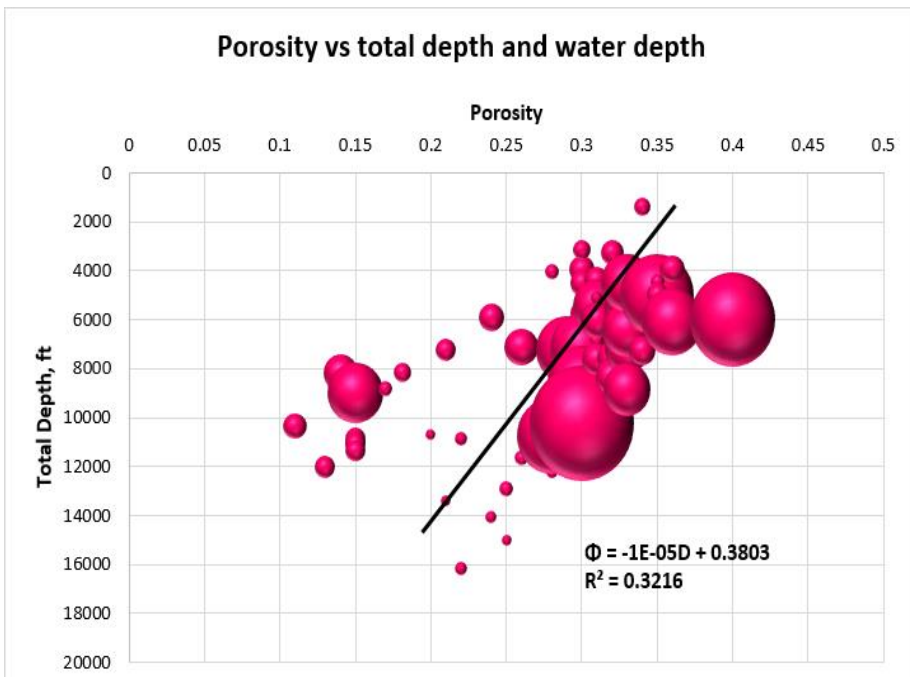

Figure 23. Porosity vs total depth and water depth

4.3 Permeability Observations

Permeability vs total depth and water depth is plotted in Figure 24. The permeability shows an overall decreasing trend with total depth, but the data points are quite scattered. The big bubbles are distributed from small to large permeability, suggesting this parameter is not sensitive to the water as well.

Permeability vs porosity and water depth is graphed in Figure 25. For small porosity, the permeability just remains at a low level. But after the porosity has increased to 0.25, the permeability is rising dramatically. For porosity above 0.25, the permeability is proportional to the porosity, making forecasting this property a possibility. However. the bubbles do not show sensitivity to the water depth.

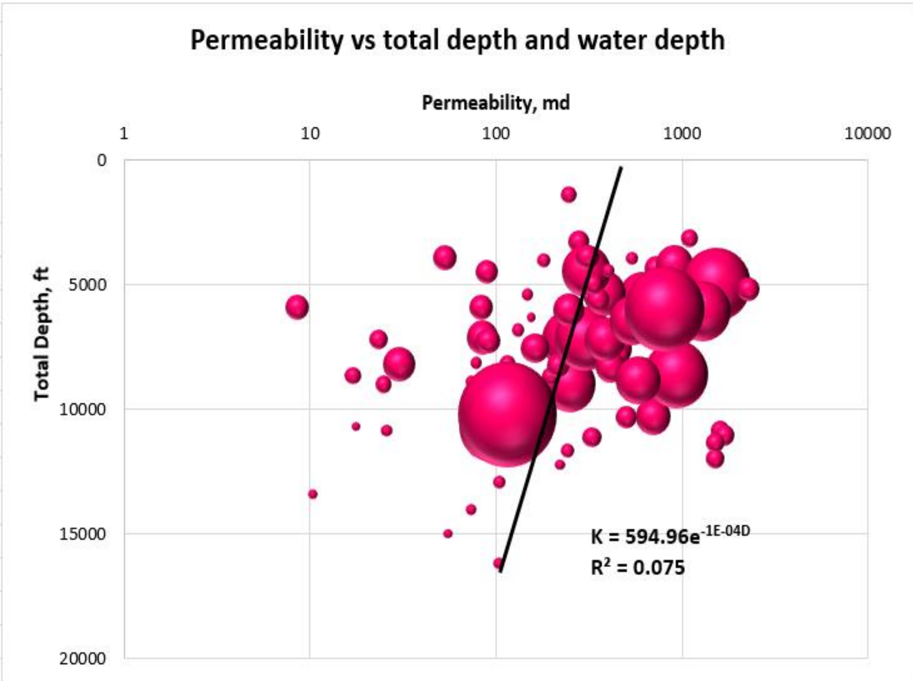

Figure 24. Permeability vs total depth and water depth

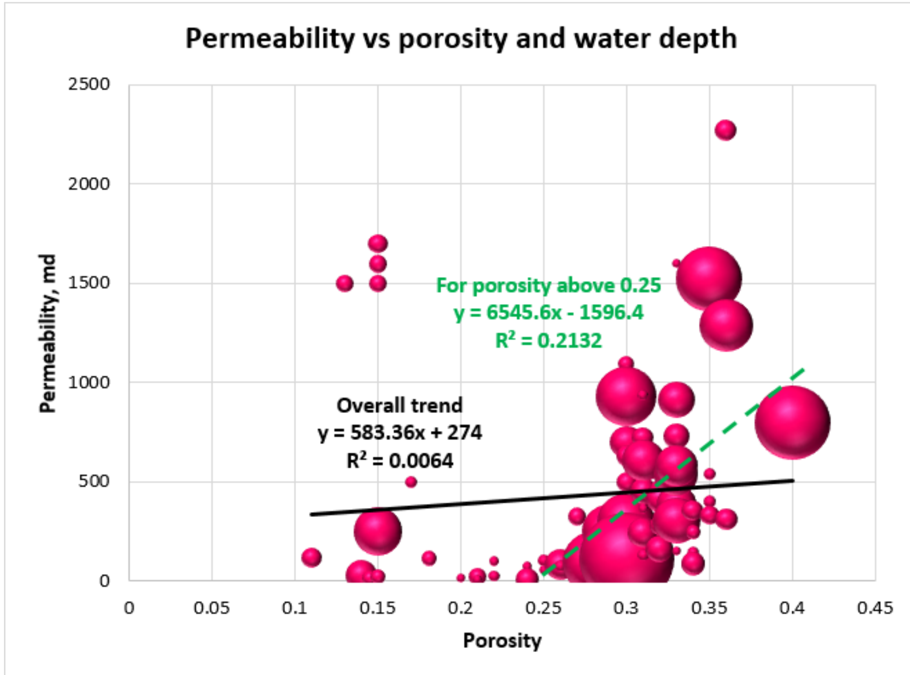

Figure 25. Permeability vs porosity and water depth

5. INTEGRATION AND COMPARISON

The Mediterranean data were not sufficient for detailed comparison to that of Gulf of Mexico. No derived properties could be obtained with limited information. However, the data still provide some basic understandings of the Mediterranean offshore reservoirs situation.

Table 1 is a summary of all the basic findings for different properties in both two regions. As the final integration and comparison, the information from database or literature review is utilized to find out the similarities and differences between the two regions. First, both of them have overpressure phenomenon for most of the offshore reservoirs with compaction reasons. Second, they both show that the porosity decreases with depth while large depth of water could make the porosity larger. This makes sense only with other conditions the same. This is also consistent with the pressure behavior. Both of the two regions have very scattered permeabilities on the depth plot, not sensitive to water depth. The biggest differences are the reservoir formation age and main reservoir type. The Mediterranean reservoirs are mainly Mesozoic aged and are mainly carbonate reservoirs while Gulf of Mexico reservoirs are largely formed in Cenozoic with the main type of sandstone.

Properties	Gulf of Mexico	Mediterranean
Age	Began from Jurassic. Most are very young, in Cenozoic Fit: A = 0.005D + 1.446 (oil) $R^2 = 0.1417$ A = 0.009D + 0.615 (gas) $R^2 = 0.1065$	Data found from Triassic More varied and older Fit: A = 0.0093D + 67.073 $R^2 = 0.0843$
Pressure	Reservoirs are generally overpressured Deeper water, higher pressure Fit: P = 0.7645D - 1531.6 $R^2 = 0.8307$	Also generally overpressured Fit: P = 0.5843D – 43.567 $R^2 = 0.8367$
Temperature	Very close to geothermal gradient Deeper water, lower temperature Fit: T = 0.0119D + 78.746 $R^2 = 0.768$	Higher temperature gradient Fit: T = 0.0158D + 108.97 $R^2 = 0.8516$
Porosity	With same total depth, deeper water, larger porosity Fit: Φ = -6E(-6)D + 0.3419 $R^2 = 0.3421$	With same total depth, deeper water, larger porosity Fit: Φ = -1E(-5)D + 0.3803 $R^2 = 0.3216$
Permeability	No relationship with water depth Fit: K = -0.0265D + 688.34 $R^2 = 0.0358$	No relationship with water depth Fit: K = -0.0236D + 625.68 $R^2 = 0.022$

Table 1. Property comparison

6. CONCLUSIONS

The data analysis and literature review suggest the following:

1. Generally reservoirs in Gulf of Mexico have younger age than in the Mediterranean region.
2. Most of the reservoirs in both of the two regions are overpressured. For Gulf of Mexico, the data indicate that reservoir overpressure increase with water depth.
3. For the Gulf of Mexico, the temperature trend is as expected with larger water depth resulting in lower temperature. Mediterranean reservoir temperature is higher than that of Gulf of Mexico.
4. The porosity trends decrease with total depth for both of the two regions. Reservoirs with larger water depth could have higher porosity under the same total depth condition.
5. The permeability decreases with total depth for both of the two regions, without sensitivity to the water depth. Also, they show similar phenomenon that the permeability appears to be increasing with porosity dramatically above a certain value.
6. For the derived properties of Gulf of Mexico ---- the gas viscosity decreases with subsea depth while the oil viscosity increases. Mobility trend haven't shown strong relationship with water depth.

In all, though the two regions have different main type of reservoirs, and are located in very distant places, the behaviors of their reservoir pressure, porosity and permeability properties with water depth are similar.

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