Improving Petroleum System Identification in an Offshore Salt Environment: Gulf of Mexico and Red Sea Case Studies*

Rick Schrynemeeckers[1]

Search and Discovery Article #41607 (2015)**
Posted April 6, 2015

*Adapted from oral presentation given at AAPG Geoscience Technology Workshop, Sixth Annual Deepwater and Shelf Reservoir, Houston, Texas, January 27-28, 2015

[1]Amplified Geochemical Imaging (schrynemeeckers@agisurveys.net)

Abstract

Offshore exploration is a costly endeavor that entails multi-million dollar expenditures to acquire synthetic aperture radar data, 2-D seismic data, as well as 3-D seismic data to evaluate subsurface structures and systems. While these technologies lend an understanding to the geologic structure of subsea systems, they do not address the critical question of the presence of a petroleum system. Additionally, in environments such as the Gulf of Mexico, offshore Brazil, and the Red Sea, thick salt sequences can radically affect the quality and utility of seismic data.

This case study was conducted by Anadarko Petroleum Corporation in their Marco Polo Field in the Gulf of Mexico. The Marco Polo Field is located in a salt bounded mini-basin in Green Canyon Block 608 which is approximately 175 miles offshore south of New Orleans, Louisiana. Production from the Marco Polo field originates from a Pliocene age supra-salt sandstone reservoirs.

The project focused on improving the detection and mapping of hydrocarbons from petroleum systems by augmenting seismic and satellite data with additional technologies. Traditional macro-seep detection schemes only average a 10% probability of detecting hydrocarbons. This is primarily due to (1) a lack of macro-seeps over an area of interest, (2) a lack of sensitivity in traditional hydrocarbon detection methods, and (3) hydrocarbon seeps are often small features that are not easily recognized by 3-D seismic data. Thus, Anadarko augmented the traditional approach with an Autonomous Underwater Vehicle (AUV) geophysical survey utilizing detailed multibeam bathymetry, side scan sonar, and sub-bottom acoustic profiling to acquire high-resolution sea floor and near sea floor characterization. Additionally, they used an ultra-sensitive hydrocarbon detection system that provided hydrocarbon detection with a thousand times greater sensitivity than traditional methods.

As a result, the high resolution geophysical data collected with the AUV significantly improved the probability and the ability to locate macro-seep sites. Additionally, the ultra-sensitive hydrocarbon system was able to identify hydrocarbons from both macro-seepage and micro-seepage. Thus, hydrocarbons were detected at various levels of intensity in one hundred percent of the core samples, instead of ten percent, thus

eliminating the need to be directly over the macro-seep expulsion feature or to be present during the expulsion event. The result was a significant improvement in the de-risking assessment of offshore exploration in the Marco Polo Field.

It should also be noted that the Marco Polo Field is flanked by two subsalt fields, the K2/K2 North Field and the Genghis Khan Field. Both fields lie beneath a 10,000-15,000 ft thick salt canopy and produce from middle/lower Miocene reservoirs. While these adjacent fields were not included in the Marco Polo assessment, it did beg the question if the more sensitive hydrocarbon detection method could detect the micro-seepage of hydrocarbons through salt canopies. A Red Sea study will be shown in an area that was overlain by 8,000 ft of evaporitic salt and anhydrite sequences that also contained inter-bedded shale sequences. The field was a fractured sub-salt rift basin producing from the Miocene Kareem and Rudeis formations. The client had drilled two producing wells, but had also drilled three dry wells. The thick salt sequence made seismic data difficult to interpret and the extensive faulting added additional risk to the exploration efforts. Given the complex geologic system and the difficulties associated with the seismic imaging, ultra-sensitive hydrocarbon mapping was employed to add understanding to the geologic structure and possibly add clarity to the boundaries of the hydrocarbon accumulations.

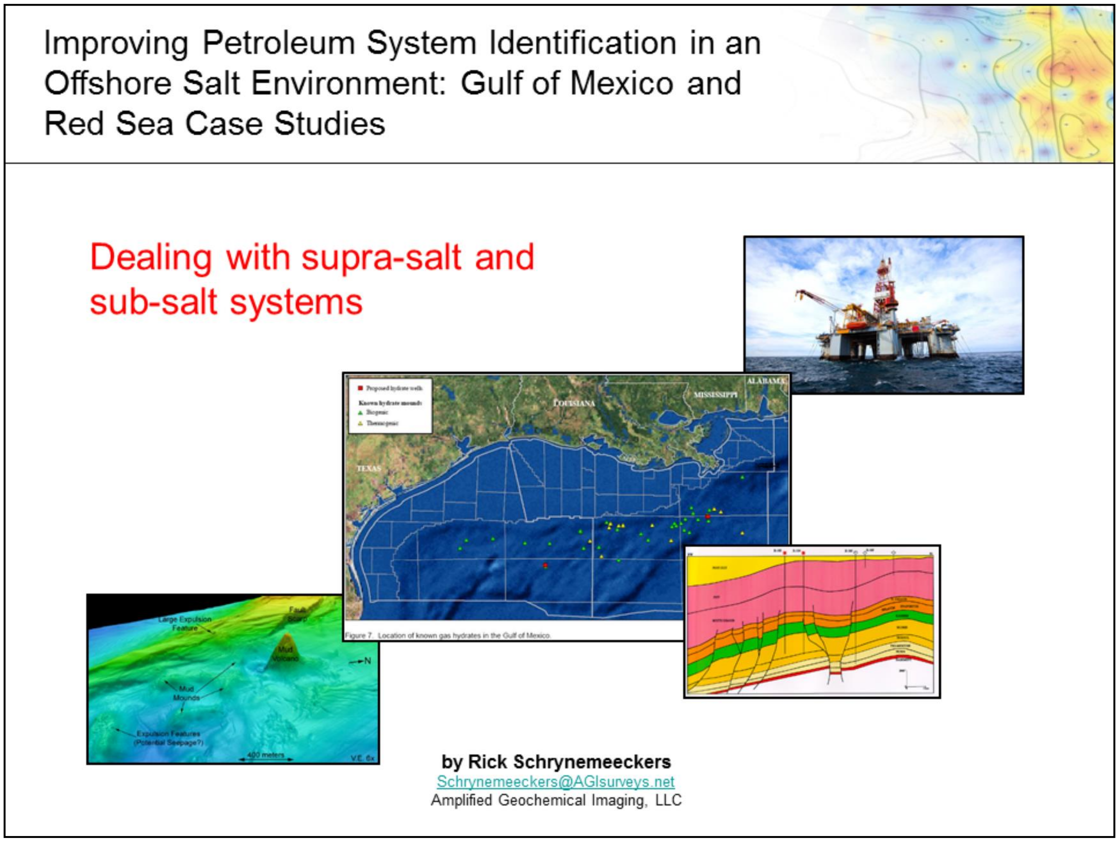
The survey was performed with 100 samples laid in transects along previous seismic lines using 250 meter and 500 meter spacing covering 35 sq km. Liquid hydrocarbons were detected through the 8,000 ft salt sequence and then mapped across the field indicating areas of high probability of oil locations and areas of low probability. The probability map correctly predicted the previously drilled producing and dry wells. From a structural sense, the hydrocarbon survey results also identified two three-way closures in the field as well as a potential fault not identified by seismic data. Subsequent to the study, a well was drilled based on the survey results and produced 800 bopd, confirming the hydrocarbon probability maps generated by the survey.

References Cited

Dembicki, Harry Jr., and Bruce Samuel, 2007, Identification, characterization, and ground-truthing of deepwater thermogenic hydrocarbon macro-seepage utilizing high-resolution AUV geophysical data: Offshore Technology Conference, 18556.

Dembicki, Harry Jr., and Bruce Samuel, 2008, Improving the detection and analysis of seafloor macro-seeps: An example from the Marco Polo Field, Gulf of Mexico, USA: International Petroleum Technology Conference, 12124.

Marchand, Ann, 2015, Depositional processes and impact of reservoir quality in deepwater Paleogene reservoirs, US Gulf of Mexico: 6th Annual Deepwater & Shelf Reservoirs Groundwater Technology Workshop, January.



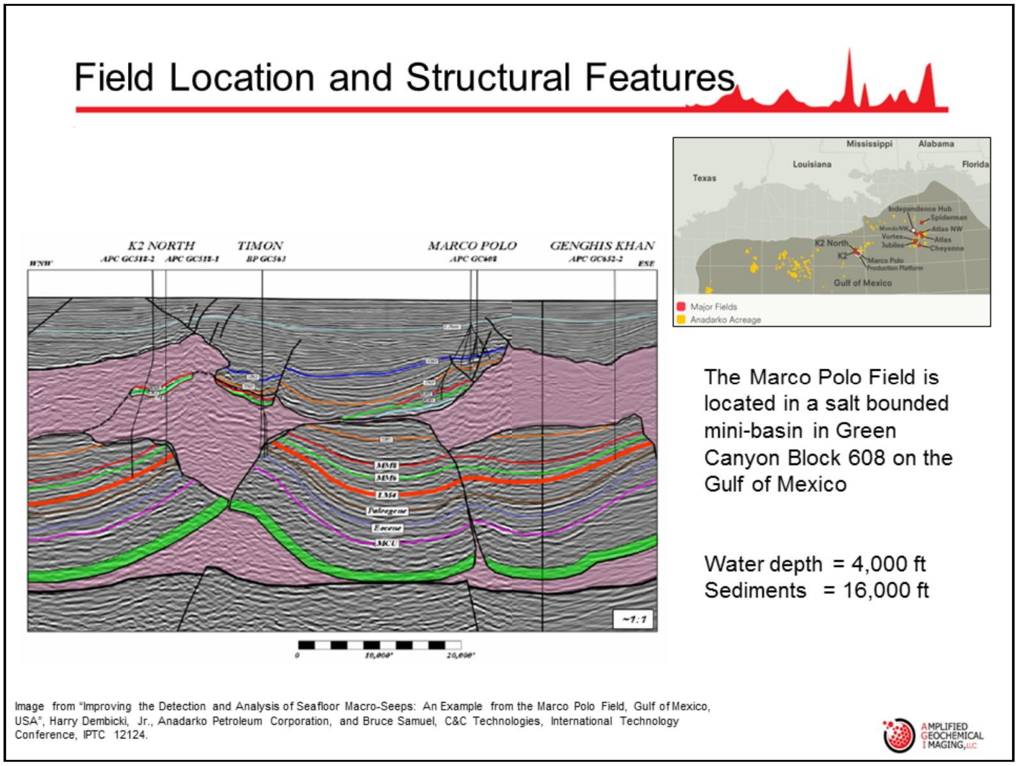
In many deepwater petroleum plays, the search for seafloor hydrocarbon macro-seepage is an important part of the exploration program. Detecting thermogenic hydrocarbons at the seafloor provides strong evidence for the presence of a working petroleum system in the subsurface. Thermogenic hydrocarbons recovered from seeps can provide insight into the contents of the subsurface reservoir such as its relationship with previously discovered hydrocarbons and/or the identification of potential source rocks before an exploratory well is ever drilled. As an integral part of a comprehensive exploration program, this knowledge can substantially reduce the risk in drilling expensive deepwater wells. However, typically in basins where seepage occurs, this results in less than 10% of the cores encountering thermogenic hydrocarbons. (this is an excerpt from ñIdentification, Characterization, and Ground-Truthing of Deepwater Thermogenic Hydrocarbon Macro-Seepage Utilizing High-Resolution AUV Geophysical Dataòby Dr. Harry Dembicki, Jr., Anadarko Petroleum Corporation, et.al., OTC 18556, 2007.)

Thus the project had several objectives:

> Identify potential locations for macroseepage sampling.

> Evaluate various technologies for improving hydrocarbon detection in drop core samples

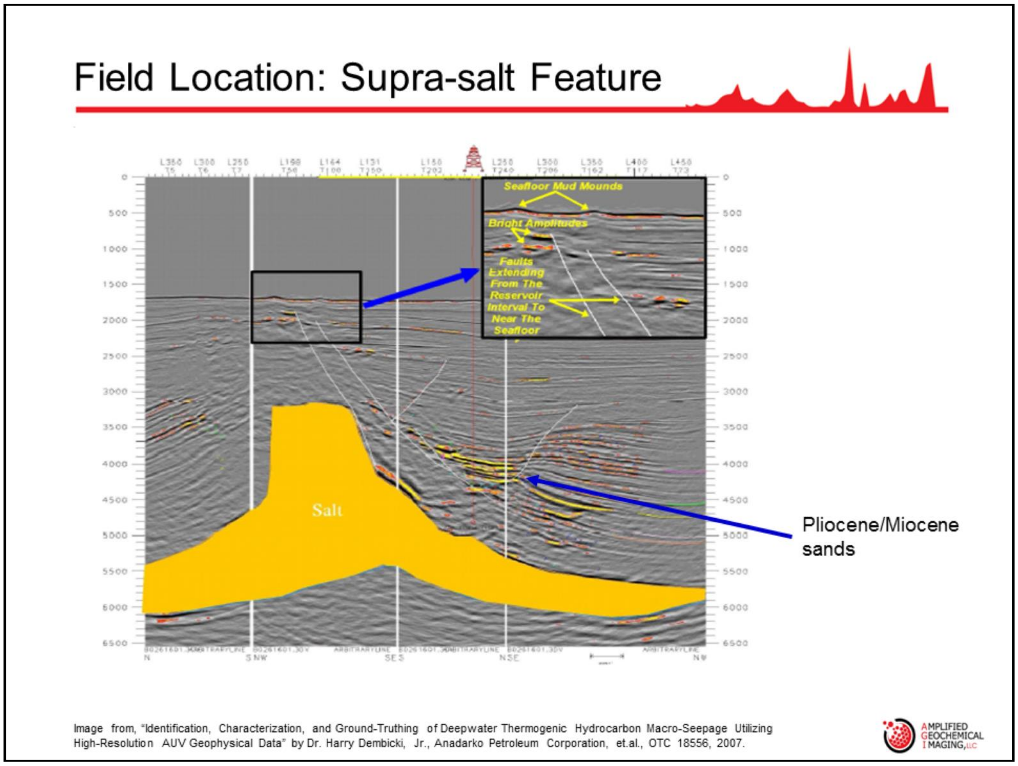
> Enhance the information potentially obtainable from piston core projects to reduce exploration risk and enhance petroleum system understanding



This is a seismic transect in Green Canyon showing the complex salt tectonics in the Marco Polo area. The salt is shaded pink and the Upper Jurassic source rock is in the green shaded sediment package.

The seep features studied are in just over 4000 feet (1219 m) of water approximately 175 miles (281 km) south of New Orleans, Louisiana in Blocks 563, 607, and 608 in the Green Canyon protraction area of the Gulf of Mexico.

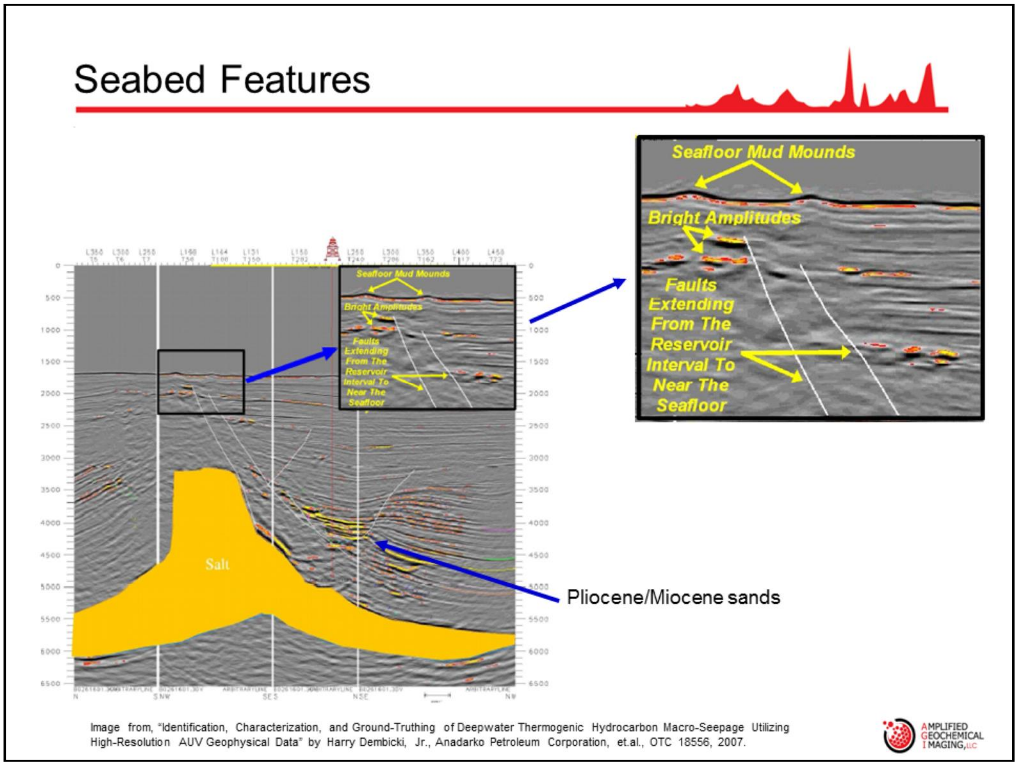
Hydrocarbons seeping to the seabed leak from supra-salt Pliocene/Miocene reservoir sands in the Marco Polo field. The field lies within a salt bounded mini-basin containing sediments up to 16,000 feet (4877 m) thick. It is believed that oil from this sub-salt Jurassic source migrated to the supra-salt reservoir through windows in the welded salt canopy that floors the mini-basin. The concave-down geometry of the salt canopy directly beneath the Marco Polo mini-basin is predicted to focus migration from the underlying depocenter towards the weld at the base of the mini-basin.



In the Marco Polo area, potential seep features were located in Block 607 using information collected from the 3-D seismic data. 2-D seismic sections extracted from the 3-D data volume revealed seafloor mounding and near surface amplitudes associated with faults, likely related to salt movement, extending up from the reservoir interval. In addition, seafloor amplitude and bathymetry maps derived from the 3-D seismic data revealed areas of high impedance contrast suggesting the presence of authigenic carbonates or near surface hydrates in conjunction with geomorphic features such as faults and mounding that may indicate potential seeps.

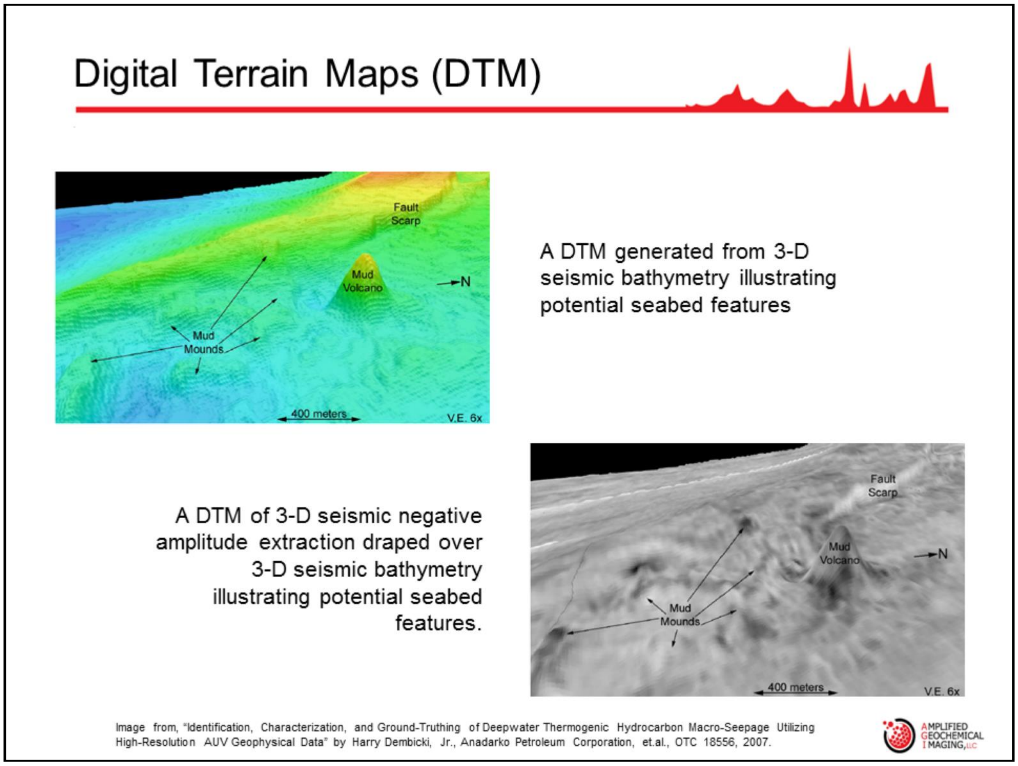
Production in the Marco Polo Field is from the Pliocene/Miocene sands above the salt. The oil within the reservoir intervals has migrated up through windows in the salt. Hydrocarbons are medium gravity marine Type II oil consistent with generation from the postulated subsalt late Jurassic source sediments.

This seismic profile line extending west to east shows salt related tectonic faults extending up from the reservoir to near the seabed floor. These faults provide potential migration pathways for the hydrocarbons to move from the reservoir to the seafloor and to form mud mounds and macroseeps on the western side of the field.



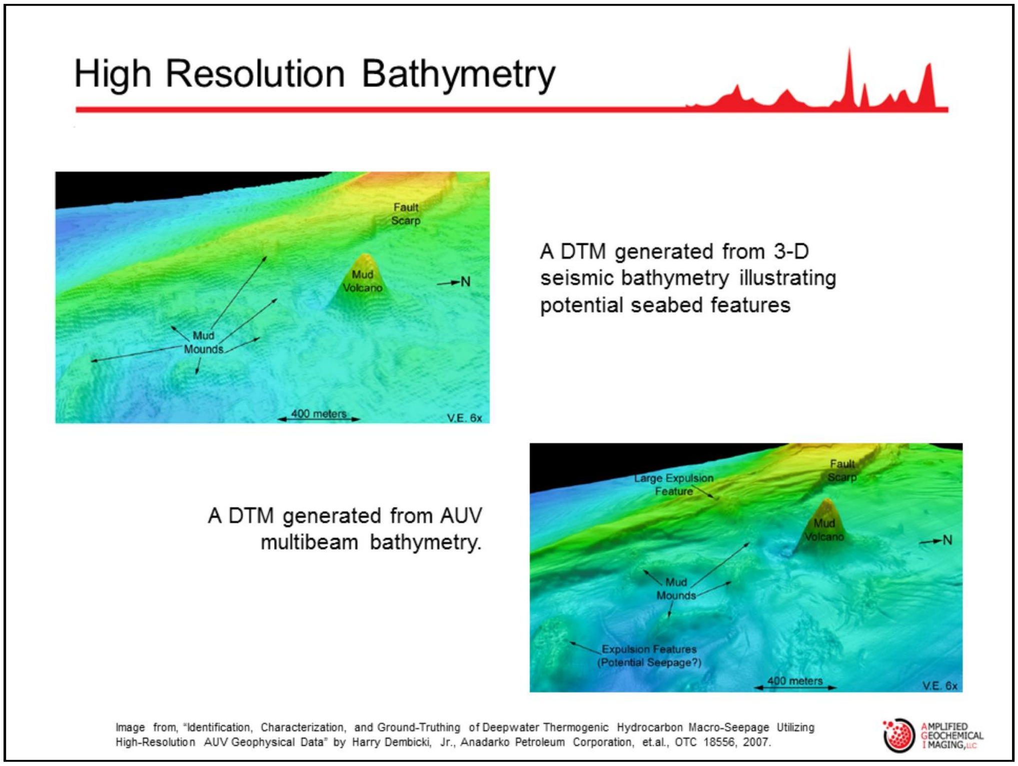
Here you can see an expanded view of the seafloor mud mounds and the ends of the faults that act as a potential migration pathway for the hydrocarbons from the reservoir to the mud mounds.

The seismic data also provides some indications of potential seepage in the near surface bright amplitudes.

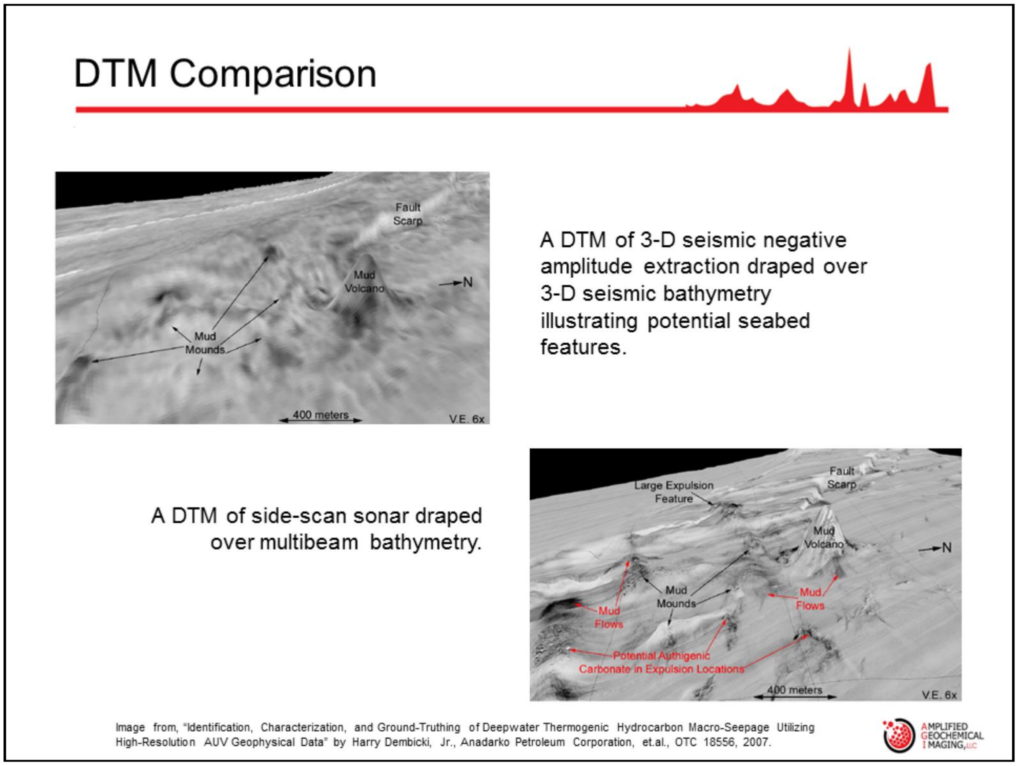


While 3-D seismic data provides some indication of potential seepage, the resolution is often insufficient the detail needed to distinguish routine bathymetric features from true sea features. You can see here that the Digital Terrain Maps provide some indications of a fault scarp, a mud volcano, and potential mud mounds the resolution and clarity is not distinct.

If you are trying design a piston cores sampling program, these maps really accentuate the problem with designing that sampling program. Obviously, from both of these maps you would be hard pressed to delineate exact sampling location, with the exception of the mud volcanoe, with a high likelihood of landing right on an expulsion feature. So, the lack of resolution in these maps provide an example of one of the reason for the low probability of finding hydrocarbons in piston core samles.



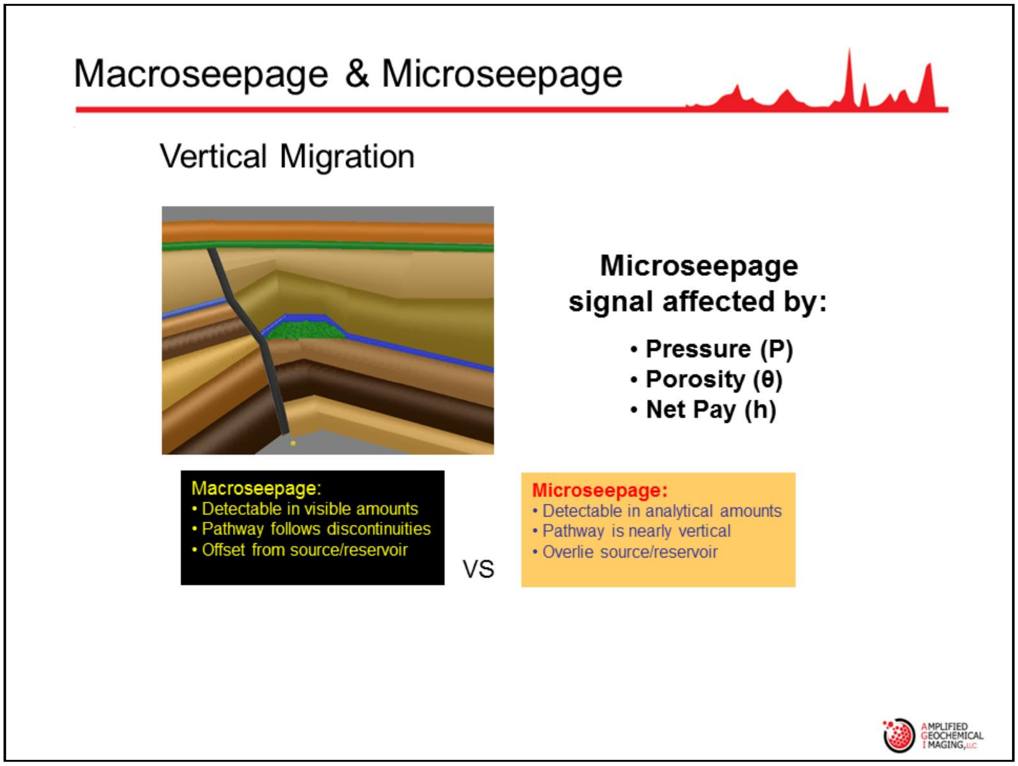
The bottom image is a DTM generated from an Autonomous Underwater Vehicle (AUV) multibeam bathymetry. At a 3m X 3m bin size the AUV provides high resolution bathymetry which gives a detailed seafloor topography that brings clarity to many of the seabed features. Notice the increased clarity in the fault scarp, the mud mounds, and even the possible identification of some explusion features.



While 3-D seismic data provides some indication of potential seepage, the resolution is often insufficient the detail needed to distinguish routine bathymetric features from true sea features. You can see here that the Digital Terrain Maps provide some indications of a fault scarp, a mud volcano, and potential mud mounds the resolution and clarity is not distinct.

AMPLIFIED GEOCHEMICAL IMAGING, LLC

Traditional Hydrocarbon Detection
&
Amplified Geochemical Imaging

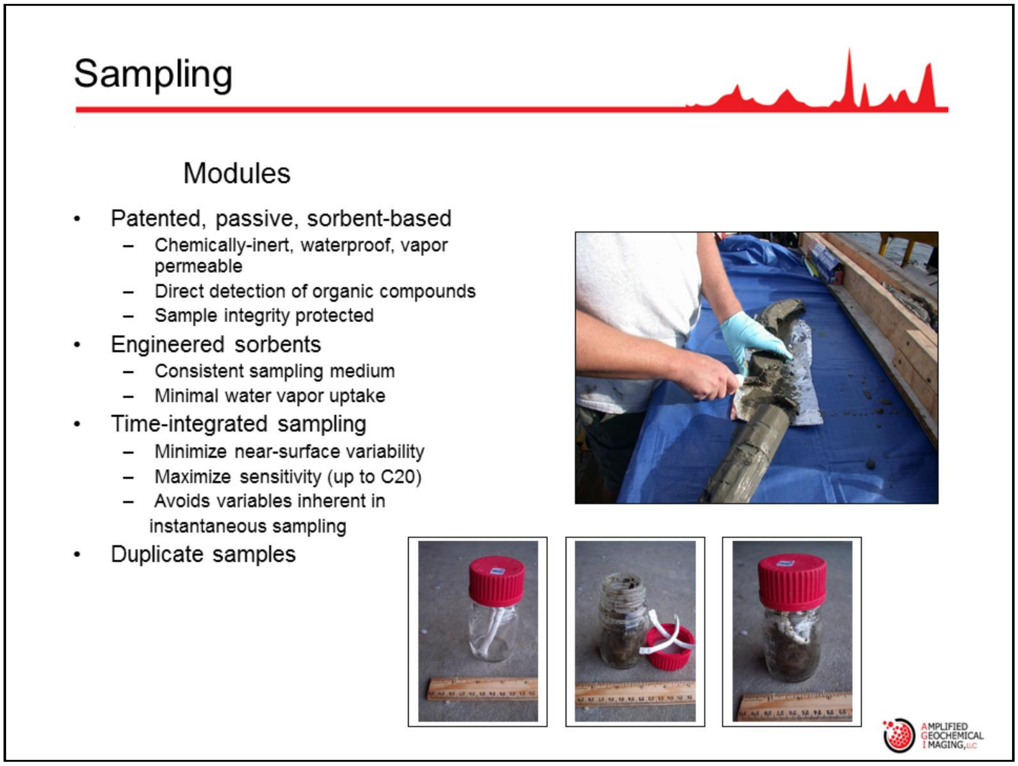


In this diagram the green section in the middle of the slide represents the reservoir and the horizontal blue line on top of it represents the seal. The thick gray vertical line next to the reservoir represents a fault.

We are all familiar with macro seepage. Hydrocarbons from macroseepage travel along faults and find their way to the surface and can be visually seen. Their concentrations are at percent levels and they are normally visual. Additionally, their location at the surface is normally off-set from the source.

What most of us are less familiar with is microseepage. Microseepage occurs when hydrocarbon molecules in the reservoir go into the gas phase. These gas molecules are lifted-up by microbuoyancy from the pressure in the reservoir. These small gas molecules move upward, essentially vertically, along grain boundaries through the seal and through the lithology above the reservoir to the surface.

So, macroseepage occurs at percent levels and microseepage occurs at part per billion levels. Macroseepage travels along faults to get to the surface and microseepage moves upward due to microbuoyancy from reservoir pressure. The location of macroseepage hydrocarbons at the surface is off-set from the source while hydrocarbons from microseepage are essentially directly above the source.



Amplified Geochemical Imaging Technology, was developed. This new technology uses passive adsorbent sampling. The passive sampler contains a specially engineered hydrophobic adsorbent encased in a layer of microporous expanded polytetrafluoroethylene (ePTFE). This module is placed in the ground about 1.5 ï 2.0 ft down in a small hole and then covered. It remains in the ground for approximately 3 weeks. This 3 week period is important b/c it allows a sufficient volume of hydrocarbons to migrate to the surface and adsorb onto the module.

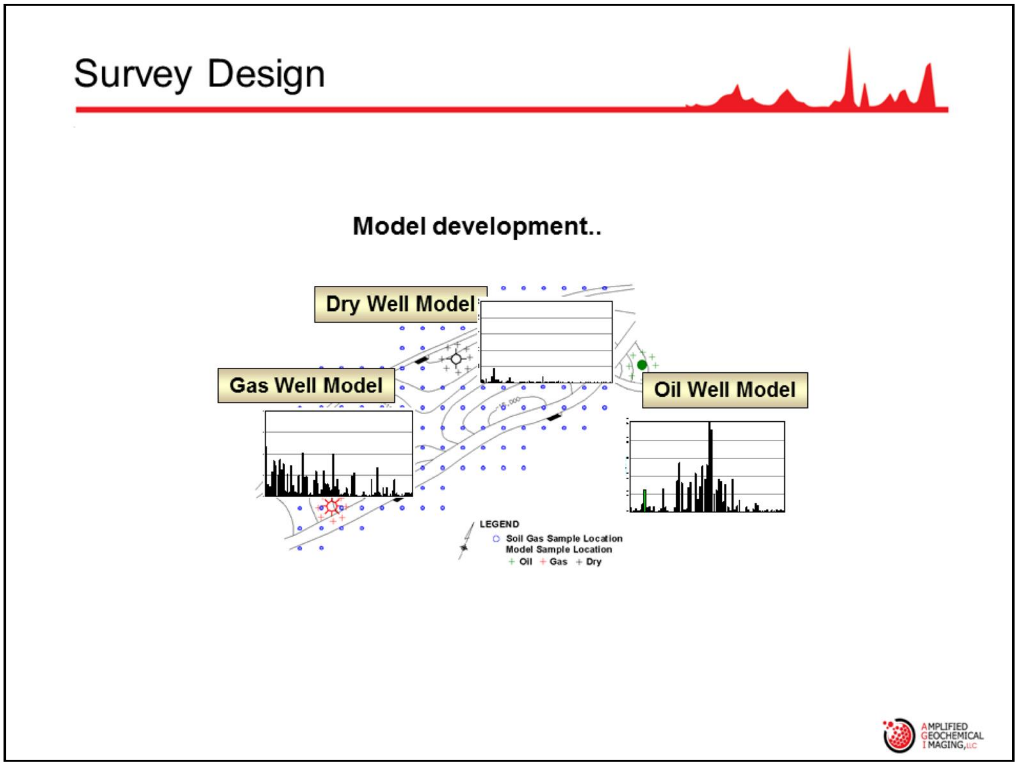
Compound Class: C2 – C20

Typical Petroleum Constituents
Hydrocarbon number in ( )

Normal Alkanes	Iso-alkanes	Cyclic Alkanes	Aromatics and PAH*
Ethane (2)	2-Methylbutane (5)	Cyclopentane (5)	Benzene (6)
Propane (3)	2-Methylpentane (6)	Methylcyclopentane (6)	Toluene (7)
Butane (4)	3-Methylpentane (6)	Cyclohexane (6)	Ethylbenzene (8)
Pentane (5)	2,4-Dimethylpentane (7)	cis-1,3-Dimethylcyclopentane (7)	m,p-Xylenes (8)
Hexane (6)	2-Methylhexane (7)	trans-1,3-Dimethylcyclopentane (7)	o-Xylene (8)
Heptane (7)	3-Methylhexane (7)	trans-1,2-Dimethylcyclopentane (7)	Propylbenzene (9)
Octane (8)	2,5-Dimethylhexane (8)	Methylcyclohexane (7)	1-Ethyl-2/3-methylbenzene (9)
Nonane (9)	3-Methylheptane (8)	Cycloheptane (7)	1,3,5-Trimethylbenzene (9)
Decane (10)	2,6-Dimethylheptane (9)	cis-1,3/1,4-Dimethylcyclohexane (8)	1-Ethyl-4-methylbenzene (9)
Undecane (11)	Pristane (19)	cis-1,2-Dimethylcyclohexane (8)	1,2,4-Trimethylbenzene (9)
Dodecane (12)	Phytane (20)	trans-1,3/1,4-Dimethylcyclohexane (8)	Indane (9)
Tridecane (13)		trans-1,2-Dimethylcyclohexane (8)	Indene (9)
Tetradecane (14)		Ethylcyclohexane (8)	Butylbenzene (10)
Pentadecane (15)		Cyclooctane (8)	1,2,4,5-Tetramethylbenzene (10)
Hexadecane (16)		Propylcyclohexane (9)	Naphthalene (10)
Heptadecane (17)			2-Methylnaphthalene (11)
Octadecane (18)			Acenaphthylene (12)

Byproduct / Alteration and Other Compounds

Alkenes	Aldehydes	Biogenic	NSO* and Other Compounds
Ethene (2)	Octanal (8)	alpha-Pinene	Furan
Propene (3)	Nonanal (9)	beta-Pinene	2-Methylfuran
1-Butene (4)	Decanal (10)	Camphor	Carbon Disulfide
1-Pentene (5)		Caryophyllene	Benzofuran
1-Hexene (6)			Benzothiazole
1-Heptene (7)			Carbonyl Sulfide
1-Octene (8)			Dimethylsulfide
1-Nonene (9)			Dimethyldisulfide
1-Decene (10)			
1-Undecene (11)			



Deployment plans differ based on the project objective (i.e. frontier areas, prospect ranking, acreage relinquishment, field development, or phase identification for unconventional plays). The most common scenario is a grid pattern over the area of interest. The blue circles represent the location of each module. The spacing between the modules can range from 250 m to 2 km depending on the size of the field and the project objectives. Note the crosses around the dry well, gas well, and the oil well. Normally 15 modules are placed around such calibration wells. Calibration wells are used as hydrocarbon signal end-members for comparison during the evaluation and statistical analysis of the data. So, for example, if an oil signature is detected in the survey, that oil signature can be compared against the oil calibration signature. Also note, that there are distinct differences between the dry well, gas well, and oil well signatures. This ability is unique to Amplified Geochemical Imaging technology because this is the only surface geochemical technology that can measure the full range out to C20, thus providing a clear hydrocarbon signature ï not just compound ratios.

AMPLIFIED
GEOCHEMICAL
IMAGING, LLC

Amplified Geochemical Imaging Analytical Results

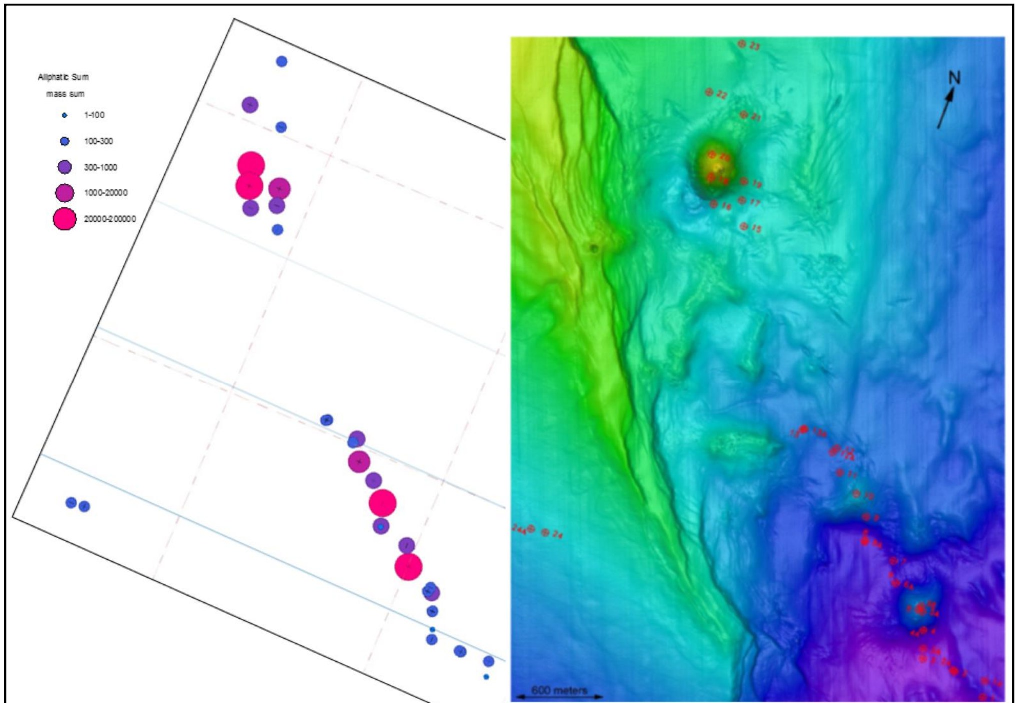
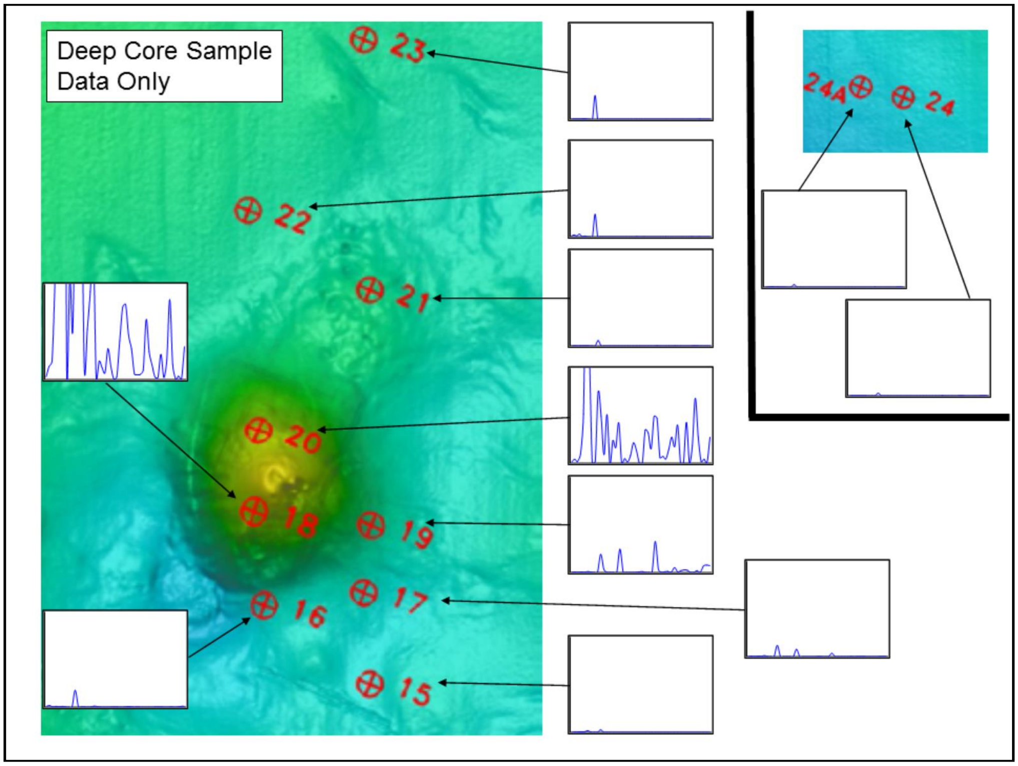


Figure 8: DTM plan view map of the high resolution multibeam bathymetry showing the sea surface locations from which the piston coring device was deployed for each core gathered. Dembicki and Samuels (2007)

Each dot represents the sum of the normal alkanes. The larger the colored dot, the greater the total mass of alkanes. Those dots were then plotted using X-Y coordinates. We were not given the bathymetry map for our mapping purpose during the survey. You can see the salt ridge feature down the center of the map with the mud volcanoe to the north and the mud mounds to the south.

The large dots to the north match well with the mud volcano and the larger dots to the south match well with the mud mounds. The two blue dots to the west, which we didn't know at the time, were on the opposite side of the salt ridge and were chosen to be background samples. You can see from the small size of the blue dots that we did indeed get very little total mass detected.

It should be noted that there were no transponders on the cables so the indicated coordinates are boat locations not exact sample locations. The depth of these samples was approximately 1400 meters.

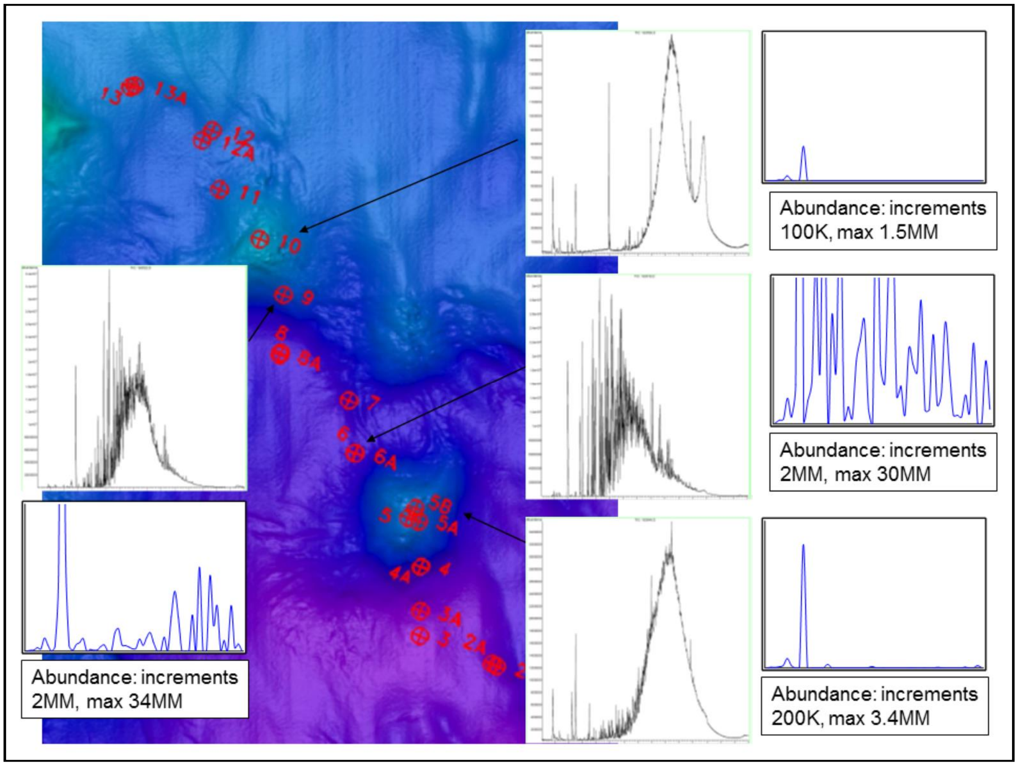


You can see here that on the sides of the mud volcano that we got very strong hydrocarbon signatures and as you move away from the mud volcano the signal decreased, which is what you would expect. Additionally you can see not only differences in the intensity, but also differences in the patterns between sample 20 and sample 18. Obviously, this pattern differentiation is not possible with techniques that only measure out to C5.

Concerning compound pattern, there is a distinct difference between 18 and 20, not related to sourcing though but rather degradation and core preservation. Some cores hit hardpan on the seabed (chemosynthetic communities) or had hydrates in the barrel causing loss of core material when brought to the surface. Core #18 only retrieved 70 cm of sediments and the sample was taken at 33 cm; while #20 had 385 cm and the sample was from 342 cm. [Core #19 retrieved 176 cm of sediment, with the sample from 143 cm.]

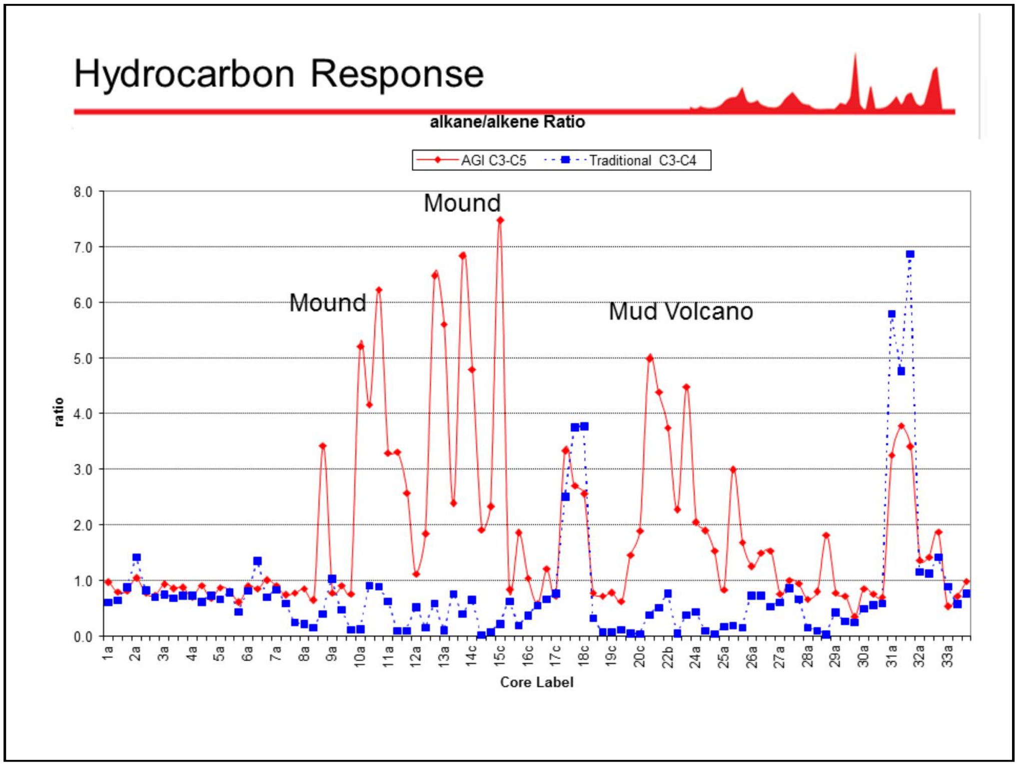
Sample #19 might be an example of a site where traditional core analyses could return an ñNDòor ñNon-Detectò, but our mass data shows response above detection limit. This is the concept of the insurance policy against no data for the high cost of core acquisition.

You can see the results for samples 24 and 24A, that we talked about in the previous slide. These are the background samples designed by the client on the other side of the salt ridge, and they show essentially very little response. It should be noted that one of the objectives of the project was to determine if the various methods could CLEARLY differentiate between background signatures and reservoir signatures.



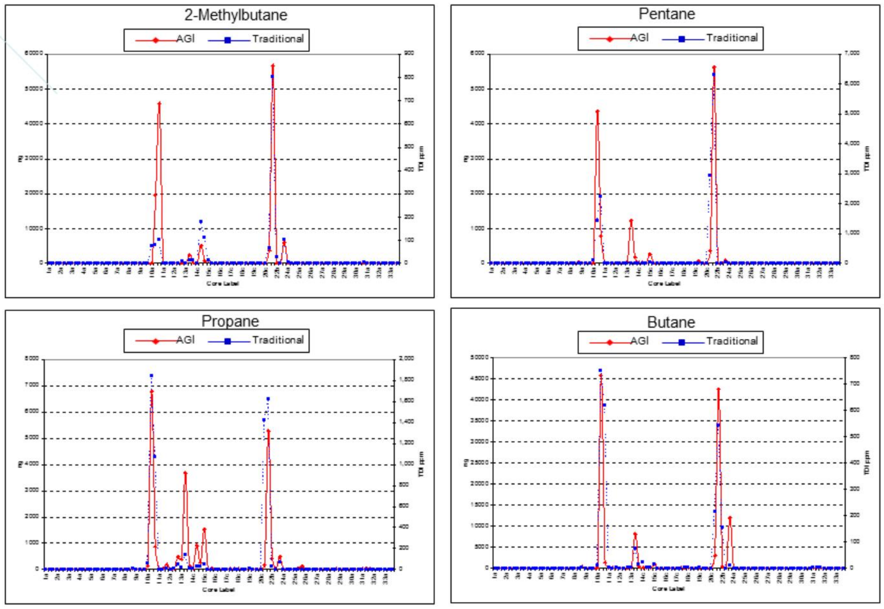
This is data from around the mud mounds. These slides show the Total Ion Chromatogram (TIC) of the mass spec analysis of each samples. The adjacent fingerprint, in blue, shows the data plotted by compound as we do it. Notice the TIC in the middle image on the right shows a fresh oil release with little or no biodegradation or water washing in the front end of the chromatogram.

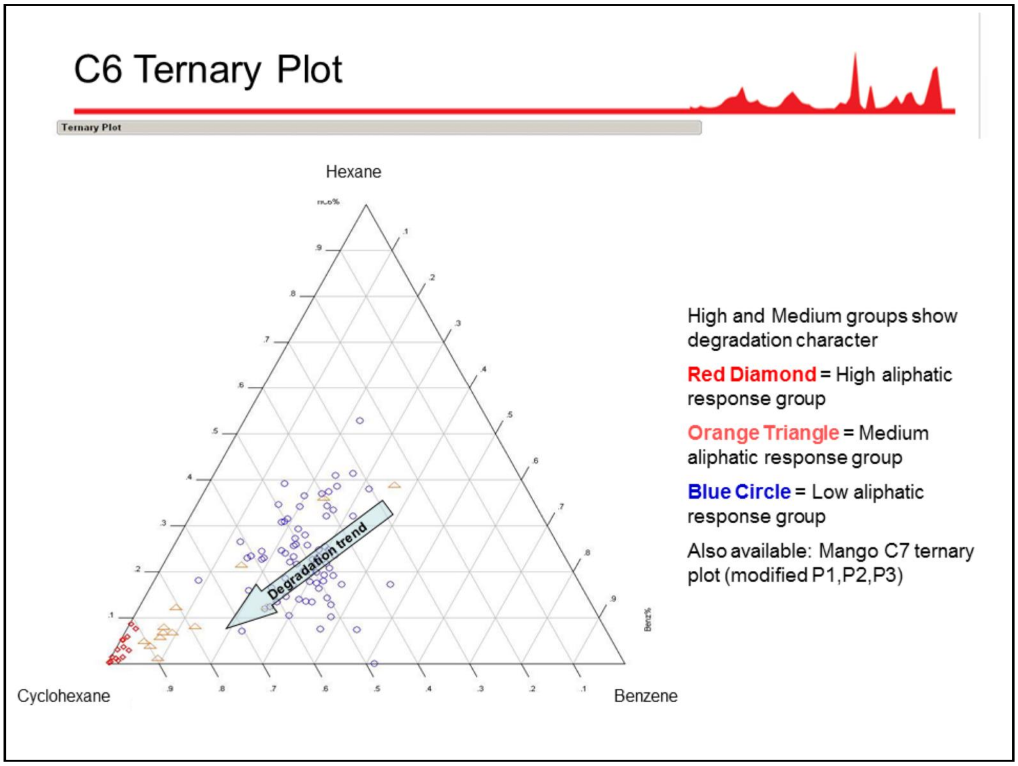
The top and bottom images on the right show significant loss of the alkanes, most likely from biodegradation and water washing. The image to the left of the map shows the beginning of biodegradation. So, this technology can provide a wealth of informationé It can accurately determine if hydrocarbons are present, what is the phase or type of hydrocarbon (i.e. gas, condensate, or oil), and note if the oil is freshly released or has alteration of the oil taken place.



As part of this independent study the client was comparing various surface sediment techniques. This graph shows a comparison of the Gore results in red and the TDI Brooks results in blue. The Gore data is a sum of C3 through C5 and the TDI Brooks data is a sum of C3 through C4. You can see a significant difference between the two techniques in there response. The TDI data showed little or no response over the mud volcano and mud mounds. That difference may be due to a difference in the sensitivity of the two techniques.

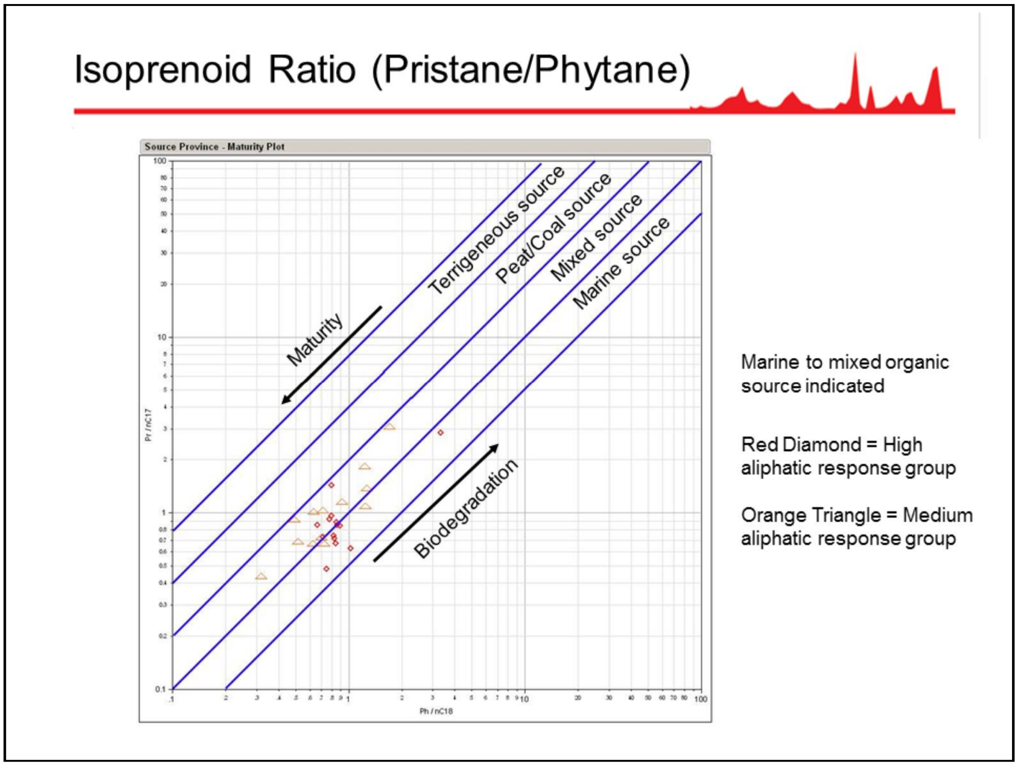
Gas Compound Response Comparison



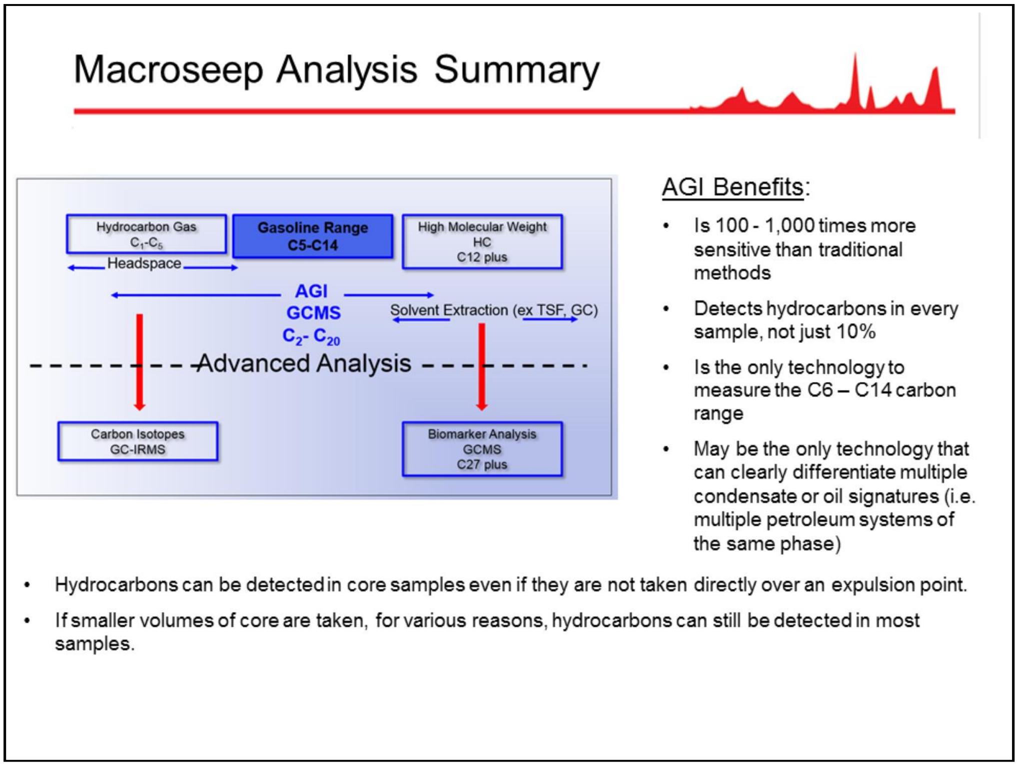


This data shows how standard geochemical plots can be used to illustrate the relations between various components. For example this graph highlights the observations we discussed in the previous slides about the biodegradation we saw when looking at the oil fingerprints. It makes sense that the higher aliphatic samples, the red triangles, would exhibit the greatest degree of biodegradation because these samples are more likely to be expelled from mud volcanoes and mud mounds. These hydrocarbon rich expulsions then provide excellent fodder or feed for local biological organisms, whereas, background samples would possess little or no hydrocarbons to invoke biologic activity because there is little or no hydrocarbons to breakdown or feed on. So, you can see, in essence, the hydrocarbon containing samples, which are the red diamonds and the orange triangles cluster together in two groups because they are hydrocarbon rich while the blue circles cluster separately in the middle of the ternary chart.

So the chart not only indicates biodegradation, as you move to the left bottom triangle point, but also serves as a trend for hydrocarbon concentration. You see a clustering of the blue circle samples with little or no hydrocarbon concentration in the center of the chart and then as you move to the left bottom triangle point hydrocarbon intensity increases.



This geochemical interpretive chart indicates a marine or mixed source depositional environment which is consistent with what we know about the oils in that they are a medium gravity Type II marine source oil.



Traditional methods analyze primarily from nC1 ï nC5 through the analysis of headspace gas in the part per million (ppm) concentration range. This data is helpful to provide gas content. Butane and isobutene are ratioed to guess at the presence of condensates or oils. This data can be useful to identify the presence of gas and also provide information on dryness and other details. If sufficient quantities of gas are present some subset of samples may be analyzed for isotope analysis.

These samples may also be extracted with a solvent and analyzed for higher molecular weight compounds (i.e. primarily >nC14).This data can provide some information to the presence of liquid hydrocarbons. Total Scanning Fluorescence (TSF) can be performed on these samples as a screening tool for liquid hydrocarbons. However, TSF is a screening tool wide a wide degree of variability. If samples show sufficient oil saturation biomarker analysis can be performed with can provide very helpful information on depositional environment, thermal maturity, age, etc. Biomarker analysis, however, can be time consuming and costly.

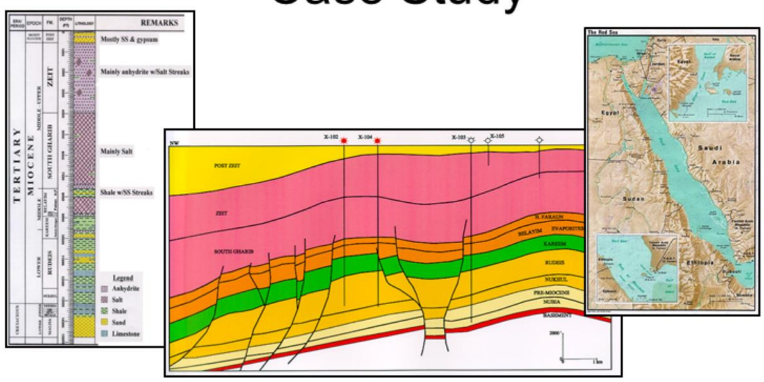
None of the traditional techniques measure the nC6 ï nC14 range. Amplified Geochemical Imaging (AGI) measures from C2 -> C20 which enables the data to provide HC fingerprints for gas, condensates, and oils. Notice I didn't say that AGI estimates or guesses at the HC phase as other methods do. AGI provides the ability to not only differentiate between gas, condensates, and oils, but it allows you to also differentiate between several different oil signatures which is not possible with other technologies..

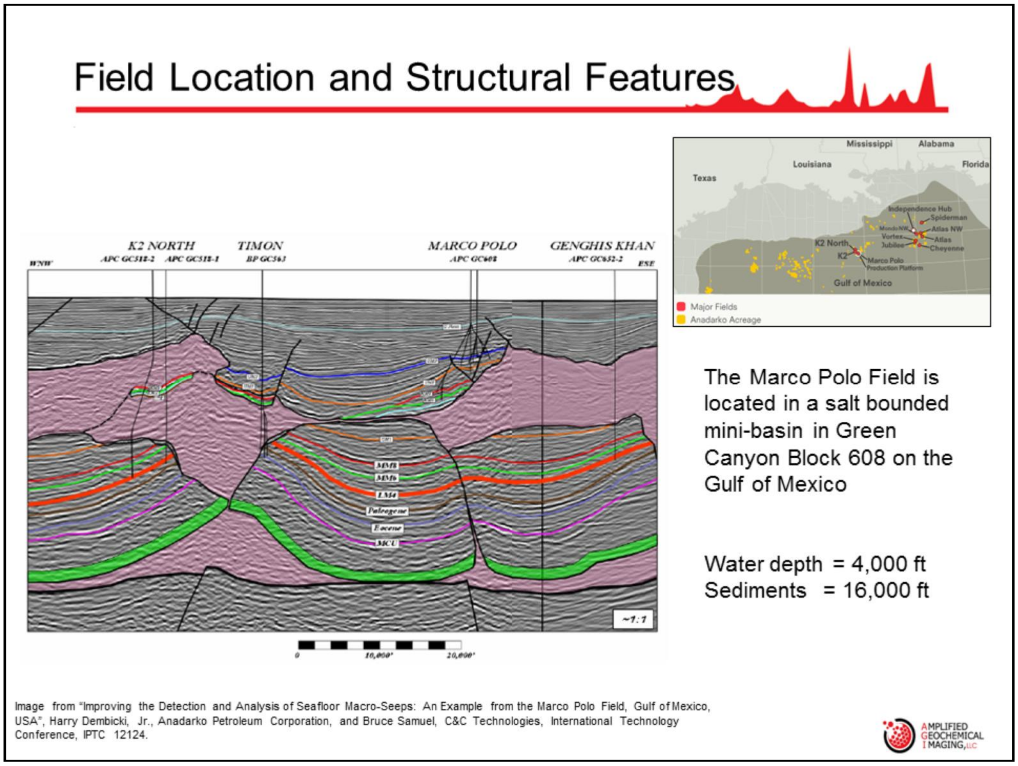
Also, AGI measures down to the Part Per Billion (ppb) range which is a 100 - 1,000 times lower than other technologies. This allows the detection of hydrocarbons in all samples. While some of these detections may be background, this at least allows the establishment of a baseline hydrocarbon or organic signature for the area which can be used a differentiation point from thermogenic signatures.

Even when a seabed feature is well imaged and hit by the core, if hardpan or chemosynthetic community or hydrate cover precludes good core retention, we may be able to image hydrocarbon signature from very sparse recoveries whereas other methods will not. Most companies / consultants want at least 5 m core recovery and use the lower portion, AGI included; however, we have managed useful data from cores <2 m. Not optimum condition, but better than putting a ñno dataòmark on the map!

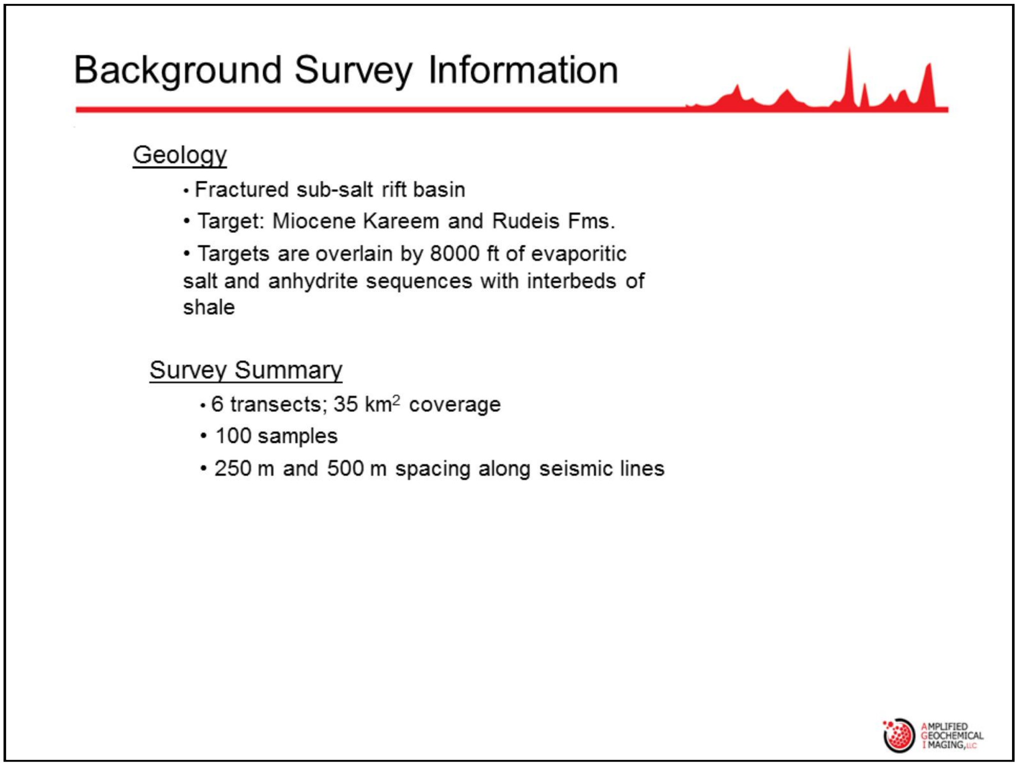
AMPLIFIED
GEOCHEMICAL
IMAGING, LLC

Red Sea Sub-salt
Case Study

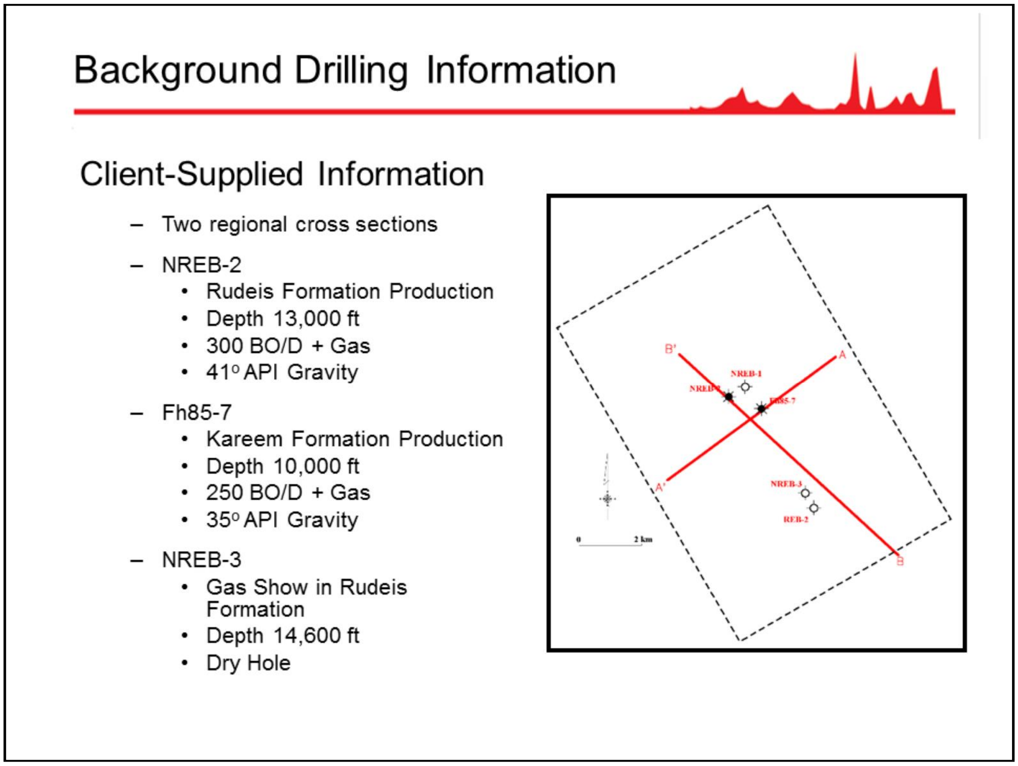




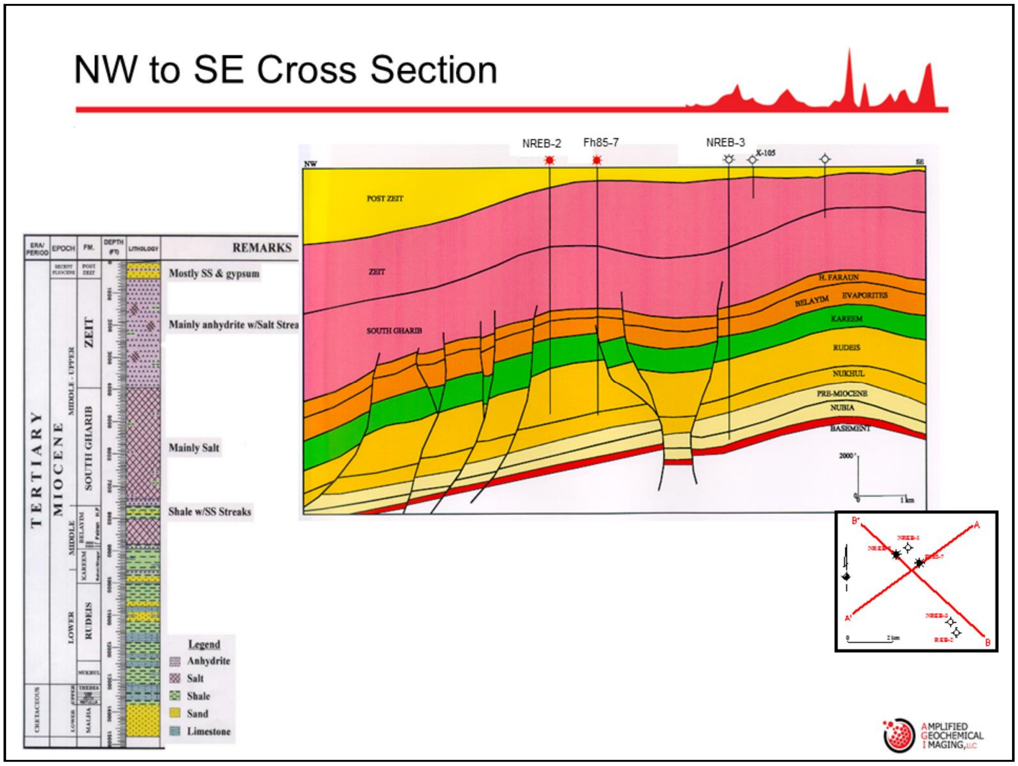
As you recall from the previous maps, the Marco Polo field is flanked by two subsalt fields, the K2/K2 North field and the Genghis Khan field. Both fields lie beneath a 10,000 ï 15,000 ft thick salt canopy and produce from a middle/lower Miocene reservoirs. While theses adjacent fields were not included in the Marco Polo assessment, it did beg the question if the more sensitive hydrocarbon detection method could detect the microseepage of hydrocarbons through salt canopies. This Red Sea study attempts to address that question.



It was a fractured sub-salt rift basin in Egypt on the edge of the Red Sea. This was a relatively small survey with only a 100 samples laid in transects using 250 meter and 500 meter spacing. What made this survey unique was the fact this basin had 8,000 ft of slat/anhydrite. That is a heck of a seal. If there was ever any situation where microseepage may not work or may not produce sufficient energy to migrate hydrocarbons to the surface, this would be it.



The field was a fractured sub-salt rift basin producing from the Miocene Kareem and Rudeis formations. The client had two producing wells, but had also drilled three dry wells. The thick salt sequence made seismic data difficult to interpret and the extensive faulting added additional risk to the exploration efforts.



The pink area of the cross section indicates the 8,000 ft salt/anhydrite section.

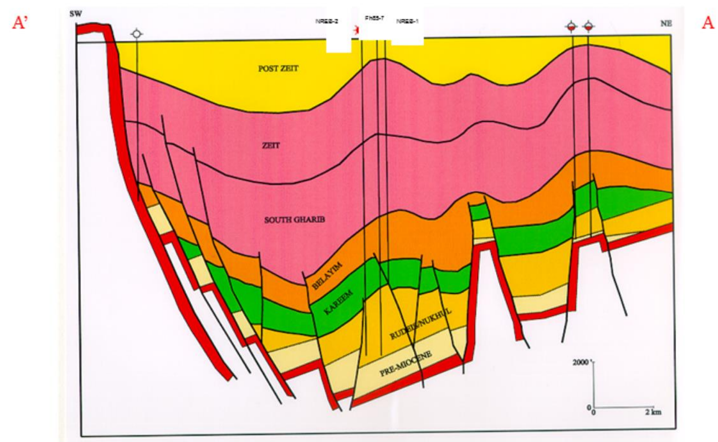
The NREB-2 production well penetrated the Rudeis formation and went to a depth of 13,000 ft. It produced 300 BO/D + Gas and had a 41o API Gravity.

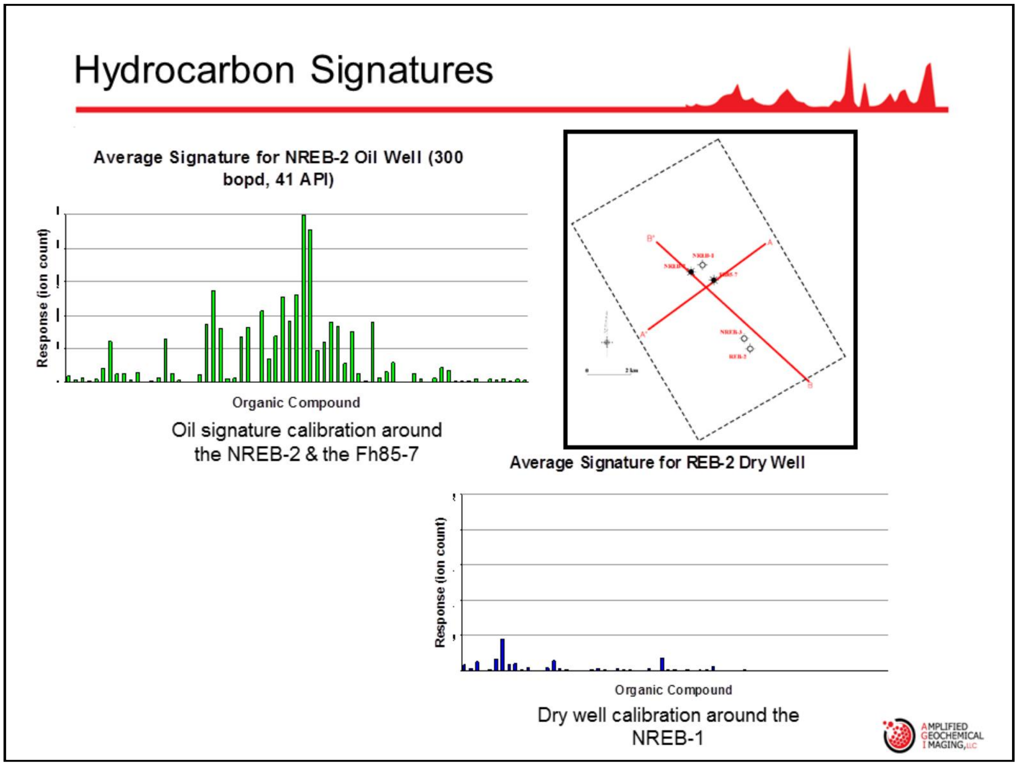
The Fh85-7 production well penetrated the Kareem formation and went to a depth of 10,000 ft. It produced 250 BO/D + Gas and had a 35o API Gravity.

The Dry Well, with a gas show, the NREB-3 penetrated the Rudeis formation at a depth of 14,600 ft.

There was extensive faulting in the area and the extreme salt section adversely affected seismic quality. The client had drilled three dry holes and wanted help to direct future drilling efforts

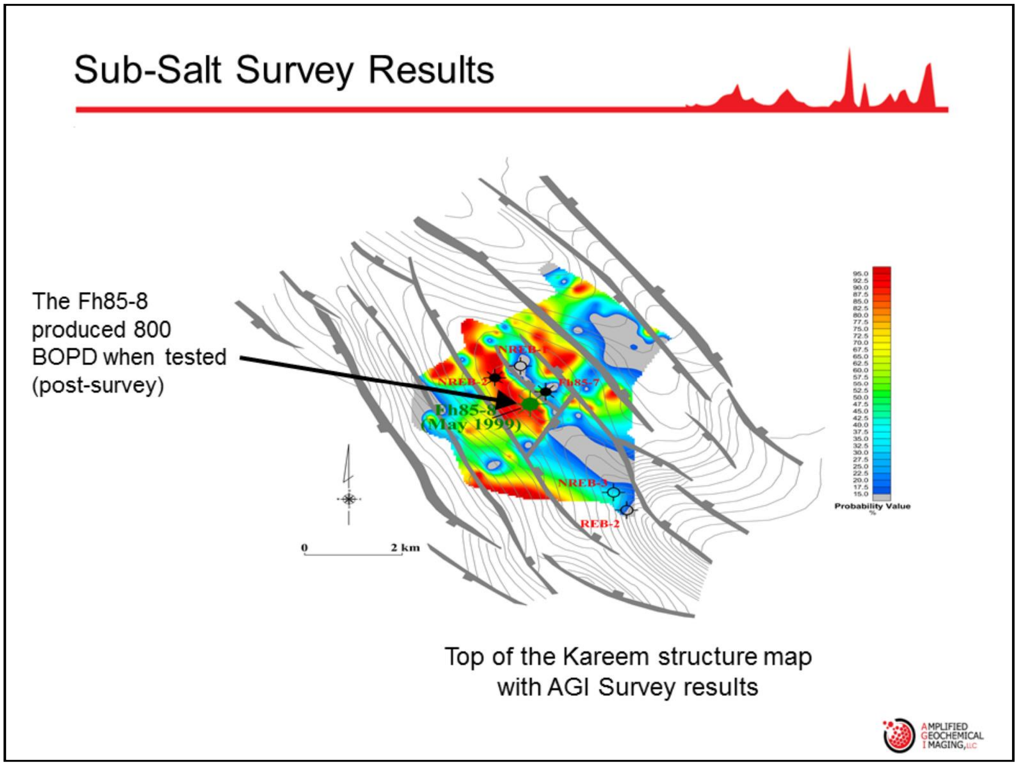
SW to NE Cross Section





Here you see the clear oil signature is differentiated from the dry well signature. So, the AGI modules were able to detect hydrocarbon migration through 8,000 ft of salt. Note the dramatic difference between the liquid, or oil, signature and the dry well signature. First of all the oil signature is 5X higher than the background signature. Secondly, the extensive compound list makes it very easy to differentiate the liquid fingerprint from the dry well fingerprint. No ratioing of compounds is necessary. A direct visualization of the two fingerprints clearly differentiates the two. Thirdly, it is important to note that a hydrocarbon signature is detected for dry wells or background. Why is this important? This is important because it means that hydrocarbons are still detected by this method for background or dry well signatures, ensuring that no hydrocarbons are being missed or overlooked.

You must also keep in mind that here we are dealing with microseepage. In the GOM Marco Polo example we were dealing primarily with macroseepage. This ability to detect hydrocarbons by booth microseepage and macroseepage enables hydrocarbon detection over an extremely dynamic concentration range and, is therefore a much more applicable and useful tool to derisk offshore exploration efforts than traditional core analysis technologies.



This map shows the modeled results as provided to the client. The thick gray lines indicate the fault lines that the client added to the map. Again, the red shading indicates an 85% - 95% probability that there is oil in this area that matches the oil from the producing wells. What is interesting is that the red anomaly is bounded by the fault lines. We were not aware of these structural faults when we generated the findings. It appears the NREB-2 red anomaly is a 3-way closure.

The light blue, or cooler colors, indicate areas of much lower probability ï in the range of 20% - 30%. Notice all the dry wells are located in areas of light blue or dark blue which, according to the survey data, indicating a high probability of dry holes. You will notice one producing well in the blue area, but while the well platform was located in a blue area the well was actually drilled on a slant and penetrated the fault.

The survey was performed using transects not a grid pattern. Thus, there was insufficient sample density to accurately map the exact boundaries of the hydrocarbon accumulations.

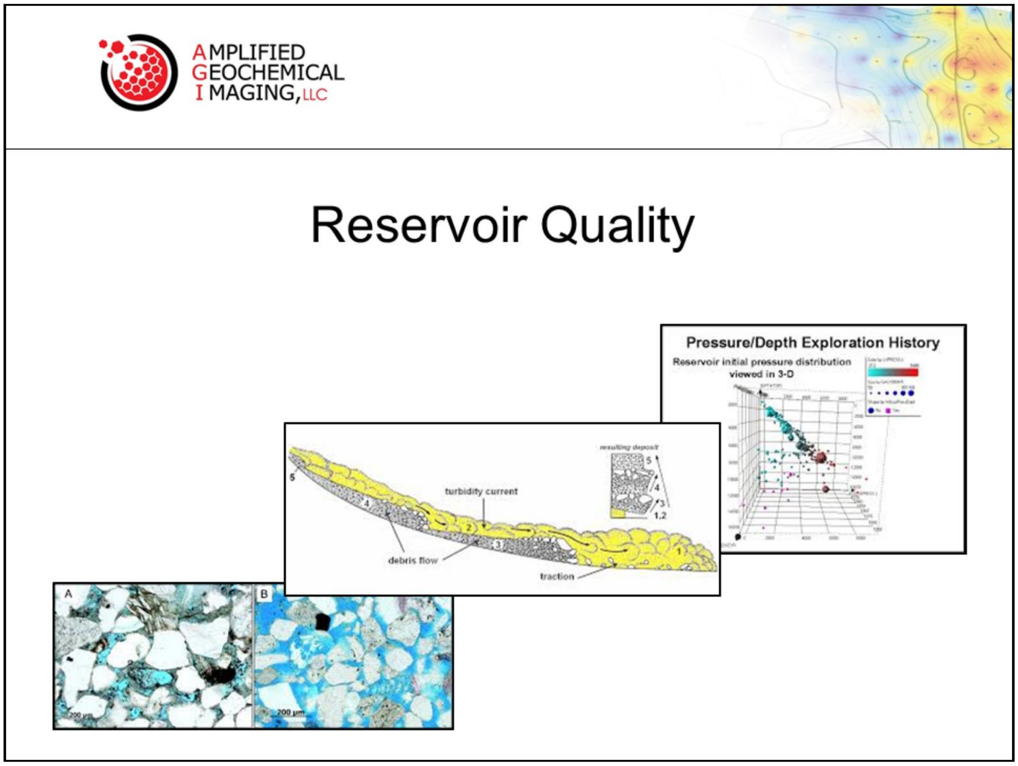
The client later drilled a well on the red positive anomaly and obtained a well that produced 800 BOPD.

Microseep Analysis Summary

Amplified Geochemical Imaging is the only technology that can detect and measure microseepage

Benefits:

- Many sites don't have macroseeps
- Can map petroleum system accumulation boundaries
- Can identify geohazards such as sealing faults
- Can add clarity to difficult seismic areas such as high salt environments (GoM, Red Sea, Brazil, etc.)
- Can be used for prospect ranking



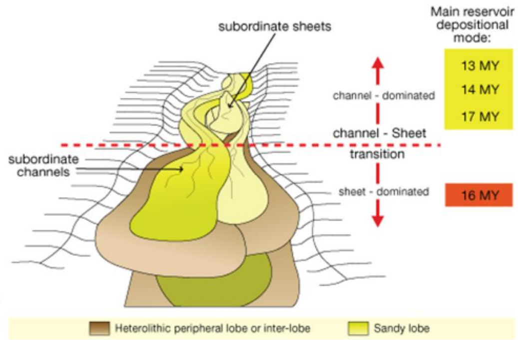
So when we drill in an offshore field why does a company often experience great production from one well and then drill another well a few miles away and experience moderate to low production. Theyõve drilled in the same field, in the same reservoir, in the same block and, yet, they get dramatically different results. Why?

The reason is reservoir quality or, perhaps more accurately, dramatic differences in reservoir quality across the field. Why is that and what can we do to optimize drilling efforts in these incredibly heterogeneous fields?

Turbidite Channels, Lobes, & Lobe Margins

Mineral distribution

- Channel architecture
  - Best reservoir
  - Fine grain size
  - Least amount of silt (~24%)
  - Least amount of ductility (~17%)
- Lobe architecture
  - Moderate reservoir
  - Fine to very fine grain size
  - Moderate mount of silt (~34%)
  - Moderate amount of ductility (~18%)
- Lobe margin architecture
  - Low reservoir
  - Very fine grain size
  - High mount of silt (~40%)
  - Moderate amount of ductility (~29%)



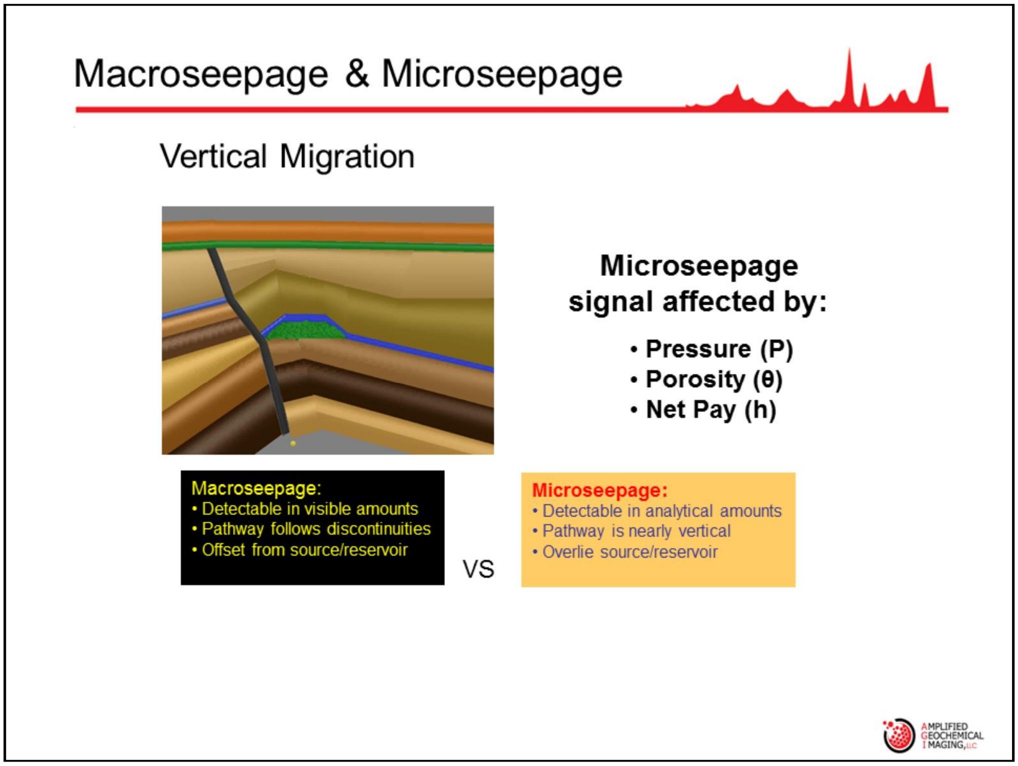
Information from "Depositional Processes and Impact on Reservoir Quality in Deepwater Paleogene Reservoirs, US Gulf of Mexico" by Ann Marchand, BP Exploration, Sixth Annual Deepwater & Shelf Reservoirs Groundwater Technology Workshop, January 28, 2015.

Most major offshore systems are associated with large amounts of sediments from major river systems like the Mississippi, Amazon, Niger, Congo, etc. As such you have channels, lobes, and lobe margins with varying degrees of porosity and permeability. Thus, by definition the field or reservoir has sweet spots. The main channel will have the best porosity while the lobe has less porosity and permeability, while the lobe margin has the least porosity and permeability. As these fans extend, move, and retreat defining those sweet spots becomes a real challenge, if not impossible.

Silt content has an exponentially negative affect on permeability, with a silt content >20% resulting in a low permeability.

The amount of ductile minerals present also affects porosity and perm because as pressure increases minerals with more ductility tend to compress and reduce porosity and perm. For example, ductile minerals in Miocene reservoirs in the GOM comprise 5% of the make-up, but comprise 20% in Paleocene reservoirs ï which have less permeability than the Miocene counterparts.

This explains why well drilled relatively closely together can have dramatically different production histories. So, the ability to predict and locate strong producing wells relies not only on oil-in-place, but also depends on that oil residing in reservoir sections with good characteristics that enable its production.

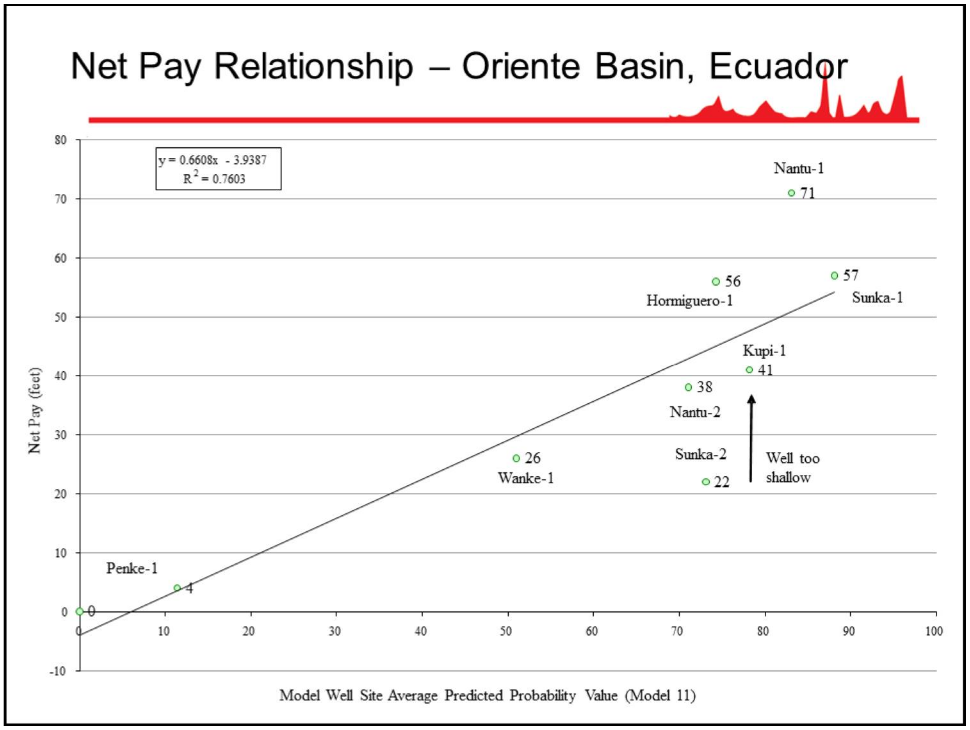


In this diagram the green section in the middle of the slide represents the reservoir and the horizontal blue line on top of it represents the seal. The thick gray vertical line next to the reservoir represents a fault.

We are all familiar with macro seepage. Hydrocarbons from macroseepage travel along faults and find their way to the surface and can be visually seen. Their concentrations are at percent levels and they are normally visual. Additionally, their location at the surface is normally off-set from the source.

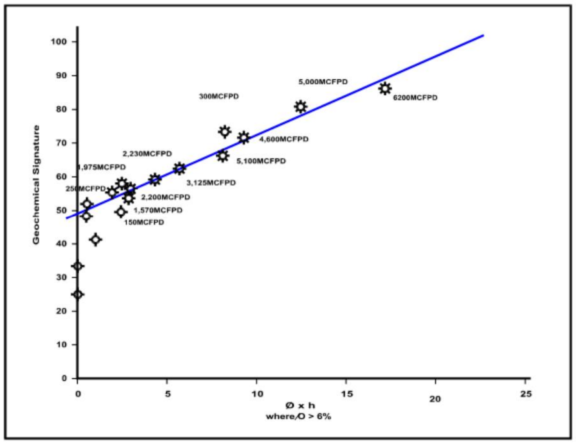
What most of us are less familiar with is microseepage. Microseepage occurs when hydrocarbon molecules in the reservoir go into the gas phase. These gas molecules are lifted-up by microbuoyancy from the pressure in the reservoir. These small gas molecules move upward, essentially vertically, along grain boundaries through the seal and through the lithology above the reservoir to the surface.

So, macroseepage occurs at percent levels and microseepage occurs at part per billion levels. Macroseepage travels along faults to get to the surface and microseepage moves upward due to microbuoyancy from reservoir pressure. The location of macroseepage hydrocarbons at the surface is off-set from the source while hydrocarbons from microseepage are essentially directly above the source.



Probability Value related to Net Pay: This is a sandstone formation at a depth of 3,000 meters in the Oriente Basin. Nine wells were modeled and the net pay is listed next to the point on the chart. This chart shows that the wells that high a higher net pay had a higher probability value. If you assume the porosity is about the same for each well, then this chart supports the next graph which is the porosity * thickness relationship.

Probability Versus Porosity Times Pay Thickness



Anadarko Basin

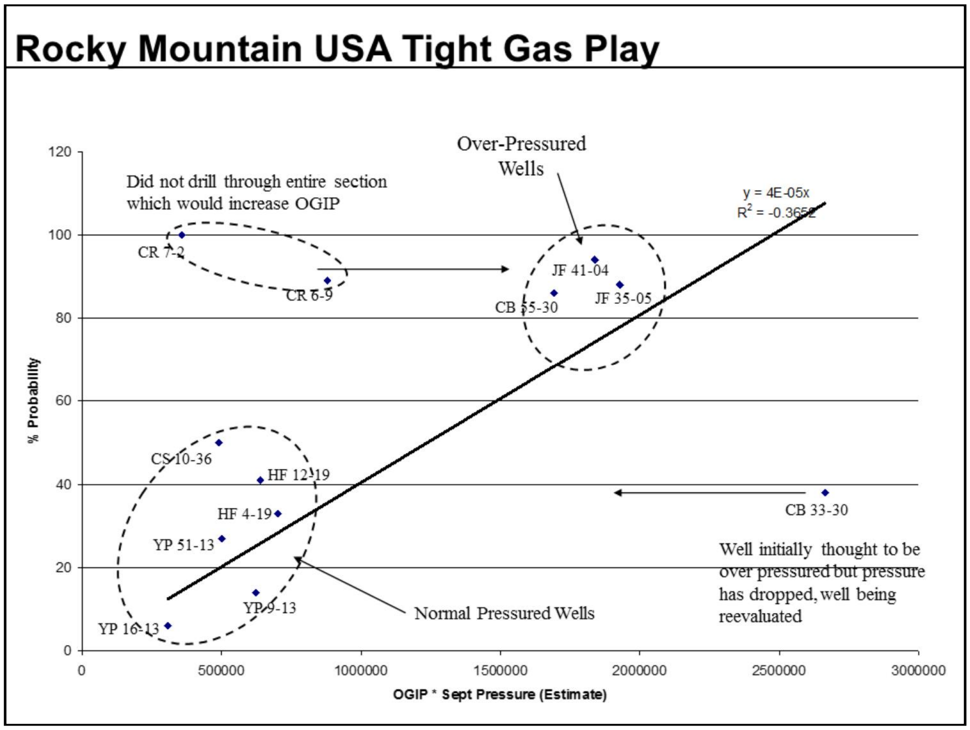
Red Fork Channel Sands

4,300 meters

Higher ø*h and higher production

Figure 13: Porosity-thickness relationship with geochemical anomaly strength; data from the Anadarko basin.

Probability Value related to Porosity*Thickness (ø*h) of Reservoir: Daily production information for 17 wells are shown in the graph. The wells that had a higher probability value from our samplers at the surface have greater production and also a higher ø*h. In most cases a higher ø*h means increased well production and that is the case shown in the chart. So there appears to be a relationship between Reservoir Characteristics and our surface Probability value. This graph by Potter et al. was published in the AAPG Memoir 66. The wells were producing from the Red Fork channel sand at a depth of approximately 4,300 meters in the Anadarko Basin.

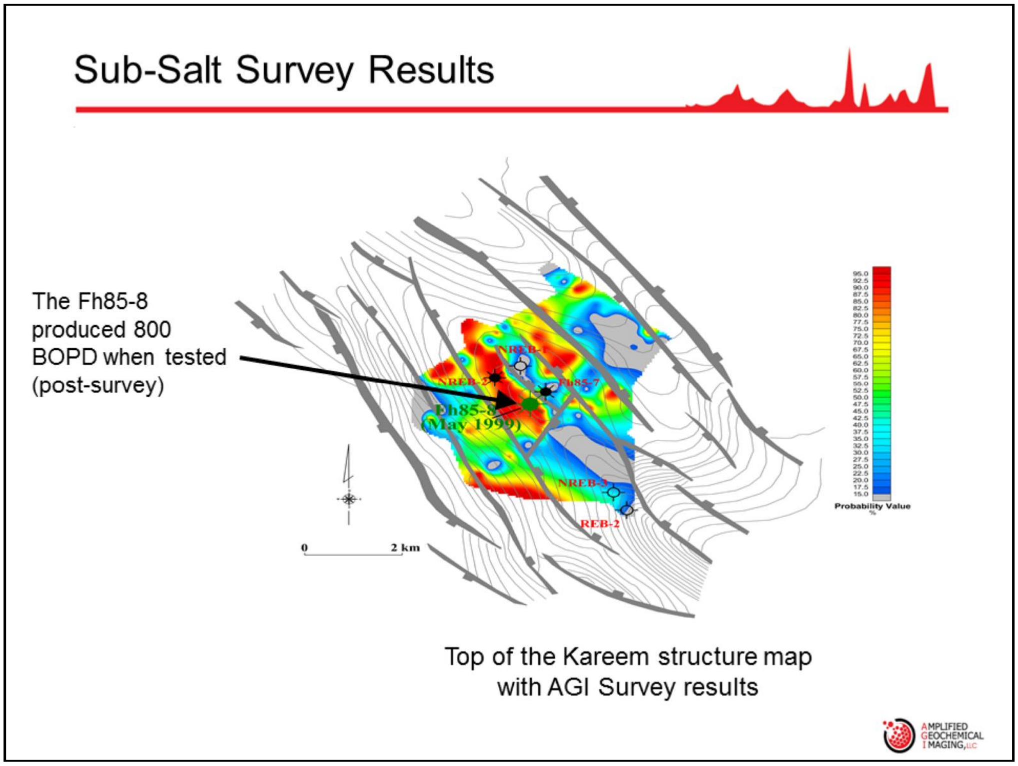


This is another independent example showing how Probability Value is related to Original Gas in Place (OGIP) times Reservoir Pressure (Estimated) :

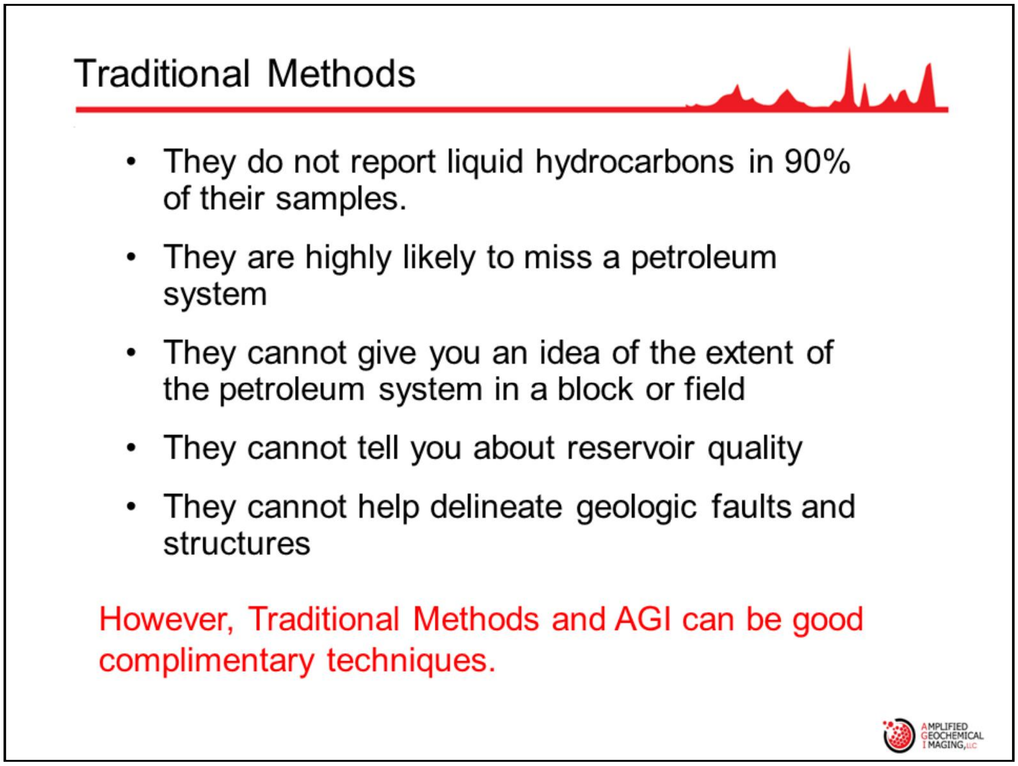
This was a tight sandstone play for gas in the western USA. Depth was around 3,000 meters. The sandstone thickness was around 400 meters. Twelve wells were sampled with 15 samples placed around each well.

The Original Gas in Place times the estimated September Pressure is on the x-axis. The survey was run in September which was important to estimate the pressure at the time of the survey. The average probability value for the 15 samples was taken as the probability value for each well. All 12 wells produce gas. The objective of this survey was to use Gore Amplified Geochemical Imaging Technology to differentiate normal pressured wells from those that were over pressured. The over pressured wells were the better producers. This chart clearly shows a difference in probability value between normal pressured wells and over-pressured wells. The 2 CR wells with high probability were not drilled through the entire gas section and therefore should have had a higher OGIP which would have moved them into the over-pressure zone on this graph. The CB 33-30 well had a significant pressure drop and was being reevaluated, so the estimated pressure was probably less than reported which would move this well in with the Normal pressured wells.

In summary, this slide is an example of how pressure plays a part in the microseepage signal we see at the surface. It emphasizes that a depleted well or field with low pressure is probably not going to give much of a hydrocarbon signature and should not be used as a strong producing model well.



So, the red and yellow anomalies both show where you have a high probability of finding oil that is similar in signature to the well that we calibrated against in this field. But as we learned in one of the previous slides optimal production doesn't just rely on oil-in-place. It also, in large part, relies on sweet spots in the reservoir that inherently have good reservoir characteristics (i.e. porosity, pressure, & net pay) So, again I say you could find oil in both the red and yellow areas of this probability map and the oil in place may actually be the same. But, the yellow areas may be those areas where you poorer reservoir quality when looking at pressure, porosity, & net pay, while the red area may have BOTH oil-in-place and good reservoir characteristics that will allow that oil to flow and be produced.



A 10% probability of success does not meet the definition of a useful derisking tool. At the cost of $150mm - $250mm per well that is not really acceptable.

The two techniques can provide confirmation for one another and Traditional Methods often include biomarker analysis when macroseeps are detected. Biomarker data can provide information about the oil system such as depositional environment, thermal maturity, age, etc. Additionally, Traditional Methods monitor methane which AGI does not. This allows you to calculate gas wetness and other parameters as well.

Technical Improvements for Derisking

The use of Autonomous Underwater Vehicles (AUVs) improve the resolution of seafloor images.

1.) high resolution multibeam bathymetry,

2.) side scan sonar over multibeam bathymetry,

Technical Improvements for Derisking

Ultra-sensitive hydrocarbon detection has a 1,000 fold increase in sensitivity.

1.) allows hydrocarbon detection in 100% of core samples,

2.) can measure both macroseepage & microseepage,

3.) has a 90% success rate in predicting dry holes over the last 15 years (cost savings $150mm - $250mm per well),

4.) works through thick salt sequences where seismic data is dramatically affected,

5.) adds to the structural understanding (e.g. faults, three-way closures)

6.) predicts areas of better pressure, porosity, & net pay.

AMPLIFIED GEOCHEMICAL IMAGING, LLC

Thank You!

We would like to give special thanks Dr. Harry Dembicki of Anadarko Petroleum Corporation for his help and contributions to this presentation

AMPLIFIED GEOCHEMICAL IMAGING, LLC