Creating a 3-D Hydrocarbon Profile in the Eagle Ford Shale Play and Relating that Information to Field Production*

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Abstract

Shale plays are an extremely difficult arena in which to explore. Lack of heterogeneity is not the only problem. The Eagle Ford play, for example, has numerous hydrocarbon sources and multiple stacked zones. These multiple stacked pays result in mixed drilling success with both economic and noneconomic drilling results. In addition, there are numerous migration pathways in various parts of the field and charge source or kitchen vary with placement in the field as well. Amplified Geochemical Imaging and Downhole Geochemical Logging technologies are two applications that can be used in conjunction to provide a 3-dimentional hydrocarbon profile to enhance understanding and success in unconventional exploration.

Amplified Geochemical Imaging is a direct surface hydrocarbon measurement technique that measures the vertical migration of volatile hydrocarbon compounds from subsurface reservoirs. These microseepage hydrocarbon compounds, up to C20, can be captured and measured at the surface resulting in the ability to identify and map subsurface hydrocarbon systems as well as clearly differentiate between various hydrocarbon phases, such as gas, condensate, or oil. These hydrocarbon maps provide a horizontal assessment of hydrocarbons across the field and can then be used to demarcate transition lines between the various hydrocarbon phases and direct exploration efforts to areas of higher profitability. This ability makes Amplified Geochemical Imaging a unique tool as a "predrill" technology.

Our Downhole Geochemical Logging technology provides a vertical assessment of the hydrocarbons in a well. Downhole Geochemical Logging analyzes downhole cutting samples to directly characterize the composition of hydrocarbons vertically through the prospect section. This methodology has the unique ability to look at a broad compound range from C2 to C20, which is significantly more expansive than the limited traditional ranges of C1-C5 or C1-C9 of most well gas logging techniques. The result is a broad characterization of petroleum phase contained in the stratigraphic intervals as well as addressing compartmentalization down the well.

However, while Amplified Geochemical Imaging and Downhole Geochemical Logging technologies aid in determining a 3-dimensional understanding of the hydrocarbons in an unconventional play, production goes beyond that. A recent presentation by Chris Fredd at the Second EAGE/SPE/AAPG Shale Gas Workshop in the Dubai recently reported that approximately 40% of all shale oil wells were not profitable because many of the fracture stages in the lateral well were not effective. While there are many reasons for the lack of effectiveness, one of the most common reasons is the focus on efficiency over effectiveness. Once production drilling begins, it is easy to understand the push to standardize drilling operation to preset well spacing, lateral lengths, the number of fracture stages, and preset fracture spacing to optimize operation and minimize costs.

However, effectiveness also plays an important part in optimizing profitability. For example, setting fracture stages in zones of a lateral well that have little or no hydrocarbon concentration and low porosity increase completion costs without increasing production. For example, in this Eagle Ford case study data showed similar production efficacy might have been obtained by using five fracture stages instead of eight by using Downhole Geochemical Logging data. Additionally, the Downhole Geochemical Logging data could have been used to optimize lateral placement to maximize production in hydrocarbon and porosity rich zones.

In this lateral well, the data helped to:

- Improve production by focusing lateral well locations in hydrocarbon and porosity rich zones
- Reduce completion costs by optimizing the number of fracture stages
- Predict Sweet Spots of higher porosity, hydrocarbon concentration, and natural fracturing.
- Identify when drilling efforts are in or out of the target formation

In this vertical well, the data helped to:

- Serve as a proxy for measuring porosity
- Clearly distinguish between various hydrocarbon phases (i.e. gas, condensate, or oil)
- Differentiate between multiple gas or multiple oil signatures
- Identify by-passed pay
- Infer compartmentalization and seals
- Identify water saturated zones or oil/water contacts

Thus, an attempt will be made in this case study to relate the information garnered from Amplified Geochemical Imaging and Downhole Geochemical Logging technologies to production in the field.

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Presenter's notes: 2Study took place in the Eagle Ford in the Maverick Basin in Dimmit County. The study included two wells. Downhole Geochemical Logging (DGL) samples were taken from both wells. Both vertical and lateral cutting samples were collected from the first well and only vertical cutting samples were tested on the second well.

Downhole Geochemical Logging Analysis


- Cuttings are collected in polypropylene jars, directly from the shaker table during drilling
- Mud blanks are also collected as well
- Analyses normally done in 2 weeks

1,000 time more sensitive than traditional methods

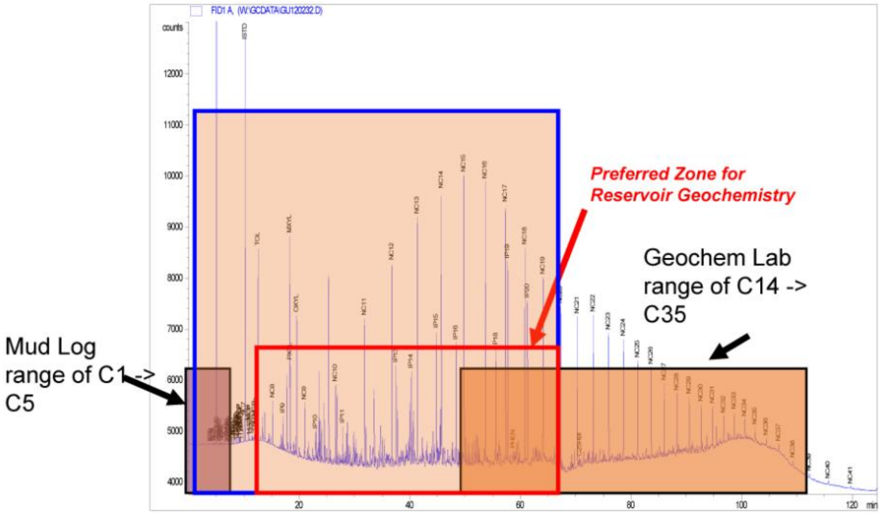
Focuses on hydrocarbon fluids in various zones

- Measures from the C_2 to C_{20} carbon range
- Easily differentiates between multiple phases
- Identifies reservoir compartmentalization
- Identify by-passed pays

Does this work with all drilling muds?
> ***No – Not with ALL Oil-based muds***

Presenter's notes: 3One of the most common tools used to understand reservoirs is conventional core analysis. Scientists look at various rock properties like porosity, permeability, variability across a core, grain density, and fluid saturation to better understand how fluids (i.e. oil) will flow through and from a reservoir. This is important in attempting to predict well and field productivity. Additionally, core analysis normally takes many months b/c of the backlog of samples in the various labs. DGL can provide you data in just a few weeks, not a few months. In addition, how do you know where to take your cores. The Expl VP at SWM recently said at an AAPG symposium in Vancouver that he prefers to wait a little while into the project to determine where is the most strategic area of the field to take cores, because when little is known they can spent a lot of money taking and analyzing cores from the wrong part of the field. However, while all of these are important properties to measure they do not really focus on hydrocarbons. They focus on rock properties to predict how hydrocarbons will flow from the well bore.

Conventional Hydrocarbon Analyses

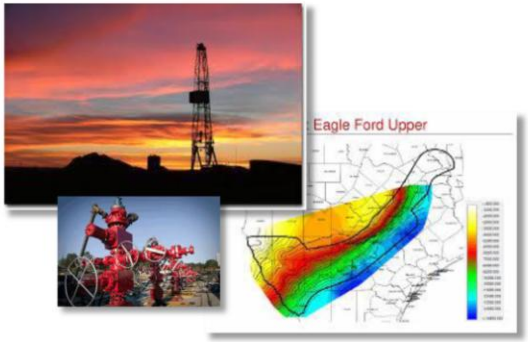


Presenter's notes: 4This shaded blue box shows the coverage range for DGL. Just looking at the box shows the density of compounds covered by the method. DGL technology measures from C2 -> C20, which enables the data to provide HC fingerprints for gas, condensates, and oils. Notice I did not say that DGL estimates or guesses (*Presenter's notes continued on next slide*)

(*Presenter's notes continued from previous slide*)

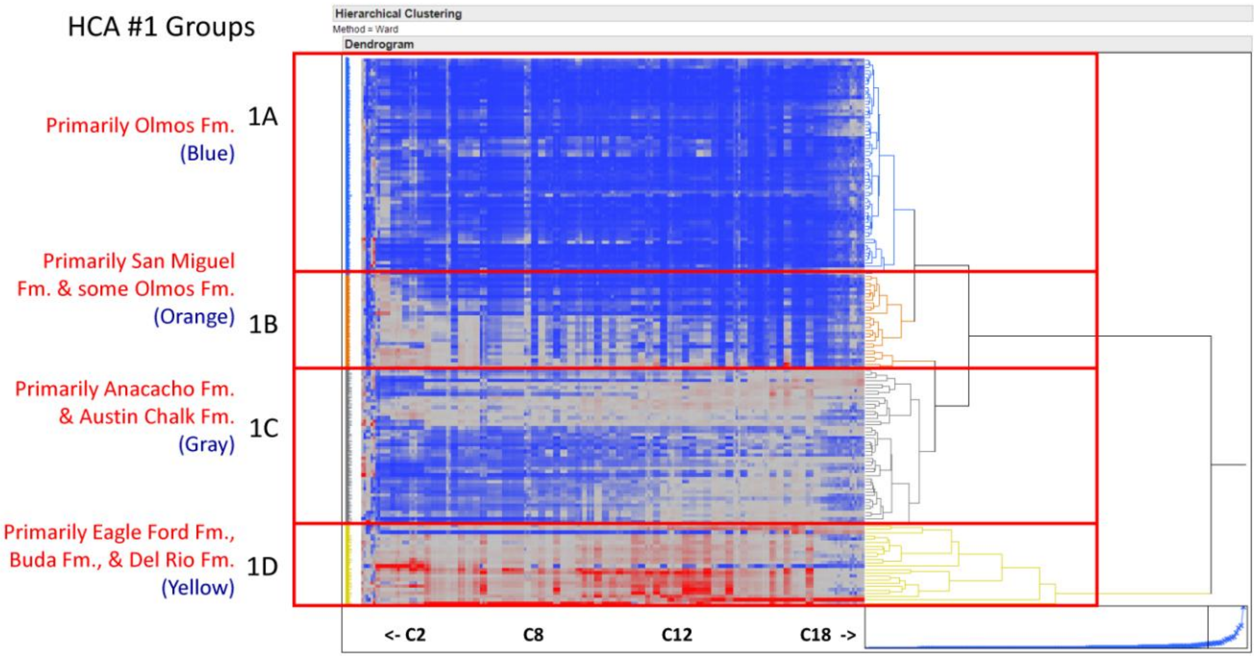
at the HC phase as other methods do. DGL provides the ability to not only differentiate between gas, condensates, and oils, but it allows you to also differentiate between several different oil signatures, which is not possible with other technologies. In addition, DGL measures down to the PPB range that is a 1,000 times lower than other technologies. This allows the method to measure seals down to the molecular level that no other method can do. Finally, and probably most importantly, since the AGI method measures many of the Isoprenoids between C10 and C20. This technology provides the ability to assess compartmentalization in the way reservoir geochemists do. While reservoir geochemists look at the entire HC to understand the HC phase (i.e. gas, condensate, or oil), assess alterations effects, and assess similarity between various HC fingerprints, they primarily work with the C10 to C22 range for evaluating compartmentalization for several reasons

Downhole Geochemical Logging in the First Vertical Eagle Ford Well



Presenter's notes: 53-D hydrocarbon detection contains a horizontal component and a vertical component. I will start with a brief overview of the Horizontal component.

Hierarchical Cluster Analysis



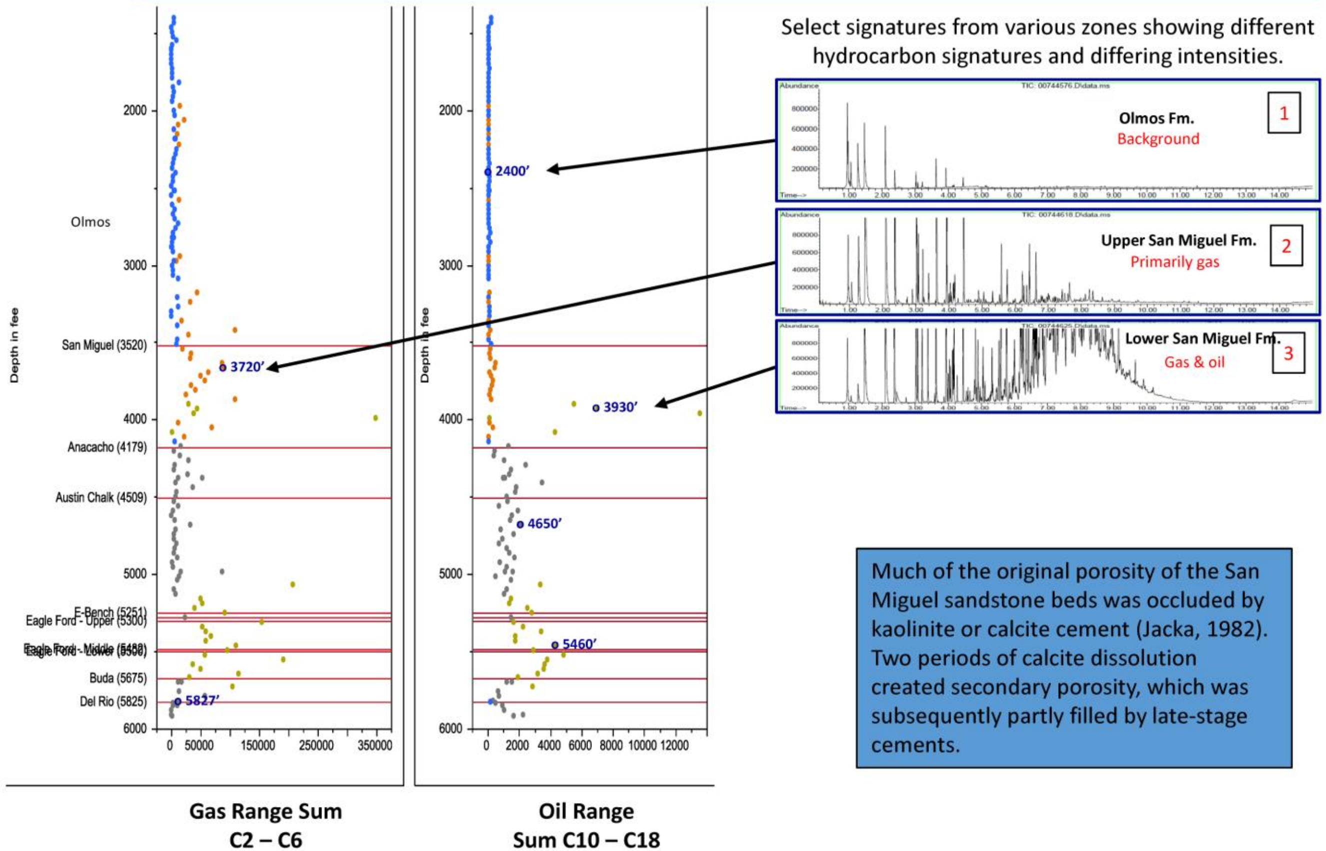
It is thought that there are three main sources of oil and gas in the assessed formations: Upper Jurassic Smackover Formation and Upper Cretaceous Austin and Eagle Ford Groups. Oils thought to have a Smackover source are mainly found in the far western part of the study area, and oils thought to have an Eagle Ford or Austin source are located in the north-central part; oils having a mixed Smackover–Austin–Eagle Ford origin are produced in the central part of the Maverick Basin (M.D. Lewan, written commun., 2003; S.M. Condon and T.S. Dyman, 2003).

Presenter's notes: 6This chart shows the output from a hierarchical cluster analysis (HCA #1) using all of the samples (shown here in individual rows of data). The Y-axis is simply each individual cutting sample and the x-axis is the carbon range from C2 – C20. Red indicates a positive HC response at that range and blue indicates a negative or no response at that carbon range. Therefore, this process groups the samples together based on their similar geochemical signatures and the (*Presenter's notes continued on next slide*)

(*Presenter's notes continued from previous slide*)

program doesn't look at what depth, lithology, or stratigraphy and samples was taken from. It simply clusters samples based on similar signatures. This data set identified four main groups which are shown with the red rectangles and which are numbered 1-4 on the far left. What is interesting about the data is when you begin to look at what samples comprise these four groups you find a very interesting pattern. You find most of the Olmos samples fall in Group 1A. Most of the samples from the San Miguel Fm fall collectively in Group 1B, the Group 1C samples are primarily comprised of samples from the Anacacho and Austin Chalk, while Group 1D is comprised of samples taken from the deeper Eagle Ford, Buda, and Del Rio Fms. What is interesting about this breakdown is that the cluster analysis correlates to published oil & gas sources for the Maverick Basin. Published data ascribes the Eagle Ford as a known HC source, which most likely charges the Eagle Ford, Buda, & Del Rio and the Austin Chalk as a source for the Austin Chalk & the overlying Anacacho. The San Miguel appears to be a third and distinct HC signal while the Olmos is a background signal.

Depth Profile with Hydrocarbon Fingerprints

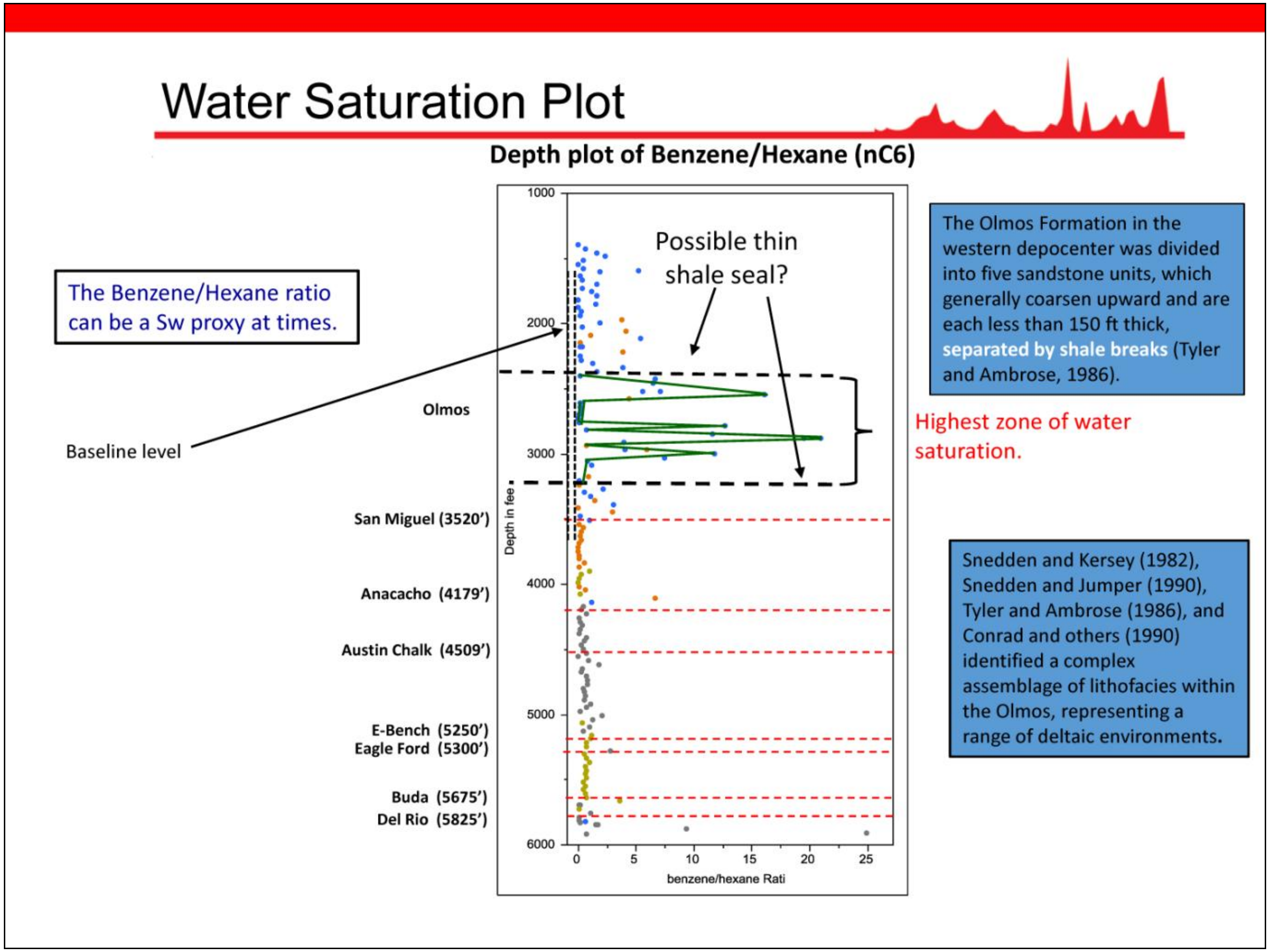


Much of the original porosity of the San Miguel sandstone beds was occluded by kaolinite or calcite cement (Jacka, 1982). Two periods of calcite dissolution created secondary porosity, which was subsequently partly filled by late-stage cements.

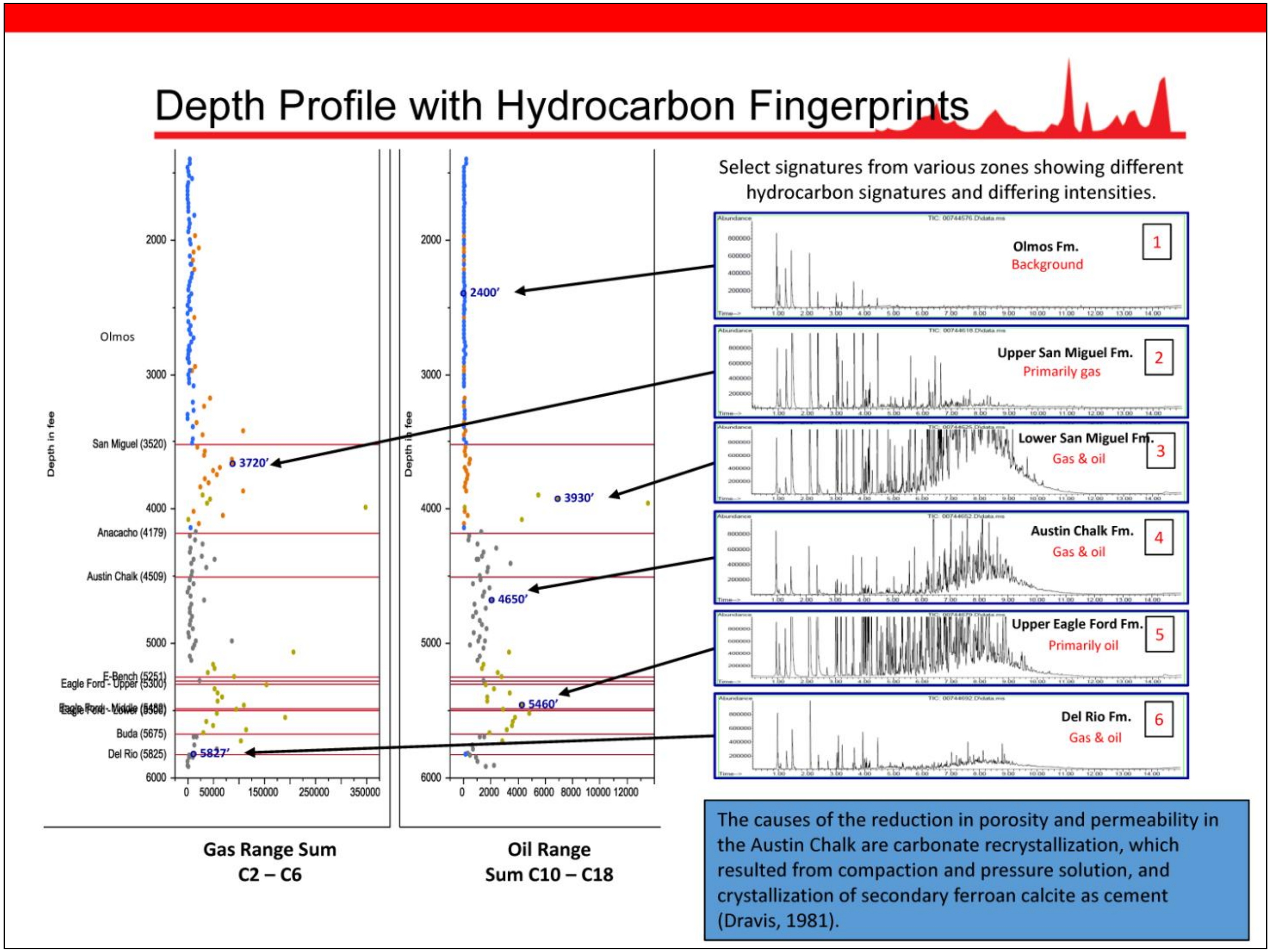
Presenter's notes: 7This slide includes the same two depth profile charts, with the addition of some select TIC signatures (total ion chromatograms) for various horizons. Of particular note is the change in the TIC patterns as the well was drilled and the apparent increase/decrease in response from the samples. One of the first things that strikes you (*Presenter's notes continued on next slide*)

(*Presenter's notes continued from previous slide*)

is that in the Lower San Miguel Fm you have a gas/oil signature. As you move from the bottom TIC to the middle TIC you notice a start similarity. The gas signature in the Upper San Miguel looks just like the HC in the Lower San Miguel without the liquid portion. It is almost as if you have a gas cap over the oil formation. Then as you look into the Olmos Fm the HC signature looks like a reduced version or background version of the Upper San Miguel gas signature. The transition between the three HC zones is intriguing. Beneath this (between 3870' and 4110') is a different signature with more oil-like characteristics appears. These samples are all within the San Miguel Fm. and perhaps a facies change or gradation towards the bottom of this formation may explain the change in the geochemical response. Note the intensity of the oil signature in the Lower San Miguel. This is the highest oil intensity in the entire well, including the Eagle Ford. This prolific liquid rich area could be missed if people were only focused on the Eagle Ford and drilled right through to the Eagle Ford. As we mentioned in the previous slide the cluster analysis separated the San Miguel samples as a unique group or cluster that was noticeably different from the Austin Chalk production and the Eagle Ford generation. However, the San Miguel is not known as a potential source; so, we do not really have an explanation for this unique HC signature in the San Miguel Fm. We also know that, by definition, HCs must have a space to reside. Therefore, the more HCs detected, typically, the greater porosity. Therefore, the greater porosity inferred here by the DGL data is supported by the well logs and the data reported by Jacka in 1982.



Presenter's notes: 8As we drill a little deeper into the data, notice the gas increase starts just above the San Miguel Fm. around 3100'. Therefore, this would imply that the gas in the San Miguel is also in the Olmos and there is no seal between the two. Yet why does the gas in the San Miguel begin to substantially increase at 3100'? One explanation may be due to a thin seal in the Olmos. Tyler and Ambrose reports that the Olmos in divided into multiple sections and whether that number is 3 or 5 depends in what portion of the field you are in. However, the point is, there are thin shale seals interlaced within the Olmos. So, the question can be raised to we have a small undetectable seal at about 3100'?



Presenter's notes: 9This graph plots the ratio of Benzene over Hexane (nC6) versus depth. The premise is that in a hydrocarbon zone the ratio of Benzene to hexane is roughly 1.0. However, in water-saturated zones, benzene preferentially dissolves in the water because benzene is very water-soluble because it is a polar compound (*Presenter's notes continued on next slide*)

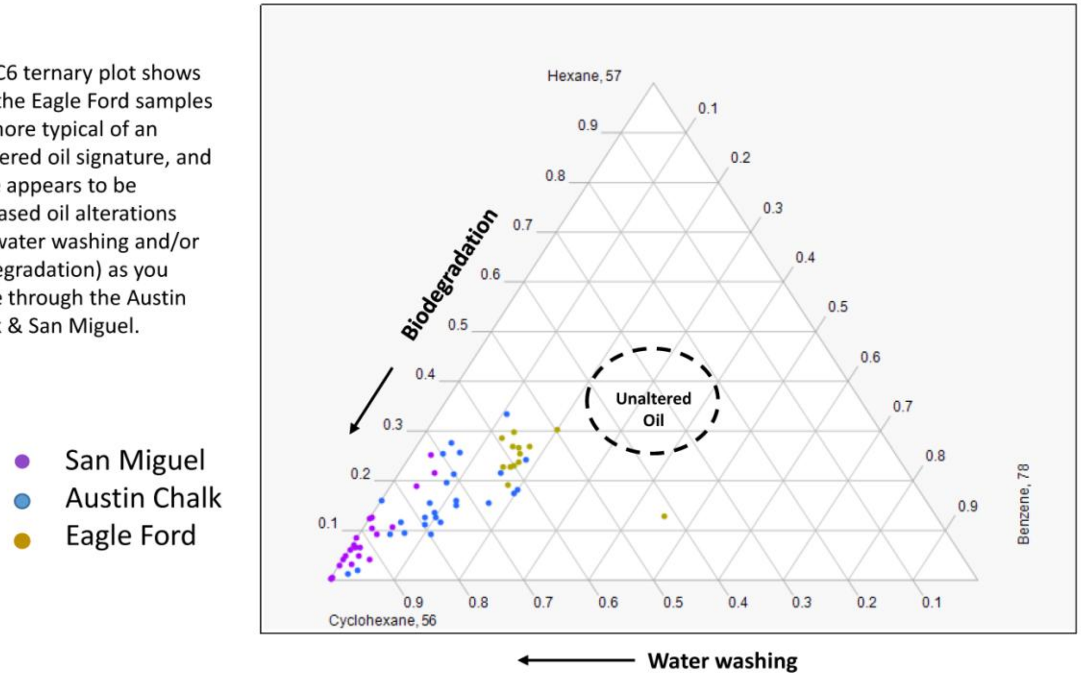
(*Presenter's notes continued from previous slide*)

while hexane, a nonpolar compound, does not readily dissolve in water. Thus, the benzene concentration increases substantially over the hexane concentration. We can see from the plot that Benzene/Hexane ratio is consistently low throughout the hydrocarbon bearing zones. However, we see in the Olmos a dramatic increase in the ratio. There appears to be a background ratio between 2 and 4, which then dramatically increases between 2400' to 3100'. So, why is this? From literature, we know that the Olmos in this area is deltaic sandy shale as reported by Snedden others. So, we would expect higher water saturation in this zone, which we see between 2400'-3100'. The resistivity log also indicated strings of high water saturation in this interval. So this begs the question does the geochemical data indicate small thin sealing shale sections at 2400' and 3100'. The gas plot and the Sw proxy might indicate that.

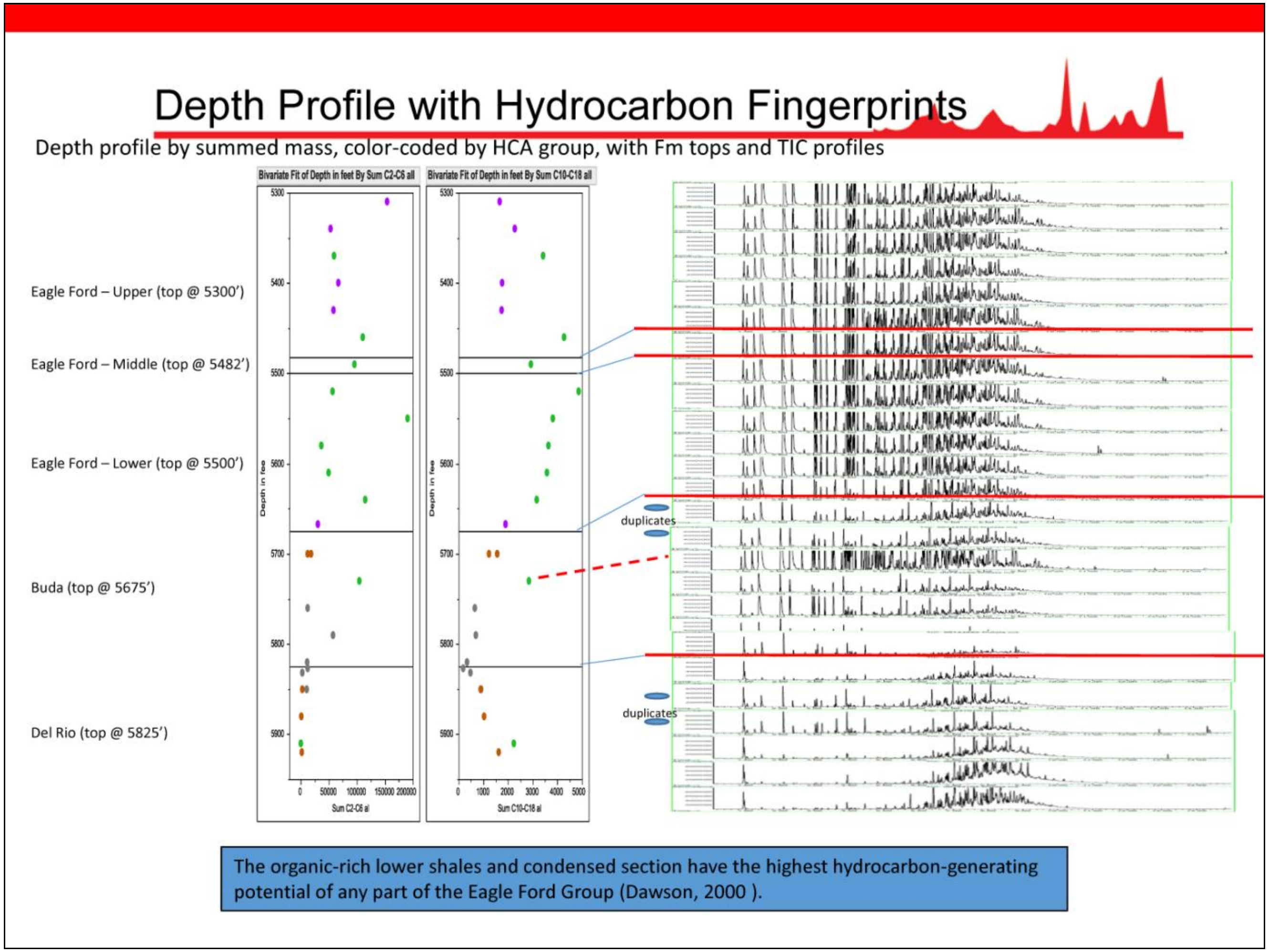
Oil Alteration Plot

The geochemistry data seems to indicate a separate source for the San Miguel Fm.

This C6 ternary plot shows that the Eagle Ford samples are more typical of an unaltered oil signature, and there appears to be increased oil alterations (i.e. water washing and/or biodegradation) as you move through the Austin Chalk & San Miguel.

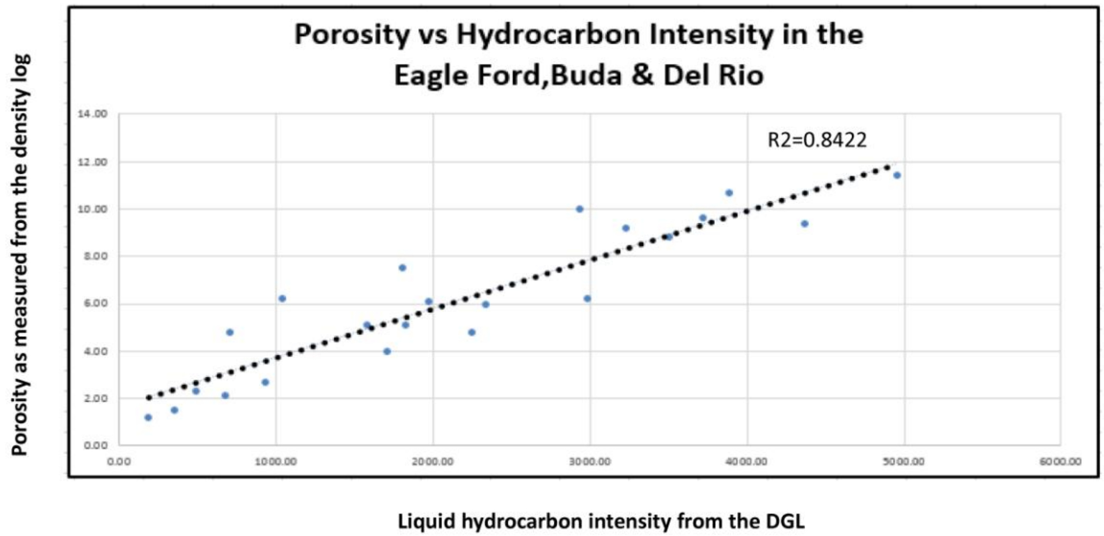


Presenter's notes: 10As you move into the Anacacho and the Austin Chalk, the HC fingerprint changes into a gas/oil signature, which is lower in intensity than both the Lower San Miguel and the Eagle Ford. You can see by the gray dots that this is a distinct HC signature from other formations and is consistent with literature that implies the Austin Chalk is self-sourcing and sources the Anacacho. The cluster analysis indicates that as you enter the Eagle Ford switch to a different HC signature that is predominately oil and the intensity increases dramatically. Then in the Del Rio Fm, you see dramatic decrease in HC intensity and once again switch to a gas/oil signature. So, several HC signatures are observed as you move vertically along the well and the highest accumulations of oil are found in the Lower San Miguel Fm and the Eagle Ford Fm, respectively.



Presenter's notes: 11This ternary plot also lends some credence to that assumption. Here we have plotted Benzene, Cyclohexane, and Hexane in an attempt to differentiate the degree of alteration between oil sets. As seen here, there is a distinct difference between the geochemical make-up of Eagle Ford Fm. samples and the San Miguel Fm. Oil samples. The separation between the three oil formations also suggests different maturities with little mixing between the three data sets; once again inferring three different potential sources and compartmentalization between the three.

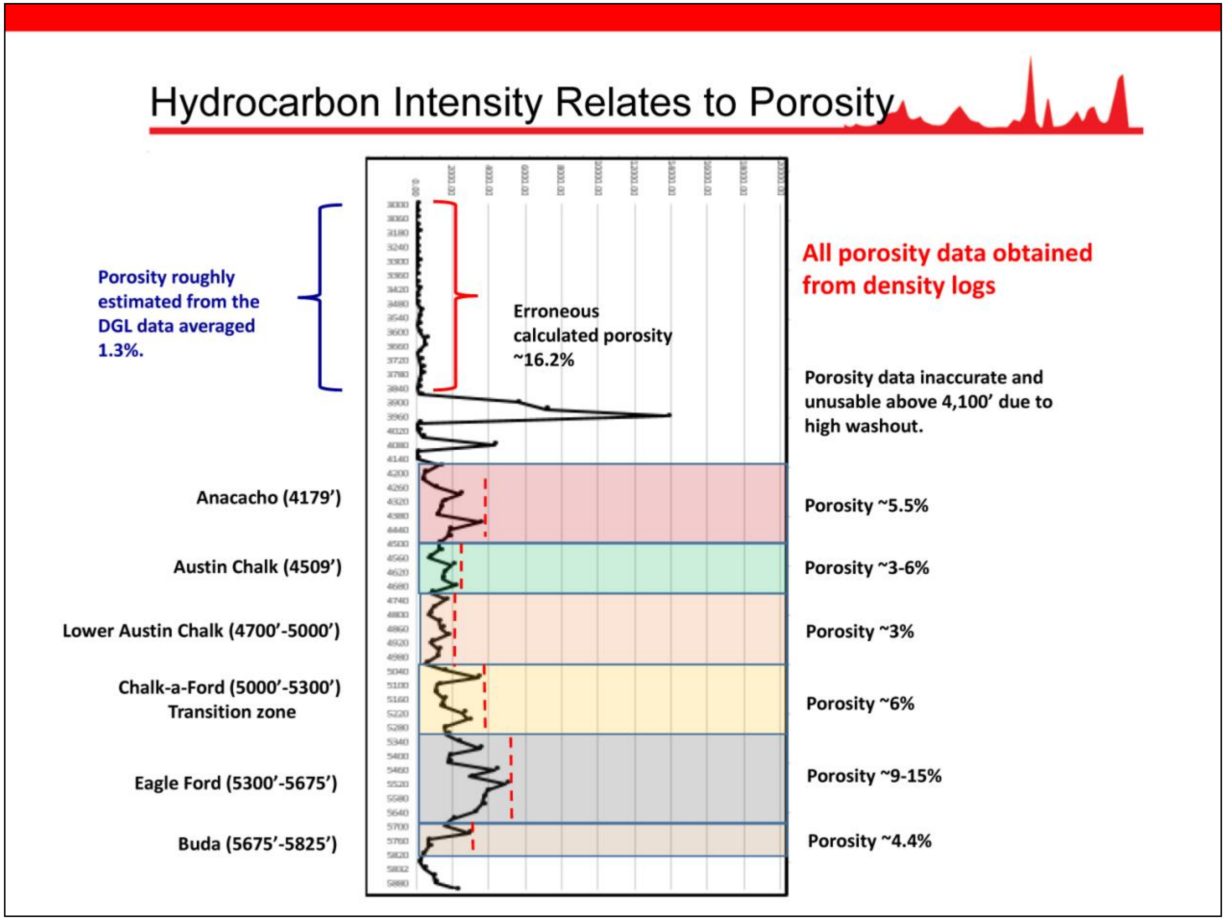
Hydrocarbon Intensity Relates to Porosity



Presenter's notes: 12This is a similar depth profile through the Eagle Ford, Buda and Del Rio sections. The TICs to the right indicate a very consistent and high mass response for all of the samples throughout the Eagle Ford (Upper, Middle and Lower). The TICs throughout the Eagle Ford support what was seen in the star plots in that there is a similar hydrocarbon signature throughout the Eagle Ford. Additionally, the data shows the highest HC intensity is found in the (*Presenter's notes continued on next slide*)

(*Presenter's notes continued from previous slide*)

Lower Eagle Ford section, which is consistent with literature that says the Lower Eagle Ford has the highest HC generating capacity due to its higher organic content. The TICs in the Buda seem visually different from the Eagle Ford. However, the radar plots in the previous slide indicate the HC's in the Eagle Ford and the Buda are very similar. Therefore, the variance in the HC signatures between the Eagle Ford & the Buda is most likely due to a decrease in intensity. That is confirmed in the depth plot. The Eagle Ford samples have an intensity range from about 2500 ng – 5000 ng while the intensity for the Buda is roughly less than 2500. Therefore, the fact that the star plots indicate a similar HC between the two Fms. In addition, that the intensity decreases from the upper Buda to the lower Buda seems to support the concept that the Eagle Ford is charging the Buda. One of the powerful messages from this slide is the fact that the decrease in HC intensity correlates to a decrease in porosity as well. We know from the well logs that the Buda generally has a lower porosity than the Eagle Ford. So the decrease in HC intensity trends with the porosity data. This porosity assertion is supported by the fact that there is one sample in the Buda at 5730' that clusters with the Eagle Ford samples, shows an increase in intensity, and the TIC pattern is similar to the Eagle Ford section and the well logs indicate this sample point has a higher porosity than the rest of the Buda. Based on this you see the Lower Eagle Ford seems to have the highest porosity of the various Eagle Ford sections. The Upper Del Rio Fm. also has an oil-like signature and is very similar to the Buda. This may indicate that the top of the Del Rio is also being charged by the Eagle Ford. Notice half way through the Del Rio Fm. the HC signature begins to change and the intensity increases. This may indicate that the bottom of the Del Rio may be charged from the underlying Georgetown Fm. What this also indicates is that there does not appear to be any seals between the Upper Eagle Ford down through the Georgetown Fm.

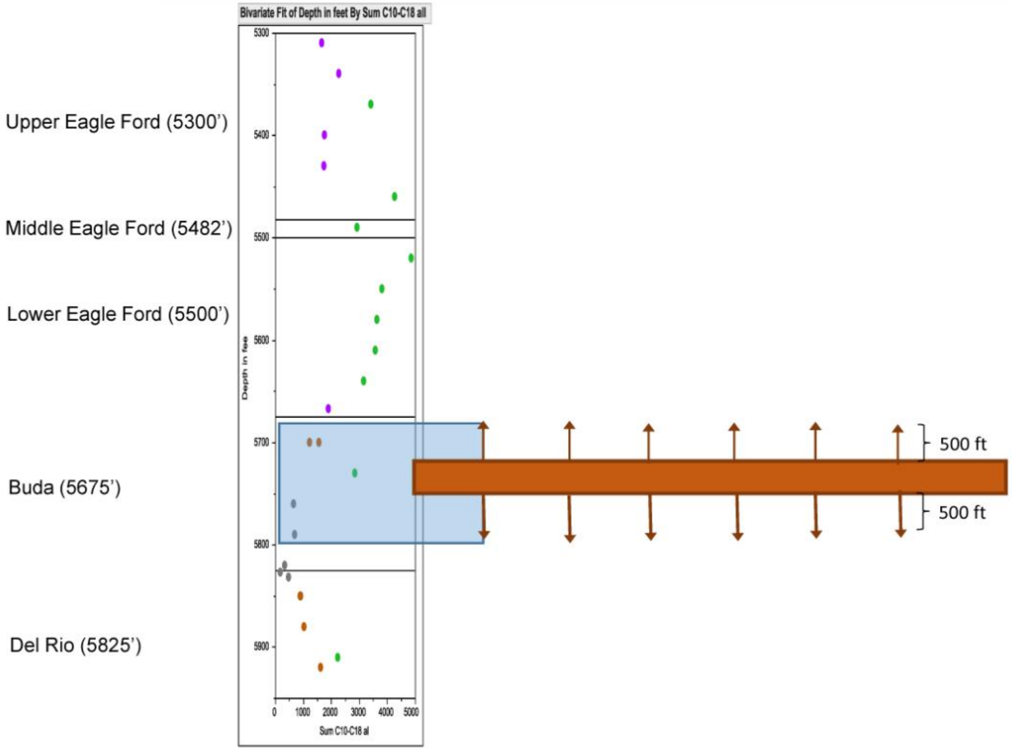


Presenter's notes: 13Density logs were used to determine the porosity values for this vertical well and are plotted in red. The liquid hydrocarbon intensities are plotted in blue. Density log data could not be used above 4,100' due to washout. So the comparison of Density Log to DGL hydrocarbon intensity was made from 4,100'-5,900'. As can be seen there is a good correlation between the two data sets. The trending is very comparable. The elevated density readings from 4,100'- 4,200', where you see a disparity between the density readings and the DGL, may in fact be an artifact of residual artificial elevation from the drilling washout. You can see that the data is not an exact match. This may be due to the fact the cuttings may not be coming from the exact location as specified. Additionally, we must remember the density log is a proxy for porosity and may not be very accurate as well. However, there is a good comparison between the two data sets.

Downhole Geochemical Logging in the Lateral Eagle Ford Well

Presenter's notes: 14Density logs were used to determine the porosity values for this vertical well and are plotted in red. The liquid hydrocarbon intensities are plotted in blue.

Lateral Placement



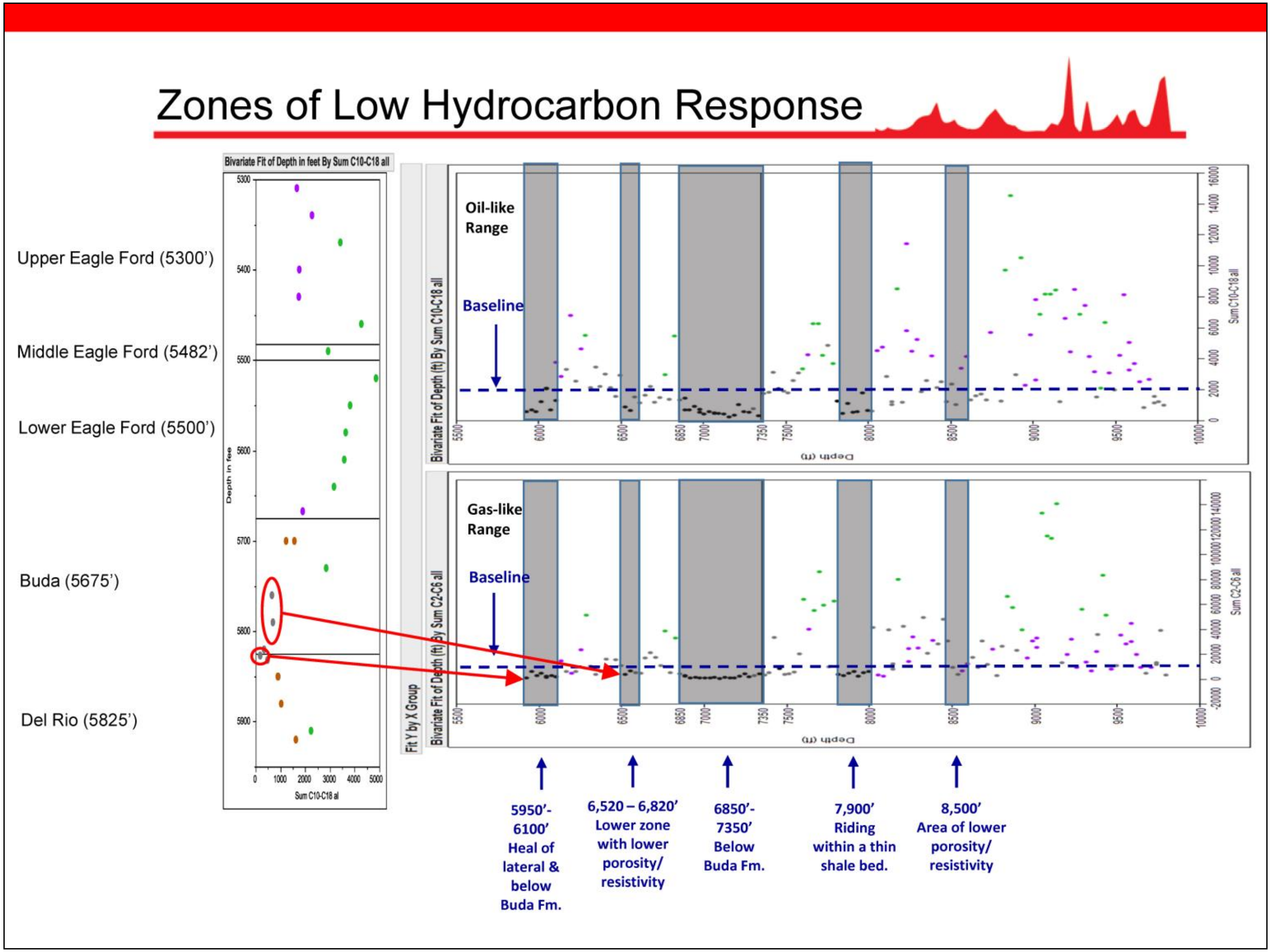
Presenter's notes: 15Density logs were used to determine the porosity values for this vertical well. Note how liquid hydrocarbon intensities correlate quite accurately with fluctuations in density log (i.e. porosity) measurements. In the Austin Chalk Fm. the porosity ranged from 3%-6%. As you move into the Lower Austin Chalk the porosity (*Presenter's notes continued on next slide*)

(*Presenter's notes continued from previous slide*)

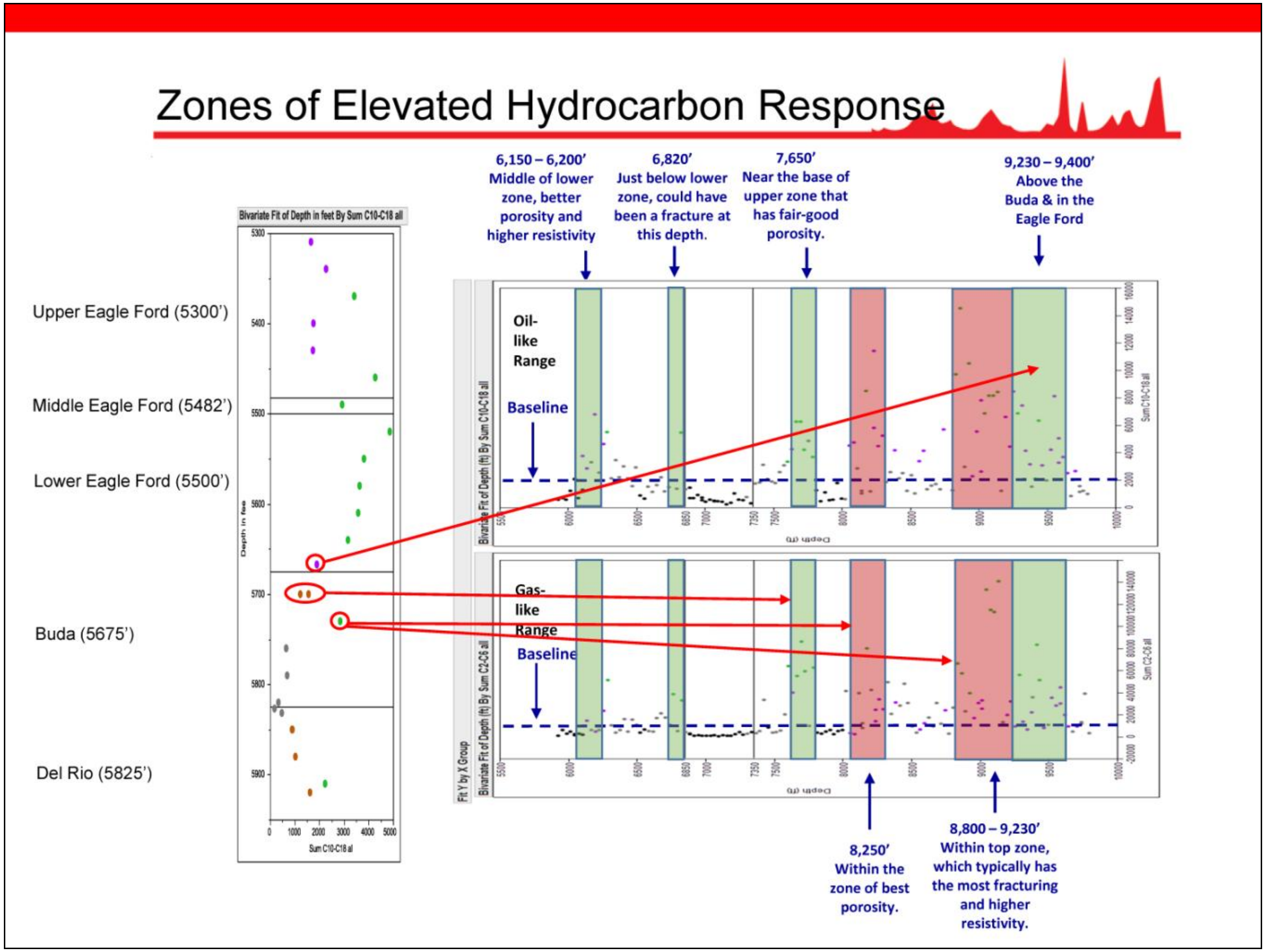
and the hydrocarbon intensity decrease simultaneously. The client refers to the zone from 5,000'-5,300' as the transition between the Austin Chalk and the Eagle Ford and thus calls it the Chalk-a-Ford. In this zone, you see a simultaneous increase in both the porosity and the hydrocarbon intensity. As you move into the Eagle Ford, you see an increase in the porosity and the hydrocarbon intensity. Note booth indicators show the highest porosity and hydrocarbon intensity in the Lower Eagle Ford. When you look at the Buda, which we know from the hydrocarbon profile, has a much reduced hydrocarbon intensity than the Buda, the porosity also decreases from the 9%-15% porosity seen in the Eagle Ford to an average of 4.3% in the Buda. So, if you look at the general trends, the DGL hydrocarbon intensity trends moves in a step-wise fashion in perfect step with the density log porosity data. It should also ne noted that the density log data has had no type corrections applied (i.e. caliper calibration). Thus, the porosity data may have inherent errors that have not been corrected. The hydrocarbon intensity also acts as a check on porosity determined from logs. In this case there was a high degree of washout above 4,100'. The avg porosity from the density log from 3,000'-3,800' was approximately 17%. However, the hydrocarbon intensity readings show this depth range in the Olmos formation as almost devoid of hydrocarbons. The use of Downhole Geochemical Logging serves as a double check of log-derived values. Using a linear regression of density Log porosity vs. DGL intensity we get an R2 = 0.9266. f we3 use that linear regression to calculate a very rough rough porosity in the Olmos from 3,030' – 3,840', the avg DGL calculated porosity is 1.3%. We can ground truth that by calculating DGL porosity in the lower Buda where we know the hydrocarbon intensity is approximately the same as the Olmos. The values were as follows:

Depth – 5,821'	Density porosity = 1.5%	DGL calculated porosity = 1.8%
Depth – 5,827.5'	Density porosity = 1.2%	DGL calculated porosity = 1.4%

This calculation does not hold through the entire well, but it does show that the DGL data can be used as a rough check on density porosity logs.

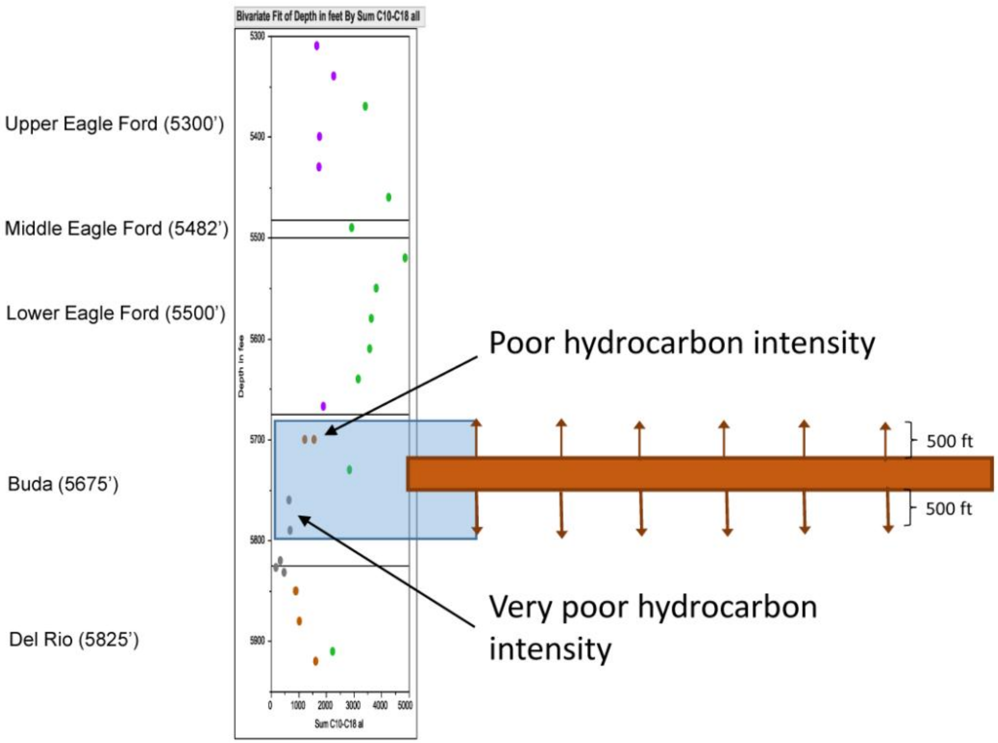


Presenter's notes: 163-D hydrocarbon detection contains a horizontal component and a vertical component. I will start with a brief overview of the Horizontal component.



Presenter's notes: 17This slide shows the approximate location of the lateral well in the Buda formation. The wide brown section represents the lateral and the brown arrows indicate possible fracture stages at 500 ft intervals. You can see the hydrocarbon (HC) profile on the left. You can also see that the client attempted to locate the lateral in the sweet spot (i.e. highest porosity and highest HC potential) of the Buda. The blue shaded area represents the possible drainage area (i.e. 500 ft above and below the lateral) of the lateral. Therefore, we are now going to talk about the hydrocarbon data gathered from analyzing cutting samples from the lateral portion of the well along that brown bar and how that data relates to the data taken in the vertical section of the well

Poor Lateral Placement

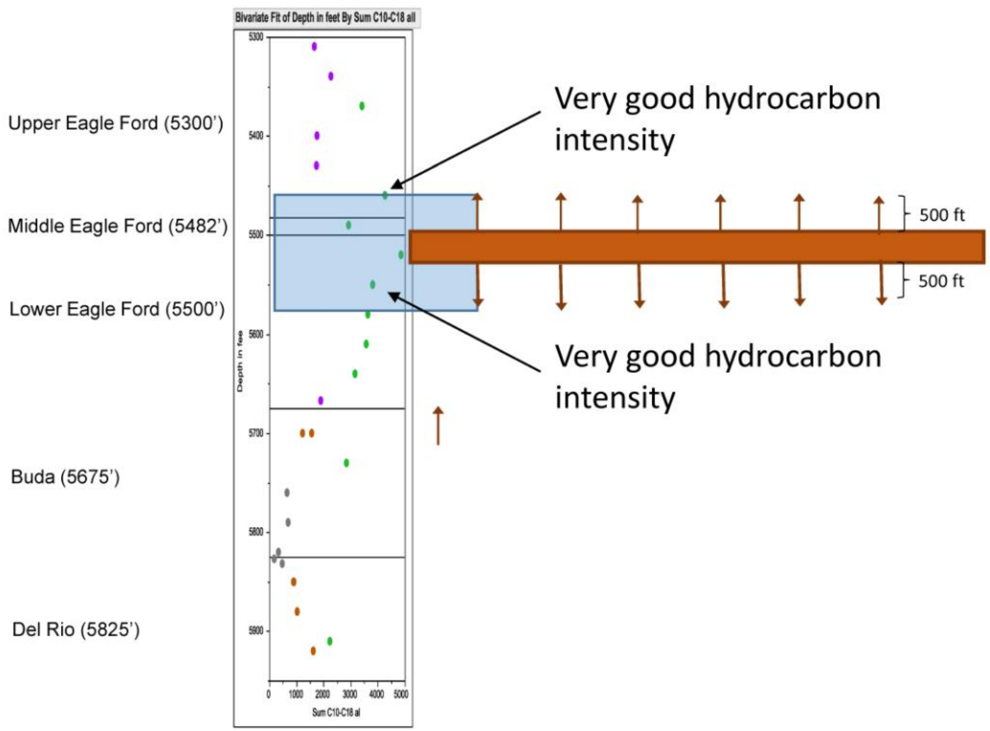


Presenter's notes: 18The Buda was subdivided into eight different zones based on porosity and resistivity. Three zones appeared to have higher porosity, resistivity, and perhaps more fractures. Oil-like components are plotted on the top scale while gas-like components on the lower scale. The X-axis on each plot is the depth and the Y-axis is the HC intensity. The depth chart has been turned on its side to more easily represent a lateral vies of the data. The color of (*Presenter's notes continued on next slide*)

(*Presenter's notes continued from previous slide*)

the dots or data points relates to cluster analysis, which will we will not go into except to say the green cluster appears to have the highest degree of intensity and the black has the lowest degree of intensity. We have also added dashed blue line to indicate the approximate HC baseline. The gray shaded areas indicate areas of low HC response according to the DGL data. Conversations with the client indicate correlations between these low DGL readings and well notes. For example, the low DGL concentration from 5950'-6100' related to the heel of the lateral drilling where the drill bit was below the intended Buda Fm. The downturn in HC concentration from 6520'-6820' corresponded to a zone of lower porosity/resistivity. Well logs indicate the decrease in HC concentration from 6850'-7350' was due to drilling out of zone beneath the Buda Fm. The decrease in HCs at 7900' was likely due to riding in a thin shale bed. Around 8500' the lateral drilling was above the upper target zone within the Buda, which was identified as an area with lower porosity/resistivity, which would explain the decrease in there. Therefore, in each case where there is a significant decrease in HC concentration in the lateral drilling event, the DGL detects that decrease and it relates to geologic anomalies on the formation.

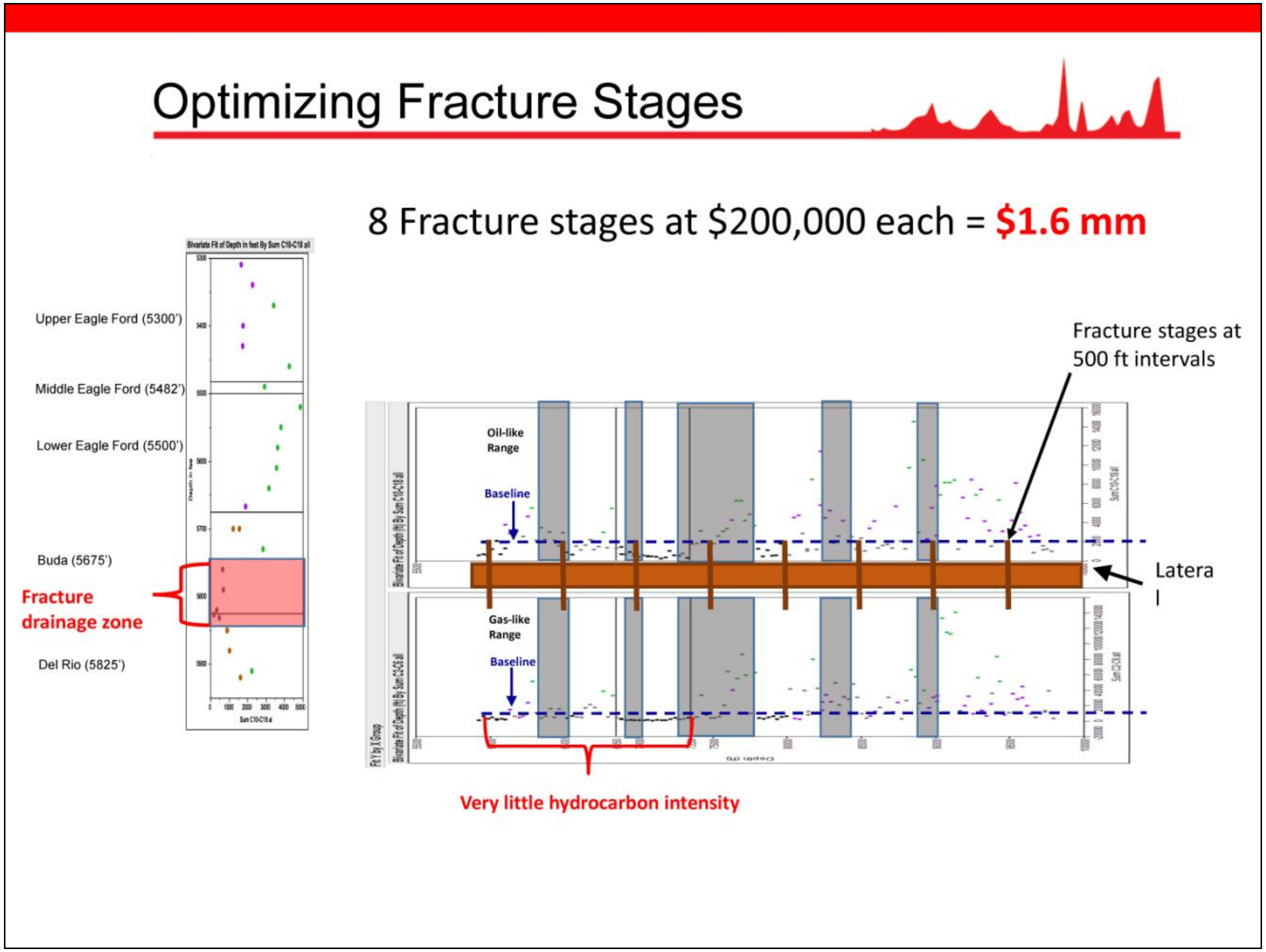
Excellent Lateral Placement



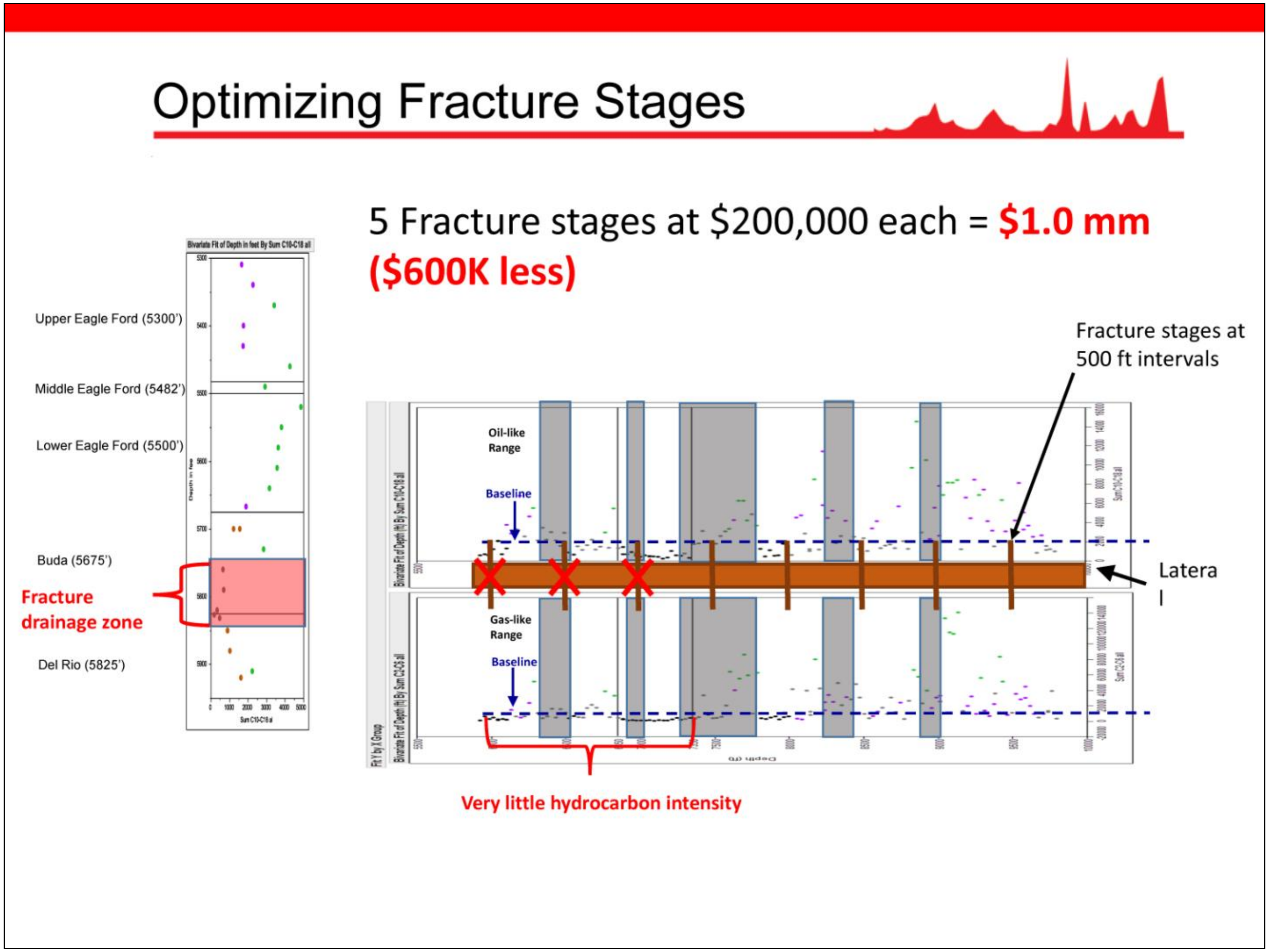
Presenter's notes: 19As mentioned previously there were three subdivisions within the Buda that had been identified as zones of higher porosity, resistivity, and perhaps more fractures. These three zones were middle of the lower zone, the base of the upper zone, and the top zone. As seen in the plot above, the increases in HC concentrations from the DGL plot tracked well with these known zones of enhancement. For example, a kick in the oil components is seen (*Presenter's notes continued on next slide*)

(*Presenter's notes continued from previous slide*)

between 6150'-6200' in the middle of the lower zone. It was believed the HC kick at 6820' coincided with a small naturally occurring fracture. At 7650' and 8250' the drill in the upper zone, which was known to have better porosity and resistivity. At 8800'-9230' they reach the top zone which typically has the most fracturing and highest resistivity. The red shading shows that these two sections, 8250' and 8800' are by far the most prolific HC bearing zones in the lateral well and stand-out in terms of HC concentration. In addition, the final section between 9230'-9400' the lateral went out of the Buda and into the Lower Eagle Ford, which we know from the vertical data, was the second most HC prolific section of the well. It is also very interesting to note that besides the 50' section at 6150' there are no strong HC responses in the lateral until you get to 7650'. So, this may indicate, at least in this well, that fracturing before 7650' may not be economically advantageous.



Presenter's notes: 20This slide shows the approximate location of the lateral well in the Buda formation. The wide brown section represents the lateral and the brown arrows indicate possible fracture stages at 500 ft intervals. You can see the hydrocarbon (HC) profile on the left. You can also see that the client attempted to locate the lateral in the sweet spot (i.e. highest porosity and highest HC potential) of the Buda. The blue shaded area represents the possible drainage area (i.e. 500 ft above and below the lateral) of the lateral. You can see that the drainage area encompasses a very poor HC intensity zone, both above and below the lateral. The result is reduced production from this well.



Presenter's notes: 21This diagram illustrates if the lateral had been placed higher in the well in the Lower Eagle Ford Fm. You can quickly see the drainage area indicated by the blue shaded area incorporates a much more HC rich zone and an area of much higher porosity. Thus, for the same amount of completion investment, the well should gain a substantial increase in production if the DGL vertical data is used to aid in the selection of the lateral placement.

Downhole Geochemical Logging in the **Second Vertical Eagle Ford Well**

Presenter’s notes: 22Once again, this slide shows the HC intensities in the lateral section. The vertical brown lines represent the possible location of fracture stages spaced every 500 ft. At a cost of $200,000 per fracture stage, the cost to fracture eight stages in this well would be $1.6 mm. This slide shows what many companies have done over the last few years or continue to do, and that is place their fractures equidistance along the well fracture with the same number of fractures and the same spacing from well to well. However, postmortem field reviews has shown while this may be efficient, it may not be economic.

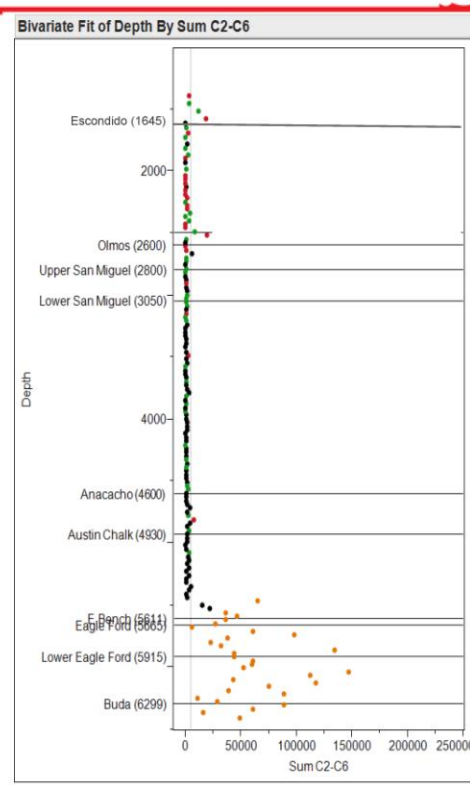
Well Number 2

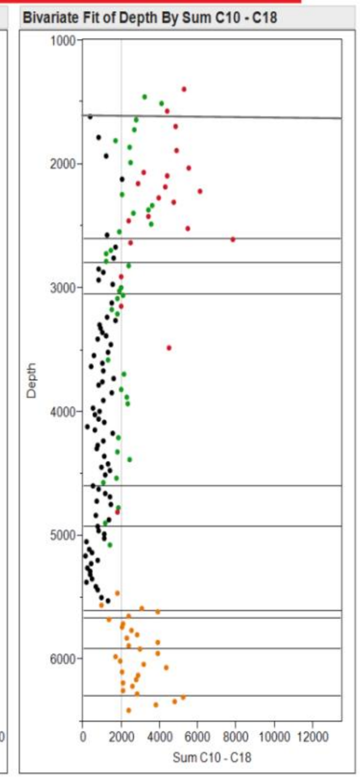
Why the difference in the two Hydrocarbon well profiles?

Well 2 was only 2.5 miles away from Well 1, but was 200' structurally lower and closer to the sourcing restricted mini-basin in Dimmit County.

Well 1:
Eagle Ford 5300' – 5675'
(thickness 375')

Well 2:
Eagle Ford 5665' – 6299'
(thickness 634')



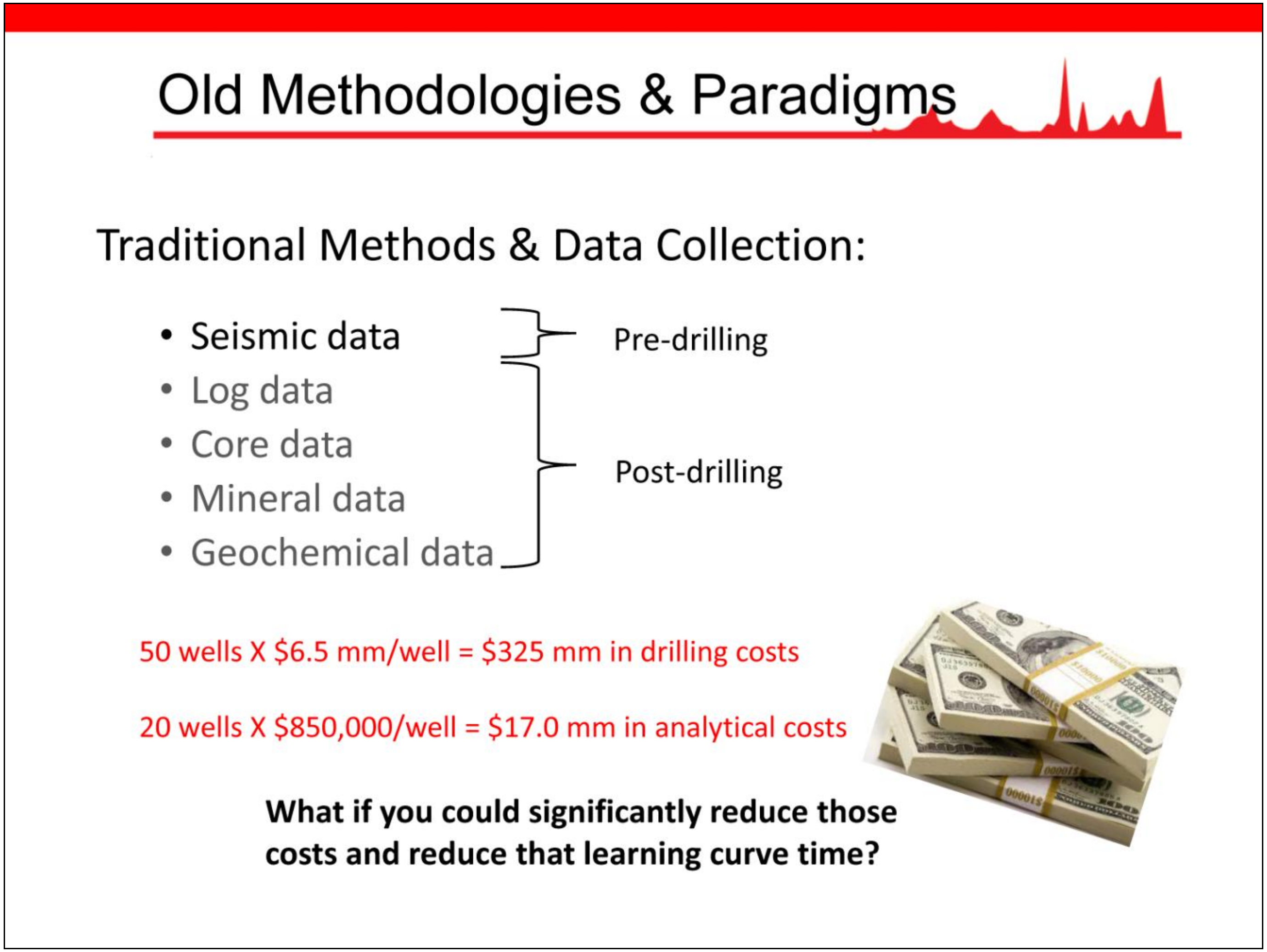


Presenter's notes: 23Once again, this slide shows the HC intensities in the lateral section. The vertical brown lines represent the possible location of fracture stages spaced every 500 ft. At a cost of $200,000 per fracture stage, the cost to fracture eight stages in this well would be $1.6 mm. This slide shows what many companies have done over the last few years or continue to do, and that is place their fractures equidistance along the well fracture with the same number of fractures and the same spacing from well to well. However, postmortem field reviews has shown while this may be efficient, it may not be economic.

Amplified Geochemical Imaging, LLC.

Pre-drill Mapping
Hydrocarbons in Shale Plays

Presenter's notes: 243-D hydrocarbon detection contains a horizontal component and a vertical component. I will start with a brief overview of the Horizontal component.



Presenter's notes: 25Forget about the coloration of the dots for a minute and just look at the gas and liquid HC profiles for this Well 2. Obviously, we are looking at the summed light compounds (C2-C6) to the left, and the heavy compounds (C10-C18) to the right once again. First notice the HC pattern in this well is dramatically different from the first well. In well 1, you had a very light gas tinge in the Olmos Fm while here there is no gas, just a liquid signature. In Well 1 we had (*Presenter's notes continued on next slide*)

(*Presenter's notes continued from previous slide*)

a strong gas-only response in the Upper San Miguel and a prolific oil-like signature on the Lower San Miguel. Here in Well 2 there is no gas signature at all and only a low concentration oil signature throughout the section. In Well 1 there was a gas/oil signature throughout the Anacacho & the Austin Chalk Fms, while in Well 2 there was no gas and the same oil-only signature seen in the San Miguel. These charts show the same color scheme as was used in the HCA 1, and it shows the mass response The cluster diagram indicates that the hydrocarbons in the E-Bench, Upper Eagle Ford, Lower Eagle Ford, and Buda Fm. appear to be similar or the same. Literature indicates that the Lower Eagle Ford is the primary hydrocarbon source in the Maverick Basin. If true, it appears that there may be no seal between the Lower Eagle Ford and the adjacent formations (i.e. Upper Eagle Ford, E-Bench, and Buda) and the Lower Eagle Ford may be charging theses formations. It is interesting to note, just like in Well 1, the Eagle Ford cluster of hydrocarbons essentially stops at the base of the Austin Chalk. Literature also indicates that the Austin Chalk is a hydrocarbon source as well. If that is true, it appears this Austin Chalk signature is pervasive upward (i.e. cluster group 3) through the Anacacho, San Miguel, and Olmos with no compartmentalized seals between these various formation.

A New Pre-Drilling Paradigm

3D Seismic and Amplified Geochemical Imaging can help to **optimize pre-drilling efforts**.

3D Seismic can provide:

- Stress orientation
- Brittleness proxy (Young's modulus)
- Open fracture proxy (azimuthal anisotropy)

Fractures, Faults, & Rock properties

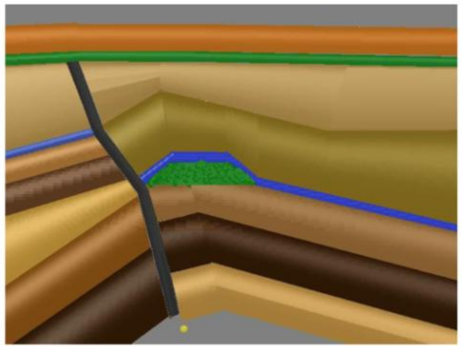
Amplified Geochemical Imaging can:

- Identify charged and noncharged portions of the field
- Map phase across the field
- Map thermal maturity
- Identify <u>sweet spots of pressure, porosity, & net pay</u>
- Potentially identify geohazards (i.e. faults)

Hydrocarbon, Structural, & Rock properties

Presenter’s notes: 27Every operator in a shale play goes through a learning curve. Years of production data in North America clearly show that. The difference between successful and unsuccessful operators is many things, but perhaps one of the most important is their ability to learn quickly and optimize their operations. You cannot optimize operations without metrics and those metrics come from data measurement. The list above shows the most common data sets that are collected. The problem with this data set is that the majority of these data sets (i.e. log data, core data, mineral data, and traditional geochemical data) can only be acquired post-drilling. It was said in the recent Middle East Shale Gas workshop in Sept 2014 that it is safe to assume it would require 50 wells to create an effective data set to evaluate all these measures properties. At $6.5 mm per well that comes to an investment of $325,000,000 in well costs to gain the knowledge necessary to optimize your field. It was also mentioned in this conference that it would cost on average (excluding seismic data) $850,000 per well to get all that information. If you did this testing on just 20 wells that would amount to $17 mm in analytical costs. What if you could dramatically reduce that?

Vertical Migration - Microseepage



Microseepage signal affected by:

- **Pressure (P)**
- **Porosity (θ)**
- **Net Pay (h)**

Macroseepage:
- Detectable in visible amounts
- Pathway follows discontinuities
- Offset from source/reservoir

VS

Microseepage:
- Detectable in analytical amounts
- Pathway is nearly vertical
- Overlie source/reservoir

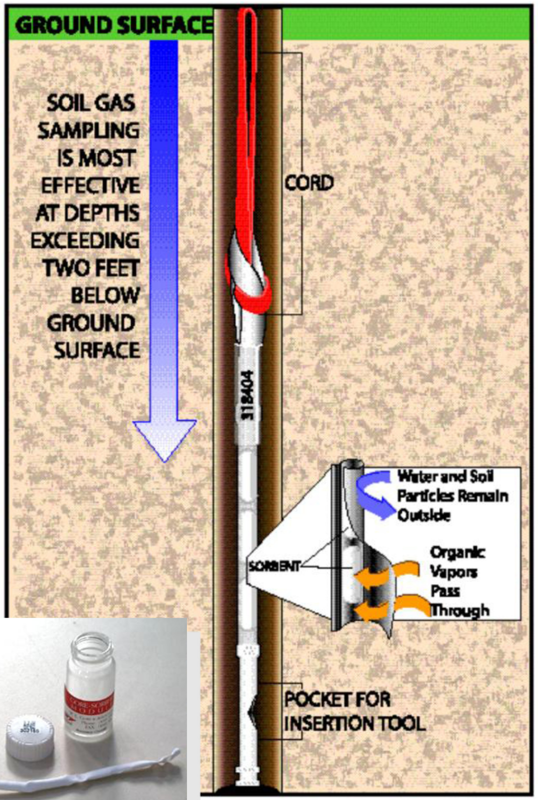
Presenter's notes: 283D seismic can add a great deal of information in terms of structural information, stress orientation, brittleness, and identifying possible open fractures. All of these are structural and rock properties that are critical to understanding the shale play. Additionally, AGI data can give information about what hydrocarbons are where. No other technology can to that. They all guess and use proxies to guess. The most important thing is all of these other (*Presenter's notes continued on next slide*)

(*Presenter's notes continued from previous slide*)

technologies measure a few points, maybe 25 or 50, and then erroneously extrapolate that across the field. AGI actually measures the hydrocarbons across the field and then maps them by phase. No guessing or extrapolating. Additionally, you have seen how AGI surveys can also be a proxy for the pressure, porosity, and net pay combination. In addition, what is great about that is that it is not a specific number but is automatically calibrated to each field and provides red anomalies over the Sweet Spots. In addition, the most important point is this information is PRE-DRILL. All of this critical information can be used to optimize your drilling program and minimize your learning curve. You have seen the math. It can save you millions of dollars in noneconomic and/or low producing wells.

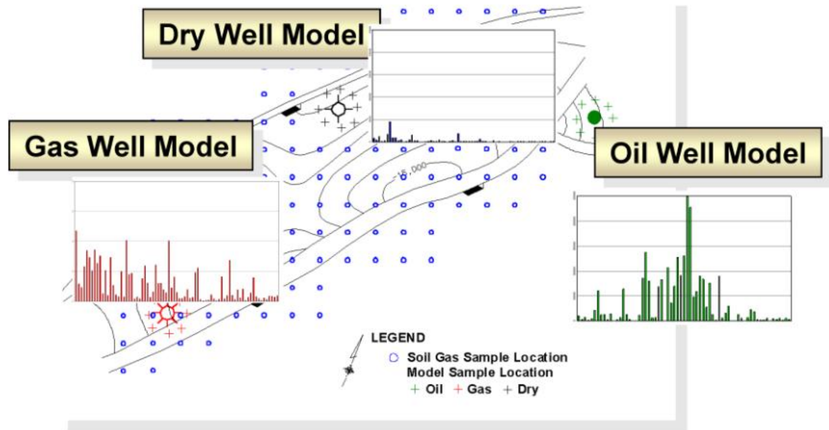
Passive Sorbent Modules

- Patented, passive, sorbent-based
  - Chemically-inert, waterproof, vapor permeable
  - Direct detection of organic compounds
  - Sample integrity protected
- Engineered sorbents
  - Consistent sampling medium
  - Minimal water vapor uptake
- Time-integrated sampling
  - Minimize near-surface variability
  - Maximize sensitivity (up to C20)
  - Avoids variables inherent in instantaneous sampling
- Duplicate samples



Typical Survey Design

Model development..

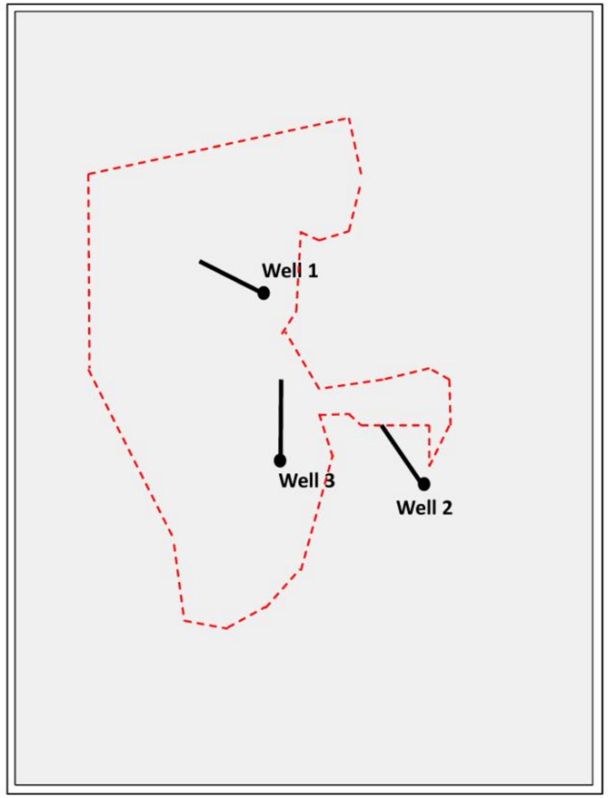


Presenter's notes: 30In this diagram, the green section in the middle of the slide represents the reservoir and the horizontal blue line on top of it represents the seal. The thick gray vertical line next to the reservoir represents a fault. We are all familiar with macro seepage. Hydrocarbons from macroseepage travel along faults, find their way to the surface, and can be visually seen. Their concentrations are at percent levels and they are normally visual. (*Presenter's notes continued on next slide*)

(*Presenter's notes continued from previous slide*)

Additionally, their location at the surface is normally offset 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. Therefore, 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 offset from the source while hydrocarbons from microseepage are essentially directly above the source.

Surface Survey Probability Map

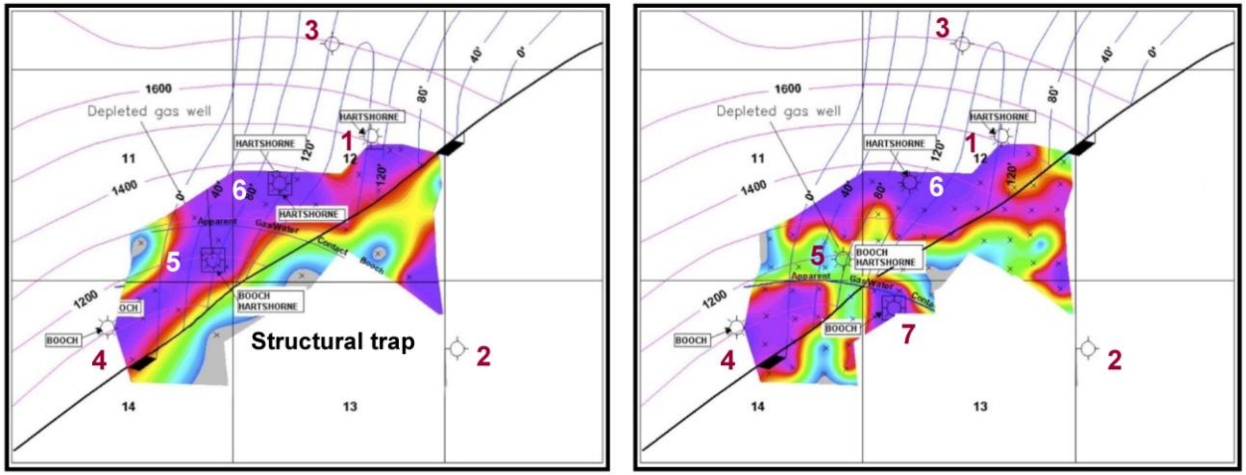


Presenter's notes: 31Amplified Geochemical Imaging Technology was developed. This new technology uses passive adsorbent sampling. The passive sampler contains a specially engineered hydrophobic adsorbent encased in a layer of microporous expanded polytetrafluoroethylene (ePTFE). This module is placed in the ground about 1.5 - 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 because it allows a sufficient volume of hydrocarbons to migrate to the surface and adsorb onto the module.

Monitoring Drainage Patterns

Phase 1

Phase 2



AGI surveys can also be used to monitor hydrocarbon drainage patterns over time.

Presenter's notes: 32Deployment 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. (*Presenter's notes continued on next slide*)

(*Presenter's notes continued from previous slide*)

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. In addition, 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 – not just compound ratios.

Surface Hydrocarbon Mapping

- can identify charged and noncharged portions of the field
- can generate phase maps across the field
- can map thermal maturity
- can Identify sweet spots of pressure, porosity, & net pay
- can potentially identify geohazards (i.e. faults)

AMPLIFIED GEOCHEMICAL IMAGING, LLC

Downhole Geochemical Logging

- is 1,000 times more sensitive than other methods
- Is the only method that measures from C2 – C20
- can be a powerful proxy for porosity
- can help improve production by focusing lateral well locations in hydrocarbon & porosity rich zones
- can reduce completion costs by optimizing the number of fracture stages

AMPLIFIED GEOCHEMICAL IMAGING, LLC

Presenter's notes: 34On the left, you can see the high probability gas area indicated in the dark purple. As you move from purple to yellow to light blue the probability decreases. You can also see the apparent gas-water contact for the Booch in the middle of the survey area. This field has channel sands coming down from the northeast that butt-up against the fault illustrated by the black line. As can be seen the sand thickness changes from 0 ft to 120 ft as you move (*Presenter's notes continued on next slide*)

(*Presenter's notes continued from previous slide*)

from east to west. In the SW section of the field, in sections 14 and 11, there is a structural trap. For this project, calibration was conducted around four wells, wells 1, 2, 3, and 4. Wells 2 and 3 were dry wells and were used to document the dry well or background hydrocarbon signature. Well 1 in the channel sands produced gas from the upper Hartshorne frm and produced water from the lower Booch Fm. Well 4 produced gas from the structural trap in the deeper Booch Fm and produced no gas from the upper Hartshorne b/c it was outside the channel sand. Well 6 was drilled post-survey and produced gas from the upper Hartshorne Fm and produced water from the lower Booch Fm just like Well 1. Well 5 was drilled post survey and produced gas from both the upper Hartshorne and the lower Booch formations. Because of the production, differences between Wells 5 and 6 the client estimated the gas-water contact, for the Booch, as shown on the map, to be between wells 5 and 6. The gas produced from the Hartshorne and Booch was dry gas (i.e. 99% methane) sourced from coal deeper in the section, and it was not possible to differentiate between the Hartshorne gas and the Booch gas. However, the client was surprised that the AGI survey could detect a good signal for dry gas given dry gas is 99% methane and the AGI survey does not monitor methane. It is believed that part of the reason an AGI survey can detect dry gas is the fact that methane acts like a solvent as it migrates to the surface; thus, it solublizes, or dissolves additional light HCs during microseepage. On the right, the survey was repeated 3 years later along an extension into Section 13, but this time with in a grid pattern with increased sampling density. Part of the reason for repeating the survey over sections 4, 11 and12 was that after three years well #5 had watered out indicating a movement in the gas-water contact. Therefore, the sampling density was increased to define the current gas-water contact as part of the survey objective. It is immediately apparent that there are dramatic differences from the previous survey 3 years earlier. Notice well 4, which is now depleted, no longer has a hydrocarbon anomaly associated with it. This also indicates that microseepage of hydrocarbons from subsurface to surface occurs in a relatively short period of time. Additionally, hydrocarbons are also detected in the NW corner of section 13 and there is a positive gas anomaly in this survey extension. A post-survey well, Well 7, was drilled on the up-thrown side of the fault based on the survey results. This well became a gas producing well from the lower Booch Fm, indicating it was above the gas-water contact. It can be seen that the gas-water contact has now moved southward as well.

Thank You!