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geoLOGIC NEWS


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this issue

A Message from our President, Hal F. Miller:

No Light at the End of the Tunnel Yet

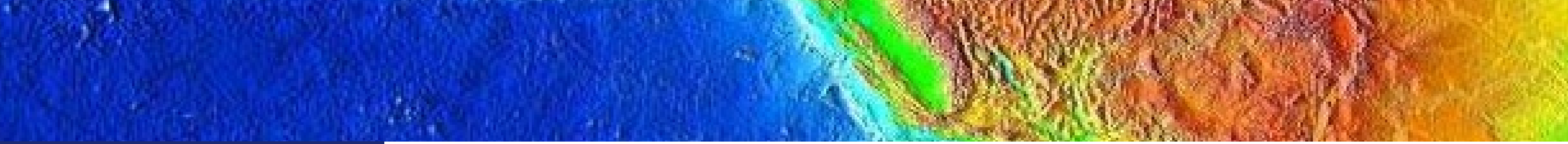
Conventional wisdom has it that lower oil prices should stimulate economies globally through cheaper energy costs (demand up), and result in reduced drilling for new oil, ultimately causing production to fall (supply down). If I remember my Macroeconomics from 40 years ago that should mean price recovery in the foreseeable future. Maybe I didn't pay close enough attention in that class (it was after all one of the main reasons that I became a geologist). It seems that each glimmer of hope for a stabilizing oil price is quickly counterbalanced by factors that undermine the price, and predictions of a light at the end of the tunnel starting in late 2015 are now fading into 2016 and beyond.

US production has begun to see the impact of the dramatically falling rig count, leveling off at just under 9.6 MMBOPD in recent weeks. The large inventory of drilled but not completed unconventional wells that has maintained US production at relatively flat levels has apparently been largely realized, at least by those companies that do not have the luxury of waiting out the price slump. So it seems likely that US production should decline in the coming months. In the longer term, major deepwater project delays in the US and elsewhere must at some point impact global supply projections. These downward supply drivers are being heavily outweighed by OPEC. No longer the "swing producer," OPEC production has surged to fill any shortfall as part of their strategy to maintain market share. Although OPEC's capacity to increase production will eventually reach its limits, Iranian oil is reportedly poised to enter the picture to the tune of 30 million barrels stored on tankers, plus capacity to ramp daily production up to 300,000 and as much as 1 million BOPD, which the Iranians indicate they are wiling sell at a discount to regain market share.

Even the US government is considering adding fuel to the fire by potentially selling over 100 million barrels of oil from the Strategic Petroleum Reserve, starting in 2018, to fund a long-term transportation bill intended to address looming infrastructure issues.

This all seems a little gloomy for those of us working in the service side of the people business. We remain optimistic that a consulting "bounce" is waiting to happen as so many companies have released highly experienced people, and in many cases encouraged them to retire. At some point they will need consultants to help fill newly created gaps and transfer all of that knowledge gained from 30+years in the school of hard knocks. Besides the increasing scarcity of mentors, reduced training budgets are creating a backlog of training needs for the early career technical professionals who will become the lifeblood of the industry in years to come.

Additionally, there are persistent indications of large amounts of "sideline money" waiting for the "fire sales" to begin. While most operators are still seeing their assets through 2014 glasses, the fall cycle of bank reevaluations of producing reserves upon which loans are based, and expiring hedges, seem likely to heat up the conventional and unconventional play deal making before year end. Might some of the larger players that came late to the unconventional dance try to jump in as well? This environment should also provide new opportunities for consulting engineers and geoscientists. No deal is a good deal unless and until the proper technical due diligence is done…especially when prices are down and everyone's crystal ball is still cloudy.



Recommended Courses Related to Habit 8

Applied Subsurface Geological Mapping (ASGM)

This is the most demanded subsurface mapping course in the world. From the newly graduated geoscientist or engineer to the seasoned professional, the course provides the applied, hands-on knowledge required to generate sound subsurface maps. Participants of this course will receive the Applied Subsurface Geological Mapping with Structural Methods 2nd Edition textbook (2003) and a lab manual with exercises. This course covers both fundamental and advanced methods of subsurface mapping that have been used by the most proficient exploration and development geoscientists in the industry, as well as an introduction to some of the more recent advances in interpretation.

Jun 22-26, 2015	Calgary
Jul 13-17, 2015	Houston, TX
Aug 03-05, 2015	Dallas, TX
Aug 24-28, 2-015	Perth, Australia
Sep 28-Oct 2, 2015	Houston, TX

see website for full listing

Quality Control for Subsurface Maps (QLT's)

This unique 3-day course addresses the need for managers to obtain a systematic approach for quickly screening interpretations, maps, prospects and potential resources or reserves and identifying fundamental interpretation, mapping and estimating errors. The course begins with a review of examples of interpretation and mapping errors that led to poorly located wells that proved to be uneconomic or dry, as well as inaccurate reserves or resources estimates. The participants are challenged with a series of real exploration and development prospects and maps for their evaluation.

Jun 29 -July 1, 2015	Houston, TX
Dec 7-9, 2015	Houston, TX

For a complete list of the 2014 public course schedule including course descriptions, target audience and dates available, please visit our website at:
www.scacompanies.com

Exploring the Ten Habits: Habit 8 -

Successful Oil Finders Map Multiple Horizons to Develop Reasonably Correct, 3D Interpretations. *by Bob Shoup*

As we have discussed before in Habit 1, our interpretations and maps must be valid in three dimensions. One way to ensure three-dimensional validity is to map multiple horizons, especially for faulted structures.

In Figure 1, we see a depth structure map for the 6000 Foot Sand, a key producing horizon in a Gulf of Mexico field. The horizon is crossed by two faults (Fault A and B) which intersect each other with a compensating pattern (two faults dipping generally toward each other). The interpreter picked Faults A and B and constructed fault surface maps for them. Then the fault surface maps were integrated with the horizon maps to determine the proper positions of the upthrown and downthrown fault traces.

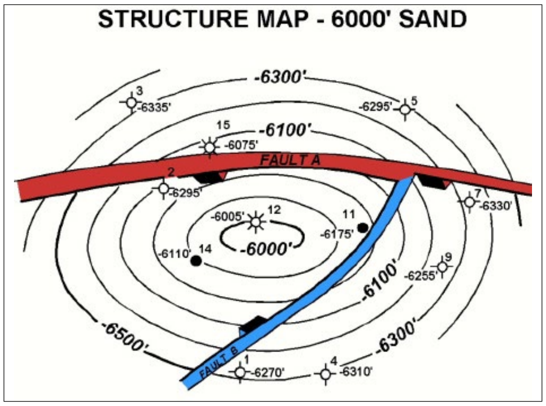


Figure 1: Depth Structure Map, 6000 Foot Sand - Fault traces generated by integrating the fault surface and horizon maps

So far, so good! However, the interpreter's boss asked to review the deeper maps the next day. So to save time, our interpreter used a common short-cut; he shifted the faults from their position at the 6000 Foot Sand level to their approximate position at the deeper levels (Figure 2). Based on those deep maps, the company decided to drill two wells (highlighted yellow, Figure 2).

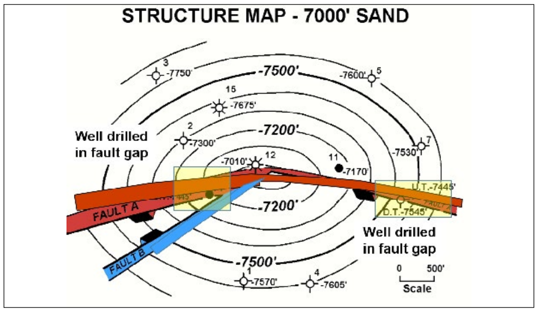


Figure 2: Depth Structure Map, 7000 Foot Sand - fault traces generated by shifting the fault polygons from the 6000 Foot Sand Map

The wells were drilled and the 7000 Foot Sand was missing in both wells. As part of the post mortem, the interpreter re-mapped the 7000 Foot Sand, this time using the proper method of integrating the fault surface maps with the horizon map. Reviewing the final, properly constructed depth structure map of the 7000 Foot Sand (Figure 3), we can see that both wells were drilled into the fault gap.

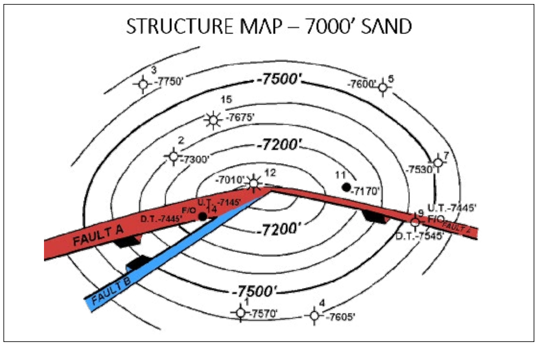


Figure 3: Depth Structure Map, 7000 Foot Sand - Fault traces generated by integrating the fault surface and horizon maps

Many interpreters simply pick fault sticks which they use to determine the position of the fault polygon. Unfortunately, this method results in the fault being mapped in its approximate position as opposed to being accurately mapped. Shifting the polygon with depth accentuates that inaccuracy, often causing wells to be drilled in the fault gap as opposed to the horizon.

One way to ensure the validity of the maps of faulted structures is to map multiple horizons and examine the way that the fault traces move with depth. The intersection of the two faults must migrate along the line of termination (red dashed line, Figure 4), which is the line on the fault surface map where the contours of one fault intersect the contours of the same value of the other fault.

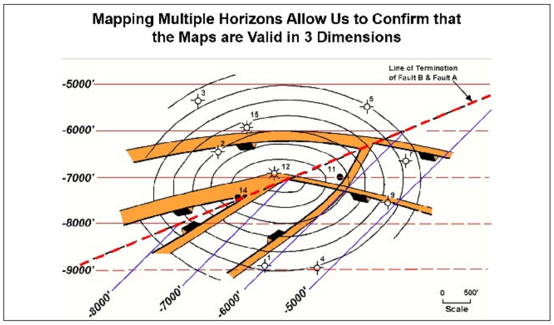
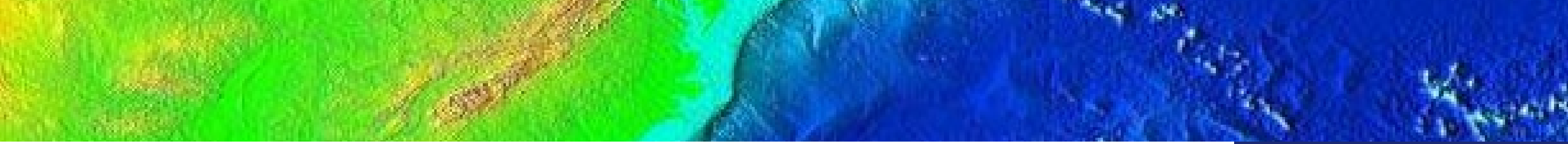


Figure 4: Depth Structure Map, 7000 Foot Sand - Fault surface map and the fault traces for the 6000 Foot Sand are overlain

Constructing maps at multiple horizons also helps ensure compatibility between horizons. It also provides interpreters a better understanding of the structural architecture of the field or prospect. For producing fields, it is especially important to map all productive reservoirs.

In one National Oil Company, which shall remain unnamed, a number of teams were assigned to map and monitor producing reservoirs in a large producing asset; one team per producing horizon. Furthermore, the teams worked on different floors, and were discouraged from talking to each other. *(Continued on Page 7)*



'Best Practices' for Conventional and Unconventional Reservoir Fracture Treatments

by: Bob Barba

Operators are constantly searching for completion "best practices" to recover hydrocarbons as efficiently as possible. A technique commonly used in the vast majority of published studies is to compare production results from wells that had different completion practices and the "optimum completion technique" was determined by which wells had the most production during a common time period. The biggest drawback of that methodology is that production depends on both the reservoir properties and the completion. A recovery factor study was done in the Pennsylvanian Red Fork where eight previous SPE papers had been published.1 Four of the studies recommended crosslinked gels, one recommended linear gel, and three studies recommended CO2 foams. A subsequent recovery factor comparison with 120 wells showed that the CO2 based fracs (foams and assists) resulted in an average recovery factor of 100% vs the crosslinked gel fracced wells with only a 39% average recovery factor (Figure 1). The other eight studies used only production rates to determine the "optimum" treatment fluid. This is only one of many studies done where the production comparison was not unique and the "best practices" determination was clouded by ignoring the reservoir component. In the unconventional world simply using close offsets is not always adequate as the vertical placement and stimulated column may not be the same for all wells in the area depending on well trajectories and proppant distribution. The reservoir component should be incorporated in all cases to get a more unique solution to the "best practices" question.

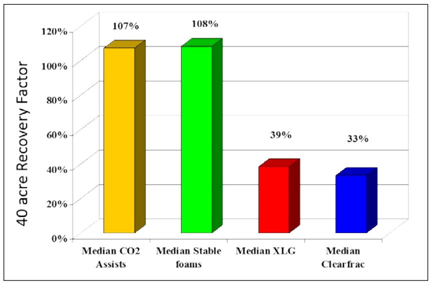


Figure 1: Frac Fluid Type vs. Recovery Factor

Reservoir Component Characterization

The choice of methodology to characterize the reservoir component depends on the type of reservoir. For all reservoirs the basic building block is a calibrated log analysis to estimate clay volume, effective porosity, water saturation, and net pay. Generally a full suite of logs is recommended for the initial pilot holes, with a density-neutron-resistivity (TCOM) suite along with dipole sonic, NMR, pulsed neutron mineralogy, and spectral GR. Subsequent pilot holes and offset legacy logs can typically be analyzed using the relationships developed in the pilot "science" hole and just the TCOM suite. For organic shale reservoirs the same properties are estimated with the addition of a kerogen correction. "Calibrated" log analysis involves validating the volume of clay with XRD or FTIR, the porosity with core, and the log derived water saturation estimate with capillary pressure data or NMR Sw data.1 From this an estimate of volumetric reserves can be calculated. For all reservoirs this "recovery factor" analysis is based on a comparison of original hydrocarbons in place with estimated ultimate recoveries (EURs) from decline curve analysis. EUR estimates are preferred, however for well performance comparisons and "best practices" shorter common production periods (preferably 6 months or longer) can be used to normalize performance without estimating an EUR.

Hydrocarbon Pore Volume Characterization

In conventional rock the log based porosity should be tied to NOB core porosity from routine core analysis. For nanodarcy organic shales the GRI tight rock porosity method using crushed core is typically used. The GRI method typically shows high effective porosity values in high clay content zones and can lead to false targets for landing wells. This was observed in one project recently where the operator tied the volumetrics to GRI data in a higher clay content zone. Their results lagged offset operators who landed laterals in the same formation in zones with lower clay content in the same field.

Permeability Characterization

For conventional reservoirs the repertoire of tools increases since permeability can be estimated from well tests or DFITs and then the logs can be calibrated to the tests.1 With a permeability input an estimate of effective producing frac length can be made to normalize the production results. This is somewhat problematic in organic shales as there is frequently a disconnect between DFIT and core permeability, with the DFIT well test perm frequently significantly higher than the core. This is rarely the case in conventional rocks unless there is significant natural fracturing present. In organic shales it appears that the fracs disturb the reservoir sufficiently to dilate existing healed natural fractures and actually increase the effective permeability of the reservoir (vs simply increasing the effective wellbore radius in conventional rocks). This introduces a complexity into the analysis which is not trivial to resolve with modeling.

Normalization Process

Once the calibration process is done to cross check the log based inputs using core and test data the remaining wells in the field are normalized to the calibration well to remove artifacts from different vintage logs and log calibration issues. In several large organic shale projects the normalization process changed wells from sub-economic to economic and vice versa.

Synthetic Spectral Gamma Ray

For unconventional organic plays an additional correlation is done between spectral gamma data and conventional TCOM log curves to provide a synthetic spectral GR for all wells. This flags the organic zones and indicates where a kerogen correction is appropriate. The kerogen correction is normally done using a multivariable regression technique that ties the TCOM log data to core porosity to remove the kerogen effects. Track 1 in Figure 2 shows this plot as well as the other typical curves presented in the hydrocarbon pore volume analysis. *(Continued on Page 4)*

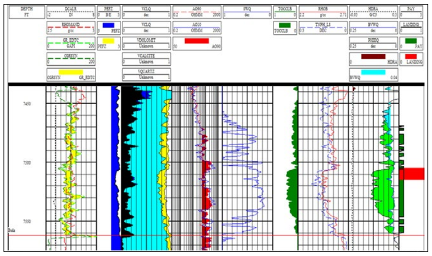
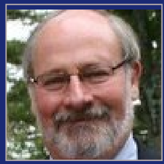


Figure 2: Example Plot with Key Outputs

Featured Instructor:
Robert 'Bob' Barba



Bob spent 10 years with Schlumberger as an open hole field engineer, sales engineer, and product development manager. While at Schlumberger he was the North American product champion for the FracHite and Quantifrac products that integrated wireline, testing, and pumping inputs to optimize hydraulic fracture treatments. He was also the product development manager for the QLA program that made the field log analysis "Cyberlook" program available to customers on personal computers. Since then he has spent 21 years consulting to over 175 companies on petrophysics and completion optimization. He served as a SPE Distinguished Lecturer on integrating petrophysics with the hydraulic fracture treatment optimization process. He has focused on the integration of petrophysics with completion designs in a variety of reservoirs in North America, conducting numerous field studies for operators evaluating the "completion efficiency" of over 1200 wells and providing "best practices" recommendations based on the study results (SPE 90483). His latest SPE paper (125008) focuses on the refracturing optimization process. He has been responsible for the petrophysical analysis of 35 major fields worldwide as part of integrated reservoir characterization studies identifying remaining mobile hydrocarbons. He has authored 33 technical papers on the integration of petrophysics with completion designs, horizontal wells, and reservoir characterization projects. His most recent major consulting projects have been optimizing completion practices in horizontal organic shale wells for major operators in the Marcellus shale and the Wolfberry. Bob has a BS from the US Naval Academy and MBA from the University of Florida. He is also a member of the SPE, SPWLA, and the AAPG.

Mr. Barba teaches this course for SCA (click below for details):

- ***' Best Practices' for Conventional and Unconventional Reservoir Fracture Treatments***

‘Best Practices’ continued from Page 3

Water Saturation and the Bulk Volume Hydrocarbon Plot

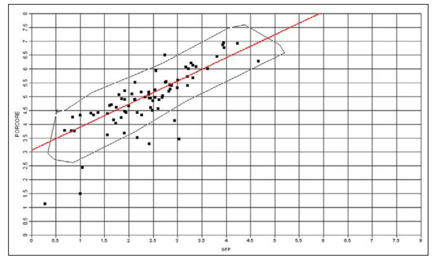


Figure 3: Bulk Volumn Hydrocarbon vs. Porosity Plot

In many organic shales the bulk volume water irreducible (BVI) is relatively constant. The Marcellus is a good example with a 2.2% BVI in all pay zones). The bulk volume hydrocarbon (BVH) vs porosity plot can provide an estimate of BVI that can be used to estimate Sw from porosity data alone and as a possible pay cutoff (Figure 3). This can be used to calibrate a conventional Archie based Sw model in the organic zones if there are mixed organic and inorganic zones. One additional process that is employed in conventional rocks is a correlation between NMR or capillary pressure BVI and triple combo curves to provide a synthetic BVI curve. This is useful in characterizing the expected produced fluid type and volumetrics in thin beds (where the resistivity based Sw is too low due to bed boundary effects).

Net Pay Model Development

Once all of the basic log inputs are calibrated an accurate net pay estimate can be made for most conventional reservoirs based on perm and Sw. Simple porosity cutoffs are not recommended as the driver for net pay is perm and there can be several orders of magnitude difference in core perm for the same porosity value. The Stiles George method1 is recommended to incorporate the variability in permeability for similar porosity values. In organic shales the porosity vs BVH plot can be used to determine the porosity cutoff where BVH= zero. Porosity values less than that cutoff will not have any matrix perm, and some operators use that value for a porosity cutoff outright although that may be optimistic.

Role of the In-Situ Stress Regimes

An understanding of the role of various stress regimes (horizontal minimum, horizontal maximum, and vertical) and their effect on fracture orientation is needed, along with the various methods available to estimate the direction of maximum horizontal stress. Along these lines the effects of reservoir depletion on these stresses is important particularly in the case of refacs where fracture reorientation can contact previously unstimulated rock. “Stress shadowing” is also a consideration in this process. For conventional wells issues associated with near wellbore tortuosity, perforation orientation, and proppant flowback from non-critical perforations need to be addressed.

In-situ Stress Profile Development

The next part of the process is the development of a mechanical properties profile to help characterize the vertical in-situ stress and Young’s modulus distribution. Quality control of the dipole sonic data is an important step that is frequently not done properly. Development of an empirical Poisson’s ratio and Young’s modulus from the TCOM data and coherent dipole data is needed for both quality control of the data in the wellbore logged with the dipole and for offset well rock property estimates where no dipole data is available. The dipole tools in use today cannot acquire 100% coherent data due to the lack of borehole compensation and the length of the receiver array. With the quality dipole data and empirical model in hand, an in-situ stress profile can be generated from the Eaton equation1

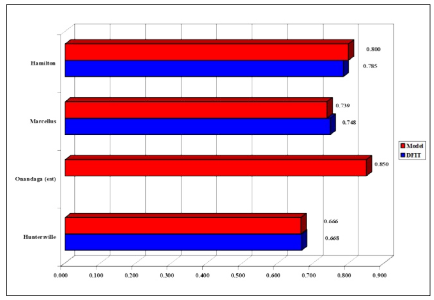


Figure 4: Marcellus Average DFIT Stress vs. Log Derived Stress

The overburden gradient is measured with the density log or a combination of density logs with different depths in a field for deeper wells. The pore pressure gradient for the equation is usually the estimated reservoir pressure. For unconventional horizontal wells this is available from DFIT tests. For vertical wells with multiple pay horizons the optimum source is a wireline formation tester.

The last component of the in-situ stress component is the calibration factor. This is applied to the log derived value to match DFIT or minifrac closure stress measurements. It is a constant for an area as it is primarily dependent on tectonics. The modeling becomes more complex in horizontal wells, where the ISIP is most likely a function of the hoop stresses forcing the frac to be initially horizontal rather than a function of the closure stress it is in vertical wells. It is not coincidental that the ISIP values in the Marcellus are closer to the overburden (1.16-1.18 psi/ft.) than the closure stress (0.80-0.85 psi/ft.). A tie between the DFIT closure stress (12 samples) and log based stress for the Marcellus is shown in Figure 4.

Young’s Modulus Estimation

The second major output from the dipole/triple combo suite is Young’s modulus, a key input to frac modeling and the brittleness equation that will be discussed in the next section. The equations for Young’s modulus are presented in refs (1) and (2), along with the procedure to convert the dynamic measurement to static.

Brittleness Estimation

A lot of operators used the “brittleness” estimate to optimize the landing zones in organic shales. It is calculated from Poisson’s ratio and Young’s modulus, with the equations provided in ref 1. It is well known that ductile shales are not conducive to fracturing as less ductile shales, and generally this is reflected in the clay content. There are limitations to the technique, though, particularly in carbonate rich shales. It is recommended that clay volume, hydrocarbon pore volume, and the in-situ stress profile be used to optimize landing zones in these cases rather than just “brittleness.”

Conductive Height in Unconventional Laterals

A key “best practice” in shales is to connect the wellbore to the pay via either propped or unpropped conductivity. In several PLT studies there were totally unproductive stages where the laterals were apparently in the target zone (Figure 5). This is important in that individual clusters are frequently not effectively stimulated in every stage with more than one cluster and that is to be expected. It is unlikely that the wellbore entered a portion of the reservoir that had no pay, though, due to the relatively consistent stratigraphy present in the shales and in the case of Figure 5 the entire trajectory was “in zone.” Within a stage, however, at least one cluster should be producing and that was not the case in any these studies. One of the key derisking factors for organic shales for the investment community is the repeatability of results due to this relative homogeneity. This significantly reduces the probability of a stage encountering a non-productive interval in the lateral provided it is in zone.

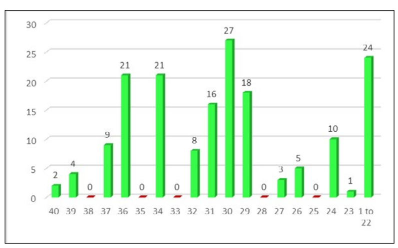


Figure 5: Bakken PLT Oil Production Distribution

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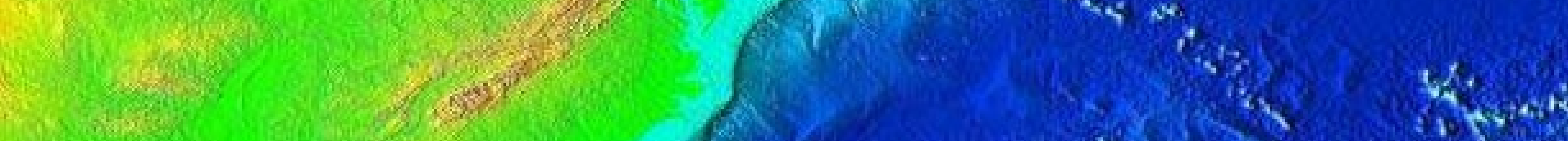


‘BEST PRACTICES - continued from Page 4

Propped Height vs Conductive Height

Figure 6: Tracer Height vs. Net Pay Thickness Marcellus

In one study with five post frac tracers in a vertical pilot hole the propped height averaged 55% of the net pay thickness (Figure 6). There was a good stress barrier below the pay to discourage downward settling, and microseismic indicated 300 ft. +/- of created height growth (Figure 7). Several studies have shown that laterals that are either in or in close proximity to the proppant bank perform significantly better than those with higher trajectories.1 In high modulus shales (Barnett in particular) well trajectories are frequently above the main pay to avoid fracing into the Ellenberger water zone. Operators have been successful there, however, in spite of not having a solid connection to the proppant bank.

The formation where the tracers were run (Marcellus) was relatively low modulus (2E6 psi), and this probably plays a role. If it is Young’s modulus dependent the problem may extend to other shales. Figure 8 shows the distribution of Young’s modulus among the major shales. The Barnett, Bakken, and Montney all have high moduli, all of the other shales are low modulus.

Improving Conductive Height

The key issue driving the limited propped height in nanodarcy shales is the disconnect between gel break time and fracture closure time. With slick water fracs this is well understood as proppant transport is being dumped into the formation and it stacks up from the stress barrier below the lateral. What is not as well understood is when gelled fluids are used the initial modeled proppant distribution is close to the created heights (200-300 ft. in most cases) yet after closure the propped height is identical to the slick water propped height (Figure 9). If more propped height is needed something other than viscosity is needed.

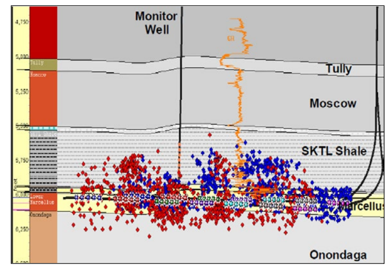


Figure 7: Marcellus Microseismic Analysis +/-300 ft. Height

Conductive Height vs Propped Height

A hypothesis can be made that the propped height is the conductive height, and a test of this can be done with recovery factor analysis.4 If only the propped height is contributing vs the entire pay height this may be apparent in a comparison of recovery factors for various heights. The analysis assumes that the frac will “bench” on the closest stress layer below the lateral and that all of the production is coming from the proppant bank and above (Figure 10). In a 123 well organic shale study this was done, and if only the propped heights were producing the recovery factors are unusually high (+/- 15%). If the assumed conductive height was increased to 100 ft. (60 ft. proppant bank plus 40 ft. of unpropped pay) the recovery factors become more believable, with the study average being 8.2% (Figure 11 - *see next page*). Multiple iterations with various conductive heights suggested that the most likely range was in the 100 to 150 ft. range.

Implications of Limited Conductive Height

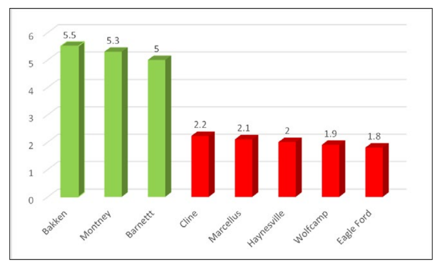


Figure 8: Static Young’s Modulus by Formation

In several plays in North America there are large vertical pay intervals that are significantly thicker than the conductive heights discussed above. One of the biggest challenges and perhaps the greatest opportunity that ensues from this is the possibility of highly productive multiple stacked laterals in these plays. In the case of the Southern Midland Basin Wolfcamp one operator published their schematic for three stacked laterals in the 1000 ft. gross interval based on microseismic survey data. It is unlikely that this model will hold based on the 100 to 150 ft. thick conductive heights that are likely based on limited propped heights and only slightly more conductive heights when the recovery factor modeling is done.

“Best Practices” from Previous Integrated Studies

In addition to the landing zone issues where there is limited conductive height, past studies have suggested there are other practices that lead to better well performance.2 Each formation has its own characteristics, though, and it is recommended that even “tried and true” practices from other areas be validated with local comparisons.

The first study finding is a strong correlation between proppant volume per foot of pay and recovery factor. Several conventional reservoir studies showed this (Figure 12 - *see next page*). In the organic shale world the more commonly used metric is the pounds of proppant per foot of lateral. Several recent press releases from organic shale operators have indicated that volumes of 2000 lb./ft. of lateral length have resulted in better well performance.

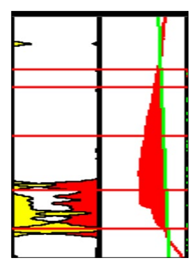


Figure 9: Tracer Height Comparison Slickwater vs. Borate

Another key “best practice” from previous studies is the use of limited perforation intervals to avoid creating multiple short fractures in vertical wells.2 Single cluster frac stages outperformed multiple cluster stages with single cluster stages averaging 269 ft. of effective producing propped length and multiple cluster stages averaging 98 ft. (Figure 13 - *see next page*). A more telling statistic is the comparison of individual clusters within a stage. The average propped length for the highest flow rate cluster (measured with a PLT) was 255 ft., with the average propped length for the remaining clusters of 1 ft. or skin removal. This suggests that one of the clusters in a multiple cluster stage will perform almost as well as a single cluster stage, and it begs the question of what benefit the extra clusters provides. This study was done with vertical wells and involved measured reservoir pressures, measured flowing wellbore pressures (via PLT), and a permeability estimate calibrated to well tests. In organic shale reservoirs the norm is to perforate multiple clusters in the same stage, with most operators averaging 4 to 5 clusters. There are a limited number of studies available with production logs that show the same phenomena in shales, with one dominant perf cluster and perhaps one with more production than the rest. A separate study done by the University of Texas Fracturing JIP (Sharma 2015) 5 indicated that the secondary clusters in each stage contribute an average of 2% of the production with the primary cluster contributing 98% of the flow. This is very similar to what was observed in SPE 90483. From this it is not clear why operators prefer multiple cluster stages.

“Best Practices” Information Gathering

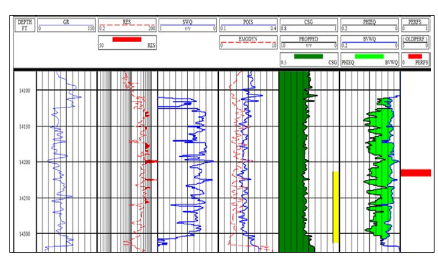
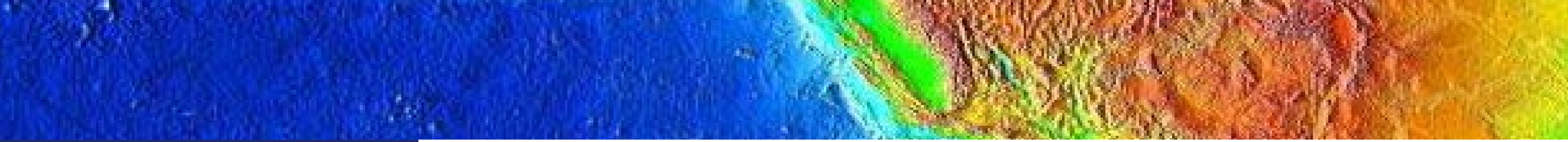


Figure 10: Eagleford Propped Height Estimate Above Stress “Bench”

The recommended data sources for developing “best practices” are well documented in the literature.1 A target interval for the lateral should be selected for further analysis based on the net pay and rock properties plot. Once the well is cased a complete diagnostic pumping procedure should be run in the vertical pilot hole. The proposed landing target should be perforated with 2 ft. of perfs and a fracced with a DFIT. DFIT “best practices” have evolved to pump rates of 3-5 bpm for 5 minutes for most organic shales. Once the DFIT is concluded a frac is recommended for the perforated interval using the same fluid and proppant types proposed for the lateral. The volume should be pro-rated to account for multiple clusters if they are to be used in the lateral. It is typically recommended that the test frac in the vertical hole use 50% of the total stage volume and 50% of the rate based on production log and distributed temperature array data. The proppant should be tagged with radioactive tracer to determine the propped height, and a temperature log should be run to determine the created height.

(*Continued on Page 6*)



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‘Best Practices continued from Page 5

For one of the pilot holes it is recommended to attempt “forced closure” to limit proppant settling, if that improves propped height it may be a consideration for the lateral using a CT based system.

For the first lateral in the field it is recommended that a fiber optic temperature sensor be run in the first well to determine the number of clusters receiving injection during the frac and where the production is coming from after the frac (assuming the GOR is high enough to exhibit a cooling profile). This will be very useful information if the wellbore is ever considered for a refrac in the future.

An evolving “best practice” with huge potential involves the use of sliding sleeves that can be mechanically activated with coil. This allows for jobs to be pumped without overflushing either during the job flush or during the plug pump down procedure. An additional advantage is for later refracturing operations. The sleeves can be closed then re-opened one stage at a time to do the refrac treatment. The coil in the hole during the frac also allows for real time bottomhole pressure monitoring that is useful in predicting screenouts in advance.

Conclusions

By characterizing the reservoir contribution to production the effectiveness of the frac treatment can be determined and “best practices” can be evaluated from normalized production results. The data requirements and calculations needed to estimate the productivity of the reservoir with various completion options are relatively straightforward. The key product of the analysis is a profile that characterizes the net pay and rock mechanical properties to ensure that the frac is optimally placed in the best pay in horizontal or vertical wellbores (Figure 14). With the reservoir component of production better characterized a more meaningful comparison can be made among wells with different completion practices to determine which practices result in the more efficient recovery of hydrocarbons.

References:

1. Barba, R.E. “Developing Best Practices for Conventional & Unconventional Reservoir Fracture Treatments” course manual, updated 2015
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3. Barba, R.E. “A Novel Approach to Identifying Refracturing Candidates and Executing Refracture Treatments in Multiple Zone Reservoirs,” SPE paper 125008 presented at the 2009 ATCE, New Orleans, La. 4-7 Oct 2009.
4. Barba, R.E. “Liquids Rich Organic Shale Recovery Factor Applications,” SPE paper 174994 scheduled for presentation at the 2015 SPE ATCE, Houston, 28-30 Sept 2015.
5. Sharma, M. et al, University of Texas Joint Industry Fracturing and Sand Control Project, annual meeting April 29-30, 2015.

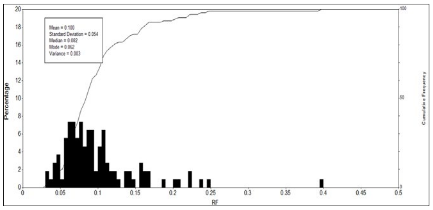

Figure 11: Recovery Factor Distribution Midland Basin Wolfcamp

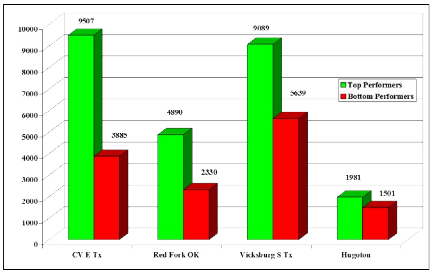

Figure 12: WEll Performance vs.Proppant Volume per Foot of Pay

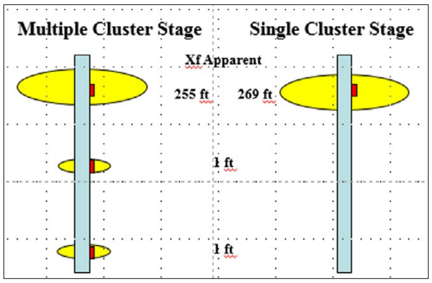

Figure 13: Frac Length Comparison Multiple vs. Single Cluster Stages

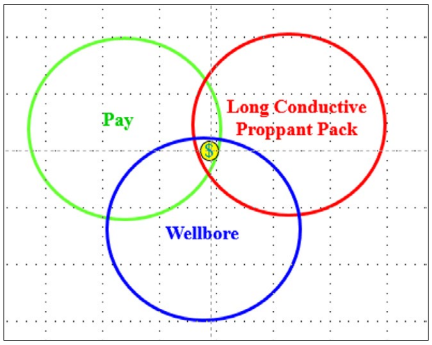

Figure 14: “Best Practices” Objective

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Word Scramble

1. nnCoaavrr Basin	
2. ailGele Basin	
3. dippIGnas Basin	
4. atOyw Basin	
5. agaronEm Basin	
6. auElc Basin	

Hint: International Sedimentary Basins. Answers on back page.

Happy Anniversary

Mary Atchison	01/19/09	6yrs
Don Lanman	03/09/04	11yrs
Cheryl Reynolds	04/21/03	12yrs
Tim Riepe	04/30/08	7yrs
Joseph Miller	05/12/08	7 yrs

HABIT 8 continued from page 2

One of the teams began to notice a sudden influx of water in several wells. The water level for this producing horizon was a long way from these wells, so the source of the water production was a mystery. The team re-mapped the reservoir, but could still not explain where the water was coming from.

Many weeks later, one of the team members was having lunch with a member of another one of the assets teams. That individual mentioned that his team had been working overtime to resolve a production problem they were having. They had recently converted several depleted wells into water injectors. However, they had not realized any increase in pressure or production in any of the offset wells, and they could not account for where the water was going.

On further review, it was learned that the maps of any one team looked nothing like the maps of any of the other teams. Faults were not consistent from map to map, and the contour patterns from map to map differed significantly. In short, the maps were not three-dimensionally valid. And this for one of the company's major producing assets. This issue could have been easily avoided had the teams simply worked together to ensure that all of their maps were compatible.

The moral of the story, map multiple horizons. It will help you know where the water is going. It will also help you to confirm the three-dimensional validity of your maps and interpretations, thereby helping to avoid dry holes.

Editor's Note: To learn more about fault and horizon integration and other tools, methods, and techniques to help ensure accurate subsurface maps, register for SCA's signature course Applied Subsurface Geologic Mapping visit www.scacompanies.com to learn more about SCA's training program and other services, or to read more of the 10 Habits of Highly Successful Oil Finders.

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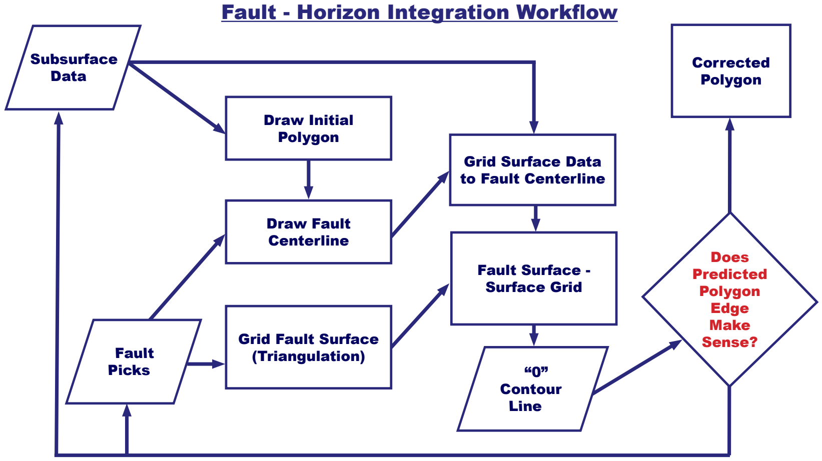
PRINCIPLES OF MAPPING ON THE WORKSTATION

"More than Just Pushing the Buttons"

Fault - Horizon Integration Workflow



For complete details, click here!

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- 06/22-26/15 - Applied Subsurface Geological Mapping - Calgary, Canada

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- 07/13-17/15 - Basic Petroleum Geology, Houston, TX
- 07/20-24/15 - Principles of Mapping on the Workstation - Houston, TX

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About SCA

Subsurface Consultants & Associates, LLC provides upstream consultancy and training to stakeholders in the oil and gas industry. Founded in 1988 by Daniel J. Tearpock, SCA's four primary services include geoscience and engineering consulting, upstream projects & studies, training services, and direct hire recruitment.

Upcoming Industry Events

EAGE	June 1 - 4, 2015	Madrid, Spain
URTeC	July 20 - 22, 2015	San Antonio, TX
AAPG ICE	September 13-16, 2015	Melbourne, Australia
GCAGS	September 19-22, 2015	Houston, TX
SPE	September 28-30, 2015	Houston, TX

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The People & Activities of SCA

'Making Strides for Breast Cancer' 5k Walk

Team SCA walked in this event on Saturday, May 16. The 3.1 mile course started and ended at Houston's Discovery Green Park. This year's event saw more than 7000 walkers and raised over $500,000 for the American Cancer Society.

Team SCA members walking: Mary Atchison, Kina Lamb, Martha Hester, Joseph Miller and Cathy Jankovic along with other employee donations raised a total of $550 dollars in honor of our own breast cancer survivors, Mary Wells (Martha's Mom) and Cathy Jankovic.

MAKING STRIDES Against Breast Cancer
American Cancer Society

AAPG Annual Convention & Exhibition 2015 with SEPM (Society for Sedimentary Geology)

SCA was well represented with several of our staff in attendance at the **AAPG Annual Convention & Exhibition** in Denver, CO, May 31 - June 3, 2015. We were again proud to participate in this annual event. Thank you to everyone who stopped by our booth. We met with lots of old friends and made a few new ones! We hope to see everyone again in Calgary next year!

Left to right: Matt Nowak, Hal Miller, Mary Atchison, Tim Riepe and Instructor Alan Cherry.

Word Scramble Answers: (Australian Basins) 1. Carnarvon 2. Galilee 3. Gippsland 4. Otway 5. Eromanga 6. Eucla