



10 Three Methods for Log-Derived Mineralogy ...primarily used for Shales (silts) & Tight Formations

19 A 12-Step Program to Reduce Uncertainty in Kerogen-Rich Reservoirs

Glenn Sather
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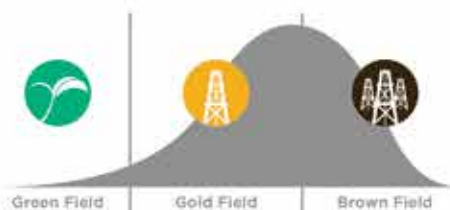
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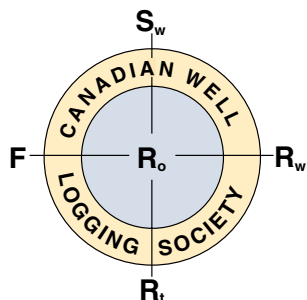
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InSite

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Editors:

Doug Kozak and Manuel Aboud

Layout and Design:

Sherry Mumford
Connections Desktop Publishing

Advertising:

Doug Kozak and Manuel Aboud

Proof Reader:

Robert Bercha

Contributors:

Dustin Menger, James Ablett,
Bob Everett, Ross Crain

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Cover Photo: Montney chip exhibiting organic banding – Siltstone is light grey to light brown, translucent to commonly opaque grains, well sorted, firm to friable, dolomitic cement; in part medium grey to brown, sub-parallel argillaceous streaks, poor intergranular porosity (2-4%), Sneider ID to minor IC.

Photo Credit: Leo Chirila, BSc, Senior Wellsite Geologist with Chinook Consulting Services

Photos: If you have a photos that the CWLS can use in its next InSite please send a high resolution jpeg format version to Doug.Kozak@datalogtechnology.com or maboud@slb.com. Include a short description of the photo with your submission.



The 2014 to 2015 CWLS Executive:

Back row (l - r): Manuel Aboud, James Ablett, Dustin Menger, Gareth Lewis, Doug Kozak
Front row (l - r): William Parrales, Tiffany Yaxley, Carley Gyori, Kathy Diaz

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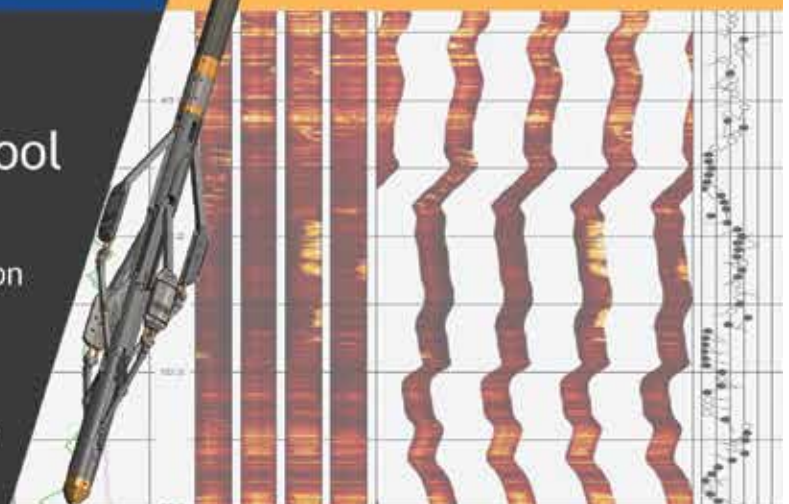


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CWLS 2014 to 2015 Executive

President

James Ablett

Halliburton
(403) 290-7670 (Office)
James.ablett@halliburton.com

Secretary

Carley Gyori

Big Guns Energy Services Inc.
(403) 206-4668 (Direct)
carley.gyori@bges.ca

Publications

Manuel Aboud

Schlumberger
(403) 990-0850 (Preferred)
maboud@slb.com

Past President

Dustin Menger

Logco Wireline Services
(403) 988-5548 (Preferred)
dmenger@logcowireline.com

Treasurer

Kathy Diaz, P.Geo.

(403) 254-9467 (Home)
Kathydiaz1@gmail.com

Membership

Tiffany Yaxley

Roke Technologies Ltd.
(403) 437-4065 (Preferred)
tyaxley@roke.ca

Vice President

William Parrales, P.Eng.

Baker Hughes
(403) 585-0373 (Preferred)
William.parrales@bakerhughes.com

Publications

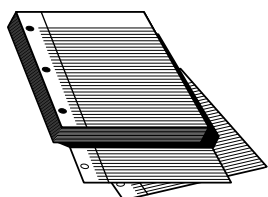
Doug Kozak

Datalog Technology Inc.
(403) 998-1966 (Preferred)
Doug.kozak@datalogtechnology.com

Committees

Gareth Lewis

Husky Energy
(403) 837-5424 (Cell)
Gareth.lewis@huskyenergy.com



Call for Papers

The CWLS is always seeking materials for publication. We are seeking both full papers and short articles for the InSite Magazine. Please share your knowledge and observations with the rest of the membership/petrophysical community.

Contact publication Co-chair:

Manuel Aboud – maboud@slb.com or

Doug Kozak – doug.kozak@datalogtechnology.com



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The President Report

What an amazing year for the CWLS. I would first like to start by saying what a privilege it has been to be elected and serve as President of the oldest petrophysical society in the world. In our 59 years of technical leadership in the fields of petrophysics and complete log analysis, I am very proud to have served this year as we have seen significant accomplishments - from the success of the 2013 GeoConvention, vastly improved student involvement at luncheons, the introduction of a well logging tool reference manual, the signing of the GeoConvention Joint Partnership, the beginning of a new website, as well as alternative communication resources such as LinkedIn and open surveys. I am truly excited about what we accomplished over the last year and confident in a very strong future. These accomplishments could not have been realized without the time and dedication put in by the 2013 – 2014 executive team who proved what can be accomplished with common goals through the power of volunteering. We truly had a fantastic group of people who deserve a great deal of credit for time they took out of their very busy days to make the CWLS as strong as possible.

2013 GeoConvention

The 2013 GeoConvention featured an amazing representation from the CWLS. In total, we offered 28 talks during the three day event, an increase of 367% from 2012. Special recognition goes to Nabil Al-Adani and Vern Mathison for their time spent in making this event such a huge success, bringing in over \$135K in profit to the CWLS. In 2014, Nabil and Jon Bryan have stepped up to lead as our general and technical co-chairs respectively.

The GeoConvention continues to be single-largest revenue generator for the CWLS, something which we guaranteed the future of by signing the Joint Partnership Agreement with the Canadian Society of Petroleum Geologists and the Canadian Society of Exploration Geophysicists. The partnership forms a new entity referred to simply as GeoConvention and will be in effect for the 2015 event. For his work in helping to form the basis of the agreement, Gord Lee must be recognized for his time and efforts in making this a reality. This new agreement consists of board members from each of the three sister societies who will endeavor to direct in the best interest of the GeoConvention. Technical and financial Contributions from the three societies were reviewed and resulted in revenue and cost split of 45% to the CSPG and CSEG and 10% to the CWLS. Again, this ensures the future of the GeoConvention and the involvement of the CWLS. I also wanted to once

more recognize Nabil Al-Adani for volunteering to be the first Director from the CWLS under the new agreement.

Website and Social Media

The transition to a new website provider ushers in a new era in communication for the CWLS. With nearly 600 members, CWLS.org must continue to be a strong resource for our membership. After reviewing the current provider's offering and sourcing two other quotes to ensure the best return on investment, the CWLS Executive voted to change website providers to an established company that will offer great customer service at a discount to what we had paid in the past. I would like to thank Jeff Dickson and James Ablett in particular for their time in sourcing the quotes and interfacing regularly with our past and future website providers. This recent change in providers will bring the content up to 2014 standards and will provide our members and those looking to join the CWLS with a positive experience where both transactions and technical content are easy to access. I am looking forward to a very positive relationship with our new provider as we continue to target giving back to our members.

We are also picking up steam with our social media offerings. LinkedIn, in particular has been used to a great extent to broadcast updates and other communications to our members. I see LinkedIn becoming a technical hub of petrophysical activity with regular discussions covering well log analysis. We also offered our membership an opportunity to be heard through an online survey that we hosted through the month of January. This allowed an appropriate outlet for our membership to voice their ideas on what is going well, as well as what areas we need to focus on going forward. The results of the survey will help direct the path forward as we again strive to bring the best value to our membership.

Students

We also strived to gain traction with students through the course of the year and had particular success with interfacing closely with The Rundle Group at the University of Calgary. Our student participation via events and Luncheon participation was considerably more pronounced in 2013 and the beginning of 2014. To ensure we continue with this momentum, Gareth Lewis has also introduced CWLS Well Logs for Beginners booklet that will focus on the basics of well logs and open-hole evaluation tools for those looking to get into our industry or folks wanting a refresher on the technical aspects and interpretation of well logs. With this and our alliance with



the Rundle Group, I am looking forward to continuing to strengthen our student relationships.

Acknowledgements

On behalf of the CWLS, I also wanted to thank APEGA for their continued partnership that has gone beyond administrative assistance and office space. Ashley Pessell in particular has been a huge asset to our team – thank you for all of your hard work!

Closing

In closing, I again wanted to say what a privilege and honor it has been to serve as your elected president and how grateful I am to all the volunteers that have stepped up to make this past year very successful for the CWLS. The executive team was an

amazing group and I would like to thank you all for your hard work over the last year. Volunteering is not easily fit into very full schedules, but you all exceeded expectations and shined admirably. I encourage all of our members to consider volunteering in one form or another, with the technical prowess and sense of community we possess, the possibilities for the CWLS are limitless.

To the 2014-2015 Executive, I wanted to offer my congratulations on volunteering to be a part of something very special; the friendships you will form and the networking you will have the opportunity to take advantage of, all while leading a premiere technical society will undoubtedly be very rewarding. I wish you all the best for the coming year.

Dustin Menger
2013-2014 Canadian Well Logging Society President

The Vice-President Report

I would like to begin by thanking everyone in the CWLS for your continued support and patronage over the last couple of years including 2013, our 59th consecutive year of operations. This last year seemed to go by very quickly as we continued our efforts to provide our members with a valuable program of high quality events and monthly technical luncheons.

The monthly luncheon talks were all well attended and received very positive feedback. The theme that we focussed on over this past year was innovations in petrophysics and log analysis of unconventional plays, with emphasis on relevant Canadian examples. This included technological innovations, new methodologies and incorporation of other progressive disciplines including LWD, Geosteering and Microseismic. I would also encourage everyone to continue to fill out the speaker evaluation forms at each technical luncheon, as these provide insightful feedback to the executive and speakers on topics that are the most valuable for CWLS members.

One of our goals for 2014 was to continue to take the message of the CWLS to other global sister societies including the

SPE, SPWLA and AAPG. We will continue to reach out to different societies in USA and in Canada to further increase the recognition of petrophysics as a profession and its vital role in the continued development of the oil and gas industry. Our April Technical Luncheon speaker, Roland Chemali of Sperry Drilling and SPWLA President in 2013, was excited to present to the CWLS and hopes to continue an annual speaker exchange between the two societies. Our 2012 President's Award winner, Craig Barnett, spoke to the SPWLA on our behalf as part of the speaker exchange. Both of these speakers reminded us that, while we deal primarily with well logging and petrophysics, we must continue to explore new methods of data acquisition through new technology and well data as the industry becomes increasingly "horizontal" and "unconventional". A brave new world awaits.

We thank all of our speakers and their respective companies for their continued support of petrophysics and the CWLS over the past year. We also whole-heartedly thank our sponsors and volunteers, to whom we owe a great debt of gratitude.



The following is a summary of the 2013-2014 Technical Luncheon speaker and topics:

Date	Speaker	Topic
January 15, 2014	Peter Elkington Weatherford	InPainting and Visualization of Microresistivity Images
December 18, 2013	Roy van der Sluis Baker Hughes	Advances in Pulse Neutron Technology for Improved Oil Sands Reservoir Saturation Monitoring
November 20, 2013	Bob Everett Robert V Everett Petrophysics Inc.	Three Methods for Log-Derived Mineralogy
October 16, 2013	Bruce Marion Schlumberger	Crosswell Seismic Imaging for High-resolution Reservoir Characterization and Reservoir Monitoring
June 5, 2013	Rick Aldred Paradigm (Geolog R&D)	The Impact of Dependencies when assessing Petrophysical Uncertainty for Resource Estimates
May 8, 2013	Carlos Haro Occidental Oil & Gas	Analysis and Implications of the Archi-Haro Equation in Modeling Resistivity of Rocks
April 17, 2013	Roland Chemali Sperry Drilling 2013 SPWLA President	Geosteering for Conventional and Unconventional Resources
March 20, 2013	Jonathan Shaftner Pinnacle	Utilizing Wellbore Logs to Help Optimize Design & Placement of Borehole Microseismic Geophone Arrays in the Duvernay Formation

The CWLS Executive polled the membership with an on-line survey early in 2014 on a variety of topics ranging from membership (fees and value), technical luncheons (ticket cost/ value, venue, and topics) and the CWLS website. Based on the responses and in line with the Legacy Committee's previous findings on similar topics, the CWLS executive will be addressing several of these subjects, starting with the CWLS website in 2014.

The recent technical issues with the website over the past couple of years have forced us to look at refining the website, so that it becomes an improved resource for members. To this end, the executive has voted to move website providers in an effort to clean up the website, making it more efficient, easier to navigate and reducing our reliance on paper records. Planned upgrades include: electronic luncheon tickets, improved membership renewal and e-voting and electronic receipt generation. Most of these improvements will be evident in the first months of the 2014 term. We are excited to work with our new provider to make the CWLS website a valuable resource for members in the coming years.

The 2013 CWLS-Fall Social was held again this year at "The Garage" in Eau Claire on October 30th and was another successful and well attended event. We hope to continue this tradition, as it is a welcome social event prior to our industry's busy winter season and gives us all a chance to network and catch-up with old friends and colleagues.

In conclusion, 2013 and early 2014 marked another successful year for North America's premier Formation Evaluation Society. Special thanks to Ashley Pessell and all the APEGA office staff for their tireless efforts, Emma MacPherson from CSPG (webcasts) and Jennifer Seguin, Rebecca Braun and Andras Kiss-Parciu (Fairmont Palliser events team). We owe a great deal of thanks to all of them for helping to keep the CWLS and its events running smoothly.

James Ablett
2013-2014 Canadian Well Logging Society Vice-President



Annual General Meeting Awards for 2013-2014

Speaker Awards

Johnathan Shaffner (*President award*)

Pinnacle

Utilizing Wellbore Logs to Help Optimize Design & Placement of Borehole
Microseismic Geophone Arrays in the Duvernay Formation

Roy van der Sluis (*Vice President award*)

Baker Hughes

Advances in Pulse Neutron Technology for Improved Oil Sands Reservoir Saturation Monitoring

Student Awards



Meriem Grifi – Best Student Thesis Award



Judith Chan – Best Student Abstract Award

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A 12-Step Program to Reduce Uncertainty in Kerogen-Rich Reservoirs

E. R. (Ross) Crain, P.Eng., Spectrum 2000 Mindware Ltd.
and Dorian Holgate, P.Geol., Aptian Technical Ltd.

Introduction

In some unconventional reservoirs, the presence of kerogen confounds standard log analysis models. Kerogen looks a lot like porosity to most porosity-indicating logs. Thus a single log, or any combination of them, will give highly optimistic porosity and free-gas or oil saturations, unless a kerogen correction is applied. This tutorial explains how such corrections can be applied in an otherwise standard petrophysical model that can be coded into the user-defined equation module of any software package.

Some quick-look methods “fake” the kerogen correction by using the density log with false and fixed matrix and/or fluid properties in an attempt to match core porosity (where it exists). When mineralogy varies, as in many unconventional reservoirs, the individual porosities calculated at each depth level are wrong, even though the average porosity may be correct. Porosity in the more dolomitic intervals will be too low and those in the higher quartz intervals will be too high. This will not help you decide where to position a horizontal well or help to assess net pay intervals because the porosity profile is extremely misleading.

Over-simplified techniques are dangerous, unprofessional, and unnecessary. Drawing an arbitrary straight line on a density log won’t “hack-it” in a world where wells cost multiple millions and a company’s stock price depends on the accuracy of the numbers in quarterly reports.

The 12-Step deterministic solution described here is easy to understand, easy to apply, and reasonably rapid. It is easier to manage than multi-mineral / statistical / probabilistic models. Parameter changes in later steps of the workflow will not change prior results, as happens in the multi-min environment. Each step in the model can be calibrated directly to available data before moving on to the next step. The workflow is simple, straight-forward, logical, controllable, and above all, predictable.

Basis for the Model

The methodology outlined below makes use of well-known algorithms, run in a deterministic model that can be calibrated with available ground truth at every step of the process. Because of the sparse nature of some of the calibration data, it may have to come from offset wells, which forces us to analyze those wells in addition to the wells of primary interest. This extra work can be minimized when the proper data collection and lab work is planned as part of the initial drilling program.

One of the most widely used petrophysical porosity models in conventional reservoirs is the shale-corrected density-neutron complex lithology crossplot. It handles varying mineralogy and light hydrocarbon effects quite well and can use sonic data if the density goes AWOL in bad hole conditions. By extending the model to include a kerogen correction to each of the density, neutron, and sonic curves, we have a universal model that has proven effective over a wide range of unconventional reservoirs around the world. The model reverts to the standard model when kerogen volume is zero.

Other steps in the workflow use existing standard methods chosen because they work well in low porosity environments. There are many alternate models for every step and you may have a personal preference different than ours. Be sure to run a sensitivity test to confirm that the results are reasonable at low porosities with high clay volumes.

The 12-Step Workflow

The petrophysical model for correcting porosity for kerogen involves calculation of kerogen weight and volume from suitable petrophysical models, and the modification of a few equations in the standard shale corrected density-neutron porosity model.

Step 1: Shale Volume

Shale (or clay) volume is the most important starting point. Since many unconventional reservoirs are radioactive due to uranium associated with kerogen or phosphates, the usual clay volume model that depends on the gamma ray log needs special attention. Calibration to X-ray diffraction data (see example in Figure 1), or thin section point counts, is essential. The basic mineral mix also is developed from the XRD data set.



Quartz	Pyrite	Carbonate		Albite	Clay	
		Calcite	Dolomite		Illite	Kaolinite
44.15	4.57	0.76	0.60	6.30	35.60	8.02
44.58	2.97			6.60	37.34	8.51
57.21	3.41			4.59	27.51	7.28
51.34	6.35			3.19	32.51	6.60
51.41	2.75			4.05	32.99	8.80
37.40	6.40			3.85	39.64	12.71
37.54	4.70			4.99	39.85	12.92
35.07	13.59			4.77	36.67	9.89
47.94	2.61	1.73		5.16	33.50	9.05

Figure 1: Typical XRD analysis of a silty gas shale showing clay-quartz ratio averages of about 40:60% by weight. This would not be obvious from the gamma ray log due to uranium associated with the kerogen and/or phosphate minerals. Some radioactive reservoirs have nearly zero clay, so the XRD bulk clay volume is the best starting point for a petrophysical analysis.

Shale volume calculations from a uranium corrected gamma ray curve (CGR) is the best bet:

$$1: \text{VSH}_{\text{cgr}} = (\text{CGR} - \text{CGR}_0) / (\text{CGR}_{100} - \text{CGR}_0)$$

When CGR is not available, we fall back to the thorium (TH) curve from a spectral gamma ray log:

$$2: \text{VSH}_{\text{th}} = (\text{TH} - \text{TH}_0) / (\text{TH}_{100} - \text{TH}_0)$$

When CGR and TH are missing, the total gamma ray curve (GR) can still be used by moving the clean (GR₀) and shale (GR₁₀₀) lines further to the right compared to conventional shaly sands:

$$3: \text{VSH}_{\text{gr}} = (\text{GR} - \text{GR}_0) / (\text{GR}_{100} - \text{GR}_0)$$

This last equation may take a little skill and daring, but that is what the XRD clay volumes are for. You can also test your clean and shale line picks in wells with CGR or TH curves then move that knowledge into other wells.

Unless shale volume is reasonably calibrated, nothing else in this workflow will work properly.

Step 2: Kerogen Weight Fraction

Kerogen weight fraction can be calculated from the resistivity log and a porosity log, using Passey or Issler methods. The Passey model is often called the “DlogR” method, with the “D” standing for “Delta-T” or sonic travel time. He also published density and neutron log versions of the equations. We have changed the abbreviations to reflect the three possible combinations:

$$4: \text{SlogR} = \log(\text{RESD} / \text{RESDbase}) + 0.02 * (\text{DTC} - \text{DTCbase})$$

$$5: \text{W}_{\text{toc}} = \text{SF}_{1\text{s}} * (\text{SlogR} * 10^{(0.297 - 0.1688 * \text{LOM})}) + \text{SO}_{1\text{s}}$$

OR

$$6: \text{DlogR} = \log(\text{RESD} / \text{RESDbase}) - 2.5 * (\text{DENS} - \text{DENSbase})$$

$$7: \text{W}_{\text{toc}} = \text{SF}_{1\text{d}} * (\text{DlogR} * 10^{(0.297 - 0.1688 * \text{LOM})}) + \text{SO}_{1\text{d}}$$

OR

$$8: \text{NlogR} = \log(\text{RESD} / \text{RESDbase}) - 4.0 * (\text{PHIN} - \text{PHINbase})$$

$$9: \text{W}_{\text{toc}} = \text{SF}_{1\text{n}} * \text{NDlogR} * 10^{(0.297 - 0.1688 * \text{LOM})}) + \text{SO}_{1\text{n}}$$

Where:

XXXXbase = baseline log reading in non-source rock shale

SlogR or DlogR or NlogR = Passey’s number from sonic or density or neutron log (fractional)

LOM = level of organic maturity (unitless)

W_{toc} = total organic carbon from Passey method (weight fraction)

SF_{1s,d,n} and SO_{1s,d,n} = scale factor and scale offset to calibrate to lab values of TOC

The constants in the Passey equations require DTC values in usec/ft and density in g/cc.

The baseline values are supposed to be picked in non-source rock shales in the same geologic age as the reservoir, but there may be none in the area of interest. This makes the Passey model difficult to calibrate, hence the scale factor SF₁ and scale offset SO₁. LOM is seldom measured except as vitrinite reflectance (R_o). There is a published chart for converting R_o to LOM. LOM is in the range of 6 to 11 in gas shale and 11 to 18 in oil shale.

Issler’s method, which is based on WCSB Cretaceous data is preferred as no baselines are needed. It still needs a scale factor for deeper rocks. Tristan Euzen’s multiple regressions of the Issler graphs give:

$$10: \text{TOCs} = 0.0714 * (\text{DTC} + 195 * \log(\text{RESD})) - 31.86$$

$$11: \text{W}_{\text{toc}} = \text{SF}_{2\text{d}} * \text{TOCs} / 100 + \text{SO}_{2\text{d}}$$

OR

$$12: \text{TOCd} = -0.1429 * (\text{DENS} - 1014) / (\log(\text{RESD}) + 4.122) + 45.14$$

$$13: \text{W}_{\text{toc}} = \text{SF}_{2\text{s}} * \text{TOCd} / 100 + \text{SO}_{2\text{s}}$$

Where:

Wtoc = total organic carbon from Issler method (weight fraction)

SF2s,d and SO2s,d = scale factor and scale offset to calibrate to lab values of TOC

The Issler equations expect density in Kg/m3 and sonic data in usec/m.

Mass fraction organic carbon (Wtoc) results from log analysis MUST be calibrated to geochemical lab data (see example lab report in Figure 2) using the scale factor and scale offset. These scale factors will vary from place to place even within the same geological horizon. Using the Passey or Issler models without local calibration is strongly discouraged – results are often 2 to 3 times too high.

Depth m	TOC wt%	S1	S2	S3	Tmax °C	Ro %	SI	OI
X025	1.35	0.05	1.72	0.63	444		128	47
X040	1.18	0.05	1.65	0.57	443		140	49
X050	0.83	0.03	1.31	0.55	443		158	66
X065	0.8	0.04	1	0.58	440		126	73
X075	0.75	0.05	1.04	0.72	438		138	96
X090	1.04	0.09	2.52	0.29	452		241	28
X110	1.02	0.05	1.16	0.56	441		114	55
X135	1.05	0.05	1.32	0.57	443		125	54

Figure 2: Geochemical lab report with TOC weight % values. Both Passey and Issler methods overestimate TOC by large factors in this particular shale gas, forcing us to use scaling factors to calibrate log derived Wtoc. Both methods can be made to give virtually identical results when calibrated to XRD.

Step 3: Kerogen Volume Fraction

Kerogen volume is calculated by converting the TOC weight fraction (Wtoc). The lab TOC value is a measure of only the carbon content in the kerogen, and kerogen also contains oxygen, nitrogen, sulphur, etc, so the conversion of TOC into kerogen has to take this into account. The kerogen conversion factor (KTOC) is the ratio of carbon weight to the total kerogen weight. The factor can range from 0.68 to 0.95, with the most common value near 0.80.

Converting mass fraction to volume fraction is as follows:

14: Wtoc = TOC% / 100 from core, or as found from Passey or Issler methods described above.

15: Wker = Wtoc / KTOC

16: VOLker = Wker / DENSkker

17: VOLma = (1 - Wker) / DENSmma

18: VOLrock = VOLker + VOLma

19: Vker = VOLker / VOLrock

Where:

KTOC = kerogen conversion factor Range = 0.68 to 0.95, default = 0.80

Wker = mass fraction of kerogen (unitless)

DENSkker = density of kerogen (Kg/m3 or g/cc)

DENSmma = matrix density (Kg/m3 or g/cc)

VOLxx = component volumes (m3 or cc)

Vker = volume fraction of kerogen (unitless)

DENSkker is in the range of 1200 to 1400 Kg/m3, similar to good quality coal. Default = 1300 Kg/m3.

Lower values are possible in low maturity kerogen.

Step 4: Kerogen and Shale Corrected Porosity

Effective porosity is best done with the shale corrected density neutron complex lithology model, modified to correct for kerogen volume:

21: PHIDker = (2650 - DENSkker) / 1650 (if PHIN is in Sandstone Units)

22: PHIDc = PHID - (Vsh * PHIDsh) - (Vker * PHIDker)

23: PHInc = PHIN - (Vsh * PHINsh) - (Vker * PHINKer)

24: PHIe = (PHInc + PHIDc) / 2

PHINKer is in the range of 0.45 to 0.75, similar to poor quality coal. Default = 0.65.

This model compensates for variations in mineralogy AND kerogen.

If the density log is affected by rough borehole, the shale corrected sonic log porosity (PHIsc) can be used instead:

24: PHISker = (DTCKker - 182) / 474 (if PHIN is in Sandstone Units)

25: PHIsc = PHIS - (Vsh * PHISsh) - (Vker * PHISker)

26: PHInc = PHIN - (Vsh * PHINsh) - (Vker * PHINKer)

27: PHIe = (PHInc + PHIsc) / 2

DTCKker is in the range of 345 to 525 usec/m, similar to good quality coal. Default = 425 usec/m.

This model is moderately insensitive to variations in mineralogy AND compensates for kerogen.

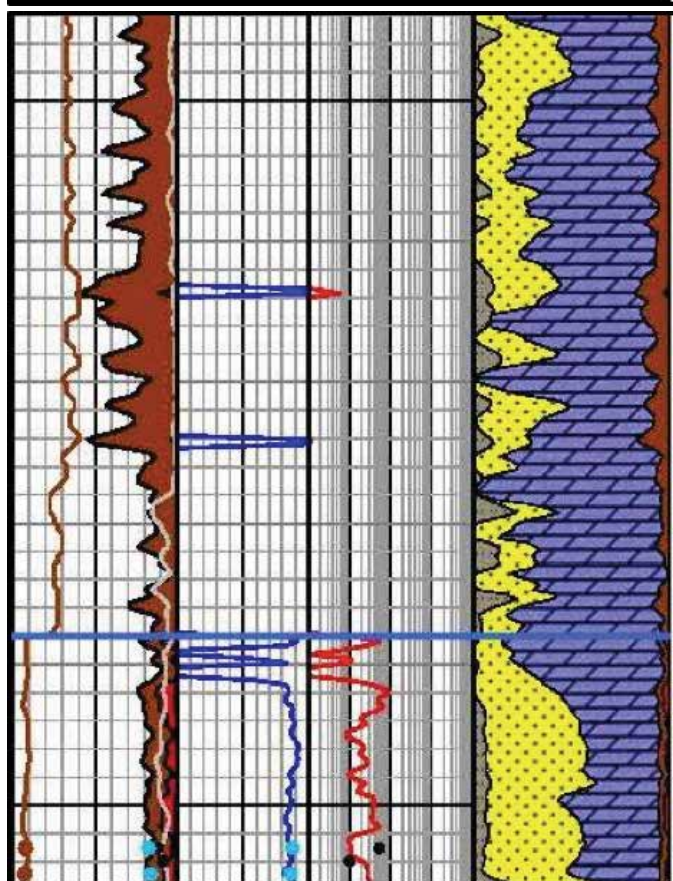
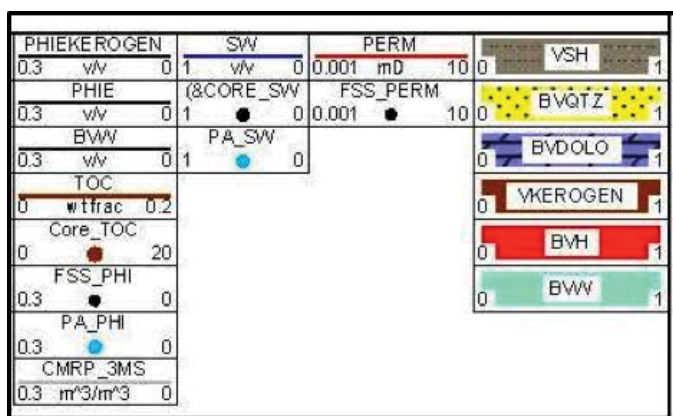


Figure 3: Example of TOC weight fraction (left hand curve in Track 1) calibrated to geochemical lab data in the Montney (2 dots near bottom of log segment – another 20+ data points are not shown to conserve space). Kerogen volume derived from TOC is displayed as dark shading to the left of effective porosity (shaded red) in Track 1. In the Doig above the Montney, there is no geochem data, so the CMR effective porosity (light grey curve) was used to back-calculate the TOC, based on the difference between raw neutron-density porosity and PHIE_{nmr} values. Scale factors for the Doig and Montney are markedly different regardless of the TOC calculation method employed. Depth grid lines are 1 meter apart.

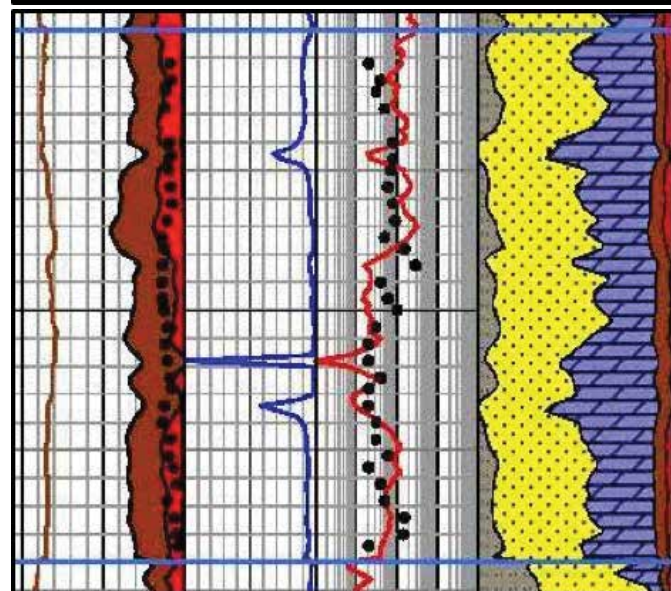
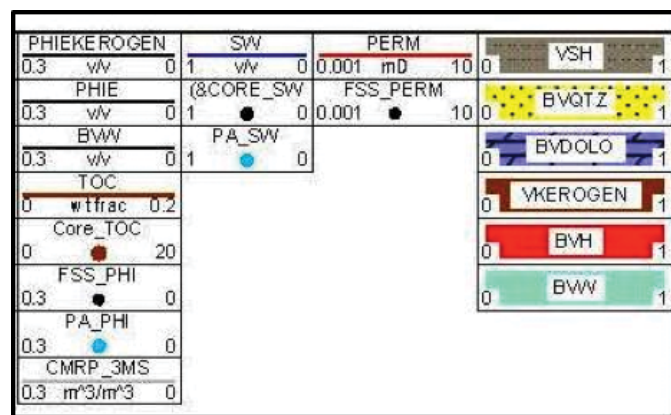


Figure 4: Example of TOC and density-neutron effective porosity after kerogen correction in a Montney interval, showing close comparison to core effective porosity (black dots). TOC reaches 4 weight percent, which converts to near 10% by volume (dark shading). Note that permeability of the free porosity is in the range of 0.01 to 0.1 milliDarcies, not the nanoDarcy range quoted in core reports based on the GRI protocol, which uses crushed sample grains instead of core plugs.

Effective porosity from a nuclear magnetic resonance (NMR) log does not include kerogen or clay bound water, so this curve, where available, is a good test of the modified density neutron crossplot method shown above (illustrated in Figure 3).

In all cases, good core control is essential. If porosity is too low compared to core porosity, then shale volume or kerogen volume are too high. Revisit the calibration of these two terms.

Some so-called shale gas zones are really tight gas with little kerogen or adsorbed gas, so the kerogen corrected complex lithology model works well because it reverts to our standard methods automatically when $V_{ker} = 0$.



Step 5: Lithology

Lithology is then calculated with a kerogen and shale corrected 2-mineral PE model or a 3-mineral model using kerogen-and shale corrected PE, density, and neutron data. Calibrate results to XRD data. Modify mineral selection or mineral end points to achieve a reasonable match.

Some people use a multi-mineral or probabilistic software package to solve for all minerals, including porosity and kerogen, treating the latter two as “minerals”. In the case of rough borehole conditions, this method gives silly results unless a bad-hole discriminator curve is also used. These models are more difficult to tune because it is not possible to calibrate shale volume, TOC weight fraction, effective porosity, and mineralogy in a step-by-step sequence, as can be done with the deterministic model described here. Changing parameters in the multi-mineral model, to strive for a better match to ground truth, often gives unexpected results. It is a multi-dimensional jigsaw puzzle and some of the pieces just won’t fit unless you trim them in the correct sequence.

To reduce this problem, calibrate shale volume kerogen volume and effective porosity by the deterministic method shown earlier, then use these as input curves as constraints in the multi-mineral model.

Recently, we have seen excellent examples of elemental capture spectrography inversions that produce both TOC, clay, and mineral weight fractions. TOC and XRD lab data are still used to drive the inversion in the correct direction.

Step 6: Water Saturation

From here onward, petrophysical analysis follows normal procedures. Water saturation is best

done with the Simandoux equation, which is better behaved in low porosity than most other models. Dual water models may also work, but may give silly results when shale volume is high or porosity is very low.

In many cases, the electrical properties must be varied from world average values to get S_w to match lab data. Typically $A = 1.0$ with $M = N = 1.5$ to 1.8 . Lab measurement of electrical properties is essential. Skipping this step is the worst form of false economy. The wrong M and N values can give zero OGIP!

Calibration can be done with core water saturation or capillary pressure data. Both pose tricky problems in unconventional reservoirs, especially those with thin porosity laminations, so common sense may have to prevail over “facts”.

Step 7: Permeability

Permeability from the Wyllie-Rose equation works extremely well even in low porosity reservoirs. We generally assume that the calculated water saturation is also the irreducible water saturation for this model, although this assumption may be incorrect in a few cases. The calibration constant in the Wyllie-Rose equation can range between 100,000 to 150,000 and beyond, and is adjusted to get a good match to conventional core permeability.

An alternative is the exponential equation derived from regression of core permeability against core porosity. The equation takes the form $\text{Perm} = 10^{(A1 * PHIE + A2)}$. Typical values for $A1$ and $A2$ are 20.0 and -3.0 respectively. This model will match conventional core permeability quite well, but will probably not match the permeability derived from crushed samples using the GRI protocol. High perm data points caused by micro- or macro fractures should be eliminated before performing the regression.

Step 8: Reconstruct the Log Curves

Reconstructed or synthetic logs have become an important part of a competent petrophysical workflow. We go to some pains to use only valid data in our petrophysical analysis, omitting bad data from our models. Reconstructed logs are generated from those results using the Log Response Equation.

There are two reasons for reconstructing the well logs. The first is to verify that the parameters used in all steps are reasonable. In good borehole conditions, the reconstructed logs should be close overlays of the original logs. If they are not, possibly some bad data snuck in, or some parameters in the overall model are wrong. You will need to use your CSI skills to chase down the guilty party and rectify the problem. A good match between reconstructed and original logs is not a guarantee of success, but it is one more piece of evidence pointing in that direction.

The second reason for reconstruction is to prepare a strong foundation for calculating rock mechanical properties. Mechanical properties developed from raw logs often contain spikes and noise, or worse, that destroys the stimulation design results. We strongly recommend that stimulation design should ALWAYS use edited or reconstructed logs, which presupposes that sufficient time and talent be allowed by management for this step to take place.

During reconstruction, we can also create missing logs, such as the shear sonic curve, for use in the mechanical properties calculation or for comparison to other wells in the project.



Step 9: Rock Mechanical Properties

All well completions in unconventional reservoirs involve expensive stimulation programs. Hydraulic fracture design depends on an accurate evaluation of rock mechanical properties based, in turn, on an advanced petrophysical analysis. Most frac design programs have only a rudimentary capacity to perform petrophysical analysis. Worse still, frac design software uses the raw, unedited log data with all its problems. Nothing good can come from this. So it is better to do the work outside the frac software and import the mechanical property curves.

The first step to accurate mechanical properties is a reconstruction of the sonic shear and compressional and density data to remove the effects of bad hole and light hydrocarbons. The frac design programs need the water filled case so the reconstruction is always needed in gas zones. More information on how to do this can be found at www.spec2000.net/10-mechsyn.htm.

The usual outputs from this step are shear modulus, velocity ratio, Poisson's ratio, bulk modulus,

Young's modulus (both dynamic and static), Lamé's constant, and a brittleness coefficient. The original and reconstructed log curves, and the lithology track, are displayed with the mechanical properties results.

Triaxial (static) and dynamic lab measurements can be used to help calibrate the mechanical properties calculated from the petrophysical model. In the absence of lab data, most of these results must fit within known ranges, depending on lithology. If values are out of range, we must suspect the input data and check the log reconstruction procedure. This in turn depends on the current state of the petrophysical results, leading us to double check all parameters and calibration steps. This kind of manual iteration is a normal part of a petrophysicist's daily grind.

Step 10: Net Reservoir and Net Pay

Once all these checks and balances are satisfied, we can get on with finding the "real" answers. Unfortunately, this is where the world gets a little fuzzier.

In many shale gas and some shale oil plays, typical porosity cutoffs for net reservoir are as low as 2 or 3% for those with an optimistic view, and between 4 and 5% for the pessimistic view.

The water saturation cutoff for net pay is quite variable. Some unconventional reservoirs have very little water in the free porosity so the SW cutoff is not too important. Others have

higher apparent water saturation than might be expected for a productive reservoir. However, they do produce, so the SW cutoff must be quite liberal; cutoffs between 50 and 80% SW are common.

Shale volume cutoffs are usually set above the 50% mark. Multiple cutoff sets help assess the sensitivity to arbitrary choices and give an indication of the risk or variability in OGIP or OOIP calculations.

Step 11: Free Gas or Oil In Place

Now we move into the reservoir engineer's territory, but it doesn't hurt to know where our petrophysical results end up. If you have never done the math before, it can be quite instructive – it is much easier to compare zones or wells on the basis of OOIP or OGIP instead of average porosity, net pay, or gross thickness.

Free gas in place is calculated from the usual volumetric equation:

- 1: $B_g = (P_s * (T_f + K T_2)) / (P_f * (T_s + K T_2)) * Z F$
- 2: $OGIP_{free} = KV_4 * PH_{ie} * (1 - S_w) * THICK * AREA / B_g$

For oil reservoirs:

- 3: $OOIP = KV_3 * PH_{ie} * (1 - S_w) * THICK * AREA / B_o$

Where:

B_g = gas formation volume factor (fractional)

B_o = oil formation volume factor (fractional)

P_f = formation pressure (psi)

P_s = surface pressure (psi)

T_f = formation temperature (°F)

T_s = surface temperature (°F)

$Z F$ = gas compressibility factor (fractional)

$K T_2 = 460^\circ F$

$K V_3 = 7758$

$K V_4 = 0.000\ 043\ 560$

If AREA = 640 acres and THICK is in feet, then OGIP = Bcf/Section (= Bcf/sq.mile). OOIP is in barrels per square mile. Multiply meters by 3.281 to obtain thickness in feet.

Step 12: Adsorbed Gas In Place

TOC is widely used as a guide to the quality of shale gas plays. This only pertains to adsorbed gas content and has no bearing on free gas or oil. Some deep hot shale gas plays have little adsorbed gas even though they have moderate TOC content.

Using correlations of lab measured TOC and gas content (Gc), we can use log derived TOC values to predict Gc, which can then be summed over the interval and converted to adsorbed gas in place. Sample correlations are shown in Figure 5.

Gas content from a best fit line versus TOC can be applied to log derived TOC:

$$4: Gc = KG11 * TOC\%$$

Where:

Gc = gas content (scf/ton)

TOC% = total organic carbon (percent)

KG11 = gas conversion factor range = 5 to 15, default = 9

Adsorbed gas in place is derived from:

$$5: OGIP_{adsorb} = KG6 * Gc * DENS * THICK * AREA$$

Where:

DENS = layer density from log or lab measurement (g/cc)

$$KG6 = 1.3597 * 10^{-6}$$

If AREA = 640 acres and THICK is in feet, then OGIP = Bcf/Section (= Bcf/sq.mile)

Multiply meters by 3.281 to obtain thickness in feet.

Multiply Gc in cc/gram by 32.18 to get Gc in scf/ton.

A more sophisticated approach uses the Langmuir adsorption curve which can be derived from reservoir temperature and pressure. The correlation of Gc with TOC seems to be adequate but the Langmuir method would be a useful calibration step.

Conclusions

A full suite of TOC and XRD mineralogy from samples, along with core porosity and saturation data, are needed to calibrate results from any petrophysical analysis of unconventional reservoirs. Bulk clay and TOC are the two critical lab measurements required through the interval of interest.

Without valid calibration data, petrophysical analysis will have possible-error bars too large to allow meaningful financial decisions.

The deterministic shale and kerogen corrected workflow allows

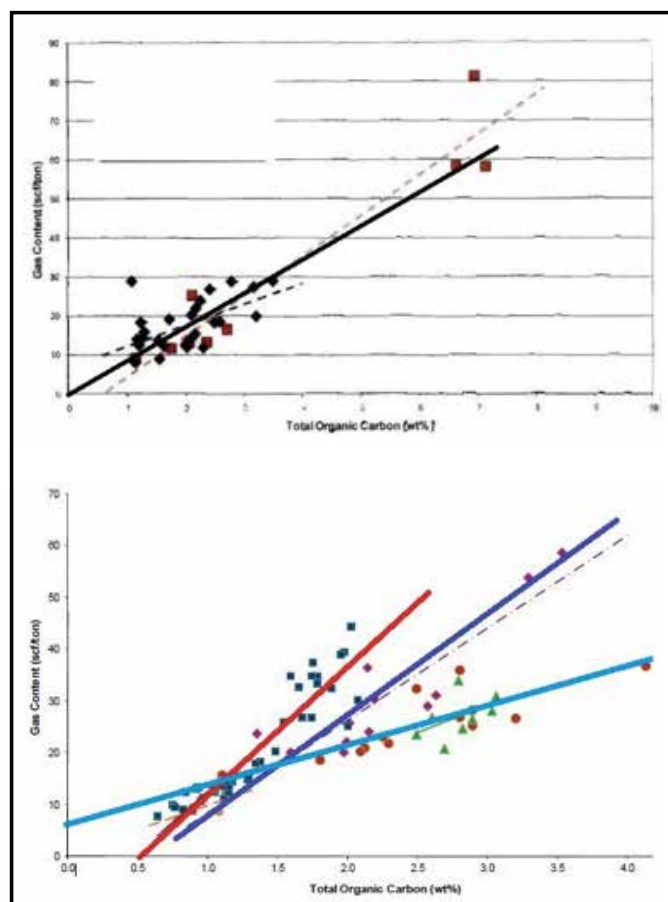


Figure 5: Crossplots of TOC versus adsorbed gas (Gc) for Tight Gas / Shale Gas examples. Note the large variation in Gc versus TOC for different rocks, and that the correlations are not always very strong. These data sets are from core samples. Cuttings give much worse correlations. The fact that some best fit lines do not pass through the origin suggests systematic errors in measurement or recovery and preservation techniques.

all available ground truth to be used in a logical and consistent manner at each step to calibrate and refine results.

Petrophysical analysis results travel well beyond the initial need to know porosity and water saturation. Oil and gas in place, reservoir stimulation, placement of horizontal wells, even financial reports, are impacted. Shortcuts are not acceptable.

In the end, the cost of the full analysis is trivial compared to the cost of completion, or worse, the cost of an unsuccessful or unnecessary completion.

About The Authors



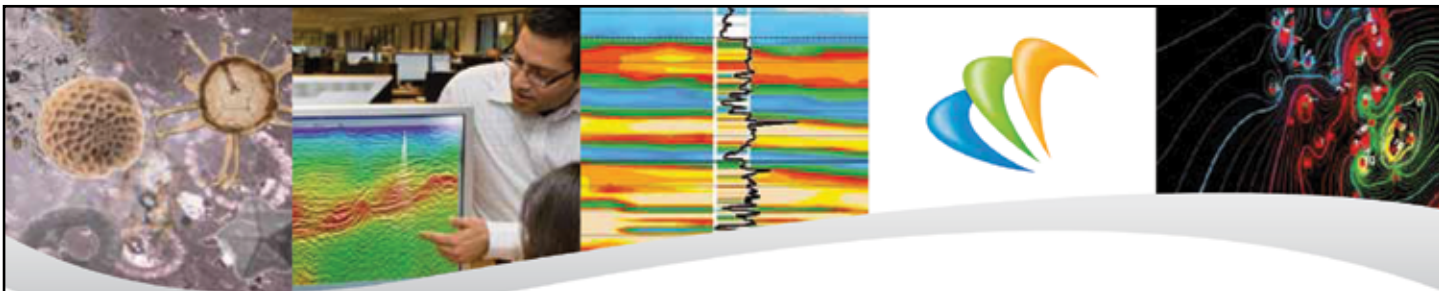
E. R. (Ross) Crain, P.Eng. is a Consulting Petrophysicist and Professional Engineer, with over 50 years of experience in reservoir description, petrophysical analysis, and management. He is a specialist in the integration of well log analysis and petrophysics with geophysical, geological, engineering, stimulation, and simulation phases of the oil and gas industry, with widespread Canadian and Overseas experience. He has authored more than 60 articles and technical papers. His online shareware textbook, Crain's Petrophysical Handbook, is widely used as a reference for practical petrophysical analysis methods. Mr. Crain is an Honourary Member and Past President of the Canadian Well Logging Society (CWLS), a Member of SPWLA, and a Registered Professional Engineer with APEGA

ross@spec2000.net



Dorian Holgate is the principal consultant of Aptian Technical Limited, an independent petrophysical consulting practice. He graduated from the University of Calgary with a B.Sc. in Geology in 2000 and completed the Applied Geostatistics Citation program from the University of Alberta in 2007. After graduation, he began working in the field for BJ Services (now Baker Hughes) and completed BJ's Associate Engineer Program. Later, he joined BJ's Reservoir Services Group, applying the analysis of well logs to rock mechanics to optimize hydraulic fracturing programs. In 2005, Dorian joined Husky Energy as a Petrophysicist and progressed to an Area Geologist role. He completed a number of petrophysical studies and built 3-D geological models for carbonate and clastic reservoirs. Dorian holds membership in APEGA, CSPG, SPE, SPWLA, and CWLS.

dorian@aptianpetrophysics.com



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Three Methods for Log-Derived Mineralogy ...primarily used for Shales (silts) & Tight Formations

R.V Everett, Robert V. Everett Petrophysics Inc.

Introduction

This is the first of a series of articles designed to explain the three methods of mineralogy determination. New spectroscopy logging tools have opened the door with providing a real time measurement of the geochemical makeup of the reservoir. The mineralogy of unconventional reservoirs such as shales, silts and tight formations will lead to more accurate reserve calculations through better porosity and permeability determination.

The Three Methods are:

- A. Nuclear Spectroscopy (NS) with core mineralogy - a spreadsheet program.
- B. Element prediction program when nuclear spectroscopy is absent; reconstruction can substitute for lack of core; otherwise, X-ray Fluorescence (XRF) core measurements are used to check our predictions. This is also a spreadsheet program. We will use this method in this article and explore the other methods in later articles.
- C. Nuclear Spectroscopy with core mineralogy and XRF chemistry - all are combined in a program called Robust Element to Minerals (ELM).

Why involve mineralogy? We can use the attributes of the minerals such as cation exchange capacity and grain density to aid in the solution of Sw, porosity and permeability.

Is core always valid? No, and we provide some checks to see if it is valid or not.

In summary, valid mineralogy from logs can improve interpretation of porosity, water saturation and permeability.

Steps involved in using Nuclear Spectroscopy

There are several sections involved in the calculations prior to entering the spreadsheet:

Preparing the log data

1. Fix the density log for washouts using clustering.
2. Find the Rw from the SP and a known Rw at any zone in the borehole. The SP propagates the known Rw to all the other depths in the well.

3. Predict any missing curves from offset wells: such as NMR's free fluid porosity, Spectral GR, Nuclear Spectroscopy elements, TOC; you usually start with neutron, density, resistivity, GR, SP and DT logs. For example, you might have many core-XRF values instead of the nuclear spectroscopy log curves. Starting with core-XRF would be a good idea, if there are many measurements of XRF, on a 1 foot (0.3m) sampling over a 50 foot (~16m) interval. In a set of logs that has resistivity, neutron, density, DT, NMR and GR spectroscopy plus XRF and XRD, we could develop a predicted nuclear spectroscopy log of elements around that data set. (Ref 1 & 2).
4. Due to the Elemental Capture Spectroscopy (ECS) having been around for some time, 99% of my interpretations use measured or offset ECS logs. The other logs available are the LithoScanner (Schlumberger™), the GEM (Halliburton™) and the FLeX (Baker™) tools.
5. The main difference between the older ECS and the newer nuclear Spectroscopy tools is the ECS measures iron + 0.14*Aluminum, whereas the other tool's iron spectrum is not contaminated by aluminum. However, the equations developed by Dr. Herron (Ref 4) are based on the ECS, so when using other tools, add 0.14Al to the Fe signal to use Herron's methods to provide groups of siliclastics, carbonates and clay. When converting the groups of minerals to individual minerals, remove the 0.14Al from the dry weight Fe signal.

Calculations in the spreadsheet

6. Solve for clastics as a group, carbonates as a group, and clays as a group.
7. Solve for porosity and permeability using the Herron formulas (Ref 3) involving the measured elements and the calculated carbonate, clay and siliclastics groups.
8. Normalize to convert the clastics to quartz, ksp, plagioclase and muscovite; carbonates to dolomite, calcite and anhydrite; clays to illite, smectite, kaolinite and chlorite. Note that we assume a core laboratory is capable of separating illite and muscovite in X-ray diffraction (XRD) but know some can't...yet. So, we need to either get a set of logs with little muscovite or do some guessing, or farm out the XRD to SGS, who can do the separation.

9. Calculate a grain density from the elements, based on Mike Herron's paper (Ref 4) and some empirical modifications made to the spreadsheet program.
10. Calculate a porosity which can be verified by core using de-ionized water instead of mercury for the invading fluid in unconventional rocks.
11. Calculate a permeability also verified by core using de-ionized water instead of helium or mercury.

Preparing the log data

Step 1

- * Fix the density log for washouts using clustering.

The sonic and density porosities are compared on a limestone scale. When the sonic porosity is less than the density porosity, a null value is assigned to the density log except in the case of coal. The null value is expected to be where washouts occurred, thereby invalidating the density measurement from a pad type tool. A measurement made with logging-while-drilling sub (LWD) should be OK as recorded.

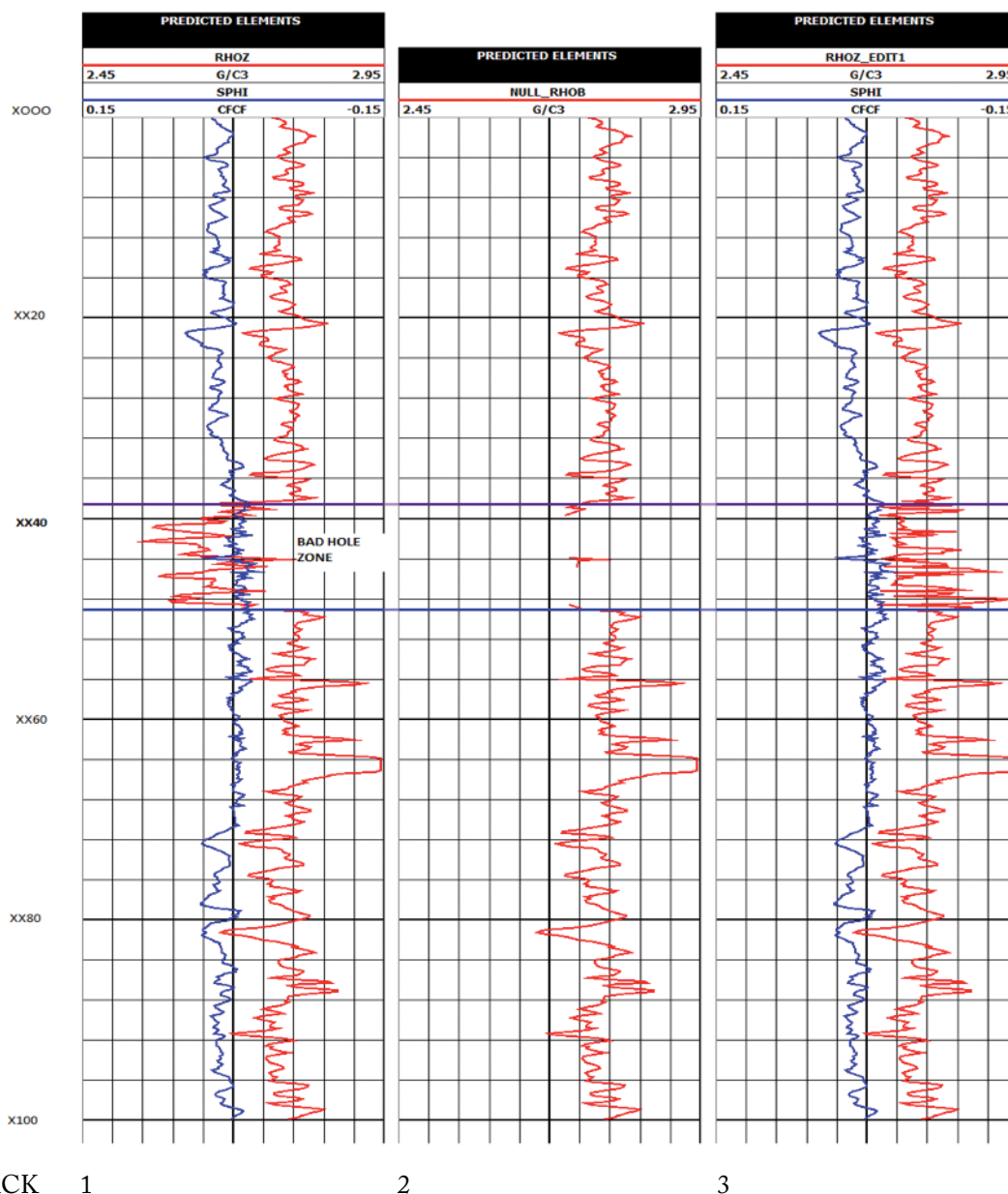


Figure 1: Bad hole example.
Track 1 shows the red density curve is greater than the blue sonic porosity.
Track 2 shows the 'nulled density'.
Track 3 shows the corrected density from clustering.

Make a cluster of the 'nulled density', neutron, GR and any other curves that are not affected by the washout. The cluster predicts what the 'good hole' values would be for the nulled density and a corrected density log results.

Step 2

- * In the following descriptions we will use Imperial units, with metric units in brackets. We need to find the formation water resistivity (Rw), from the recorded spontaneous potential (SP) and a 'known Rw' at any zone in the borehole.
- * We will use the equation, $SP = -k \cdot \log_{10}(R_{mf}/R_w)$, where k is a function of temperature.
- * The SP propagates the 'known Rw' to all the other depths in the well. The steps involved in making this calculation are, after correcting the SP for drift:

- a. Calculate a temperature profile. We usually use the following formula and check to see if the BHT from the log heading is about ~20 degrees F [~11C] less, as it is unlikely that the reservoir has warmed up the borehole mud, to reservoir temperature.

1. $Temp_degF = 0.0198 \cdot Depth_{ft} + 42.805$
2. $Temp_degC = [((0.0198 \cdot Depth_{m} / 0.3048) + (42.8058)) - 32] \cdot (5/9)$

- b. Calculate a resistivity profile for an Rw of 0.05 at 308F (153C); the reason an Rw of 0.05 is selected is that a surprising number of formations, such as the oil-wet Cardium, have a similar Rw. Also, many shale gas/oil formations have an Rw close to this value. So it is convenient to use it, based on serendipity:

1. $R_{w_05} = (0.05 \cdot (308 + 6.77)) / (Temp_DegF + 6.77)$
2. $R_{w_05} = (0.05 \cdot (153 + 21.5)) / (Temp_DegC + 21.5)$

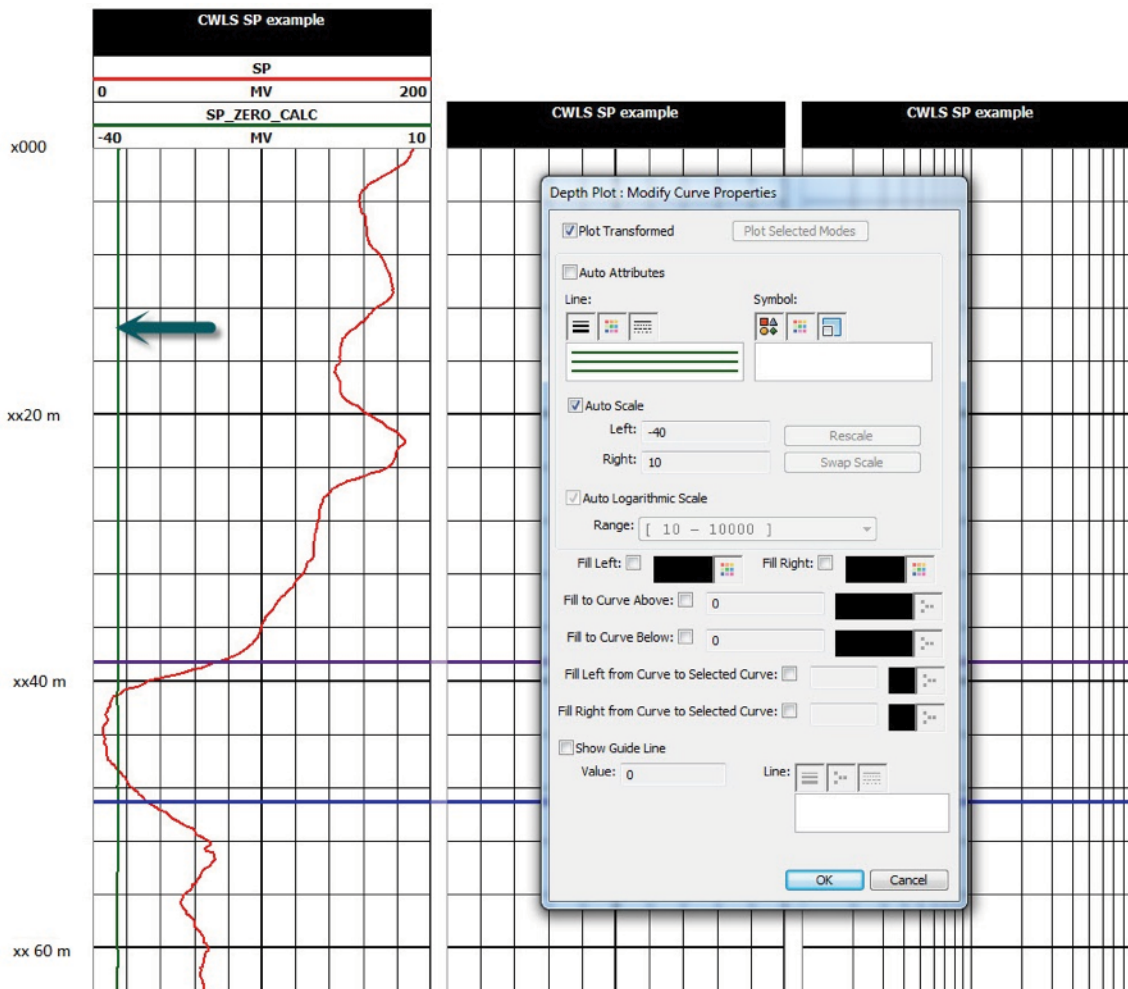


Figure 2: SP Zero Calculation. In this example, the 'auto' scale is -40 to +10 (green arrow); to make the middle of the auto scale read zero, we have to add plus 36.

- c. Calculate a resistivity profile for resistivity of the mud filtrate, R_{mf} , of 0.85 at 51F [10.6C], or whatever the real R_{mf} is:

$$1. R_{mf} = (0.85 * (51 + 6.77)) / (Temp_DegF + 6.77)$$

$$2. R_{mf} = (0.85 * (10.6 + 21.5)) / (Temp_DegC + 21.5)$$

- d. Calculate a 'zero' for the SP based on the R_{mf}/R_{w_05} ratio.

$$1. SP_zero = \log_{10} (R_{mf}/R_{w_05}) * (-1) * (61 + 0.133 * Temp_degF) + 'Add1'$$

$$2. SP_zero = \log_{10} (R_{mf}/R_{w_05}) * (-1) * (65 + 0.24 * Temp_DegC) + 'Add1'$$

The 'Add1' is a number used to average SP to zero over the entire well, as the temperature increases with depth.

Now we get to the trick in the process. We calculate a temporary value of a term we call SP_Shift , and we add another 'Add2' term which we will use later, in order to 'calibrate' the SP to the real R_w in any known R_w value for any zone.

$$SP_Shift_temporary = Recorded\ SP + 'Add2'$$

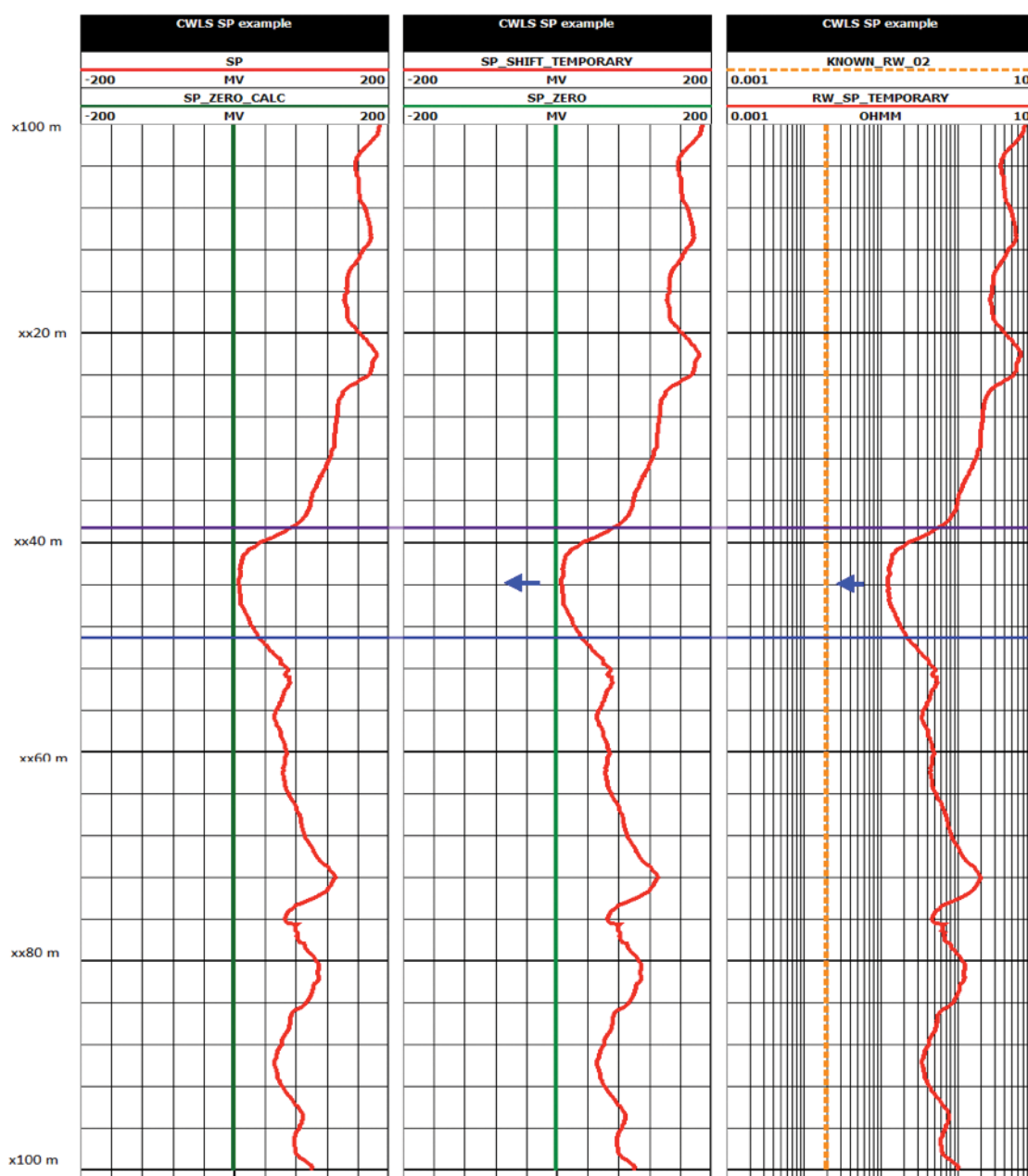


Figure 3: CWLS R_w Temporary. The red R_w_SP in the right hand track, is too high, relative to the orange 'Known R_w ' of 0.02; so we must add a shift in the direction of the blue arrows.



Initially, 'Add2' is 0.0. Now calculate a temporary baselined SP as

$$SP_Baselined_temporary = SP_Shift_temporary - SP_zero.$$

Calculate a temporary Rw from the SP called:

$$Rw_SP_temporary = Rmf / \{(\log_{10}) [SP_Baselined_temporary / (-1 \cdot (61 + 0.133 \cdot Temp_degF))]\}$$

$$[Rw_SP_temporary = Rmf / \{(\log_{10}) [SP_Baselined_temporary / (-1 \cdot (65 + 0.24 \cdot Temp_DegC))]\}].$$

In order for this process to work, you must know, or guess, an Rw value at any depth in the well. The 'known Rw' is 0.02

at formation temperature. Compare the Rw_02 value to the Rw_SP_temporary. If they agree, you are finished. If not, you go back to the 'Add2' term and put in 50mv, 100mv, 200 mv or whatever it takes to iterate until the Rw from the SP agrees with your known value (this example required -80mv). This might sound complicated but it is not, once you play with it a couple of times.

Caveat: we assume the SP has been corrected for drift before you start. We also assume that the bed thickness and hydrocarbon effects in the zone of interest and the zone where the Rw is 'known' are similar, so no further correction is required.

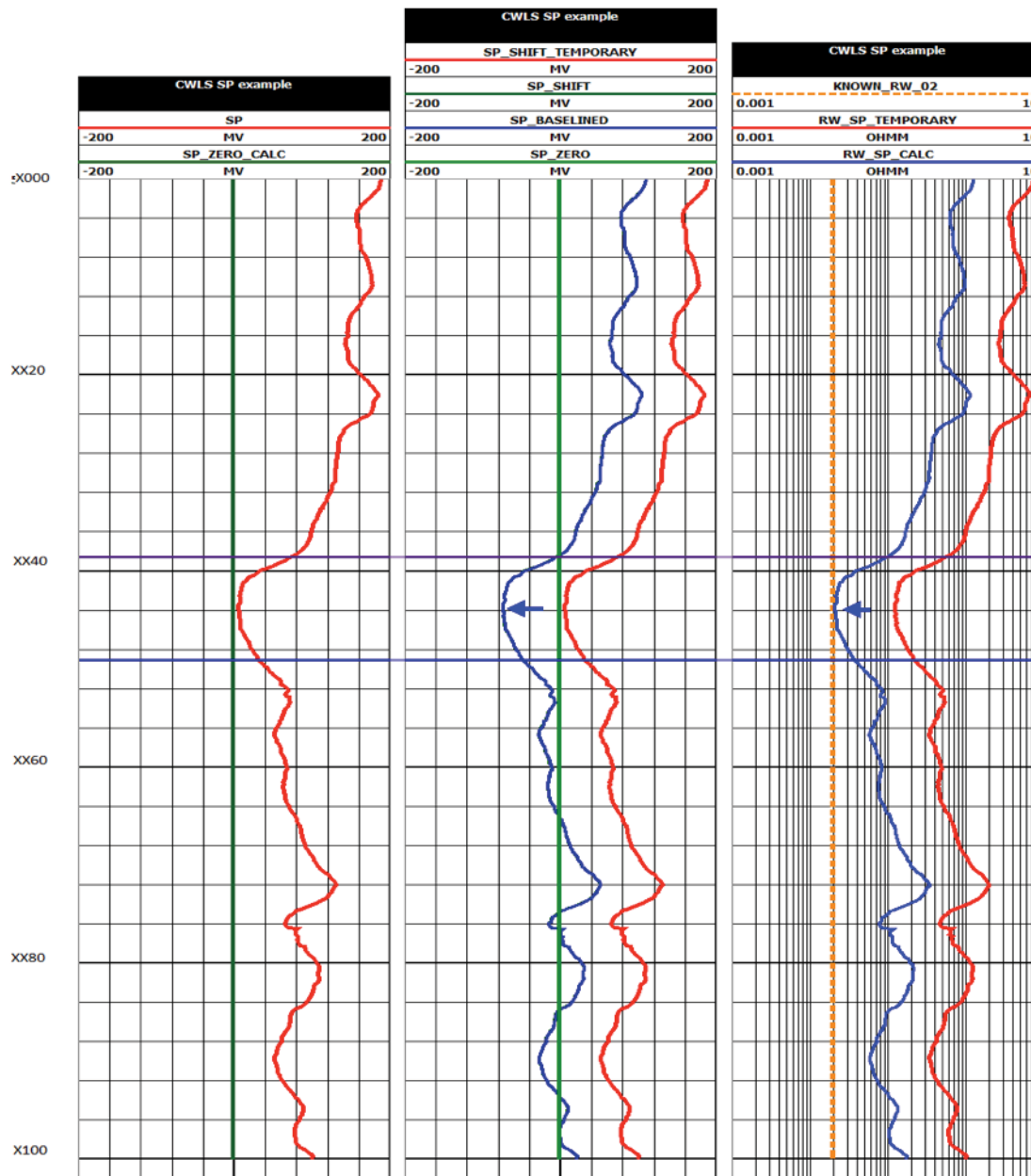


Figure 4: CWLS Rw_SP. Add -80mv to SP_Shift_temporary and now the Blue Rw_SP matches the orange 'known Rw' in the zone. So the Rw from the SP is now calibrated for the entire hole. One might also use the CWLS 'Rw catalog' to check at the zone of interest, to ensure one has the correct Rw for the zone of interest. If not, repeat the previous 'Add2' process.

Step 3

- * Predict any missing curves from offset wells: NMR's free fluid porosity, Spectral GR, Nuclear Spectroscopy elements, TOC. Having started with neutron, density, resistivity, GR, SP, DT logs.

For example, a well may have a number of elemental X-ray Fluorescence (XRF) values instead of the nuclear spectroscopy log curves. If the measurements of XRF are sampled a meter apart with an offset of logs that have resistivity, neutron, density, DT, NMR and GR spectroscopy plus XRF and XRD, you could develop a predicted nuclear spectroscopy log of elements around that data set. When sample spacing is greater than 3m, the data is less useful as greater uncertainty is involved.

When predicting Ca in a zone that has high calcium, such as the Alberta Devonian, here's another tip. There is a relation-

ship of the computed gamma ray, CGR (no uranium) and the Ca:

The problem is that predicting calcium from an ECS that has some carbonate zones plus some clastic zones, often results in predicted calcium that is too low due to the influence of the clastics. So we trick it by using the CGR. The calcium and GR are related, except that uranium makes the relationship poor. You compute a GR of just Th & K (CGR) from:

$$\text{Ca from CGR} = 0.4 - ((4.6/120) * \text{CGR}/10 - 0.0005 * \text{CGR})$$

Rather than multiplying and dividing the numbers, we have left it in this format to show that a Ca of 0.4 (100% Carbonate) is equivalent to a CGR of 4.6 GAPI; and a Ca of 0.0 is equivalent to a CGR of 120 GAPI. Then you use the ECS log to predict the other elements using the above Ca as an input over the carbonate section.

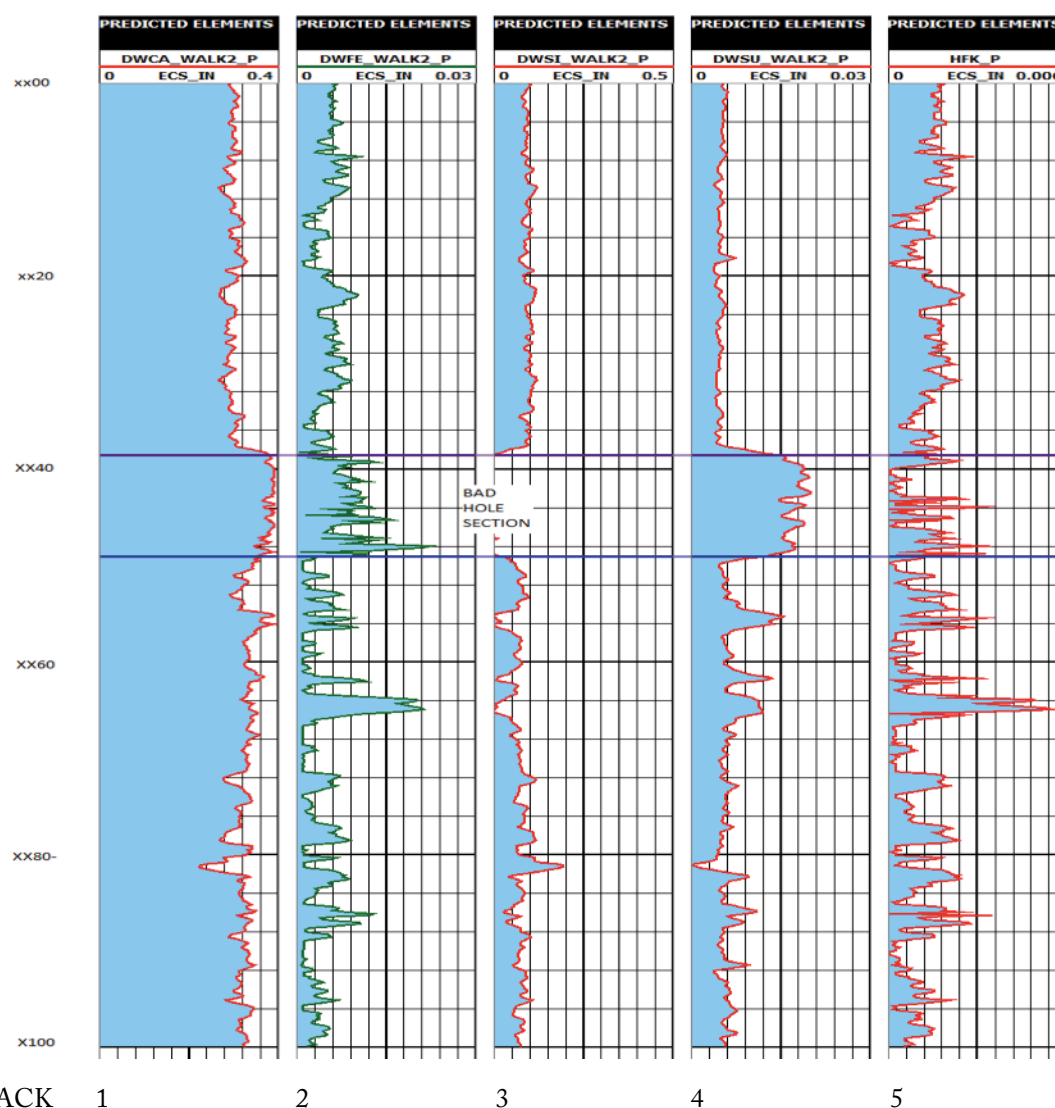


Figure 5: Predicted Elements. The Ca, Fe, Si, S and K curves have all been predicted, after correcting the bad density. It would be better if they were measured of course, but when one works with older log suites, not all data is available.



DI	DL	DP	DQ	DR	DS
ADD AN OPTION TO MAKE MORE CARBONATE WHEN NECESSARY IF DOLOMITE IS THE DOMINATE CARBONATE MINERAL					
carbonate wt%: what is the denominator?		CA*/0.394 + DOL*/0.216			
Pe% calcite*Ca/0.4	Pe% dolomite*Ca/0.22	CARB CAL-DOL	anhy%*S/0.236	anhy%*S/0.236	ANHY SUM NUM/DENOM PRODUCT
Pe% calcite	Pe% DOL	CARB CAL-DOL	ANHY%*S*0.236=NUM FOR S	0.236 PART	ANHY SUM NUM/DENOM PRODUCT
0.096	0.944	1.247842273	0	0.2353	0
0.96408	0.89992	1.948289918	0	0.2355	0
8	11	15	16	17	18
IF((("JAMIE INPUT"ADS-3)/(5.5-3)<0, IF((5.5-"JAMIE INPUT"ADS)/(5.5-3)>=1, 1, IF((("JAMIE INPUT"ADS-3)/(5.5-3)<0, ("JAMIE INPUT"ADS-3)/(5.5-3)))))					
The PEZF is 3 for dolo and 5 for calcite. So 3-5.5 describes the range, with a bit of slop at the calcite end. The Pefz describes how close it is to calcite		F5*DIS/DIS+F5*DL5/DM N5*H5*MINERALS!\$AH MINERALS!\$A 5 \$40 H\$40 DQS/DRS			
The PEZF is 3 for dolo and 5 for calcite. So 3-5.5 describes the range, with a bit of slop at the calcite end. The Pefz describes how close it is to dolo.		carb from calcite fraction plus carbonate from dolomite fraction boils down to anhydrite sulphur in wt fraction from IMS. amount of anhydrite boils down to anhydrite wt fraction from NS.			

Figure 6: Carbonate Calculation. Carbonate tip: combine calcite and dolomite via the Pe; then add anhydrite. Note the term 'Jamie Input' refers to a data input sheet.

Q	R
0.035	95.00
1.05	2900
SET CARB TO CA/0.4 ABOVE DEPTH R\$2	
<<<use WCA/0.4 if O5=1; SET DEPTH R\$2 FOR MONTNEY TO GO TO "0"	
WCARB_ECS	199 Fe
69.1323	4.3581
99.99	0.6169
WCARB_ECS	
21	22
from col DU	
IF(O5=1,DU5,IF((IF(100*(DP5+DS5)>=100,99.99,(100*(DP5+DS5))))<=0,0.000001,(IF(100*(DP5+DS5)>=100,99.99,(100*(DP5+DS5)))))	
199*G5	
if the switch is on 1, use Ca/0.4 for an estimate of carbonate. Else, use the mixture of calcite, dolomite and anhydrite dependent on Pe to partition Ca and Do. If <0, make it a small non-zero amount, to avoid divide by zero. Constrain between 0.000001 and 99.99.	
this factor takes care of the abundant iron that is not in any of the formulas for clay and pyrite, in this method.	

Figure 7: Carbonate Result. The depth in column R2 (blue arrow, top right) is set to 2900 (890m); so Ca/0.4 is used to 2900 ft (890m) for total carbonate; below this depth, a combination of {Ca/0.4*Pe_calcite_ratio + Ca/0.22*Pe_dolomite_ratio + anhydrite} is used for total carbonate, since there is appreciable dolomite below this depth. The combination of calcite, dolomite and anhydrite results in more carbonate and is appropriate in formations that are nearly 100% carbonate. The more carbonate, the less clay, consistent with the observation that the carbonate formations have little clay. Incidentally, the question may come up of "Do I work in ft or metres in the spreadsheet?" The answer is to use the same units that the log was recorded in to avoid round-off errors when converting depth to rows in the spreadsheet. Older wells like this one were recorded in ft so the spreadsheet is computed in ft.



Calculations in the spreadsheet

Now you are ready to enter the data into the Master Herron Spreadsheet. The spreadsheet starts with the elements and calculates the following results:

1. Solve for mineral groups. Solve for clastics, carbonates and clays respectively.
2. Solve for porosity.
3. Use a normalization process to convert siliclastics, carbonates and clays to individual minerals, quartz (Q), k-spar (Potassium Feldspar), plagioclase (Sodium Feldspar), muscovite (M), (the 'QFM' group of siliclastics) plus calcite, dolomite and anhydrite (the 'carb' group of carbonates) plus illite, smectite, chlorite and kaolinite (families that make up the 'Clay' group).
4. Solve for permeability, based on Dr. Michael Herron's Paper (Ref 3); we actually modify an equation to lower the low end of the perm, even lower than that indicated in his paper.

Solve for the Mineral groups

The following equations are from Herron's paper (Ref 4):

Calculate SiO_2 , CaCO_3 , $199 \cdot \text{DWFe}$, and sum them. Remember the tip in solving for CaCO_3 and also apply this tip:

When the formation is primarily clastic, then carbonate is, as Herron recommends, $\text{DWCa}/0.4$; however, when the formation is primarily a carbonate with little clay and little to no QFM, then use a sum for carbonate:

$$\text{DWCa}/0.4 \cdot (\text{Pe factor for Calcite}) + \text{DWCa}/0.216 \cdot (\text{Pe factor for Dolomite}) + \text{Anhydrite},$$

where the Pe factor is based on dolomite Pe ~ 3 and Calcite Pe ~ 5.5 . Note that 5.5 is used instead of the more accurate 5.0 for CaCO_3 , to accommodate some inaccuracy in the Pe.



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Anhydrite is based on the sulphur, where a partition is made between pyrite and anhydrite, based on how much anhydrite would be calculated using all the sulphur. If this maximum anhydrite from sulphur is greater than 3.6% and the $DWCa/0.4 \geq 3.6\%$, then there will be anhydrite but no pyrite and vice versa.

Solve for clay from three equations, constraining the result between zero and 100:

Equation 1, Low feldspar, low clay: (Example, most formations except GOM and Shales)

$(1.91 \cdot (100 - \text{SUM}))$; constrain between 0 and 100.

Equation 2, High Mica, medium clay: (Example Shale gas/oil with high muscovite)

$(2.43 \cdot (100 - \text{SUM}))$; constrain between 0 and 100.

Equation 3, High feldspar, high clay: (Example, Gulf of Mexico)

$(3.34 \cdot (100 - \text{SUM}) - 18.5)$; constrain between 0 and 100.

One does not usually know a priori, which equation to use for clay. For shale resource plays we always use the coefficient of 2.43, Equation 2, the high mica equation. For all other formations we use the minimum value of equations 1, 2, and 3. When the SiO_2 is near zero, such as in a ~ 100% carbonate, clay becomes 100-carbonate and special considerations are made to avoid divide by zero problems.

Solve for Porosity

You need a grain density and fluid density to calculate porosity from the [repaired] density log. The grain density is calculated from elements (Ref 4). The fluid density is calculated from

T	U	V
low feld; low clay	high mica medium clay	High feldspar High clay
WCLAY_ELM_ECS modified col FN	WCLAY_ELM_ECS modified col FN	WCLAY_ELM_ECS modified col FN
Wclay eqn1	Wclay clay+mica eqn2	Wclay Hi feld eqn3
45.45813838	57.83417606	60.99224199
0.955	1.215	0
24	25	26
IF((IF((1.91*(100- \$S5))<0,0,(1.91*(100- \$S5))))>100,100,(IF((1.91*(100-\$S5))<0,0,(1.91*(100- \$S5))))))	IF((IF((2.43*(100- \$S5))<0,0,(2.43*(100- \$S5))))>100,100,(IF((2.43*(100-\$S5))<0,0,(2.43*(100- \$S5))))))	IF((IF((3.34*(100-\$S5)- 18.5)<0,0,(3.34*(100-\$S5)- 18.5)))>100,100,(IF((3.34*(100-\$S5)- 18.5)<0,0,(3.34*(100-\$S5)- 18.5))))))
from the sum, apply one of three clay eqns; this clay eqn has an 1.91 slope that is meant to apply in formations with low feldspar and low clay.	from the sum, apply one of three clay eqns; this clay eqn has an 2.43 slope that is meant to apply in formations with medium clay but high muscovite as	from the sum, apply one of three clay eqns; this clay equation is for high feldspars as in the Gulf of Mexico and similar deltaic environments

Figure 8: Three clay equations.

AF	AG	AH
	use 3.5 when TOC<3 and 1.5 when TOC>3	use 1.8 when TOC<3 and 1.0 when TOC>3
KEROGEN INCLUDED IF >\$AG\$2	3.5	1.80
RHOG IF NO APA; CONSTANT SET TO GL2 FOR KER	RHOG_ker when TOC >>3; use 1.5 and 1	2.962915264
RHOG_ECS	RHOG_KER_ECS	MAX
2.728215332	2.728215332	BLANK
2.703358004	2.703358004	BLANK
	RHOG_KER_ECS	
34	940	
IF(\$I5<IP_INPUT_PARAM!\$D\$21,(2.62+0.049*\$E5+0.2274*\$F5+1.993*\$G5+1.193*\$H5),((1-\$I5/100)*(2.62+0.049*\$E5+0.2274*\$F5+1.993*\$G5+1.193*\$H5))+(\$I5/100)*((IP_INPUT_PARAM!\$D\$22+0.049*\$E5+0.2274*\$F5+1.993*\$G5+1.193*\$H5))*(1)))		
IF(\$I5<IP_INPUT_PARAM!\$D\$21,(2.62+0.049*\$E5+0.2274*\$F5+1.993*\$G5+1.193*\$H5),((1-\$I5/100)*(2.62+0.049*\$E5+0.2274*\$F5+1.993*\$G5+1.193*\$H5))+(\$I5/100)*((IP_INPUT_PARAM!\$D\$22+0.049*\$E5+0.2274*\$F5+1.993*\$G5+1.193*\$H5))*(1)))		
blank		
Derived from Herron's relationships of elements to grain density from 400 cores. It is modified to include kerogen when kerogen is greater than 3.5%, with a coefficient change from 2.62 to 1.8 for the kerogen over 3.5%. The value of 3.5% and the 1.8 are empirical, based on my work with Alberta Energy Regulator.	When TOC is high, there is a substantial effect on grain density. Make a pass with the "standard" of kerogen <3.5% and if core or high TOC >> 3, indicate grain density should be lower, change the IP_INPUT_PARAM!\$D\$21 to 1.5% and IP_INPUT_PARAM!\$D\$22 to 1 from 1.8.	

Figure 9: Rhog_ECS and Rhog_Ker_ECS. Grain density with 'normal' TOC <3 (RHOG_ECS) and 'High' TOC >>3, (RHOG_KER_ECS).

the mixture of fluids in the density zone of investigation. We need an estimate of water saturation in order to formulate the hydrocarbon (gas and oil) effect. At this stage, we start with an Archie water saturation based on the R_w from the SP, an input cementation factor of 1.85 and an input saturation index of 1.85 as well as an input tortuosity factor, 'a' of 1.0. When the RHOF is calculated in this manner, it provides a correction for gas effect on the density log.

The grain density is a modification of the element equation described by Dr. Herron. The actual equation used is

- a) If kerogen (ker) is less than (IP_INPUT_PARAM!D21) of 3.5%, by weight then

$$\text{RHOG_ECS} = \text{IF}(\text{ker} < 3.5, (2.62 + 0.049 * \text{DWSi} + 0.2274 * \text{DWCa} + 1.993 * \text{DWFe} + 1.193 * \text{DWSu}), ((1 - \text{ker}/100) * (2.62 + 0.049 * \text{DWSi} + 0.2274 * \text{DWCa} + 1.993 * \text{DWFe} + 1.193 * \text{DWSu}) + (\text{ker}/100 * ((\text{IP_INPUT_PARAM!D22} + 0.049 * \text{DWSi} + 0.2274 * \text{DWCa} + 1.993 * \text{DWFe} + 1.193 * \text{DWSu}))))))$$

Where DWSi is the dry weight of Silicon;

DWCa is the dry weight of Calcium;

DWFe is the dry weight of Iron;

DWSu is the dry weight of Sulphur;

and IP_INPUT_PARAM!D22 is the special density of kerogen assigned of 1.8 g/c3.

Note this is different than the usual kerogen density of 1.35 g/c3 but was selected empirically to result in a fit to core grain density. On the other hand, if kerogen is greater than 3.5% (i.e. TOC >> 3.0), the effect of kerogen on grain density is large and we select a combination based on the portions less than 1.5% kerogen and greater than 1.5% kerogen; we change the 3.5% (IP_INPUT_PARAM!D21) to 1.5% and the 1.8 to 1.0 (i.e. IP_INPUT_PARAM!D22= 1.0):

- b) $\text{RHOG_KER_ECS} = \text{IF}(\text{ker} < 1.5, (2.62 + 0.049 * \text{DWSi} + 0.2274 * \text{DWCa} + 1.993 * \text{DWFe} + 1.193 * \text{DWSu}), ((1 - \text{ker}/100) * (2.62 + 0.049 * \text{DWSi} + 0.2274 * \text{DWCa} + 1.993 * \text{DWFe} + 1.193 * \text{DWSu}) + (\text{ker}/100 * ((\text{IP_INPUT_PARAM!D22} + 0.049 * \text{DWSi} + 0.2274 * \text{DWCa} + 1.993 * \text{DWFe} + 1.193 * \text{DWSu}))))))$,

where IP_INPUT_PARAM!D22 is the special density of kerogen now assigned, of 1.0

The above Herron formulas include modified equations derived empirically using core grain density as a guide. We make an initial pass which computes RHOB_KER_ECS but does not use it for porosity. If you have a TOC >> 3 and want to use



the high kerogen impact on grain density, then adjust the IP_InPUT_PARAM!D21 to 1.5 and IP_InPUT_PARAM!D22 to 1.0 and rerun.

The grain density and fluid density are now combined to calculate total porosity. The next step is Permeability.

Solve for Normalization of Elements to Minerals and Permeability

Using empirical evidence from cores to modify the Herron K-Lambda equations, one derives permeability (Ref 3). We start with Cation Exchange Capacity (CEC) and it becomes immediately apparent that the group called 'Clay' is not sufficient to find the total CEC, as the CEC varies from ~2 for chlorite to ~100 meq/100g for smectite. Therefore, we now need to know how much of each clay family, illite, kaolinite, smectite and chlorite, we have. This leads to an involved normalization process where we convert the groups into their constituents. The method is to use a hierarchy of assigning the elements to the minerals:

Start with sulphur and divide into anhydrite and pyrite, as mentioned previously, assuming there is neither Gypsum nor Barite.

Next divide the carbonate group using calcium and Pe as also mentioned previously, assuming there is neither Ankerite, Apatite nor Calcium feldspar.

Now divide the aluminum amongst the clays by initially assuming clay is all illite (call it illite 1) and the feldspars, potassium (call it k-spar1) and plagioclase. Note this is an addition to the above hierarchy used in Robust ELM (Ref 2). Incidentally, Kaolinite and Muscovite are higher aluminum minerals.

The next step is to divide iron but first we also insert potassium as we will compare illite from both an iron calculation and a potassium calculation. What iron is not used after pyrite is determined, between illite (call it illite2), chlorite. Also divide the potassium between illite (call it illite 3) and potassium feldspar (call it k-spar2). Assumed absent minerals are Biotite, Siderite and Hematite. Smectite is assumed to be mixed layer with high illite. The iron in Kaolinite in the above list is not present; it is artificially included in the list for Robust ELM so that all the clay families are grouped together. We find the minimum of illite1, illite2, and illite3 and call that illite 4. We find the minimum of kspar1, kspar2 and call it kspar3. Now we can calculate chlorite from the leftover iron and plagioclase from the leftover aluminum.

Silicon is used last to determine the feldspars, potassium feldspar and plagioclase (mainly sodium feldspar). Then quartz is determined from the silicon that is left over.

Here is the trick. We haven't calculated muscovite yet. To do this we assume that the Herron clay includes muscovite as the illite and muscovite could not be separated when his study was

Sulfur	Pyr		FeS_2	
	Anh		$\text{Ca}(\text{SO}_4)$	
	Gyp		$\text{Ca}(\text{SO}_4) \cdot 2(\text{H}_2\text{O})$	
	Bar		$\text{Ba}(\text{SO}_4)$	
Calcium	Cal		CaCO_3	
	Dol		$\text{CaMg}(\text{CO}_3)_2$	
	Ank	0.20	$\text{Ca}(\text{Fe}_x\text{Mg}_{(1-x)})(\text{CO}_3)_2$	
	Apa		$\text{Ca}_5(\text{PO}_4)_3(\text{F}_{0.00}, \text{Cl}_{0.00}, \text{OH}_{1.00})$	
	Csp		$\text{CaAl}_2\text{Si}_2\text{O}_8$	
Iron	Kao	0.01	$\text{Al}_{2-x}\text{Fe}_x\text{Si}_2\text{O}_5(\text{OH})_4$	Insert Aluminum
	Smc	0.20	$(\text{K}_{0.165}, \text{Na}_{0.165})(\text{Al}_{1.67-x}, \text{Fe}_x\text{Mg}_{0.33})(\text{Si}_4\text{O}_{10})(\text{OH})_2$	
	I/S	0.50	Fraction of Ill layers in Ill/Smc	
	Ill		$(\text{K}_{0.70})(\text{Al}_{1.53}, \text{Fe}^{3+}_{0.22}, \text{Fe}^{2+}_{0.03}, \text{Mg}_{0.28})(\text{Si}_{3.4}, \text{Al}_{0.6})\text{O}_{10}(\text{OH})_2$	
	Chl	2.70	$(\text{Fe}_x/(\text{Fe}_x + \text{Mg}_{(3-x)}))(\text{Si}_3\text{Al})\text{O}_{10}(\text{OH})_2 (\text{Fe}_x/(\text{Fe}_x + \text{Mg}_{(3-x)}))(\text{OH})_6$	
	Msv		$\text{K}[(\text{Al}_{0.50}, \text{Fe}^{3+}_{0.50})(\text{Mg}_{0.50}, \text{Fe}^{2+}_{0.50})](\text{Si}_{3.5}\text{Al}_{0.5})\text{O}_{10}(\text{OH})_2$	
	Bio	0.00	$\text{K}(\text{Mg}_{1.5-x}\text{Fe}^{2+}_{1.5+x})_3(\text{Si}_3\text{Al})\text{O}_{10}(\text{OH})_2$	
	Sid		FeCO_3	
	Hem		Fe_2O_3	
Si	Ksp		KAISi_3O_8	Insert Potassium
	Nsp		$\text{NaAISi}_3\text{O}_8$	
	Qtz		SiO_2	

Figure 10: Hierarchy to assign elements to minerals for Robust ELM (Ref 2). There are two additions in the spreadsheet method: aluminum which affects all clays plus all feldspars and potassium which affects illite clay and potassium feldspar (Ksp).



done. So, we test for 'muscovite1' as 100-sum of minerals. We also make another assumption that the neutron-density separation is caused by the clay minerals as well as muscovite. So, we calculate this separation, convert from volume to weight and call it 'WMIN', for water or hydrogen, in the clay minerals.

Then we assign a portion of WMIN to each clay. For example, we might use kaolinite = 6% of WMIN, illite = 25% of WMIN, smectite = 6% of WMIN, and Chlorite = 4% of WMIN. The actual numbers used require a match of the clay minerals to core clay analysis. When we have no core, we estimate these percentages and depend on reconstruction to validate their abundance. These percentage estimates would account for 41% of WMIN, leaving a remainder for muscovite and other neutron absorbers. We then sum the kaolinite + illite + smectite + chlorite to provide the total clay from WMIN. We use the clay group calculated at the beginning, which also contains muscovite and subtract the clay group from 'WMIN-clay' resulting in 'muscovite2'.

Another sum of all the minerals is made and re-normalization to 100% is performed. Assign errors to particular minerals and apply limits by the input elemental abundance. The resulting minerals are deconvolved to their oxide chemistry components and summed to 100%. Another normalization is performed and iteration is continued until the sum of the minerals is 100%+/-0.01.

Finally, having the clay minerals separated, we can calculate CEC from the sum of the mineral abundance times the CEC for each clay. We use

$$\text{CEC} = \text{kaolinite} * 6 + \text{illite} * 25 + \text{smectite} * 50 + \text{chlorite} * 2$$

Smectite varies from 50 to 100 depending on the mixed layer status and we usually use a 'high' illite-smectite CEC of 50 rather than zero illite in illite-smectite of 100.

We now need surface area and m-star (m^*) for permeability.

First, Surface area, $So = \text{Quartz_silt} * 1.2 + \text{Kspar} * 0.3 + \text{Plag} * 0.3 + \text{Muscovite} * 2 + \text{Calcite} * 0.6 + \text{Dolomite} * 2 + \text{Anhydrite} * 1 + 0.1 * \text{kaolinite} * 23 + 0.1 * \text{illite} * 101 + 0.1 * \text{smectite} * 100 + 0.1 * \text{chlorite} * 15$.

Note that we usually use Quartz as Quartz-silt, surface area of 1.2 when computing shales. Otherwise we might use Quartz-medium grained, surface area of 0.22.

The 0.1 clay factor is changed to 0.2 for diagenetic clays.

Second, $m^* = 1.653 + (0.0818 * \text{Surface area} * \text{grain-density}) * 0.5$

Third, permeability is in two steps to account for perm above 100 mD and perm below 100 mD

$$\text{Perm1} = 20,000 * \text{TPOR}(m^* + 2) / ((1 - \text{TPOR})^2 * (\text{RHOG2}) * (0.1 * 60 * \text{CLAY} / 100 + 1.2 * \text{Qtz} / 100 + 2 * \text{Carb} / 100 + 0.3 * \text{pyrite} / 100)^2$$

$$\text{Perm2} = 0.037325 * \text{Perm1}^{(1.714)}$$

Note that this Perm2 formula is not the one from Herron's paper but is an empirical modification, resulting in a lower perm from Perm2. We finish by combining Perm1 and Perm2,

Final Perm = If Perm1 > 100, Perm1, otherwise, use Perm2.

Conventional reservoirs often use Perm1 ($K > 100$) whereas unconventional will always use Perm2.

Matrix-adjusted Density and Neutron Porosity

In order to determine a gas effect, we calculate 'matrix-adjusted' [instead of limestone or sandstone] porosities.

First, matrix-adjusted neutron, PHIN_MAN, is

$$(\text{PHIN_MATRIX} - \text{NPHI}) / (\text{PHIN_MATRIX} - \text{PHIN_FLUID}),$$

Where,

$$\text{PHIN_MATRIX} = 0.408 - 0.889 * \text{DWSi} - 1.014 * \text{DWCa} - 0.257 * \text{DWFe} + 0.675 * \text{DWSu},$$

and,

PHIN-FLUID is the neutron response in gas, 0.52; and NPHi is the recorded neutron in limestone units.

Similarly, $\text{PHID_MAD} = (\text{RHOG} - \text{RHOB}) / (\text{RHOG} - \text{RHOF})$

where RHOG and RHOF were determined earlier;

then Gas Flag = 1 if $\text{PHIN_MAN} < (\text{PHID_MAD} + 0.03)$;

the constant, 0.03, helps to avoid cross-over at bed boundaries that may be slightly off depth.



Modeled Neutron, M_NPHI

The modeled neutron is compared to the measured neutron to provide an approximation of the derived mineral's neutron capture cross section. If the modeled neutron matches the recorded neutron, one grins and says, "There I told you so; it works and all my minerals are correct." This is not the normal case. The recorded neutron is lowered by gas and increased by clay; the modeled neutron is dependent on the porosity so, in porosity less than 15%, it is more affected by the clay than the gas. The recorded neutron is usually not corrected for borehole size, so a large borehole size will lower it. The recorded and the modeled neutron are increased by the clays. In the absence of gas, we expect them to be 'close' together. We have an approximate

check that the abundance of clays is in the right ball park. The calculation follows:

$$M_NPHI = (TPOR * TNPH_FLUID) + ((1-TPOR)*TNPH_MATRIX),$$

Where,

$$TNPH_FLUID = (Sw_Archie*0.9)*(1-0.85) + ((1-SwArchie)*AS5*(0.52))*(1-0.85) + ((1-SwArchie)*(1-AS5)*(1.0561))*(1-0.85) + (1.5)*(0.85),$$

where 0.85 is the invasion fraction of the depth of investigation of the recorded neutron,

1.5 is the mud filtrate TNPH response

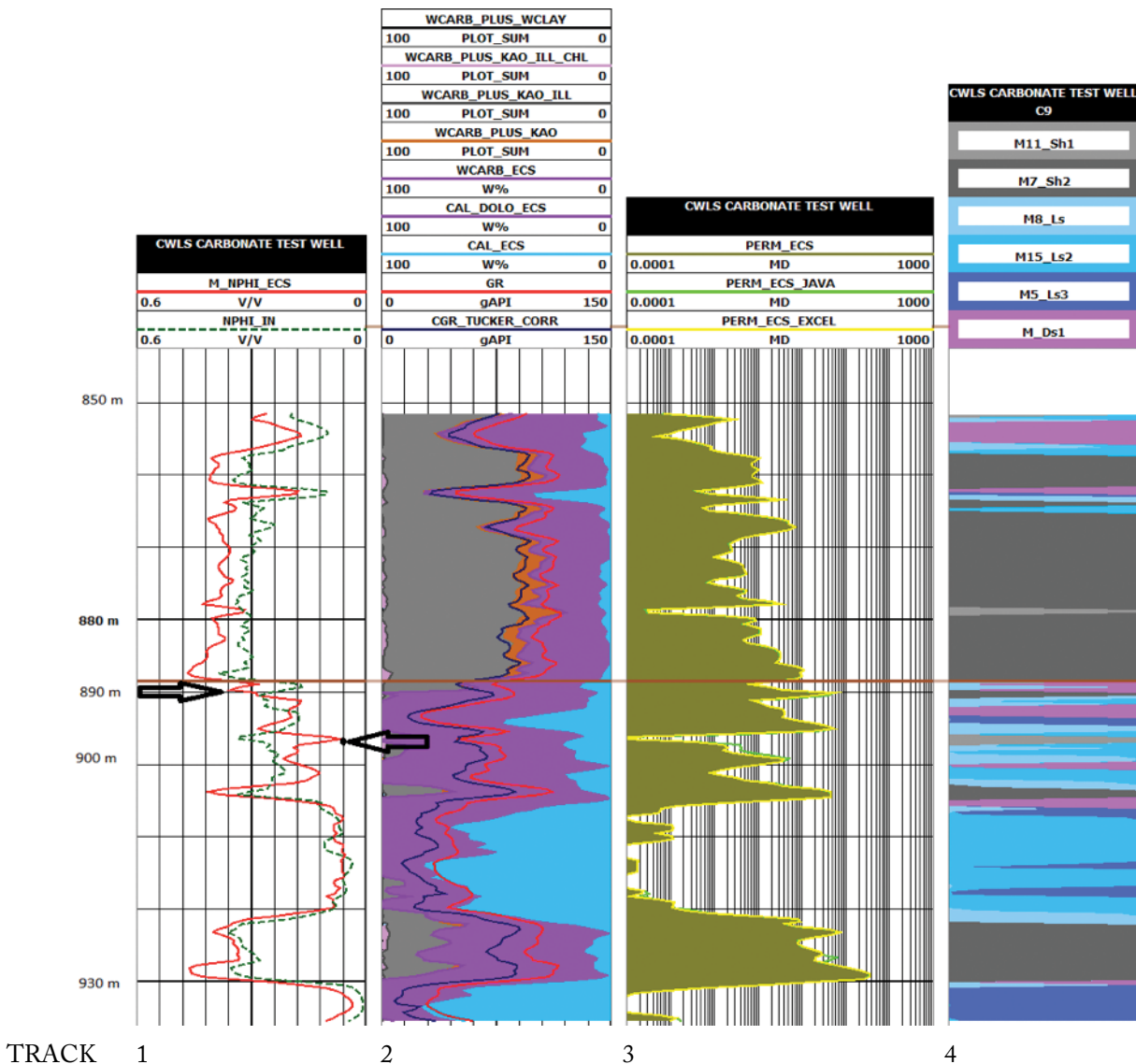


Figure 11: Modeled Neutron vs. Recorded Neutron. Track 1, Modeled neutron is red and recorded neutron is dashed-green. Modeled and recorded neutron curves are relatively close but the modeled neutron is consistently higher than the recorded neutron, above the black arrow at 890 m. At the lower black arrow, where the modeled neutron is less than the recorded neutron, the porosity is spiking low, as evidenced by the low permeability spike.



0.52 is the gas TNPH response

1.0561 is the oil TNPH response

and AS5 is the RHOF2 fluid response for the mixture of mud filtrate, gas, oil and formation water, based on an input estimate of GOR (0 or 1) and a calculated Sw_Archie .

$$AS5 = ((RHOF1)*(1-0.85)) + ((IP_InPUT_PARAM!D13)*(0.85)),$$

where $IP_InPUT_PARAM!D13$ is the mud filtrate density of, usually, 1.05 and,

$$RHOF1 = (Sw_Archie*IP_InPUT_PARAM!D10) + (1-Sw_Archie)*(GOR)*(IP_InPUT_PARAM!D11) +$$

$$(1-Sw_Archie)*(1-GOR)*(IP_InPUT_PARAM!D12), \text{ and}$$

$IP_InPUT_PARAM!D10$ = formation water fluid density, usually 1.05, and

$IP_InPUT_PARAM!D11$ = Gas density, usually 0.13, and

$IP_InPUT_PARAM!D12$ = Oil fluid density, usually 0.83.

Consequently, above 890m, the modeled neutron may see too much clay or, at least too much of the higher thermal neutron capture cross section clay such as kaolinite (and chlorite, but there isn't much chlorite). Below 890 m, in the Carbonate, the modeled neutron is closer. Considering the input elements were predicted, we accept the minerals as modeled, to provide some confidence in the derived mineralogy.

On Track 2, we have superimposed a GR in red and a CGR in dark blue, on the mineralogy. It is serendipity that the CGR follows the illite on the particular CGR scale chosen, above 890 m. Note that it does not follow the illite in the carbonate zone below 890m.

Track 3 shows the permeability from three sources: the original spreadsheet computation, the new spreadsheet (EXCEL) and the JAVA computation, which was coded from the new EXCEL spreadsheet. The fact that they are all close to being the same means our Java computation is OK. Java uses a different Math Pack than Excel, so it is important to check that they produce the same result. An interesting observation is that some of the clay zones have the highest perms, although the overall perm is still quite low (average ~ 1 mD for clay zones and ~ 0.0001 for carbonate zones). Clay porosity is high (~30%) relative to the carbonate porosity (~6%).

Track 4 shows the lithology from a cluster of Density, Neutron, GR, DT, Pe, DWCA_p, and DWSI_p. The 'p' means the Ca and Si were predicted. The clustered 'shales' (a lithology term) reflect the clay minerals as one would expect.

Summary

We walked through the steps for the spreadsheet calculations of the mineral groups and their normalization process to convert the mineral groups to individual minerals. There are many parameters available to adjust, if the resulting minerals do not match quantitative mineral measurements.

Along the way, we calculated grain density, total porosity, permeability and CEC.

In the next stage (a later installment) we will determine water saturation and 'water flags' with our calculated parameters to decide if the water saturation is low enough to produce hydrocarbons water-free.

We will use magnetic resonance to determine the free porosity to make this water-free determination. If the formation is fractured, the water in the small capillaries of the effective porosity can also produce water, so we need to determine what effective porosity is, using the cation exchange capacity. So, stay tuned for the next installment.

References

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About The Author

Robert (Bob) Everett is the sole owner of Robert V Everett Petrophysics Inc. Bob works from his office in Merville, BC (Vancouver Island). He also works as a consultant for Eric Geoscience, using probabilistic interpretation methods. When living in Austin, Bob worked at the University of Texas at Austin on a Gas Research Institute tight gas project and consulted for UnoCal and Z & S Consultants in Houston.

After graduating from UBC in Mechanical Engineering in 1964, he worked 17 years with Schlumberger of Canada, 4 years at Schlumberger Doll Research (SDR) and 6 years with Schlumberger Well Services in New Orleans and Austin. While at SDR, Bob was team leader of a group tasked to develop an improved volume of shale model interpretation method. The result of the work was the nuclear spectroscopy methods. Now tools such as the ECS, LithoScanner, FLeX and GEM provide element measurements, enabling the use of nuclear spectroscopy interpretation methods.

The methods can be applied to shales, clastics and carbonates. When combined with nuclear magnetic resonance, the combination of nuclear spectroscopy and nuclear magnetic resonance can be applied anywhere in the world to coax the signals out of the rocks.



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Appendix

Glossary

* Names Used For Output & Description

1. CAL: calcite abundance by weight.
2. CAL_DOLO: calcite plus dolomite abundance by weight.
3. CEC: cation exchange capacity summed from the CEC of each clay * abundance of each clay type.
4. CHL: chlorite abundance by weight.
5. DOL: abundance of dolomite
6. DWAL_WALK2_P: dry weight aluminum that was input to the program. This input may have been a predicted value or a measured value but the output is always with a '_P'.
7. DWCA_WALK2_P: dry weight calcium that was input to the program. This input may have been a predicted value or a measured value but the output is always with a '_P'.
8. DWFE_MINUS_14WAL: dry weight iron minus 14%*aluminum that was input to the program. This input may have been a predicted value or a measured value but the output is always with a '_P'.
9. DWFE_WALK2_P: dry weight iron that was input to the program. This input may have been a predicted value or a measured value but the output is always with a '_P'.
10. DWK_WALK2_P: dry weight potassium that was input to the program. This input may have been a predicted value or a measured value but the output is always with a '_P'.
11. DWSI_WALK2_P: dry weight silicon that was input to the program. This input may have been a predicted value or a measured value but the output is always with a '_P'.
12. DWSU_WALK2_P: dry weight sulphur that was input to the program. This input may have been a predicted value or a measured value but the output is always with a '_P'.
13. DWTI_WALK2_P: dry weight titanium that was input to the program. This input may have been a predicted value or a measured value but the output is always with a '_P'.
14. FELD: abundance of kspar plus plagioclase.
15. GAS_FLAG: indicates that the neutron (PHIN_MAN) is less than the density porosity (PHID_MAD).
16. HFK_P: potassium either predicted or measured that was input to the spreadsheet program. Identical to DWK_WALK2_P.
17. ILL: illite abundance by weight% .
18. KAO: kaolinite abundance by weight%.
19. KAO_ILL: kaolinite plus illite abundance by weight% for plotting.
20. KAO_ILL_CHL: kaolinite plus illite plus chlorite abundance by weight%, for plotting.
21. KAO_ILL_CHL_MUSC: kaolinite plus illite plus chlorite plus muscovite abundance by weight% for plotting.
22. KAO_ILL_CHL_SME: kaolinite plus illite plus chlorite plus smectite abundance by weight% for plotting.
23. KSPAR: potassium feldspar abundance by weight%.
24. M_NPHI: modeled neutron reconstruction, based on a calculated neutron matrix based on a thermal neutron response for each mineral. The fluid response is based on the [invaded] zone of investigation of the thermal neutron with whatever fluids are in that zone. Its use is intended to be a quality control factor for the minerals. If the modeled and the measured neutron agree, then the minerals are feasible.
25. MUSCOVITE: the sum of the muscovite from the 'total clay plus muscovite' Herron calculation minus the illite, kaolinite, smectite and chlorite.
26. PERM_ECS: permeability derived from mineral surface area and total porosity, TPOR.
27. PHID_MAD: matrix-adjusted density porosity, where the matrix density is determined by elements.
28. PHIE: effective porosity, = TPOR*(1-SWB)
29. PHIN_MAN: matrix-adjusted neutron porosity, where the matrix is determined from elements.
30. PLAG: plagioclase, where the assumption is 60% Na-spar and 40% Ca-spar ~ oligoclase.
31. QTZ_KSP: abundance in wt. % of quartz plus Kspar for plotting.
32. QUARTZ: abundance in wt.% of quartz.
33. RATIO_PEF_CAL_DOLO: ratio of calcite to dolomite from the Pef curve where Pef of 3 is dolomite and Pef of 5.5 is calcite.
34. RATIO_PEF_DOL_CAL: ratio of dolomite to calcite from the Pef curve where Pef of 3 is dolomite and Pef of 5.5 is calcite.
35. RHOG_ECS: grain density of minerals, including kerogen when < 3.5%, in g/c3, calculated from elements.
36. RHOG_KER_ECS: grain density of minerals, with kerogen above 1.5%, in g/c3, for calculating porosity_GRI. Calculated from elements and kerogen.
37. RO: wet resistivity.
38. RUTILE: TiO2 from input titanium.
39. RW_SP_USED: formation water resistivity used in calculations of Sw_Archie, Ro and Swt_ECS.
40. SMEC: abundance of smectite in wt. %.
41. TOC_USED: selected TOC equation for calculations of adsorbed gas.
42. TPOR: total porosity calculated from the density log, using 1.0 for fluid and RHOG_ECS [FROM ELEMENTS with Ker<3.5%].

43. WANH: abundance of anhydrite, derived from sulphur.
44. WCAR_WANH: abundance of carbonate minus anhydrite for plotting.
45. WCARB_ECS: abundance of carbonate.
46. WCARB_MUSC_WCLAY: abundance of carbonate plus muscovite plus clay for plotting.
47. WCARB_PLUS_KAO: abundance of carbonate plus kaolinite for plotting.
48. WCARB_PLUS_KAO_ILL: abundance of carbonate plus kaolinite plus illite for plotting.
49. WCARB_PLUS_KAO_ILL_CHL: abundance of carbonate plus kaolinite plus illite plus chlorite for plotting.
50. WCARB_PLUS_KAO_ILL_CHL_SME: abundance of carbonate plus kaolinite plus illite plus chlorite plus smectite for plotting.
51. WCLAY_CM: weight fraction of clay + muscovite using the Herron clay-mica model.
52. WCLAY_HF: weight fraction of clay + muscovite using the Herron high feldspar model.
53. WCLAY_LF: weight fraction of clay + muscovite using the Herron low feldspar model.
54. WMIN: used to estimate the fraction of each clay type from the separation of the neutron density porosity. Nominally water in the minerals.

$$WMIN = (NPHI_IN - DPHI_2.71) / (1 - DPHI_2.71) * 2.71$$
 Dimensionally correct calculation is:

$$WMIN = (NPHI_IN - DPHI_2.71) / (1 - DPHI_2.71) * 1/2.71$$
55. WQF: abundance of quartz plus plagioclase plus kspar.
56. WQFM: abundance of quartz plus plagioclase plus kspar plus muscovite.

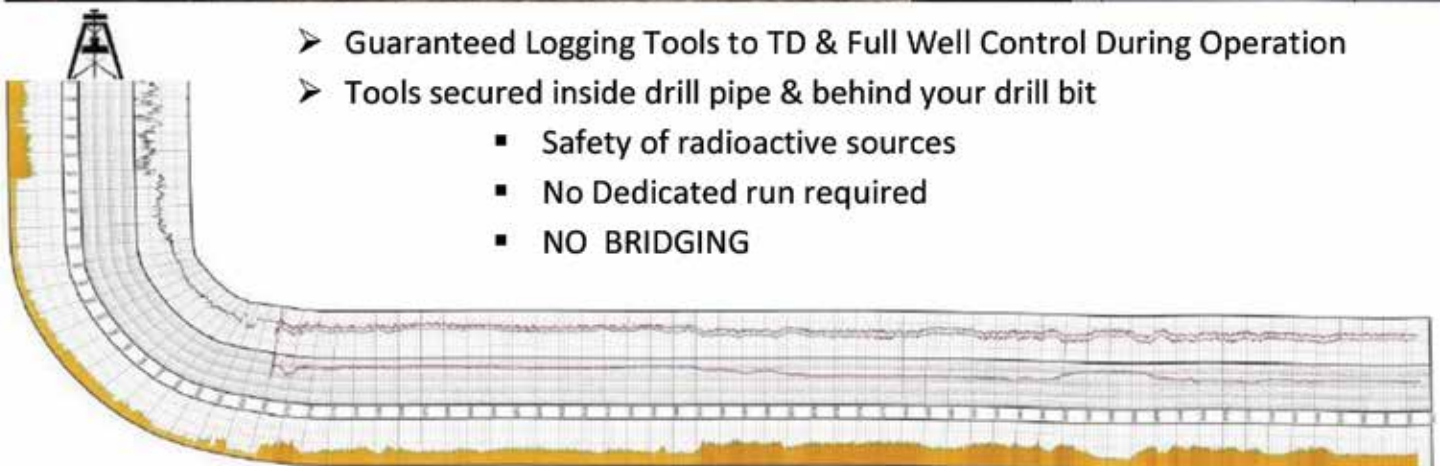


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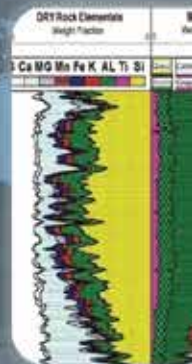
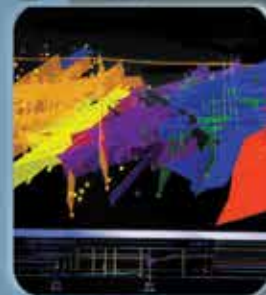
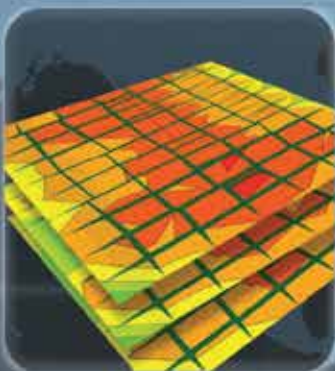
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