InSite

CWLS Magazine
June 2006 Issue 2 Volume 25

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CWLS Magazine **June 2006**

Issue 2 **Volume 25**

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InSite is published 4 times a year by Sundog Printing for the Canadian Well Logging Society.

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Cover Photos: *Twilight photo of the rig Rowan Gorilla 5 (RG V) in Halifax Bay waiting to get towed out to sea for the drilling of El Paso Mariner I-85 well, offshore Sable Island. Photo courtesy of Edwin Macdonald.*

No auto digger on this rig in Kazakhstan (and not really much of a control panel), so the driller stays at the brake handle for his entire shift. Photo courtesy of Carole Augereau.

If you have a photo that the CWLS can use on its next InSite cover please send a high resolution jpeg format version to tmaksymchuk@br-inc.ca or ben@waveformenergy.com. Include a short description of the photo with your submission.

The 2006 - 2007 CWLS Executive:

Front row (l - r): Jeff Taylor, John Nieto, Peter Kubica, Michael Stadnyk
Back row (l - r): Gordon Uswak, Gary Drebit, Dave Ypma, Benjamin Urlwin, Tyler Maksymchuk

President's Message

It is a pleasure to work with the strong executive that the membership elected this year.

The continuity from last year provided by both the Publication Co-chair, Ben Urlwin, and the Treasurer, Gary Drebit, are proving to be very valuable. Gary Drebit's previous experience in keeping us in line financially has been extremely helpful. Also, the rest of the executive has taken over their functions very successfully.

We are very keen to build on the efforts and achievements of the previous executive that initiated great improvements in our website and its functionality. Our plans for this year include further expansion of the SCAL database which is currently available to all our current members.

The CWLS's monthly luncheons have been well attended. It is our intent to continue to bring in speakers with presentations that are of high interest to the membership. The CSPG-CSEG-CWLS joint conference was a great opportunity to attend sessions of interest for our members. Four of the sessions were dedicated to wireline technologies, core analysis and formation evaluation. In addition, the CWLS also organized six one-day short courses presented by experts in their fields. All courses were well attended, with some of them being overbooked due to space limitations.

The provinces of Sakatchewan and Manitoba recently initiated paperless submissions of wireline data to the associated government agencies. In the future, instead of having to submit three paper copies of the logs, the operating companies will need to send in just one CD with LAS and image files. This will represent great savings in data handling for all parties involved – service companies as well as operators. Together with representatives of the oil and gas industries the CWLS is participating in initiating a similar proposal for Alberta. I think there is support from all parties in this proposal. If you have any comments on this issue please do not hesitate to contact me.

The executive is in the process of deciding on the student awards for this year. We believe that it is important to support and encourage students to enter our profession and soon we will be announcing the winners of 2006 student awards.

Finally, we are in the early stages of preparation for the Fall Topical Conference in Kananaskis (Oct 30-Nov 2/2006). This will be a joint topical conference with the SPWLA on measurements and interpretations of stress in subsurface formations. The proximity of the location will provide an opportunity for CWLS members to participate in presentations and discussion with the top experts in the field of stress analysis.

We believe that our 2006 planned activities will be of interest to our membership and that they will provide good value. If you have any questions for the executive, or have some ideas and suggestions for CWLS activities, do not hesitate to contact me.

Peter Kubica
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Editor's Note

Welcome to the June, 2006, InSite publication, the second publication for what is looking like another record year for Calgary, and in particular, Calgary's oil and gas sector. Although gas prices have softened significantly over the past months (due to warmer winter weather and high stored reserves), oil continues to remain high, driving our industry's record breaking pace. From the beginning of January through to the end of April, total metres drilled increased by over 20% to approximately 10 million meters, reflecting a 29% increase in rigs released during the same period (2,590, up from 2,015 for the same period in 2005). However, despite the record pace for the past 12 months, the 2006 breakup period through April saw the lowest number of wells spudded since 1999 (280 versus 635 for the same period in 2005 – source: DOB). Towards the end of May, activity levels rebounded with rig activity reach upwards of 800 once again. Even with the slow period during the melt, there appears to be no foreseeable turn around in the high oil prices, particularly with worldwide demand continuing to increase, despite high crude prices.

China (currently the second largest oil consumer in the world) still registers as a country with one of the most rapidly escalating energy demands in the world. China's demand for oil increased by nearly 11% in April alone, with the country now consuming nearly 7 million barrels of oil per day. With such a strong and ever-increasing demand, China is continuing to look to Canada for future supply, particularly with the massive oil sands projects that are currently getting under way in the Athabasca area. Land sale revenues for oil sands prospects have already breached the $2 billion dollar mark for 2006. All signs are pointing towards the continuation of this strong pace for the remainder of the year. If this pace is maintained, the oil sands area will easily reach the CAPP production forecast of 3.5 million barrels a day by 2015, almost guaranteeing Alberta's prosperity into the coming decade.

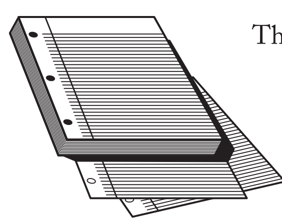
In this month's InSite issue we have the final of four Myth Interpretations written by Ross Crain, entitled "Density Logs Read Porosity in Sandstones". The CWLS would like to sincerely thank Ross for his excellent and thought provoking contributions over the years, and hope that his work will continue, inspiring more contributors to come forward. Tying in with Ross' paper, is the first of a two part series written by Gene Ballay and Roy Cox titled "Formation Evaluation: Carbonate vs. Sandstone" (the second and final part to be presented in the Sept, 2006, InSite edition). Our second paper addresses the challenges of CBM development within Alberta. The title is "An Update: Meeting the Legal, Regulatory and Environmental Challenges of Coalbed Methane Development in Alberta". This summation was written by Alan Harvie, and is an excellent breakdown of the issues that will be at the forefront of the emerging CBM plays within this province.

If you wish to submit, or learn more about submitting, an article for publication in InSite, please feel free to contact either of our Co-Chairs of Publications (whose contact details are in the magazine) or visit the CWLS website at www.cwls.org.

Enjoy this edition of the InSite!

Tyler Maksymchuk
Ben Urlwin
Co-Chair Publications

Call for Papers



The CWLS is always seeking materials for publication. We are seeking both full papers and short articles for the InSite Newsletter. Please share your knowledge and observations with the rest of the membership/petrophysical community. Contact publications co-chairs Ben Urlwin (ben@waveformenergy.com) at (403) 538-2185 or Tyler Maksymchuk (tmaksymchuk@br-inc.ca) at (403) 260-6248.

As the Winch Turns: Too Long in the Bush

The other day I stepped out of my shack and noted the number of new trucks on the lease. There were new Dodge and Ford diesels and a couple of Chevrolets. Seven or eight trucks with a retail value of more than $50,000. Only my truck looked like it belonged in the used car part of the dealers' lot. That is because I remember the last time.

It was the spring of 1986 and the rig count was probably in the high two hundreds. There was a complete lack of work. The only geologists still working were either stupid or stubborn. Two jokes were making the rounds in Calgary. "How do you get a geologist's attention?" and "What is the difference between a pigeon and a geologist?"

Everyone in the field was driving older vehicles. The most common crew vehicle was an old Chevrolet Impala with the spare tire bolted to the trunk lid to increase the luggage capacity. Generally the sole job of the motorman on nights was to repair the crew vehicle so that the boys could leave on long change morning. It always seemed that the drilling companies could have saved money by buying every crew a reliable truck.

Of course my truck was of an older vintage: a 1980 Toyota four wheel drive with a four cylinder motor. It could have been charitably described as "experienced". In truth it was worn out, but with the low oil price it was all I could afford. Its' greatest strength was that it always started. Even in Helmet, in the middle of the winter, not plugged in. First time, every time. The only time it was ever stuck was when I lost Highway 22 in a snow storm and drove into a farmers duck pond.

I had lucked out that spring and got a two week job in the middle of a big mud puddle near Valleyview. Once the job was finished, I rushed back to town, changed into a suit, and roared off to the client. The suit was, of course, meant to impress the client enough to hopefully get another job and keep eating.

The closest parking was at the old parkade on Sixth Avenue. Since the parking stalls had a decided slope and the engine did not have enough compression to hold the truck in place, against my better judgment I set the parking brake. Two hours later when I got back the mud had set up as hard as concrete and the brake would not release. But not to worry I had my trusty Estwing rock hammer. I climbed under the truck and started chipping at the mud. It was nerve wracking work because there was the distinct possibility of becoming the second wellsite geologist to run over himself. Not to mention the urge to avoid a dry cleaning bill. Things were progressing when I heard two sets of foot steps. A quick glance out from under the back bumper showed a pair of dress shoes and a pair of high heels with lovely ankles.

The female voice asked, "What on earth his he doing?"

The reply was, "Don't ask, he's just a geologist."

I crawled further under the truck and stayed there until I hear the car leave. Oh, and the answers are: "Hey waiter!" and "A pigeon can make a deposit on a new truck."

Dave

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Executive Message

The CSPG-CWLS-CSEG conference during the week of May 14 was well attended, with many of the presentations having standing room only. The CWLS had a booth near the common area and many acquaintances were renewed. Congratulations to the attendees who stopped by the booth and were drawn for the CWLS anniversary watches. As people were registering for the conference, there were a few calls made to the CWLS office to obtain their membership number, which reduced the early bird registration fee. The goal of establishing individual membership numbers was initiated by the previous Membership Chairman, Dion Lebreau, and has been passed on as a goal to be completed in 2006. Part of the goal will be to establish a method by which the membership numbers will be easily distributed to the individual members.

The current 2006 active membership is 515 and continues to grow. Many of the new memberships and renewals have been done through the CWLS website (www.cwls.org). The website provides access to previous publications, technical luncheon updates, LAS Info, employment opportunities, student information, events, contact to the CWLS executive, industry courses and links to various government agencies and other professional societies.

With active membership and, having set up a personal password, members will also have access to the Community of Practice, which provides a bulletin board environment for discussion of petrophysical queries. Also available in the member's only section is the core database, Rw mapping application and online publications. Once logged in the member can also update their personal profile, by clicking on the "Profile" tab in the upper right hand corner of the webpage. I encourage all members to review their profiles in the near future to ensure that there are no errors in their contact information.

In the fall, prior to the 2007 renewals, more information on using the CWLS website will be forthcoming. Wishing all members a safe and healthy summer.

Micheal Stadnyk
Membership Chair

New Members

Mikhail Alexeev, McDaniel & Associates Consultants Ltd.
Brian Allan, Weatherford Canada
Irfan Baig
Mohamed El Amine Bencherif, Baker Hughes-Baker Atlas
Evan Bianco, University of Alberta
Shpetim Cobaj, Tucker Wireline Service
Devon Corporate Library, Devon Canada Corporation
Kimberly Crawford, BJ Services Company Canada
Fred Dewis, Ryder Scott Company-Canada
Irma Eggenkamp, Shell Canada Ltd.
Bruce Elijah, Southwestern Energy Production Co.
Brian Evans, Dominion Exploration Canada
Charles Fensky, Schlumberger
Alain Fleury
John Folnovic, Petrodell Energy Inc
Nader Gerges, Tucker Energy
Brenda Gregoire, Enterra Energy Trust
Yujun Han, Baker Atlas
Edward Hasiuk, Paddock Lindstrom & Associates
Lori Hill, Sequoia Oil & Gas Trust
Camelia Horvath, Penn West Energy Trust
Mohammad Irfan, Belloy Petroleum Consulting Ltd.
Amine Khelil, ENSP
James Koch, Weatherford Canada Partnership
Andy Kristianto, UGM
Bob Lee, BAKK Lee Limited
Nicole Lehocky, Precision Energy Services
Chris Letcher, Tucker Wireline Services
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Peter Lywood, Schlumberger
Alexandra MacDonald, Weatherford Canada
Rochelle Mack, EnCana Corporation
Greg Mann, Weatherford Canada
J. Kim McLean, Paradigm
Shelly Mepham, Western Oil Sands Inc
Peter Milbradt
Mandy Miller, Penn West Energy Trust
Firoze Mondegarian, Shell Canada Limited
Mariela Parra, Devon Canada Inc
John Person, Halliburton
Gerry Peters, Devon Canada
Ryan Quigg, Precision Energy Services
Don Rae, Canadian Western Oilsands
Partha Saikia, Gujarat Petroleum Corporation Ltd.
Ralph Sanford, Sanford Consulting Inc.
Kenneth Shaw, Energy and Geoscience Institute
Moe Shehada, Halliburton
Rob Sutherland, Schlumberger
Jeff Tooth, Trigger Resources
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Hugh Wishart, Alberta Clipper Energy
Sam Zhao
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Penny Colton, Exploratech Service Ltd
Darin McBeath, Tusk Energy Corp.
Jack Deng, SAIT
Mirza Baig
Liese Mclaren, Pengrowth Corporation
Inge H. A. Pettersen, Statoil ASA
Brent Goy
Melanie Pedersen, Sundawg Canada Inc.
Ed Janicki, Ryder Scott Company
Peter Aukes, Kinwest Corporation

Formation Evaluation: Carbonate versus Sandstone

R. E. (Gene) Ballay and R. (Roy) E. Cox, Consultants

Abstract

The professional geoscientist of today will typically work both sandstone and carbonate provinces, possibly even simultaneously. Many of the wireline tools upon which their efforts and results are based will be the same in both environments, but the utility and underlying physical meaning of the response may differ between sandstone and carbonate.

By summarizing the key issues, and how the routine open-hole tools respond and are used, one is able to focus their efforts in a more efficient manner. There are, of course, exceptions to virtually every rule, which is why experience in a specific Field is of such value.

Long experience, with many wells successfully drilled, does not of itself eliminate surprises: Ballay (2001, 2002). In this example, with 120 successful wells drilled (45 of which were cored), a completely unexpected poor formation was encountered in an area previously drilled. And so one returns to the value of understanding the basics, and being just as alert with well # 121, as when the first well was drilled.

This article summarizes key response attributes and sandstone vs carbonate differences for routine open-hole tools. In a later article we plan to examine specialty tools.

Genesis, Diagenesis and Consequences

The carbonate (ie containing CO_3) environment is typically one that has formed 'in place' via the growth of organisms and/or precipitation. One may also encounter evaporites (halite, anhydrite, gypsum) in association with the more routine limestone ($CaCO_3$) and dolostone ($CaMg(CO_3)_2$).

Sandstones (SiO_2), on the other hand, are typically clastic in origin and consist of fragments of material that were originally deposited elsewhere, broken up and transported via water or wind, and re-deposited. While carbonates can be clastic, this is much less common than the 'in place' origin. In the sandstone world, complications are often associated with 'clay/shale', although other issues (such as feldspar, glauconite) arise in certain provinces.

Clay, silt and shale are the common obstacles present in sandstone formation evaluation. The exact meaning of these terms is sometimes dependent upon location, and context, but a general definition is one of grain size, with shale being a consolidation of both silt (4 ➜ 74 um) and clay (< 4 um) sized particles.

Clay usually consists of one (or more) of the following minerals: chlorite, illite, kaolinite and smectite. In contrast to both sand and carbonate, these materials are electrically conductive, and therein lies one of the fundamental distinctions in carbonate vs sandstone formation evaluation: resistivity will be lowered relative to the 'clean sand' value and thereby give rise to a pessimistic Sw(Archie). The presence of clay will also affect the porosity determination, and the composite correction for effects on both porosity and saturation is referred to as The Shaly Sand Problem.

Clay distribution mode, in addition to the volumetric amount, is also an issue – structural, dispersed and laminated – and impacts both the associated electrical circuit and appropriate adjustment to porosity.

Perhaps surprisingly, the question of dispersed or laminated geometry (pore systems) is also an issue with carbonates (Chris Smart, 2005). In a recent Topical Conference the five most common causes of Low Resistivity Pay in Carbonates were ranked as (most ➜ least common):

- Dual porosity system (dispersed large and small pores) with the small pores being water filled while the larger pores are hydrocarbon charged
- Layered formation, in which the large (grainstone, etc) and small (micrite, etc) pore size rock is laminated
- Fractures, which may be oil-filled and present in a (small pore) water filled matrix
- Conductive minerals (rare)
- Incorrect Rt (excessive invasion, etc) measurement (rare)

Sandstones are then clastic in origin with diagenesis typically limited to compaction and cementation. Carbonates, which are more soluble in water, have usually grown in place, and then evolved via cementation, compaction, dolomitization and dissolution (Jerry Lucia, 2004). The importance of dissolution is immediately apparent in the carbonate outcrops, road cuts and caves of the Midwest USA (Figure 1).

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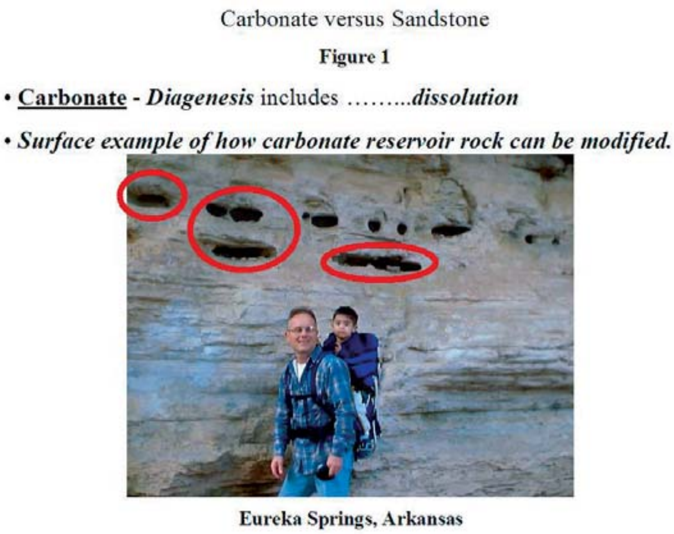

In many regards, the key distinction between sand and carbonate, is then one of clay effects versus pore size distribution.

SP and Gamma Ray

Spontaneous potential (SP) is the naturally arising voltage difference between the borehole (at a specific depth) and surface, measured in milli-volts (though it is relative magnitude, and not absolute value, that is important). There will typically be Baseline Drift (which should be removed prior to using the data in a quantitative fashion) and a depth-specific Deflection (voltage potential) that is a function of the difference in Rmf (drilling mud filtrate) ↔ Rw (formation brine), and clay content.

In the case of distinctly different Rmf and Rw, and across relatively thick beds, one is often able to use the (baseline straightened) sandstone SP to estimate both V(Clay) throughout, and formation Rw (in the 'clean' intervals).

There is, to our knowledge, no direct, general relation between the magnitude of SP deflection and the actual value of porosity and/or permeability. It's rather a V(Clay) indicator, to be fed into the downstream calculations just as other indicators are.

Carbonates, with their wide range of pore sizes, result in a less well defined SP response, and the SP measurement is not even displayed in many Carbonate Country log suites.

Natural gamma ray activity arises from three sources: ^{40}K and daughter products of ^{232}Th and ^{238}U.

In the clastic world, GR activity is often (but not always) a result of clay, and therefore indicative of a decrease in rock quality. It is for this reason that V(Clay) calculations nearly always include the GR as one estimator (linear as below, or some other functional form).

$$V(Shale) = (GR - GR\_clean) / (GR\_shale - GR\_clean)$$

Specific clay types have specific relative radioactive components (^{40}K, ^{232}Th, ^{238}U), specific GR activities, and can be identified by means of spectral gamma ray logs.

When faced with variable clay types, or the possibility of additional radioactive components, it's a very good idea to supplement the GR V(Shale) estimates with alternatives from the SP and / or Density – Neutron. For example, we have seen shallow horizon clastic intervals (above the expected pay), logged with only GR / SP / Sonic for which there was very little indication of reservoir quality rock by the GR, yet the SP clearly revealed potential (which was validated with production). And in the cleanest of these intervals, Rw(SP) was in agreement with independently derived values, suggesting that the measurements were valid.

Confusion can arise by failing to clearly distinguish between shale and clay. Bhuyan (1994) found a common error to be the assumption that shales are 100 percent clay whereas in fact shales are commonly composed of 50 to 70 percent clay, 25 to 45 percent silt- and clay-sized quartz, and 5 percent other minerals.

In our experience, there is also a tendency to sometimes regard the rock as being composed of sand – silt – clay, in the absence of any silt compositional information, and in the face of likely (even verifiable) vertical clay compositional variations. We have also found that when the logs are compared to core, relatively few sedimentary laminations within 'clean' sand bodies can give rise to log responses that are then interpreted as reflecting a silt interval. One is sometimes (but not always) able to work with the more simple sand – shale model and develop from there 3-D geological models that are just as reasonable as the three component results.

A final word about clastics: KCl mud may be used for borehole stability and will shift the GR upwards: the effect must be accounted for if the GR is to be used for V(Clay).

Uranium-bearing minerals are rare but soluble, transported easily and can be precipitated far from their source. In carbonates it's not uncommon to find the GR being driven by uranium, in a fashion that is not necessarily indicative of rock quality. The presence of uranium, and the associated higher

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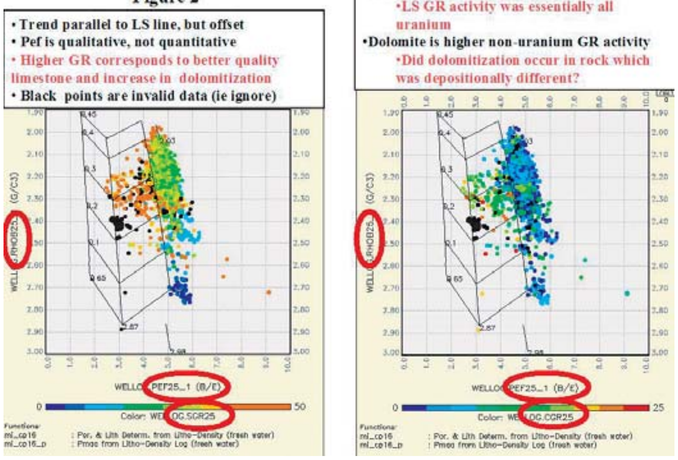
GR, can signal stylolites, fractures, super-perm and / or general increases and decreases in quality (Figure 2). Spectral GR data is particularly useful in the interpretation of carbonate GR responses.

Carbonate versus Sandstone
Figure 2



In today's world of highly deviated wells, for which the tools may be pipe-conveyed, one must also be alert for tool-induced GR response (Ballay 1998). The GR module is typically at the top of the string, and when data is acquired going 'into the hole', particularly at pipe connection time, the GR response will be affected by formation activation associated with the other tools (which precede the GR, in the downwards direction).

Ehrenberg et al (2001) have documented an application of the spectral gamma ray in a Barents Sea carbonate.

In many regards, the key distinction between sand and carbonate, is then the utility and meaning (or lack thereof) of SP / GR response.

Porosity

Sandstone porosity is normally thought of as consisting of Total and Effective, with the two being related by the following equation (or something similar):

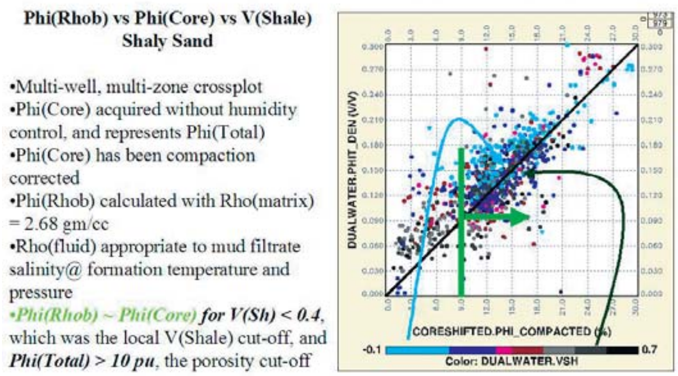
Phi(Effective) = Phi(Total) – V(Shale) * Phi(Shale)

The porosity difference is clay-bound water, which will appear as 'porosity' to the logging tools. Since this 'water' is in fact immobile, not to be displaced by hydrocarbon, the associated pore volume is referred to as ineffective.

Common porosity estimators are the density, neutron and sonic, used individually, in tandem or all three together.

In some (shaly) sands (Figure 3) the density, by itself, will yield a reasonable estimate of Phi(Total) across concentrations of 0 .LE. V(Shale) .LE. V(Shale) Cutoff and Phi(Total) > Phi Cutoff.

Carbonate versus Sandstone
Figure 3



Phi(Rhob) = [Rho(matrix)–Rhob(wireline)] / [Rho(matrix) – Rho(fluid)]

Figure 3 illustrates the situation, which we have found in a variety of provinces.

- The nearly 1,000 core grain density measurements, which include the cleanest to shaliest cored (as opposed to the absolute cleanest and shaliest) intervals, peaked strongly at 2.67 – 2.68 gm/cc.
- Phi(Rhob) is calculated from the density log, using the above core-based matrix density and the mud filtrate density adjusted for salinity, temperature and pressure
- Phi(Rhob) correlates with Phi(Core) for V(Shale) less than the local cut-off and for Porosity greater than the local cut-off. Phi(Rhob) is systematically larger than Phi(Core) in the lower porosity rock.
- In this particular case, even the black (high V(Shale)) Z-axis points are similar to core for Porosity > 10 pu (ie there is agreement in the very shaly points at higher porosities).

This fortuitous event happens because

- Rho(matrix) of sand and shale are locally similar in magnitude (in spite of the significant variations reported in various reference summaries), and/or
- The 'limited range of calibration / applicability' of the method (ie within pay cut-offs) has restricted the evaluation to the domain in which the assumption is valid (which would appear to be the situation in Figure 3).

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An alternative porosity estimator is the neutron log, which is subject to many more environmental corrections (than is the density), in addition to experiencing a relatively larger shale effect and potentially large light hydrocarbon suppression. If a valid neutron log is available, the density-neutron combination offers a common solution to the shaly sand porosity problem.

The third routine porosity estimator is the sonic log, which requires no environmental correction, but like the neutron, will often be more sensitive to shale. One should also be aware of the 'adjustments' to the acoustical porosity that may be necessary in 'soft rock' country: sometimes in country that is not thought of as soft rock.

Per the Schlumberger Principles Manual, and observed in our own experience, if the bounding shales have Travel time >100 us/ft, both of the common porosity transforms (Wyllie and Field Observation) may require a correction factor. Travel time (Shale) ~ 90 = >100 us/ft may not be thought of as soft rock country, yet we have encountered core – log comparisons which demonstrated the need for the compaction adjustment.

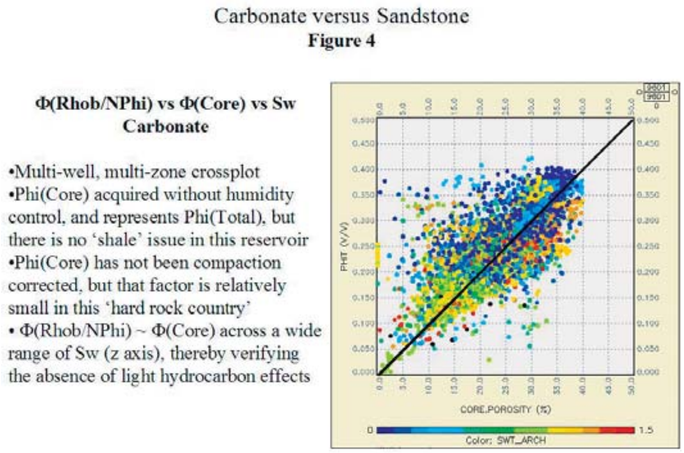
Carbonate porosity determination (Jerry Lucia, 2004), as contrasted to sandstone, is a completely different issue. Now one is faced with Interparticle (intergrain and intercrystal), and Vuggy porosity. Vuggy porosity is everything that is not interparticle, and includes vugs, molds and fractures. Vugs are divided into separate and touching.

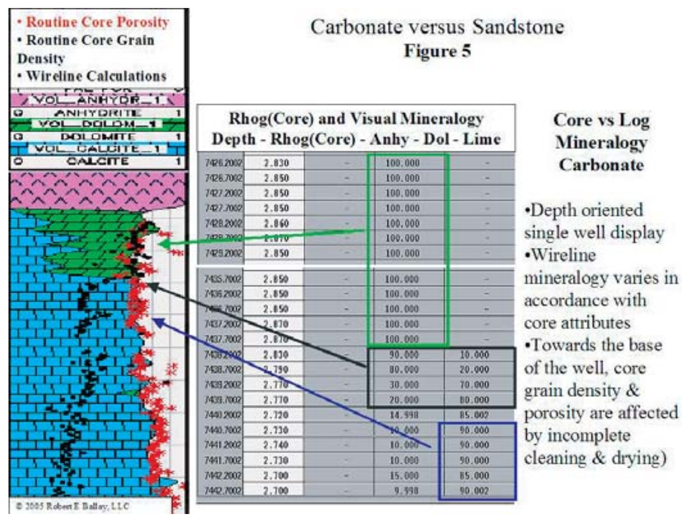
One sometimes encounters the Phi(Total) / Phi(Effective) terminology in the carbonate literature, but the meaning of these terms is now related to irreducible capillary pressure water saturations, and not clay-bound water. For example, Melas et al (1992) define Phi(Effective) = Phi(Total)*(1-Swi), in their study of the Smackover.

Porosity estimates in the carbonate world must often allow for a mix of minerals – limestone and dolostone with distinctly different grain densities – plus possibly anhydrite and halite. Determination of component percentages now requires multiple measurements and equations: two components require two measurements, etc.

The neutron-density combination is the common tool of choice (Figures 4 and 5).

In Figure 4 the z-axis is annotated with water saturation, as a check for light hydrocarbon effects on the porosity estimate (note that Sw drops to less than 10%).





Light hydrocarbon effects on the porosity estimate are an issue in both sandstones and carbonates, and in both environments we have found

- The density will be less affected than the neutron (common knowledge).
- In single mineral environments, Phi(Rhob) estimated with mud filtrate attributes (ie complete flushing), will match core better than the commonly reported iterative approach (calculate Phi, calculate Sxo, calculate weighted average invaded zone fluid density, re-calculate Phi, etc until the Δ Porosity per iteration reaches some pre-set value.)
- Although the iterative correction for light hydrocarbons makes logical sense, it may be that the different vertical res-

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olutions and depths of investigation of the independent measurements that go into the iteration have compromised it. In any case, comparisons to core in both sandstone and carbonate reservoirs have shown that the simpler (assume complete flushing) Phi(Rhob) estimate is a better match. If one wishes to implement iteration, they should consider halting the iteration at some pre-determined point, but prior to convergence, in which case we have been able to achieve matches to core.

- If multiple minerals are present, multiple input measurements will be required and this 'simple' Phi(Rhob) method will not suffice.

In addition to the multiple mineral problem, we have also found LWD Rhob measurements, just behind the bit, for which the simple (Rhob) porosity estimate will not be realistic. Now, light hydrocarbon effects that would not be nearly so evident with wireline data (which is acquired relatively longer after bit penetration and thereby allows more filtrate invasion to take place) can be apparent. In this case our preference is a probabilistic approach if the software is available.

The need to distinguish between interparticle and vuggy porosity, will require the introduction of an additional independent tool (an additional dimension requires an additional input), and the sonic is often the (routine) tool of choice.

An early documentation of this capability is attributed to Wyllie (1958), in which he plotted measured dolomite core porosity (intercrystalline, vuggy, fracture) versus compressional transit time, and observed the intercrystalline response to fall along the expected time average equation trend line, whereas the other ' porosity types' were not 'fully seen'.

Conceptually, the radioactive tools respond to all porosity, while acoustical waves are more pore size dependent. John Rasmus (1983) used a comparison of Phi(Rhob/Nphi) – Phi(Sonic) – Core to illustrate the effect with actual data.

Anselmetti et al (1999) and Eberli et al (2003) have followed-up on this question to find that "moldic porosity exhibits a range of responses that varies from intercrystalline – interparticle to intraframe".

Jennings et al (2001) summarized the situation as

- Not all deviations from the Wyllie time-average equation are caused by separate-vug porosity
- Not all separate-vug pore space causes deviations from the Wyllie curve
- Careful testing and calibration with core data will be required for each carbonate reservoir

Physically, there is a scattering that takes place in the acoustic waves, similar to that modeled by John Rasmus et al (1985) in the dielectric log: the contrast of dielectric and resistivity responses in rock that ranges from intercrystalline / interparticle to vuggy can be used to characterize the porosity type.

The dielectric will 'see' the vuggy oomoldic porosity more effectively than resistivity, since dielectric response does not depend on pore connectivity, but the contribution is not (initially) 100 % (John Rasmus, 2004) – "The ribs are caused by the "scattering" effect of the inclusions on the electromagnetic wave. There is a similar effect on sonic waves. Alain Brie has shown that the sonic "sees" approximately 20-30% of the inclusions in addition to the intergranular porosity".

Whether working in the carbonate or sandstone world, it's important to be alert for data integrity issues. In a 41 well carbonate study, drawing upon more than 30,000 core measurements, we (Ballay, 1994) found:

- 22 % of the sonic logs required adjustment (~ 1 pu)
- This reservoir was generally non-vuggy, interparticle / intercrystalline porosity and pore type did not play a role in the QC
- 51 % of the density logs required adjustment (~ 1 pu)
- Constant shift usually sufficient
- 88 % of the neutron logs required attention
- Usually small (~ 1 pu) shifts at low porosity, but large (4 – 6 pu in 30 pu rock) in high quality rock. Part of this was light hydrocarbon effect, but the magnitude was far beyond what either of the two sets of Service Company documents would have predicted, and was never explainable in a quantitative manner.

Halite, if present, requires that one be aware of how the density measurement is actually accomplished. Most, but not all, elements have an Atomic Number / Atomic Mass ratio of very close to 2.0. Silicon and Oxygen, for example, are 2.01 and 2.00 respectively. Salt, on the other hand, does not satisfy this ratio and so the wireline-measured bulk density departs from the actual.

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Formation Evaluation: Carbonate versus Sandstone *… continued from page 13*

Mineral	Actual Density	Tool Density
Quartz	2.654	2.648
Calcite	2.710	2.710
Dolomite	2.850	2.850
Anhydrite	2.960	2.977
Halite	**2.165**	**2.032**
Gypsum	2.320	2.351

Courtesy of Schlumberger

In certain areas of the world, anhydrite beds are widespread and referenced for log QC purposes. In doing so, one should realize that 'chicken wire' appearing impurities are not uncommon, are not present in the same concentrations from one well to the next, and can give rise to genuine variations in log response.

There is, finally, the question of the benchmark for porosity estimation: the core. Although the grain density is typically determined as a part of the lab procedure, it may not be included in the reported tabulations (particularly in the older reports). When included, its usefulness may not be recognized by the interpreter.

The laboratory measured grain density should be used to quality control both the core data and the log interpretations. If the reservoir is known to consist of limestone and dolostone, Rhog(Core) < 2.71 gm/cc should raise a red flag: the core may not have been completely cleaned or dried (Figure 5). Cleaning is an obvious issue in tar but can present a challenge in lighter oils as well. We have also found residual salt in the core plugs, which shifts the measured grain density downwards.

In many regards, the key distinction between sand and carbonate, is then one of correcting for clay 'porosity' versus allowing for multiple minerals and pore sizes.

Summary

Evaluation of sandstones and carbonates typically bring different issues to the forefront. As the geoscientist of today moves from one province to another, it's worthwhile to summarize those key differences, and thereby focus one's attention.

This particular contrast has addressed the routine wireline tools. Additional ideas and techniques may be found on-line, at the following links.

http://www.kgs.ku.edu/Gemini/
http://www.spec2000.net/index.htm

The authors welcome comments and additional perspectives, which may be directed to their e-mail address

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We plan to next address specialty tools, and suggestions / observations / references for that effort would also be appreciated.

Acknowledgements

We appreciate Roberto Aguilera, Ross Crain, John Doveton, Jerry Lucia, John Rasmus and Chris Smart's review of this effort. Roberto's comments about shaly sand Pickett Plots, and Ross' experience with shaly sand porosity estimates brought forward perspectives and ideas that were not in the original version, but have now been incorporated.

Much of this material was extracted from the Carbonate Petrophysics course that was developed, and is taught by, Gene Ballay. He gratefully acknowledges the 47 contributors to that effort, who are individually listed in the Introduction Module of the Course.

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Myth-Interpretation

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This series on interpretation myths is intended to provoke discussion, rebuttal, dialog, or solutions. I do not contend that my views are the only possible views, or even a correct view, on the subject. Responses should be addressed to CWLSorg@gmail.com.

Myth #4: Density Logs Read Porosity In Sandstones

"Sandstone" describes a rock texture, not a mineral. Clean (clay-free) sandstones may be 100% quartz, or may contain no quartz at all, as in the Gilwood, Keg River, and Bakken sandstones in Western Canada. Most sandstones contain quartz plus other minerals, plus clay or shale. So sandstones seldom have the physical properties associated with pure quartz, although a myth to the contrary pervades our industry.

The myth emanates from the pre-calculator, pre-computer days of the late 1960's when the density log was marketed as the "magic bullet" for visual log interpretation. It has been perpetuated by thousands of quick-look log analysis seminars given by log analysts who don't check their work against core data.

This myth has several log analysis corollaries, such as "Density porosity in a sandstone when recorded on a Sandstone Scale, is a good estimate of effective porosity" or "The density log doesn't need any shale corrections". Like many myths, these two statements are actually true in very limited areas, but not true in most of the world.

The shale (or clay) volume correction is zero only when the shale density is precisely the same as the matrix density of the shale-free sandstone fraction. Since this is almost never true, we might as well admit that shale corrections are always necessary, and let the computer do the appropriate work.

Correcting for shale is only half the battle. The other half is to correct for the mineral composition of the sandstone fraction. In most carbonate reservoirs, the lithology is usually reasonably well known from sample descriptions or can be determined from log response, so this step is relatively straight forward. However, this is not true in sandstones because the mineral makeup of the sand is not usually described in much detail.

There is a universal trend to give sandstones the physical properties of pure quartz, but this is almost universally not appropriate. Most sandstones contain other minerals such as mica, volcanic rock fragments, calcite, dolomite, anhydrite, and ferrous minerals, as well as the shale and clay described above. All of these minerals have densities higher than quartz. If a sandstone is assumed to be pure quartz when it is not, the commonly used properties of quartz will provide pessimistic porosity answers. Typical "heavy sands" will appear to be 2 to 4% porosity lower than core porosity – this could be 10 to 20%, or more of your oil/gas-in-place!

Most charts and tables in textbooks, technical papers, and service company chartbooks show the word "sandstone' when they really mean "quartz". Authors who present quartz properties for "sandstone" are misleading their audience into believing these properties are constant for all sandstones. In more than 40 years of petrophysical analysis, I have never seen a thin section or XRD report that gave an assay of 100% quartz in any petroleum reservoir. A 100% quartz sand is very rare. If anyone doubts this statement, look at the PEF curve in a clean sand. If it reads more than 1.8, you have "quartz plus other things" in your sandstone.

There is a story (it may even be true) that reserves for the early North Sea discoveries were seriously underestimated because the (high density) mica in the sands was not accounted for properly. The engineers used density log porosity without correcting for the real matrix density. If true, good engineering practice would have undersized all the offshore equipment. Cash flow, net present value and rate of return on investment would have been significantly reduced.

If the myth that sandstone has the physical properties of pure quartz is perpetuated, there will be more economic blunders of this type. Most Lower Cretaceous and Triassic/Jurassic sandstones in Western Canada suffer from the heavy mineral problem so, as my Grade 7 teacher was too fond of saying, "Govern yourself accordingly!"

There are, of course, log analysis models that prevent the underestimation of porosity from the density log, but they generally require a decent computer program and a trained analyst. Some people change the matrix density in the porosity calculation from 2.65 to 2.68 gm/cc, but this only moves the problem from one sandstone to another.

A better approach is to use a log analysis model that doesn't need to know the matrix properties. The shale corrected complex lithology density neutron crossplot model does an excellent job, but the conventional shaly sand density neutron cross-

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Myth-Interpretation *… continued from page 16*

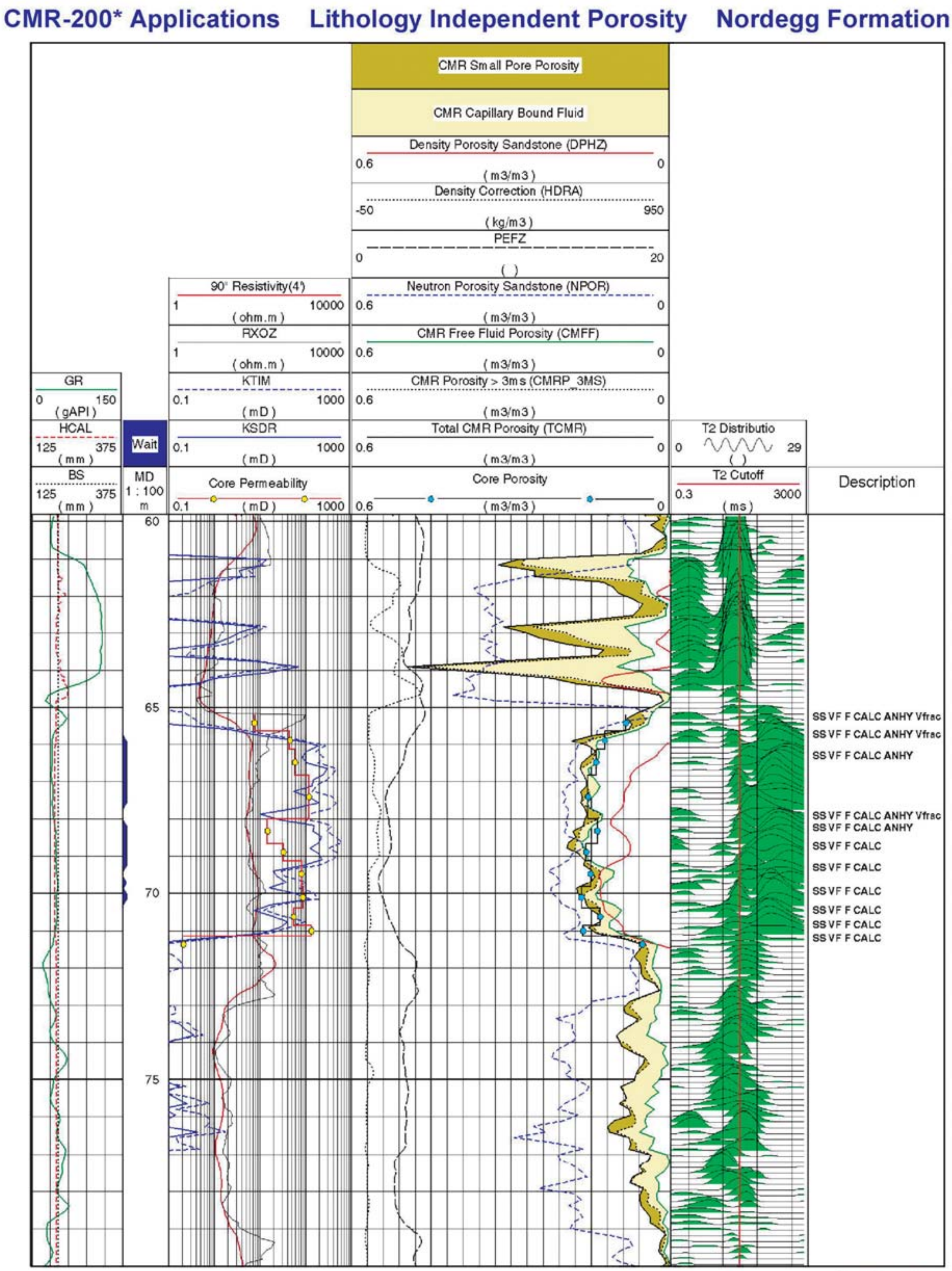

Figure 1: Log segment in a heavy sandstone showing separation between density and neutron porosity curves. Core porosity is significantly higher than density porosity, a common occurrence when sandstone is assumed to be pure quartz. (Illustration courtesy of Schlumberger)

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Myth-Interpretation *... continued from page 17*

plot model does not (but it is still widely used because its name suggests that it is an appropriate model). Calibration of any log or combination of logs to core porosity will also do a good job, as will some probabilistic models if you can provide rational mineral properties for the non-quartz fraction.

Figure 1, provided courtesy of Schlumberger, shows a sample of a log suite in the Nordegg sandstone. Notice the large separation between the density (red curve) and neutron porosity (black short dash), even though the sand is clean according to the gamma ray log. The core porosity (blue dots) and CMR total porosity (solid grey) are about halfway between the two conventional porosity curves, which is where the complex lithology model would also put the porosity. The shaly sand model would place the porosity equal to, or below, the density porosity – definitely not a good model to use in a heavy sand.

The PE (black heavy dash) varies between 1.8 and 4.5 showing the heavy mineral content. Sample descriptions beside the log indicate that quartz, calcite, and anhydrite would be a good starting point for a three mineral model. This is a fairly extreme example of the heavy mineral problem, but even the Cardium, Viking, and Upper Mannville suffer to some extent when heavy minerals are not accounted for.

Conclusion: density log porosity is not a good indicator of effective porosity when heavy minerals are present, which is most of the time. The myth that it is a good model should be shelved once and for all. The standard shaly sand density neutron crossplot is similarly useless in heavy sands because the heavy minerals are converted to clay volume, reducing the porosity even further below the measured density porosity. Use the complex lithology model. It works well whether there are heavy minerals or not, and handles shale corrections reasonably well.

About the Author

E. R. (Ross) Crain, P.Eng. is a Consulting Petrophysicist and a Professional Engineer with over 35 years of experience in reservoir description, petrophysical analysis, and management. He has been a specialist in the integration of well log analysis and petrophysics with geophysical, geological, engineering, and simulation phases of oil and gas exploration and exploitation, with widespread Canadian and Overseas experience. His textbook, "Crain's Petrophysical Handbook on CD-ROM" is widely used as a reference to practical log analysis. Mr. Crain is an Honorary Member and Past President of the Canadian Well Logging Society (CWLS), a Member of Society of Professional Well Log Analysts (SPWLA), and a Registered Professional Engineer with Alberta Professional Engineers, Geologists and Geophysicists (APEGGA).

An Update: Meeting the Legal, Regulatory and Environmental Challenges of Coalbed Methane Development in Alberta[1]

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Introduction

Coalbed methane (CBM)[2] is a well developed energy resource in the United States, with thousands of wells drilled through coal-bearing lands. Canada, with vast coal resources, especially in Alberta, is experiencing the start of a significant CBM development boom. The first ever commercial CBM production in Canada started in 2002 and since then numerous commercial projects have been announced. However, like many other mineral bonanzas, legal, regulatory and environmental issues may dampen some CBM development.

This paper outlines some of the legal, regulatory and environmental issues which might confront a CBM developer in Alberta, beginning with the significant issue of split freehold title to CBM underlying a parcel of land. The regulatory approval process to take a CBM development project from concept to concrete is also discussed, as are some of the common environmental challenges and some potential responses to meet such challenges.

While technical challenges facing Alberta's CBM industry are being addressed, many of the biggest obstacles going forward are non-technical. Landowners, communities, environmental groups and other stakeholders appear to be increasing their challenges of CBM development. The issues raised include the intensity of development, such as well spacing and other surface impacts, the use of scarce fresh water supplies and the disposal of salty produced water, flaring, and other issues. Some people opposed to CBM development in Alberta try to draw analogies with problems associated with some CBM plays in the United States, such as in Wyoming's Powder River basin, and have called for a stop to CBM development in Alberta by raising fears that similar problems are and will be found in Alberta. This paper addresses some of those legal, regulatory and environmental challenges.

What is CBM?

Gases are found in all coalbeds. They are created by biochemical and physical processes during the conversion of plant material to coal, known as coalification. Methane, the same substance burned in the furnaces and stovetops of many Canadians, constitutes 80% to 99% of coalbed gases.

CBM is one of the main gases found in coalbed gas. It is chemically and physically similar to conventional natural gas and can be interchanged and intermixed with conventioned natural gas. This means CBM can be withdrawn from the coal seams by wells, added directly to natural gas pipelines, used as a chemical feedstock or in a gas turbine, burned directly as fuel, or converted to a liquid.

CBM is found in coal seams in three different states: as a free gas, as gas dissolved in water residing within the coal, and attached to the surface of the coal itself. It is desorbed (i.e. released) from coal when pressure on the coal is reduced. Typically, this is accomplished by pumping water out of the coal seam (i.e. dewatering), thereby decreasing the hydrostatic pressure.

CBM is also relatively pure; carbon dioxide (CO_2) and water vapour are the primary components released when combusted. Sulphur dioxide (SO_2) and hydrogen sulphide (H_2S) are usually not present, even when the CBM originates from sulphur-rich coals.

For many years CBM has been a coal miner's enemy as methane is highly explosive. It is part of the everyday vocabulary of the coal miner, but probably in a profane sense. Many miners have died due to CBM accidentally igniting in mine shafts.

In the seminal case of U.S. Steel[3] the trial court judge described CBM as follows:

It is a gas ... which ... has ... a close affinity for and association with coal seams. In its original state it permeates and penetrates the coalbed, is its alter ego, its constant companion, its geological handmaiden, and is sometimes viewed as its contumacious free-spirited bride, but more generally regarded as its ill-chosen

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[1] *This paper is largely a 2005 update of a paper presented at the 4th Annual Unconventional Gas Conference in Calgary, Alberta on October 23 – 25, 2002.*

[2] *CBM is also known as "natural gas from coal" or "NGC" or "coalbed gas." There is no distinction between the terms. For simplicity, the most commonly used term, CBM, is used in this paper.*

[3] *United States Steel Corp. v. Hoge, 450 A.2d 162 (1983) (Penn. S.C.).*

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bridesmaid. It is found with the coal when they come to mine it, stays with the coal as it leaves, and remains in the space after the mining has been done. Its past has been filled with peril and tragedy, its present is seen as having a modest commercial attractiveness, and its future as a fuel potential has become increasingly brighter.

CBM Reserves and Development in Alberta

According to the Alberta Energy and Utilities Board (AEUB or the Board), Alberta is blessed with extensive CBM reserves, predominantly found in four distinct coal zones or formations. Established CBM reserves were estimated by the AEUB as of December 31, 2004 to be 263 billion cubic feet (BCF). [4]

The Horseshoe Canyon/Belly River coals extend from the Province's south to northwest of Edmonton. The majority of the Province's CBM wells drilled to date have been drilled into the Horseshoe Canyon coals (3,240 wells out of 3,575 as at December 31, 2004), and the majority of CBM wells with production are in the Horseshoe Canyon coals (1,560 producing wells out of a provincial total of 1,735 as at December 31, 2004).[5]

The Horseshoe Canyon coals, unlike many other CBM-bearing zones in the world, are relatively dry with little produced water. As the economics of CBM development can be dramatically affected by the costs of dewatering the coal seams to release the methane, the Horseshoe Canyon coals have to date been a favoured target of CBM developers.

Industry experts have called the Horseshoe Canyon play as "one of the last great gas accumulations in North America."[6] Typically, wells are only 200 to 300 m deep, typically access 2 BCF per section of gas in place, and reportedly cost in the $250,000 range. Given the favourable economics relative to other CBM plays, land prices in the Horseshoe Canyon fairway have reportedly jumped from $350/acre to over $1,200 acre.

The Province's largest CBM reserves are believed to be in the Mannville formations which are more widely distributed throughout the Province than the Horseshoe Canyon coals. The Upper Mannville might have as much as 150 trillion cubic feet (TCF) of gas in place, seven times more than any other CBM resources in Alberta. However, at typically more than $1 million per well it can be an expensive place to drill. These coals are commonly deeper and are usually only producible after dewatering. Few Mannville CBM projects have reached beyond the pilot or experimental stage and there are indications that horizontal wells and unique proprietary completions may be the key to unlocking the estimated average of 5 to 12 BCF per section of gas in place.

As of December 31, 2004, only 240 CBM wells were reported to have been drilled into the Mannville, with only 127 producing. Gas production has been relatively insignificant (approximately 10% of the Province's total CBM production) but accounting for approximately 85% of the cumulative produced water associated with CBM development.[7]

Other CBM reserves include the Ardley coals and the coal seams of the Kootney formations. Only a handful of wells (48 out of 1,735 total CBM wells as at December 31, 2004) have production from these zones.

Unlike the water produced from the relatively deeper Mannville, the wells in the shallower Ardley zone coals produce non-saline water, and at times the Ardley is a source of potable water supplies.

One should note that it can be difficult to obtain accurate figures about the status of CBM development in the Province for two reasons. First, recompletions of existing wellbores in CBM-bearing zones do not necessarily require relicensing. Second, operators have historically licensed wells using different criteria. Although CBM wells have always been subject to the same reporting requirements that apply to conventional gas wells in Alberta, it has only been since October 2004 that the AEUB began requiring additional data from operators of CBM wells which identify such wells in the AEUB's databases as CBM wells.[8]

[4] *See the AEUB's Alberta's Reserves 2004 and Supply/Demand Outlook 2005 – 2014 (www.eub.gov.ab.ca).*

[5] *All figures from the AEUB's Alberta's Reserves 2004 and Supply/Demand Outlook 2005 – 2014 report, ibid.*

[6] *Dan Allan, Vice President, Exploration and Production, Rockyview Energy Inc., quoted in Daily Oil Bulletin, June 10, 2005.*

[7] *See Coalbed Methane/Natural Gas in Coal Preliminary Findings, Prepared by the CBM/NGC Multi-Stakeholder Advisory Committee report, published by the Alberta Department of Energy in July 2005 at www.gov.ab (the MAC Report).*

[8] *See AEUB Bulletin 2004-21.*

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Title Issues: The Freehold Question

A common first step in a CBM development project is acquiring legal title or rights to the methane trapped in a coal seam.

As the provincial Crown owns approximately 81% of Alberta's mineral rights, most of the land base is controlled by the Alberta Department of Energy (DoE). The remaining 19% are owned as "freehold" rights. Acquiring rights to develop CBM on freehold land is problematic if the title to the land has been split from the title to the natural gas, known as "split title" lands.

A challenge in determining who owns the methane in a coal seam underlying a parcel of split title land is to decide what CBM is in law: is it part of the coal seam and hence owned by the coal owner, or is it a gas owned by the owner of the natural gas underlying the tract? The answer has important ramifications for CBM developers as in some places in Alberta the title to coal underlying a tract has historically been and remains separated from the other minerals, such as natural gas. For instance, the Canadian Pacific Railway (CPR), which historically acquired mineral title to 25 million acres in Western Canada, transferred some of the mineral rights to settlers but reserved "coal" or "coal and petroleum" to itself. Many of these and other historic freehold title and mineral conveyancing instruments are silent about the rights to the CBM. The question, simply stated, is whether CBM belongs to the coal or the natural gas owner?

For the last several years developers of CBM underlying freehold lands in Alberta have wrestled with this freehold title question, assessed the title risks of proceeding with CBM development without holding both the coal and natural gas rights and attempted to negotiate agreements with the holder of the coal rights, commonly known as a "Coal Certainty Agreement."

The legal question of who is entitled to CBM on freehold land – the coal rights holder or the holders of the natural gas rights – has not been directly addressed by the Alberta Courts. Recently, however, there have been two legal developments which may lead industry to answer the split title question. EnCana Corporation (EnCana) has commenced a lawsuit against Trafina Energy Ltd. (Trafina) in the Court of Queen's Bench.[9] As well, EnCana has sought leave to appeal to the Alberta Court of Appeal a decision of the AEUB to dismiss an objection by EnCana to the issuance of CMB well licenses.[10]

EnCana v. Trafina and EnCana v. AEUB are both illustrative of the types of legal claims that a CBM developer should consider.

EnCana v. Trafina

In this lawsuit EnCana alleges that the Dominion of Canada granted to CPR by patent on July 2, 1901 a fee simple interest in a section. A Certificate of Title was issued to the CPR on December 13, 1906. In March 1910 the CPR transferred the north half of the land to an individual, followed by a transfer of the southeast quarter in July 1910 to another individual. Both transfers expressly excepted and reserved "all coal" to the CPR. EnCana alleges it is the CPR's successor to the substances and strata underlying the lands which were reserved and excepted from the 1910 transfers.

Trafina licensed with the AEUB and then drilled two wells on the lands which it perforated in coal seams without EnCana's consent or permission. EnCana claims that Trafina has been capturing and producing the "excepted and reserved" substances which EnCana alleges are its property.

EnCana has alleged that Trafina has been unjustly enriched and that EnCana has suffered a corresponding deprivation as a result. EnCana has asked the Court for a declaration that Trafina is in trespass to the excepted and reserved strata and substances and that Trafina has converted the excepted and reserved substances. EnCana has sought an accounting, with interest.

EnCana v. AEUB

In this proceeding, the record shows that EnCana holds an interest in eight quarter-sections of land where it claims it is the successor to a transferor who in 1921 transferred all of its interest in the lands, but expressly excepted and reserved all "coal, petroleum and valuable stone which may be found to exist within, upon or under the said land." EnCana's predecessor granted petroleum and natural gas leases, now held by Devon Canada Corporation (Devon). The leases specifically state that they grant rights to "all petroleum and natural gas, natural gasoline and related hydrocarbons other than coal."

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[9] *EnCana Corporation v. Trafina Energy Ltd., Court of Queen's Bench of Alberta, Judicial District of Calgary; Action No. 0501-10483; Statement of Claim filed July 15, 2005.*

[10] *Notice of Motion filed with Alberta Court of Appeal on June 22, 2005 in EnCana Corporation v. Alberta Energy and Utilities Board; Appeal No. 0501 016/AC.*

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Devon advised EnCana of its intention to drill for CBM on the leased lands and submitted applications for well licenses to the AEUB. Devon completed the application forms by indicating that it held all the rights for the intended purposes of the wells. Devon also applied for CBM well licenses with respect to various lands where Luscar Ltd. (Luscar) held fee simple title to the coal.

EnCana and Luscar filed objections with the AEUB to Devon's well license applications on the grounds that Devon did not hold the legal right to produce CBM, or alternatively to hold Devon's application in abeyance until the CBM ownership issues were settled. EnCana argued, among other things, that Section 16 of the Oil and Gas Conservation Act (the OGC Act) provides that no person may apply for or hold a well license for the recovery of gas unless they held a right to produce the gas and that Devon had no right to the CBM gas. EnCana also urged the Board that it was in the public interest for the Board to take the time to establish entitlements to develop CBM so that uncertainty and conflicts amongst competing interests are minimized.

Luscar argued that the owner of the conventional gas rights did not hold a clear and recognized legal title to the CBM at the time it granted leases to Devon. As such, Devon could have no better title to the CBM than did the lessor. Luscar argued that the Board did not have the jurisdiction to make a determination as to the respective property rights of Devon, as lessee of the conventional natural gas rights, and Luscar, as owner of the coal.

The Board ruled that Devon had shown that it was entitled to produce all natural gas from the wells and zones applied for. The Board noted that Devon's leases had not been cancelled or otherwise determined to be invalid and that there was no settled law in Canada that natural gas produced from coal is a substance different than conventional natural gas. The Board therefore dismissed the objections on the basis that EnCana and Luscar had failed to demonstrate that they would be adversely affected by the Board's decision to grant the well licenses.

EnCana then filed a Notice of Motion with the Alberta Court of Appeal for leave to appeal the AEUB's decision to dismiss EnCana's objections.[11] EnCana's leave to appeal is on the basis that the AEUB erred in law when it decided that Devon satisfied Section 16 of the OGC Act by its right alone to produce natural gas when Devon's applications were for CBM wells. EnCana also claims that the Board erred in law when it decided that EnCana was not directly and adversely affected by the Board's decision to grant the well licenses.

How the freehold title issue with respect to CBM development in Alberta will be resolved is unknown. EnCana v. Trafina and EnCana v. AEUB may provide some of the answers.

Looking south to the history of CBM development in the United States may be instructive in understanding the scope of the issue. There are persons asserting ownership of the CBM rights who have claimed they can halt coal mining activities or, in the alternative, receive compensation from coal miners who necessarily have to vent the methane as a prelude to or part of the mining process. Conversely, coal mine operators have asserted that they have no liability for methane incidentally released during mining.

The magnitude of the legal issue is directly related to the mineability of the targeted coal seam: the greater the chance the coal might be mined, the greater the chance for conflict. There have also been legal disputes in the US with the owner of the natural gas rights where the owner of the coal rights has attempted to convey the CBM for commercial gain and where the coal rights holder challenges the gas rights holder's claim to the methane.

Consideration of only scientific facts that CBM is, in part, a gas adsorbed to coal during the coalification process or consideration of technical classifications of CBM as either "coal" or "gas" is probably insufficient to fully determine the legal answer about what CBM is in law in Alberta. Although the science and technical considerations will play a very important role before the Courts, the answer in Canada, at least as best can be determined from the present state of the law, arises from a mixture of common law and statute law.

Common Law

The "common law" is that part of the law of England formulated by the old common law courts and subsequently exported to England's dominions and territories, including English Canada. It is different from statute law, which is law established in Acts of Parliament and the Legislature.

The common law contains various concepts which one must respect in attempting to determine who among competing mineral owners has the right to the methane trapped in a coal seam.

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[11] *Leave to appeal (i.e. permission) from the Court of Appeal to appeal an AEUB decision is required before an appeal may be heard by the Court of Appeal.*

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These include the concept of determining the intention of the parties when mineral rights are granted, and the concept of the "rule of capture."

The Intention of the Parties

A vendor of freehold mineral rights cannot convey rights he or she does not possess. Accordingly, a prior conveyance by a freehold mineral owner of the "gas" underlying their tract might mean that they cannot later separately convey the CBM, or alternatively, if they previously have conveyed the "coal" to one person they might not later be able to convey the CBM to another.

The problem is that historically landowners commonly conveyed the "gas" and then the "coal," or vice versa, probably without even consciously thinking – or perhaps even knowing – about the CBM. Hence the terms of the various historical freehold grants (i.e. the language in the conveyance instruments) likely do not expressly resolve CBM ownership issues. At the time the freehold mineral owner granted one person rights to the coal, and granted another rights to the gas, had they thought about the CBM they might have been clear as to who gets the rights to the CBM. But in the absence of such clarity one is left to apply various common law rules in trying to determine the parties' intent.

An intention to convey – or not to convey – coalbed gas along with the coal may be inferred from a conveyance instrument silent on the point. For instance, a conveyance of coal which includes "...all the rights and privileges necessary and useful in the mining and removing of the said coal, including the right of ventilation..." has been found – at least in Pennsylvania – to include a grant of the methane in the coal. However, other conveyancing language has resulted in other American courts coming by inference to the opposite conclusion, namely that a grant of a coal lease with a right of ventilation did not include the CBM.

It may also be necessary to examine the sequence by which the mineral rights are granted. For instance, if the freehold mineral owner first granted the gas lease and then the coal lease, it may be possible to argue the coalbed gas was conveyed along with any other gas underlying the tract and that a subsequent coal lease could therefore not have included the coalbed gases.

Legal decisions from various US jurisdictions are contradictory and do not lead one to necessarily conclude under the common law in Canada that the holder of freehold natural gas rights owns the CBM in priority to the holder of the coal, or vice versa.

A complicating factor is that CBM is inseparable from the coal notwithstanding that it can be chemically classifiable as natural gas. For instance, CBM generally does not without intervention migrate like conventional natural gas in sandstone formations. In fact, it is only released when the pressure on the coal seam is reduced, either by dewatering, mining or ventilation. In other words, one cannot remove the coal without freeing the gas, and one cannot extract the gas without disturbing the coal.

Hence, the freehold owners of the coal might argue that their right to dissipate the coalbed gases prior to mining implies that they own the CBM. In some circumstances they may have a statutory duty to ventilate the gases. For instance, in Alberta ventilation equipment that eliminates flammable gases is mandatory for underground mines.[12] On the other hand, the owner of the natural gas might argue his or her deed gives them the right to all "gas" underlying the surface, and that "gas," according to its plain and ordinary meaning, is not the same as a liquid or solid; coal clearly being a solid.

As mentioned above, the Alberta Courts have not yet directly addressed the issue as to ownership of methane from coal seams. However, a recent decision from the Supreme Court of Canada might be insightful. In Anderson v. Amoco,[13] the Court confirmed that ownership of a mineral substance must be determined at the time of the mineral reservation and that phase changes (i.e. from a liquid to a gas or from a gas to a liquid) that occur subsequently are irrelevant to ownership. That is, if a substance such as natural gas is in a liquid form under initial reservoir conditions (i.e. prior to any drilling or mining) it is owned by the holder of the petroleum rights. The fact that the liquid form of natural gas in a virgin reservoir might change phase to a gaseous form of natural gas due to changes in pressure and temperature as it is drawn into a well bore and brought to the surface does not transfer ownership to the owner of the natural gas rights.

In Anderson, Mr. Carl Anderson held lands originally held by the CPR. He claimed ownership to whatever minerals the CPR did not reserve to itself, the CPR having reserved "all coal

[12] *The ventilation requirement was previously found in the Mines Safety Regulation (AR 292/95), but it was repealed on April 30, 2004 and provisions regarding the ventilation and elimination of flammable gasses have been subsumed in the new Occupational Health and Safety Act and its regulations.*

[13] *Anderson v. Amoco Canada Oil and Gas, [2004] 3 S.C.R. 3.*

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and petroleum." Wells were drilled which could produce a mixture of gas, natural gas liquids and petroleum. Eighty-four lawsuits were launched, and Mr. Anderson argued that gas that emerged from the liquid phase during production was not included in "petroleum."

The Court's answer included a detailed examination of the original CPR mineral reservations. Noting that at the time of the reservations the hydrocarbon reservoir had not been drilled, the Court found that the parties must have meant that "petroleum" meant petroleum in its initial reservoir state, undisturbed by humankind. In such a state, the gas was in a liquid state, and therefore was considered "petroleum" instead of "natural gas."

Anderson might suggest that title to methane trapped in a coal seam therefore is determined using its initial condition; that is, the methane in the coal seam found in a gaseous state is held by the holder of the gas rights, the methane attached to the coal is held by the holder of the coal rights and, perhaps the methane dissolved in the water is held by the holder of the water rights. However, coal is a solid and it may be difficult to argue that the methane itself is a solid; it is simply hydrostatically attached to a solid. Expert evidence will be needed to assist in determining the issue. Further, the lower Courts expressly suggested in Anderson a discomfort with using CBM as an analogy to determine ownership of gas in a conventional reservoir. Arguably, using solution gas as an analogy for determining CBM ownership may be just as discomforting.

The point is that the issue of CBM ownership has not been decided yet in Canada. It is readily apparent that the words used and implied into each mineral agreement, and expert evidence, will be key in determining the CBM ownership issue for freehold lands.

The Rule of Capture

A further concept to consider in determining CBM ownership issues for freehold lands is that, at least in Alberta, a "lessee" of natural gas may not actually hold a lease whereby they obtain an ownership interest in the natural gas molecules underlying a tract. Instead they may hold a licence to explore for, and capture, the natural gas, notwithstanding that the document granting such rights might be called a "lease." This is known as a profit à prendre, which is the right to come into ownership of something by capturing it and reducing it to possession. It is only when the substance or thing is captured and reduced to possession that it becomes subject to absolute ownership. An example of a profit à prendre is the right to have wild animals on one's land; the landowner does not "own" them until they are captured or killed, and until then, they are free to escape onto a neighbour's property, who in turn has the opportunity to capture or kill them and thereby come into ownership of them.

This rule of capture concept complicates the CBM ownership picture because a person purporting to have the rights to the CBM runs the risk that the methane will be "captured" and released by a coal mining operation or natural processes. Contrary to this "law of capture" doctrine is the legal concept (found in some US jurisdictions) that a conveyance of a strata underlying tract conveys all that is found within that strata, whether it be oil, gas, water, coal or CBM.

In Alberta the issue has not been finally decided for CBM: is it subject to the law of capture or does someone who is conveyed the coal strata get all of the CBM from that strata?

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It is possible to argue by analogy that CBM is subject to the law of capture. For instance, for some time legal disputes centered around whether casinghead gas was the subject of a competing gas lease or an oil lease. Casinghead gas is gas which flows in the oil solution from the casinghead of an oil well.

If CBM is subject to the rule of capture then it may be "captured" and reduced to possession – and hence ownership – by the holder of a natural gas lease, even though some of the methane is inextricably bound up with the coal under natural conditions.

Other situations analogous to CBM may be found in US law with respect to the ownership of the oil in oil shale (which is a consolidated mud or clay which contains no oil as such but from which oil may be obtained by distillation), ownership of oil in salt brine wells, and to the ownership of helium in Texas' natural gas fields.

It is clear that the common law concepts of determining the parties' intentions in granting freehold mineral rights has a role to play in deciding who has title to coalbed methane, as does the rule of capture. It is also clear that no one general rule can yet be stated setting out in all cases that one party has the rights to the CBM and another to the coal for freehold lands; it will depend upon the intention of the parties at the time of the grant, expert evidence and how the courts chose to apply, or reject, the rule of capture with respect to CBM.

What is clear, however, is that full and proper consideration must be given to all of the historical conveyancing and titles for both the freehold coal and the natural gas underlying a tract in order to determine who has the title or right to the CBM. This is usually accomplished by experienced land persons or lawyers reviewing the instruments and opining on the title to the CBM rights. A key is to anticipate potential disputes over the CBM by identifying possible conflicting claims. The possible solution, however, is for a CBM developer to acquire the rights to both the coal and the natural gas, thereby eliminating the possibility of a future adverse claim, or to get the coal rights owner to waive their claim to CBM in a Coal Certainty Agreement.

Statute Law

The freehold split title situation is significantly different for Crown Lands. In Alberta, about 81% of the mineral acreage is owned by the Alberta Crown, the vast majority of which has not been brought under the Land Titles Act. The Mines and Minerals Act applies to all mines and minerals and related natural resources vested in or belonging to the Crown in right of Alberta. Natural gas and coal are treated as distinct substances and are leased separately under that Act.

The historical and present policy position of the Alberta Government is that CBM is a form of natural gas. This was articulated nearly 15 years ago in the AEUB's Information Letter IL 91-11, Coalbed Methane Regulation (IL 91-11) which was released in August 1991 by the AEUB's predecessor. IL 91-11 states that the Board and the DoE consider CBM to be a form of natural gas. As a result, according to IL 91-11, all statutes and regulations administered by the Board or DoE that pertain to natural gas are to also pertain to CBM and that most of the practice and policies relating to drilling and production of conventional gas reservoirs will be applied directly to CBM. IL 91-11 goes on to state that a coal developer would only obtain rights to CBM where the developer applies to the Board to obtain rights to the CBM for safety reasons or where the Board thinks it is necessary for the coal developer to obtain the methane for conservation purposes and the Minister agrees.

Recently, the Legislature chose to solidify the government's policy in legislation by amending the Mines and Minerals Act to provide that a Crown coal lease does not grant any rights to any natural gas, including CBM, other than that the Minister may, on the recommendation of the AEUB for reasons of safety or conservation, authorize a Crown coal lessee to recover CBM contained in a coal seam. [14]

The Alberta Government's decision to change the legislation to expressly state who holds the rights to CBM on Crown lands follows similar moves in Nova Scotia and British Columbia. In Nova Scotia, the Petroleum Resources Act defines "petroleum" as expressly including coal gas, existing in its natural condition in strata, and contains authority for the Nova Scotia Crown to grant coal gas agreements which grant the right to explore for, develop and produce coalbed gases. In British Columbia, the Coalbed Gas Act proclaimed in 2003 provides coalbed gas "must be considered to be and to have always been natural gas." It defines coalbed gas as all substances that may be recovered at the surface through a wellbore from subsurface coal deposits and any reservoirs in communication with the coal deposits, and the volume of which can be measured as a gas.

Further support for the Alberta Government's position that the natural gas lessee obtains the rights to the CBM is found in the DoE's Technical Guidelines for Continuation. These

[14] *See Energy Statutes Amendment Act, 2003, the relevant parts of which came into force on March 17, 2004.*

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Guidelines set out the Department's policy for continuing Crown petroleum and natural gas leases beyond their primary term under the Petroleum and Natural Gas Tenure Regulation. The Guidelines define CBM as a "naturally occurring hydrocarbon gas, predominantly Methane, generated by coal and stored in coal seams." The Department takes the position that a well that is being used for the purpose of CBM production, including a well that is still in the dewatering stage, may qualify for continuation.

It also should be noted that Alberta's Coal Conservation Act and regulations, created thereunder, are silent about CBM other than authorizing the Board to require a coal developer to measure gases and fluids encountered while exploiting coal resources. No royalty is payable by the coal developer for methane encountered during such operations; presumably this would not be the case if the coal developer was obtaining the rights to the methane trapped in the coal seam.

The Crown's position that the holders of natural gas rights rather than the Crown coal lessee is entitled to the CBM is further supported by the Petroleum and Natural Gas Tenure Regulation which expressly provide that rights granted by the Crown under a petroleum and natural gas lease do not include the right to natural gas in a coal seam for which the Minister has authorized the coal lessee to recover under the Act. The argument is that a petroleum and natural gas lessee by implication gets such rights to natural gas in the coal seam in the absence of the Minister authorizing the coal lessee to recover it.

A legal question persists, however, as to whether the legislative changes recently brought into force only applies to Crown coal leases issued after March 17, 2004. Lessees of prior Crown coal leases may be able to argue that the change in the law does not apply to them.

The Future?

One remains hopeful that the freehold split title issue with respect to freehold coal and natural gas rights will be answered by the Courts or the Legislature. Only time will tell if the Courts provide more certainty to the title issue.

It is possible the Legislature could pass legislation clarifying the issue. Although this writer doubts this, there is precedent in Alberta. For example, in Western Minerals v. Gaumont,[15] the CPR in 1906 transferred freehold lands it held. Subsequent transfers reserved "all mines, minerals and valuable stone," and the titles for such "mines, minerals and valuable stone" came to be held in 1944 by Western Minerals Limited (Western Minerals). The surface title came to be held by Mr. Gaumont and Mr. Brown.

The presence of gravel in the area had been known since at least 1915. In 1942 Mr. Gaumont opened a gravel pit on his lands, followed by Mr. Brown opening a pit on his land in 1948. Both mined the gravel in commercial operations. Western Minerals sued claiming that the gravel was part of the "mines, minerals and valuable stone."

The Alberta Supreme Court held that sand and gravel were "minerals" and that their ownership rested with Western Minerals. It is reported that within hours of the Court rendering its decision Premier E.C. Manning directed his staff to begin drafting a legislative change to retrospectively give rights to the gravel to the surface landowners.[16]

Five weeks later the Legislature passed the Sand and Gravel Act, declaring the law to be that the owner of the surface of land "is and shall be deemed at all times to have been the owner of and entitled to all sand and gravel on the surface of the land." The legislation deemed sand and gravel to not be a "mine, mineral or valuable stone," and provided that notwithstanding any patent, title, grant, deed, conveyance, lease, agreement or disposition, the holder of all existing or future titles containing mines, minerals or valuable stone had no right to the sand and gravel.

Meanwhile, the surface landowners appealed the Court's decision that Western Minerals owned the gravel. The Supreme Court, Appellate Division allowed the appeal on the grounds that the Sand and Gravel Act had changed the law. Western Minerals then appealed to the Supreme Court of Canada, which also found for the surface owners on the grounds that the Sand and Gravel Act applied and was fatal to Western Mineral's claim. The Supreme Court of Canada found that the Act was within the jurisdiction of the Province and that the Province had by exacting the legislation settled that sand and gravel were never owned by a person holding title to "mines, minerals or valuable stone."

In short, the Alberta Legislature had taken away any claim to a substance in dispute. Hence there is legal precedent for the Legislature to take away any claim of a freehold coal rights holder or a natural gas rights holder to CBM if the Legislature chooses to do so.

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[15] *(1951), 1 WWR (NS) 93.*

[16] *See A Gentleman From a Fading Age, by Fred M. Diehl (published privately).*

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Regulatory and Environmental Issues

The regulators of CBM development on Provincial lands, including freehold lands, predominantly consists of the AEUB and AENV.

In Canada, jurisdiction for the regulation of mankind's interaction with the natural environment is split between provincial and federal authorities. Typically, federal regulatory approvals are rare and are only required for a CBM development if some aspect of the project encroaches into an area of federal jurisdiction. This would include any impact on federally-regulated lands, such as Indian lands, military facilities or national parks. Federal regulatory approvals may also be required if a project's footprint crosses inter-provincial or international borders.

The most likely area of federal regulation for a CBM development is probably under the Fisheries Act given the large volume of water production that may be associated with CBM development. The federal Fisheries Act prohibits the deposit of any deleterious substance in or near water that might be occupied by fish. A "deleterious substance" is essentially any substance that if added to water would degrade or alter the water quality so that it is rendered or is likely rendered deleterious to fish or fish habitat. It includes any water that includes a deleterious substance. Accordingly, CBM well water discharges, especially saline-water, could invoke the Fisheries Act.

Other possible "triggers" of federal jurisdiction for CBM development projects include the requirements for regulatory approvals for water body crossings by pipelines under the federal Navigable Waters Protection Act and the Fisheries Act.

As CBM developments generally result in the extraction of a large volume of groundwater along with the methane, the handling and disposal of that water is by far the most significant environmental issue facing a CBM developer. Some CBM wells can generate 10 to 100 times more produced water than a conventional gas well. Often the water is saline. In fact, CBM development might better be described as a water management business rather than a gas business. Accordingly, water issues, such as the right to divert the water from the coal seam to the surface, and what to do with the water at the surface, are important and controversial issues. Many of the objections by landowners, environmental groups and other stakeholders to CBM development in Alberta and elsewhere focus on water-related issues.

Well density is also a controversial topic as many CBM projects are designed to have more (and sometimes many more) wells per square mile than the conventional natural gas exploration and production business.

Hence, in addition to outlining some key regulatory approvals required for CBM development, the following parts of this paper look at water and spacing issues, as well as other environmental and regulatory issues.

Spacing and Holdings

Conventional well spacing rules apply to CBM development in Alberta. Well spacing rules set the maximum number of subsurface drainage locations which are felt necessary to maximize the recovery of oil and gas in a reservoir. The well spacing rules also provide some equity protection for competitive mineral right owners and are designed to maximize the conservation of the resource.[17]

Existing regulations establishing baseline well densities were created for the early development stage of the Alberta sedimentary basin, in which a few companies developed large oil and gas reservoirs. Today, many operators are developing smaller and lower productivity reservoirs, and higher well densities are frequently required to optimize recovery of the oil and gas. As a result, there has been a significant increase in the number of applications requesting higher well density spacing.[18]

Standard gas well spacing for much of Alberta is one well per section per pool. This is known as the Drilling Spacing Unit, or "DSU." CBM wells generally produce at low gas rates and low pressures. To optimize gas recovery, developers often want to locate CBM wells closer together than the standard one well per section per pool. Increasing the number of wells in a section usually means increased surface disturbance and increased cumulative effects.

CBM developments have been criticized for the larger surface footprint, especially in ecologically sensitive and important areas, such as where native grasslands still exist. Dramatic photo-

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[17] However, well spacing rules do not approve or imply approval of gathering and production facilities, well site locations, number of well sites or access. AEUB approval of a well spacing application does not predispose the AEUB to grant approval for associated surface developments.

[18] On October 11, 2005 the Canadian Association of Petroleum Producers advised its members that in September 2005 the Board was working with additional staff to clear the backlog of approximately 1,000 spacing applications.

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graphs of the intense downspacing in some US basins have been circulated among rural Alberta showing intense industrialization of the agricultural landscape.

Developers might address this challenge by pointing out that closer well spacing is a long established practice in Alberta for conventional oil and gas development, especially heavy oil development and shallow gas. Experience has shown that desirable well spacing for CBM wells in Alberta is two to eight wells per section, which is comparable to conventional oil well density and is lower than heavy oil well density.[19] In some US basins, the spacing is typically 16 CBM wells per section, and sometimes as high as 32 wells per square mile. This level of intensity of wells is not believed to have been experienced in Alberta and early indications are that Alberta's coals typically do not require such high numbers of wells per square mile. Comparing the tight well spacing of some US basins to Alberta may not be appropriate

The footprint of each CBM well may also vary. Typically a relatively small well pad (such as 3 m x 3 m) is used for the majority of Horsehoe Canyon wells.[20] Somewhat larger wellsites are sometimes needed if water handling facilities must be included. However, few Horseshoe Canyon wells require such facilities. Further, if horizontal wells truly are the key to unlocking the Upper Mannville where most of Alberta's CBM resources are located, then surface disturbance can be dramatically reduced. For instance, in a four section CBM play, an operator recently suggested that instead of 16 vertical wells drilled from 16 well pads spread over four sections with the associated pipelines and roads, one well pad drilling 12 horizontal wells could access the same resource.[21] In addition to a significant reduction to the surface impact, peak production can apparently

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[19] *See MAC Report, supra, note 7.*
[20] *Ibid.*
[21] *Mike Simpson, CBM Manager, Nexen Inc., quoted in Daily Bulletin, July 7, 2005.*

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be reached faster than if horizontal wells are used, which may favourably increase economics. However, only time will tell if Alberta's mighty Mannville coal resource is predominantly accessed by horizontal or vertical wells.

With respect to CBM well spacing, the Board uses its normal rules of one well per section per pool unless the operator requests a change as provided for under the Oil and Gas Conservation Regulations (the OGC Regulations) and which meets the application requirements in Directive 065: Resource Applications For Conventional Oil and Gas Reservoirs,[22] in which case the Board usually considers the potential impacts on gas recovery, surface impacts and equity.

Higher well density spacing may be obtained in two ways. The first and historically more traditional method of tighter spacing has been through Section 4.040(2) of the OCG Regulations. It provides that the Board may reduce the size of a DSU if an applicant shows that improved recovery will be obtained, additional wells are necessary to drain the pool at reasonable rates that will not adversely affect total recovery from the pool or, in a gas field, increased deliverability is desirable. Also, if the DSU is in a pool where there already are reduced size DSUs, the Board may reduce the size of the DSU. Applications of this nature are made in accordance with Directive 065.

The effects of a reduced DSU are that more wells may be produced from a section. For instance if the standard one section DSU is reduced to quarter section DSUs, then four wells may be drilled in the section, with one located in each of the four quarter sections.

The second method of downspacing is through the approval of a "holding" application under Section 5.190 of the OGC Regulations. The concept of a holding was first introduced into the legislation in 1993. Unlike a traditional downspacing for the reduction in the areal size of a DSU, a holding retains the traditional one section DSU but typically allows up to a set number of wells to be drilled in the DSU provided a minimum interwell distance is respected and a buffer is set on the boundaries of the DSU into which no wells may be drilled.

Holdings are popular among the CBM development community as they provide for flexibility in not only the number of wells in the DSU (up to the set maximum), but also in the location of the wells within the DSU (subject to the minimum interwell distance requirements and the buffer requirements). Unlike a reduced DSU where one may still only produce one well per reduced DSU, in a holding one may produce more than one well in the DSU. The flexibility may not only be advantageous from a technical perspective, but it also allows for operators to more easily move surface locations to avoid environmentally sensitive areas and areas of concern to landowners and stakeholders.

In March, 2005, the Board announced that it was seeking stakeholder input on a proposal to improve the spacing regulations and application process.[23] The proposal has four components, one of which is to increase the standard well density of one well per pool per section to a maximum of four wells per pool per section above the Mannville group, and a maximum of two wells per pool per section for the Mannville group.[24]

According to the Board, large areas of eastern Alberta are already subject to spacing orders for increased well densities. The area accounted for 60 per cent of spacing applications filed for the period January to August, 2004. In this region, existing developments, coupled with AEUB mapping of resource potential and review of geological information and production data, demonstrate the need for greater well densities to provide optimum oil and gas resource recovery. The AEUB's proposal, if accepted, will likely eliminate many repetitive applications that pose little resource conservation or reservoir equity risk. It should therefore assist CBM developers.

Well and Facility Licenses

The OGC Act and OGC Regulations require that CBM wells, pipelines and facilities are licensed by the AEUB. An application must include the documentation required by Directive 056.

Directive 056 is intended to help companies better understand the Board's expectations and requirements so that they can meet them, and file complete and accurate applications. It covers energy developments for wells, pipelines and facilities and is intended to apply to all development activities required for a projection in one integrated process.

The Board processes applications by conducting a corporate records check, reviewing the application from a technical perspective, informing applicants of deficiencies in their application, completing some calculations and then issuing the appropriate regulatory approvals. Applications which the Board considers as meeting all of the requirements are considered routine

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[22] *Formerly Guide 65.*

[23] *See AEUB Bulletin 2005-08.*

[24] *For the region of Alberta east of the 5th Meridian and south of Township 53.*

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and licences are usually issued in a timely manner. Non-routine applications are subject to increased scrutiny. Should there be potentially serious issues, deficiencies in public consultation or objections from the public about a proposed project, the Board may call and conduct a public hearing. Both routine and non-routine applications are subject to the Board auditing the application to confirm compliance and completeness with the Board's requirements.

Licenses issued under the OGC Act are licences to construct and operate components of the project. Construction and operation prior to licensing is considered to be a serious non-compliance situation. Similarly, pipeline licences are required to construct and operate pipelines for both the produced methane and the produced water, and an approval is required for any gas processing facilities.

Various approvals may also be required from AENV for the methane production, depending upon the H_2S content in the gas stream, the size of the pipelines and the size and nature of the facilities. The environmental and regulatory requirements for the handling and disposal of the water diverted during CBM production is discussed below.

Experimental Status

Data submitted to the AEUB is generally available to the public. However, an applicant may request the AEUB keep the data confidential and have the project deemed to an "experimental scheme" under the OGC Regulations. Results from flow tests during drilling and extended production tests after completion may be kept confidential for several years if the Board approves the project as an experimental scheme. Many of the original CBM projects in Alberta were classified as experimental schemes, with information about the projects considered confidential by the Board and the operators. However, given the proliferation of CBM development, the Board is far less willing than it used to be to grant experimental status to CBM projects.

The Right to Divert Groundwater

Under Alberta's Water Act, all water in the Province, including groundwater and water found on or under freehold land, is owned by the Crown. A licence is typically required in order to divert groundwater. Dewatering a coal seam for CBM production is a form of water diversion. However, the Water (Ministerial) Regulation provides that a licence is not required for the diversion of saline groundwater, which means water that has total dissolved solids exceeding 4,000 milligrams per litre. Accordingly, if the produced water is not saline then a licence is required from AENV under the Water Act.

AENV has published Guidelines for Groundwater Diversion for CBM/NGC Development (April 2004). The Guidelines summarize the rules and processes that are currently in place to guide CBM development where non-saline water is involved.

Before AENV issues a license for water diversion under the Water Act, evidence must be provided to AENV to show that the proposed non-saline groundwater diversion will not cause adverse effects on the water supply of nearby users over the short-term or long-term, and will not cause adverse effects (for example, aquifer dewatering) on the source aquifer or other aquifers.

When a target coal zone is anticipated to contain and produce non-saline groundwater, a CBM/NGC developer must conduct a Preliminary Groundwater Assessment (PGA) containing baseline resource inventory data and other required information, and submit the PGA to AENV before drilling or well re-completion activity, or groundwater diversion. The purpose of the PGA is to collect baseline data and identify issues to regulators and the public.

The PGA should be prepared under the guidance of a qualified groundwater practitioner. The PGA must include, but not be limited to, the following:

- a description of the proposed CBM investigations;
- the results of a field-verified survey of water wells, springs and dugouts within at least 1.6 km of each of the proposed test holes and wells for the purpose of obtaining baseline conditions in the area;
- a detailed description and interpretation of the geology of the area, including plans, cross-sections and tables identifying the formations;
- a description and discussion of the hydrogeologic conditions in the area; and
- a conceptual Operational Water Management Plan (OWMP) addressing the handling of produced water during exploration and testing phases. The OWMP should describe the proposed method of produced-water disposal. Discussions on the potential effects of the proposed method on the environment such as soil, surface water, groundwater, and so forth must be included. AENV must approve the OWMP prior to exploration.

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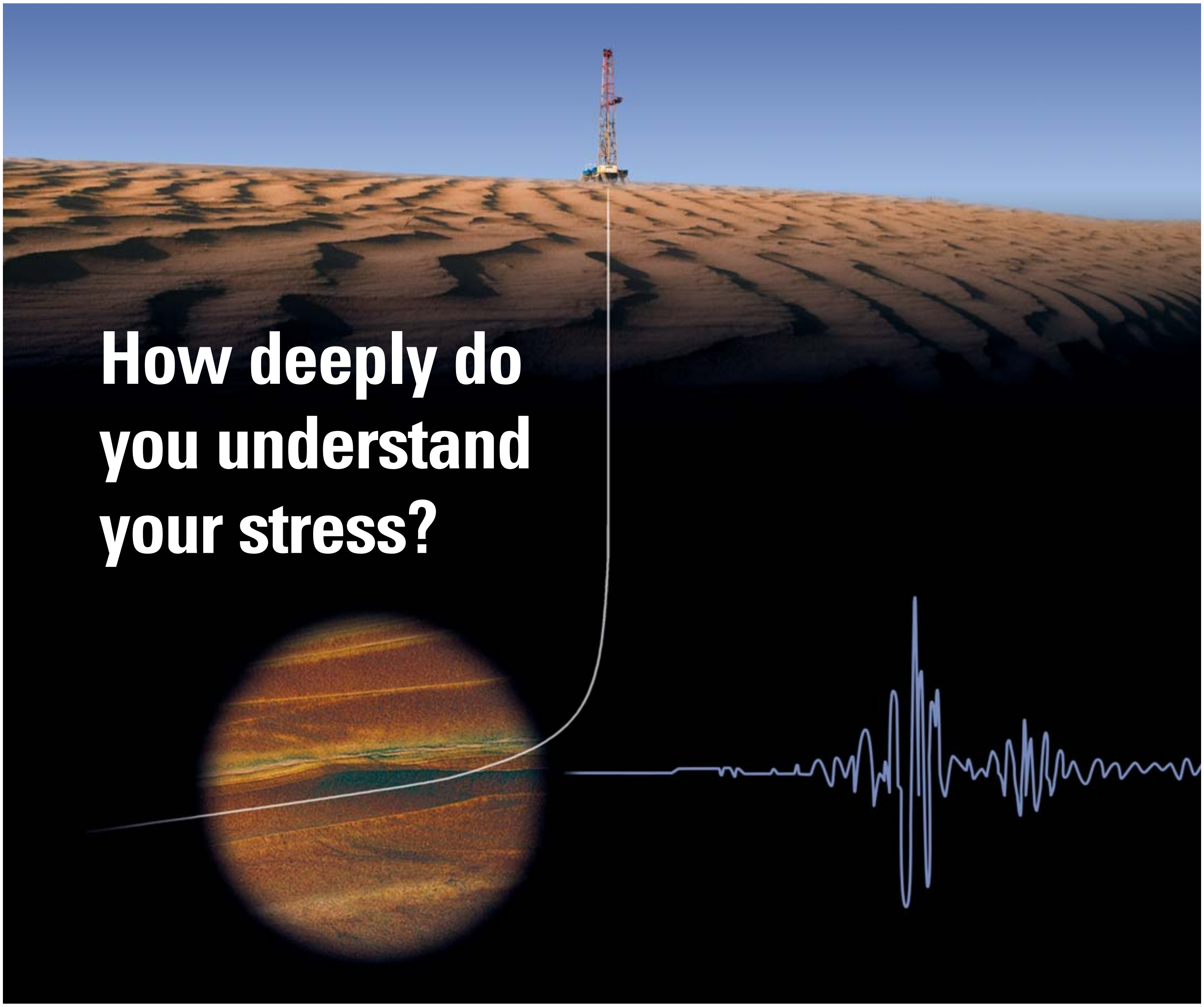
How deeply do
you understand
your stress?

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Once the PGA has been conducted and the OWMP approved, a CBM developer who is contemplating the production of non-saline water must then apply for a license under the Water Act.

After an application is complete public notification is required, often in the form of advertisements in local newspapers. This provides an opportunity for interested parties to submit Statements of Concern (SOCs) within a period specified by the public notice.

The CBM developer must respond, in writing, to any SOCs from directly affected parties and a copy of all correspondence must be filed with AENV. All parties that submit a SOC that are considered to be directly affected will have their SOCs considered by AENV prior to a Water Act license being issued.

Authorizations will contain conditions under which the project may proceed, but the conditions may vary depending on the nature of the project. Conditions typically require production volumes to be metered, on-going water quality analyses, and water levels to be monitored in the target aquifer and overlying and/or underlying aquifer units. Dedicated observation wells completed in the target coal zone and other specific aquifer intervals may be required. These observation wells will be used to monitor the effects of groundwater production and other issues that may arise, such as changes in water quality, within the main project development area and in the larger surrounding area.

CBM wells that produce non-saline groundwater must comply with the Water (Ministerial) Regulation, which prohibits, among other things, the construction of wells with multiple-aquifer completion, and prevents the co-mingling of groundwater of different quality and salinity.

Conditions may also require the CBM developer to investigate and resolve any allegations of impact on any existing water supply. Measures to resolve any impact may include lowering the pump, deepening the impacted water well, providing water supply to the well owner for their current water needs, and drilling new water wells.

Something important a CBM developer must remember is that licenses issued under the Water Act for the diversion of groundwater are subject to appeals to the Alberta Environmental Appeals Board (the EAB) by any person who filed a SOC and who is directly affected. Hence, a CBM developer who has obtained AEUB well licenses, perhaps after an AEUB hearing where landowners have objected to the issuance of the well license, may in certain circumstances be forced to another hearing before the EAB, perhaps facing the same landowners opposed to the CBM wells.

Produced Water Disposal

Because CBM development can at times result in the diversion to the surface of large volumes of groundwater along with the methane, handling and disposal of the produced water has attracted substantial attention and significant controversy in the United States. CBM development in Canada are likely to receive the same type of attention.

The two most common methods of disposing produced water from CBM projects are underground injection and surface discharge. Evaporation ponds have also been used in the US. In a few instances, where the produced water quality is acceptable without treatment, some produced water has been used for livestock watering, irrigation and domestic purposes in the United States. The method used depends upon the water quality and quantity in the CBM basin.[25]

Surface disposal is controversial in the US given that surface discharge has the potential to increase soil salinity and sodium absorption, as well as contaminate lands and surface water resources with trace metals such as arsenic and barium and cause erosion and flooding. Some point out that the average CBM well in Wyoming's Powder River basin discharges 15,000 to 20,000 US gallons of salty water per day and that 80,000 CBM wells in Montana and Wyoming will discharge four trillion gallons of water over the next 15 years. Some people in Alberta opposed to CBM development point to these US problems. However, in Alberta surface disposal is not allowed unless the requirements of AENV are met, and this author is not aware of any current CBM projects where surface discharge is occurring.

In April 2002 the US Interior Department's Board of Appeal ruled that CBM leases for 2,500 acres in Wyoming are illegal because they were issued by the US Bureau of Land Management without proper analysis under the National Environmental Policy Act of CBM's unique impacts. Apparently, a further 51,000 proposed CBM wells could be impacted by this ruling.

Surface Water Disposal in Alberta

An approval is required by AENV to surface discharge produced water under EPEA.

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[25] *For instance, in the San Juan basin, approximately 99% is injected, while in the Powder River basin, approximately 99% is discharged to the surface.*

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In Alberta, water quality parameters for surface water discharges are set by the Surface Water Quality Guidelines For Use in Alberta.[26] The Guidelines are meant to provide general guidance in evaluating surface water quality throughout Alberta.

The Guidelines can be used in combination with water quality monitoring data to assess ambient conditions and to identify areas with existing or potential water quality concerns. If monitoring data do not exceed the Guidelines, problems are unlikely. If the Guidelines are exceeded, a detailed assessment might be required in order to determine the extent, cause, and potential adverse effects arising from the exceedance. The Guidelines are also used in setting water quality based approval limits for wastewater discharges.

The acute (maximum) and chronic (continuous) guidelines for numerous substances are set out in tables in the Guidelines. These are important when establishing limits based on water quality.

Surface water discharges from CBM projects may therefore be allowed by AENV if the discharge water meets the Guidelines on its own accord or upon treatment. Seasonal discharges may also minimize impacts.

Re-injection

Deep well disposal of oilfield and industrial wastewaters are considered by the Alberta Government to be a safe and viable disposal option where wells are properly constructed, operated and monitored. CBM-produced water may therefore be re-injected in Alberta.[27] Disposal wells, including disposal wells for disposing of water produced from CBM wells, are classified and have to be designed in accordance with the EUB's Guide 51: Injection and Disposal Wells – Well Classifications, Completion, Logging and Testing Requirements.

In all cases the location and purpose of a disposal or injection well must first be approved by the Board in accordance with the OGC Act and the OGC Regulations. Guide 51 identifies the information required to be submitted in support of an application for approval to inject or dispose of produced water, as well as operating and monitoring procedures. The primary purpose of this information is to ensure wellbore integrity during disposal or injection operations.

Injection and disposal wells are classified to identify those wells that require increased levels of monitoring and surveillance based on the type of the fluids injected. Accordingly, wells accepting wastes beyond common oilfield or similar wastes are subject to a program of more stringent ongoing monitoring and review. By contrast, wells injecting fresh or potable water are subject to minimal monitoring and surveillance.

Regulatory activities focus on issues related to:

- wellbore integrity to ensure initial and ongoing containment of the produced water in the interests of both hydrocarbon conservation and groundwater protection;
- formation suitability to ensure initial and ongoing confinement of the produced water in the interests of both hydrocarbon conservation and groundwater protection;
- suitability of the waste stream for deep well disposal having regard for the nature of the produced water, the integrity of the well and alternative disposal and management options; and
- reporting and manifesting of produced water.

Matters of fluid-fluid, fluid-equipment, and fluid-formation compatibility are left primarily to the disposal well operator, with regulators relying on operating and monitoring requirements to provide for early detection and mitigation of potential problems. The party generating the produced water has the primary responsibility to ensure that the produced water has been properly identified, characterized, and is handled, treated, and disposed of in an acceptable manner.

The AEUB has also published a guideline for determining water production from gas wells and when water production from gas wells must be reported: Directive 004: Determining Water Production at Gas Wells. The Directive outlines the Board's measuring, sampling and reporting protocols.

Produced Water Rights

Questions have arisen, especially given the recent drought on the prairies, about whether the extensive water resources diverted from coal seams as part of a CBM development have a commercial value to the developer for irrigation or other purposes. For instance, in some parts of the United States water is considered a commodity which may be privately bought and

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[26] *See www.gov.ab.ca/env/info/infocentre.*

[27] *For an excellent analysis of CBM produced water disposal issues in British Columbia, see Disposal of Coalbed Methane Produced Water in British Columbia by Tony Fogarassy, Paul Mooney and Neo Tuytel of Clark, Wilson (www.cwilson.com).*

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sold for over $250 US per acre/foot in some basins. In some areas, the water may be nearly as valuable as the methane.

In Alberta, all water resources are owned by the Crown pursuant to the Water Act. Accordingly, a CBM developer is not entitled to “sell” the water produced to area farmers or anyone else.

Surface Disturbances

CBM developments result in increased surface disturbances due to seismic lines, well pads, compressors, pipelines, roads, plants and infrastructure. For instance, the Bureau of Land Management in the US has estimated that development of some 80,000 CBM wells expected to be drilled in Montana and Wyoming in the next 15 years will result in an estimated 17,000 miles of new roads, 20,000 miles of new pipelines, 200,000 acres of soil loss and potentially thousands of saline water reservoirs.

Surface disturbances may adversely affect local landowners with noise, dust and general nuisance, as well as impact local ecologies and disturb wildlife. The results cumulatively may not be trivial if Alberta’s and British Columbia’s extensive coal basins follow the trends in the United States where thousands of CBM wells have been drilled. The surface impacts in British Columbia could be significant as some of its extensive coal-bearing areas have not historically experienced the degree of surface disturbances associated with conventional oil and gas exploration and production activities. Drilling rigs could soon be found in areas where they have not before typically been seen, such as on Vancouver Island.

In Alberta, the acquisition of mineral rights or the issuance of a well license does not guarantee a CBM developer the right to access the surface of the land for drilling and production purposes. Instead, a separate surface rights access entitlement is required. For Crown lands, a surface disposition may be obtained under the Public Lands Act. For privately-held lands, a negotiated surface lease is required with the landowner. A right-of-entry order could be obtained under the Surface Rights Act for the removal of minerals contained in or underlying the surface of the land or for or incidental to drilling operations or for the construction and operation of pipelines, roads, tanks, stations and structures. The Surface Rights Act provides a regime for determination of compensation payable to the landowner.

Flaring

An environmental issue that must be addressed with CBM development is the need for additional flare testing to prove production on new wells. Flaring is the controlled burning of gasses that are uneconomical to be processed or sold. Flaring is often necessary for an operator to assess a well’s production capability and to determine the appropriate gathering and processing systems required to handle the well’s production. Flaring can also occur for operational reasons, such as equipment failures and to safely dispose of gas while de-pressurizing equipment.

Some CBM wells are flared for longer periods than now occur for conventional gas wells because of the lower pressure and volumes associated with CBM wells. For instance, during the often long period of dewatering the gas production may not be sufficient to run compressors or justify gathering line construction.

In Alberta, flaring has steadily been at the forefront of the public and landowner’s opposition to oil and gas exploration and development. The Board extensively regulates flaring through performance and reporting requirements, permits and data collection as detailed in Guide 60: Upstream Petroleum Industry Flaring Guide.

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A flare permit is required from the Board for well test flaring when the flared gas contains more than 50 moles of hydrogen sulphide (H_2S) per kilomole of gas or the total well test volume exceeds 200, 400, or 600 thousand cubic metres, depending on the type of the well.

Prior to planned flaring, operators are required to provide 24 hours' advance notice to the appropriate AEUB Field Centre, to all residents within a 3 km radius for sour gas well tests, and to all residents within a 1.5 km radius for oil and sweet gas well tests, regardless of the H_2S content.

Additional "good neighbour" notification, including notice for short-duration events, should be conducted where members of the public have identified themselves as being sensitive to emissions from the facility or if they are interested in receiving notice of planned flaring for other reasons.

The AEUB expects operators to provide an information package to the public prior to flaring (other than in an emergency). The information package must include:

- company name and contact information,
- location of the test flaring, duration of the flaring (start date and latest expected completion date),
- expected flaring volumes and rates,
- information on the type of well (oil or gas) and, if applicable, information on the H_2S content of the flared gas, and
- telephone numbers of operator and AEUB Field Centre contacts.

The Board also expects the company to address any concerns raised by the public prior to flaring.

Greenhouse Gas Emission Reduction Credits

Although there may be many complex environmental burdens facing a CBM developer, there may also some environmental opportunities.

Methane is a greenhouse gas. So is CO_2, which is sometimes found with coalbed methane. By capturing methane and CO_2 from a coal seam instead of it being vented or released to the atmosphere, a CBM developer may be able to claim, and subsequently sell, a greenhouse gas emission reduction credit.

Air emission reduction credit trading programs have emerged in the United States as key environmental policy instruments in the last decade for the control of SO_2 to curb acid rain. By capping individual SO_2 sources, operators who do not use all their allocated SO_2 allowances may trade the excess to operators who are unable to stay within their allowances. This is known as emission reduction credit trading. The flexibility inherent in market mechanisms such as emission reduction credit trading have been proven to lower the cost of achieving environmental objectives. Such market-based emission credit trading programs are being extended to greenhouse gases to reduce overall emissions.

Coal also has a natural affinity to sequestering CO_2, one of six greenhouse gases covered by the Kyoto Protocol created under the United Nations' Framework Convention on Climate Change. The idea is that CO_2 could be injected by wells into unmined coalbeds with the pressure from the CO_2 driving out the methane. Coal can store CO_2 in twice the volume that it stores methane. The net result, at least in theory, is that there would be less CO_2 in the atmosphere and potentially significant CBM production.

Obviously, the technical and logistical hurdles for such a project could be significant as it is unproven technology with only a handful of pilot projects worldwide, one of which is in Alberta's Ardley coals. Simulation work apparently suggests the potential for an increase in CBM recovery of up to 40% from CO_2 injections Enhanced CBM recovery projects could theoretically store 7.5 gigatonnes of CO_2 in Canadian coals, which is more than 50 years of industrial emissions in Alberta.[28]

CBM developers who sequester CO_2 in coalbeds might be able to create a greenhouse gas emission reduction credit which they could sell or use to offset potential future obligations to reduce carbon emissions.

At present the greenhouse gas emission reduction credit markets are embryonic and the regulatory and political environment in Canada uncertain. Future regulatory clarity is required, but with careful planning and creativity a CBM developer may in the future be able to capitalize on the unique opportunities presented.

One of several hurdles facing a CBM developer contemplating entering the emission reduction game, either with or without CO_2 sequestration, is that the CBM developer as a potential seller of a reduction credit will have to convince a potential buyer of the credit that the emission reduction truly represents an "additional" reduction in greenhouse gases above any that would occur in the absence of the project. In other words, if the greenhouse gas emissions would not have occurred in the first

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[28] *As reported in the Daily Oil Bulletin, September 29, 2005.*

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place in the absence of the CBM project, it is difficult to argue that there has been a net reduction.

Captured methane that would have otherwise been vented or released from a coal mine may satisfy the "additionality" requirement as the methane would clearly have been emitted into the atmosphere but for the CBM recovery effort. It will be harder to prove that recovery of methane from a deeper and unmineable coal seam is "additional" as it would not likely end up in the atmosphere in the first place.

It is important to remember that this "additionality" requirement currently is not well-defined. Rather, satisfaction of this requirement depends on the characteristics of the trade in question and on the buyer's belief that the purchased credit will "qualify" under whatever greenhouse gas emissions reduction credit trading regime may ultimately be implemented in Canada.

In the meantime, it is critical that CBM developers seeking to create credible and marketable greenhouse gas emission reduction credits rigorously quantify and document their purported reductions.

Conclusions: Mitigating the Legal, Regulatory and Environmental Challenges

Development of Alberta's extensive CBM resources undoubtedly presents economic, geological, and technical challenges to which most Canadian conventional gas operators are unfamiliar. But legal, regulatory and environmental issues may also come into play in attempting to successfully develop a project, the most significant of which include confidently obtaining the legal rights to the CBM in a complex mineral tenure system for freehold lands. Hopefully, Alberta's Courts will soon provide clarity. Greater legislative certainty could not only mitigate the title risks for freehold land, but also for Alberta Crown land.

The regulatory risks of permitting a project are probably one of the most easily ascertained, and therefore manageable risks, from a legal stand point. This is because the regulators in Alberta consider CBM development akin to conventional gas development, and generally apply the same laws, rules and policies to CBM as they do to conventional gas.

The significant issue of handling and disposing the produced water has its own significant legal issues and it is with respect to the water disposal that most challenges from landowners, environmental and public interest groups and others can be expected. The solutions are essentially technical in nature in that

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projects deploying superior water handling and disposal technology will be less likely to attract controversy from persons concerned with preserving ecosystems or other values. It is expected that few, if any, CBM projects in Alberta will result to surface disposal of produced water. Hence it may be inappropriate to draw analogies with the experience in some US basins to what is actually happening in Alberta.

Further, much of the criticism to some US CBM development is with respect to the lowering of potable water aquifers. Alberta's coals being tapped for CBM are largely either dry or contain only saline water. Only a very small percentage impact potentially fresh water supplies and strict environmental and regulatory oversight is warranted for these few unique areas.

Similarly, the intensity of CBM well pads in some US jurisdictions is unlikely to be felt to the same extent in Alberta. CBM well density in Alberta is typically no more, and in fact is less than, the density experienced in many heavy oil and shallow gas plays. Further, horizontal wells are thought by some to hold the technological key to unlocking the Province's largest CBM resource and such wells dramatically reduce the industrialization of the surface.

Similarly, CBM projects which enjoy the opportunity of utilizing existing surface infrastructures (seismic lines, well pads, roads, pipes and facilities) should have an advantage over projects which will potentially adversely affect undisturbed areas.

Air emissions are an identifiable but manageable risk. Opportunities may exist for combining CBM extraction with carbon sequestration. A thorough understanding of Canada's embryonic greenhouse gas emission reduction credit trading markets is required as is alertness to the changing policy and regulatory environment in Canada.

About the Author

Alan Harvie is a partner of Macleod Dixon LLP and has 17 years oil and gas, regulatory and environmental law experience. He is chairperson of Macleod Dixon LLP's Environmental Law Practice Group.

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Wednesday, June 21th, 2006
CWLS TECHNICAL LUNCHEON PRESENTATION
FAIRMONT PALLISER HOTEL
133, 9TH AVE. S.W. CALGARY

TIME: 12:00 PM (COCKTAILS AT 11:30 AM)
RESERVATIONS BY: Friday June 16th, 2006 (NOON) - CALL 269-9366 TO CONFIRM A SEAT

COST: MEMBERS RESERVED MEAL: $30.00; NON-MEMBERS RESERVED MEAL: $35.00
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TOPIC: **THE LIFE OF A WELL LOG**

SPEAKER: Karl Norrena, Numerical Modeler for Nexen Inc.

ABSTRACT:

Numerical modeling has become mainstream science. Numerical modeling is a cheap alternative to physical testing. In the petroleum industry numerical reservoir models are relied upon for many things; allocation of resources among multiple owners, reporting of oil in place, quantification of recovery factors, and the sizing of facilities for example. An essential ingredient of the numerical reservoir model is log and core data. This presentation will take a tour through a typical numerical reservoir modeling and quantification of uncertainty exercise and track the life of the well log. In particular we will look at upscaling from the log data to the reservoir model grid and upscaling from the numerical reservoir model, also known as the static reservoir model, to the dynamic model also known as flow simulation. More generally we will look at how the well log plays a part in the numerical modeling process.

BIOGRAPHY:

Karl Norrena calls himself a numerical modeler. He currently works for Nexen Inc., where his role is to construct numerical models of reservoirs, act as an internal consultant for constructing numerical reservoir models, and as a peer reviewer for projects. He is in the final stages of completing his Ph. D. in Geostatistics, and holds an Engineering degree.

Notes: Please forward this notice to any potentially interested co-workers. Thank you.

CWLS GENERAL INFORMATION

INCORPORATED – January 21, 1957

Objective

The objective of The Society (as stated in the Letter of Incorporation) is the furtherance of the science of well log interpretation, by:

(A) Providing regular meetings with discussion of subjects relating thereto; and

(B) Encouraging research and study with respect thereto.

MEMBERSHIP

Active membership is open to those within the oil and gas industries whose work is primarily well log interpretation or those who have a genuine interest in formation evaluation and wish to increase their knowledge of logging methods.

FEES

The CWLS fiscal year commences February 1, and all fees are due at this time.

Initiation Fee (including first year's membership fees) : $40.00
Annual Dues : $30.00
Student (no initiation fee) : $10.00

Memberships not renewed on or before June 30 of each year will be dropped from the roster and reinstatement of such a membership will only be made by re-application, which will require re-payment of the initiation fee plus the annual dues. All dues (Canadian Funds) should be submitted with the application or renewal of membership (Cheque, money order MasterCard, AMEX or Visa).

ACTIVITIES

The Society also furthers its objectives by sponsoring symposiums and exhibits.

Research committees encourage and support research on relevant problems.

The Society is the spokesman to industry and government on topics pertaining to well logging and formation evaluation.

The Society holds a monthly luncheon meeting (except July / August) to hear an address on a relevant topic.

Each active member will automatically receive the CWLS Journal, 'InSite' newsletter and Annual Report.

APPLICATION

Should our activities interest you we invite you to complete the attached application form and forward it to the CWLS membership Chair.

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To apply for membership to the CWLS, please complete this application form in detail.

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June 20, 2006

CSPG Technical Luncheon
Telus Convention Center
Speaker: Paul Colburn Board Chairman CEO
TriStar Oil and Gas Ltd.

June 21, 2006

CWLS Technical Luncheon
Speaker: Karl Norrena,
Numerical Modeler for Nexen Inc.
The Life of a Well Log
Fairmont Palliser Hotel, Calgary, AB

June 21 - 23, 2006

CPGO 46th Annual Tournament
June 21-23, 2006
Elbow Springs Golf and Country Club

Check website http://www.cspg.org/events/events-social-golf-cpgo.cfm

November 5 & 6, 2006

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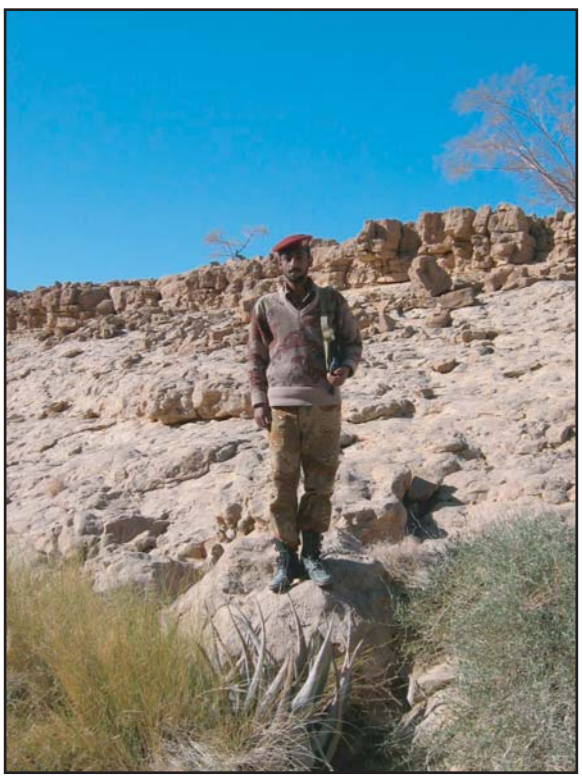
Drilling in springtime during cropping in PEI.
Photo courtesy of Edwin Macdonald.



Security personnel (Yemeni Military) on location in Yemen. Note the full army uniform and a sweater! Definitely pays to be a local.
Photo courtesy of Carole Augereau.

Union Drilling Incorporated Rig No. 50 drilling in PEI.
Photo courtesy of Edwin Macdonald.

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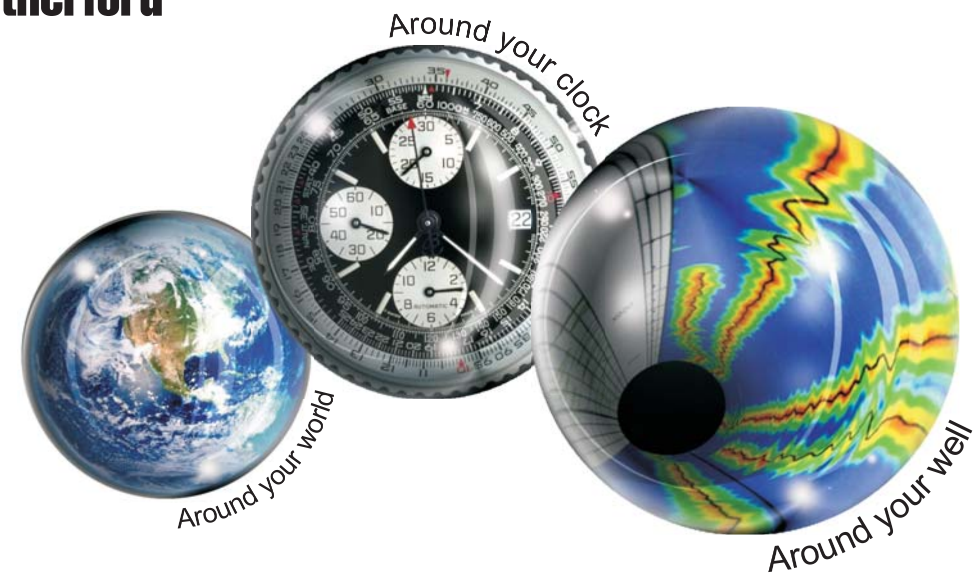
Weatherford®



All Around Faster Data

Exclusive Compact™ formation evaluator runs safely inside drillpipe at high speed.

No longer do you have to put wireline logging tools on the end of pipe and try jamming them down rugose or deviated boreholes. Our *Compact* formation evaluator (FE) system with a diameter of just 2¼ inches fits safely inside the drillpipe where it can be run as quickly as you can trip drillpipe.

Speed and efficiency make a huge difference in today's world where maximizing mature assets might involve drilling 10 times as many wells as in the past. You can run your quad combo in a fraction of the time and get better wireline measurement quality and reliability because the tools are protected.

Along with the *Compact* FE system, Weatherford's acquisition of Precision Energy Services brings many other exclusive technologies in wireline logging and directional drilling into our measurement portfolio. It's all a part of our 360 Service built around you and your needs. For more information, call **403-265-6060** or visit us at **www.weatherford.com**.

Drilling | Evaluation | Completion | Production | Intervention