CARP Weekly Info - Postings on LinkedIn Summarized

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1 Sales Promotion

1.1 Sales Promotion 1 (post #1)

Are you looking to get a better understanding of your carbonate reservoirs? Our carbonate reservoir properties tool, CARP, can help! With this tool, you'll be able to quickly and accurately determine key reservoir parameters such as porosity, permeability, variable porosity cutoffs, effective porosity, pore throat size distribution, capillary pressures, saturations etc. This information is crucial in exploration and for optimizing reservoir management and maximizing production.

Not only is CARP easy to use, but it's also highly reliable. It's been tested and validated using a variety of real-world carbonate reservoirs, so you can trust that you're getting accurate results.

One of the best things about CARP is that it's versatile, and it can be used on a variety of carbonate reservoir types. Because it's web-based, you can access it from any device with an internet connection. So if you want to get a better understanding of your carbonate reservoirs and make informed decisions about their management, give CARP a try. You won't be disappointed!

Lonoy Geoconsulting AS is now offering free trial accounts to CARP. Read more at https://geoconsulting.lonoy.no/tools.php#overview

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1.2 Sales Promotion 2 (post #2)

CARP (CArbonate Reservoir Properties) demonstrates a new methodology for reservoir characterization and modelling, which can be applied in exploration, field evaluation and field development. It shows the relationship between pore types and different reservoir parameters, and is based on both published and unpublished global data. Predicted reservoir parameters are controlled by empirical relationships between different parameters. These parameters are critical for hydrocarbon volume estimation and flow properties in carbonate reservoirs. The methodology and the predicted values are believed to be applicable to any carbonate reservoir, regardless of age, burial depth, depositional setting or geographical location. CARP has also been successfully applied to producing siliciclastic reservoirs.

CARP can be applied to predict reservoir parameters that go into static reservoir models and, if necessary, the results can be simplified for transfer into dynamic reservoir models. Predictions can be made at wire-line log and cell-grid resolution. A simple overview of how this is done is illustrated in the video below.

https://youtu.be/KgENRClcwIE

1.3 Sales Promotion 3 (post #3)

CARP technology has been successfully applied to producing carbonate reservoirs in Russia (1 field), Iran (4 fields), Iraq (4 fields) and UAE (2 fields), and to exploration of the Barents Sea and Norwegian Sea. It has also successfully been applied to a producing siliciclastic field, the Brage Field, in the North Sea. The technique has been tested and approved by BeicipFranlab on behalf of a Middle East field operator. It has also been extensively tested by Shell research, Holland.

An example of how CARP technology is applied in a producing Cretaceous field in Iran has been published by Equinor:

https://www.researchgate.net/publication/274270550_Capturing_the_Effect_of_Fracture_Heterogeneity_on_Multiphase_Flow_During_Fluid

1.4 Sales Promotion 4 (post #4)

Methodologies related to pore-type control on reservoir properties have been developed over the last 20 years and has led to the development of CARP. Elements of CARP have been presented at several international conferences, including AAPG (El Paso 2004 and Mallorca 2006), IQPC (London 2006), EAGE (Shiraz 2009) and SPWLA (Abu Dhabi 2010 and Abu Dhabi 2013).

CARP has a lot of features and can handle a wide range of reservoir properties which can be applied in reservoir models at wire-line log or cell-grid resolution.

A flyer which gives a simplified overview of this can be watched at:

https://cloud.squirrel365.io/embed/C7D8882957194C5B8F443CEDCB539355

Please note that the flyer is interactive and that radio buttons associated with the black info boxes are active.

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2 Rock Types

2.1 Introduction (post #44)

Rock typing is the process of assigning reservoir properties to geological facies. Geological facies is a wide term and can include depositional setting, texture, diagenesis, porosity characteristics etc. The purpose of rock typing is to be able to understand and predict spatial distribution of different reservoir properties across a field. The type of facies to apply may vary and depends on the purpose.

It is important that the facies applied can be related to sedimentologic & diagenetic processes. Frequently, reservoir properties are applied directly to depositional settings or textures. However, this is not always optimal as the reservoir properties commonly only are indirectly related to depositional setting, textures or diagenesis.

2.2 Examples (post #44)

Images A & B show two samples from the same depositional setting (high-energy, shallow marine oolitic shoal), having the same sedimentary texture (grainstone). Grouping these in the same rock type would therefore be natural. However, the samples show significant differences in pore type, pore geometry, pore-throat diameters, permeability and MICP curves due to differences in diagenetic alteration. Measured permeability and MICP curves are not available, but we will compare predicted values based on CARP prediction tools. Based on image analysis, the porosity of both samples is ca. 20%.

Image A
Cross-polarized Light
Porosity: black
Pore type: 1.13 (primary interparticle, uniformly distributed macropores)
Predicted permeability: 91 mD
Predicted Hg capillary entry pressure: 4 PSI
Predicted OWC above FWL: 0.9 m

Image B
Porosity: blue
Pore type: 3.13 (secondary moldic macropores)
Predicted permeability: 6.3 mD
Predicted Hg capillary entry pressure: 23.5 PSI
Predicted OWC above FWL: 5.2 m

Predicted OWC is based on assumed oil and water densities of 0.80 and 1.04 g/cc, respectively, and a surface tension and contact angle of 30 dynes/cm and 38 degrees, respectively.

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Images C and D show predicted MICP curves for A and B, respectively.

This shows that when reservoir parameters are involved, pore type should be applied as rock type because this incorporate information on important reservoir parameters such as pore size, pore geometry, pore-throat diameters, porosity distribution and porosity-permeability relationships. There is not always a 1:1 relation between pore types and depositional setting, and a limited set of pore types are usually present within each depositional setting. Pore type distributions are usually derived from empirical statistical data, and pore types are distributed in reservoir models based on the statistical probabilities within each sedimentary and/or diagenetic facies.

For these reasons, pore types are always applied as rock type in CARP.

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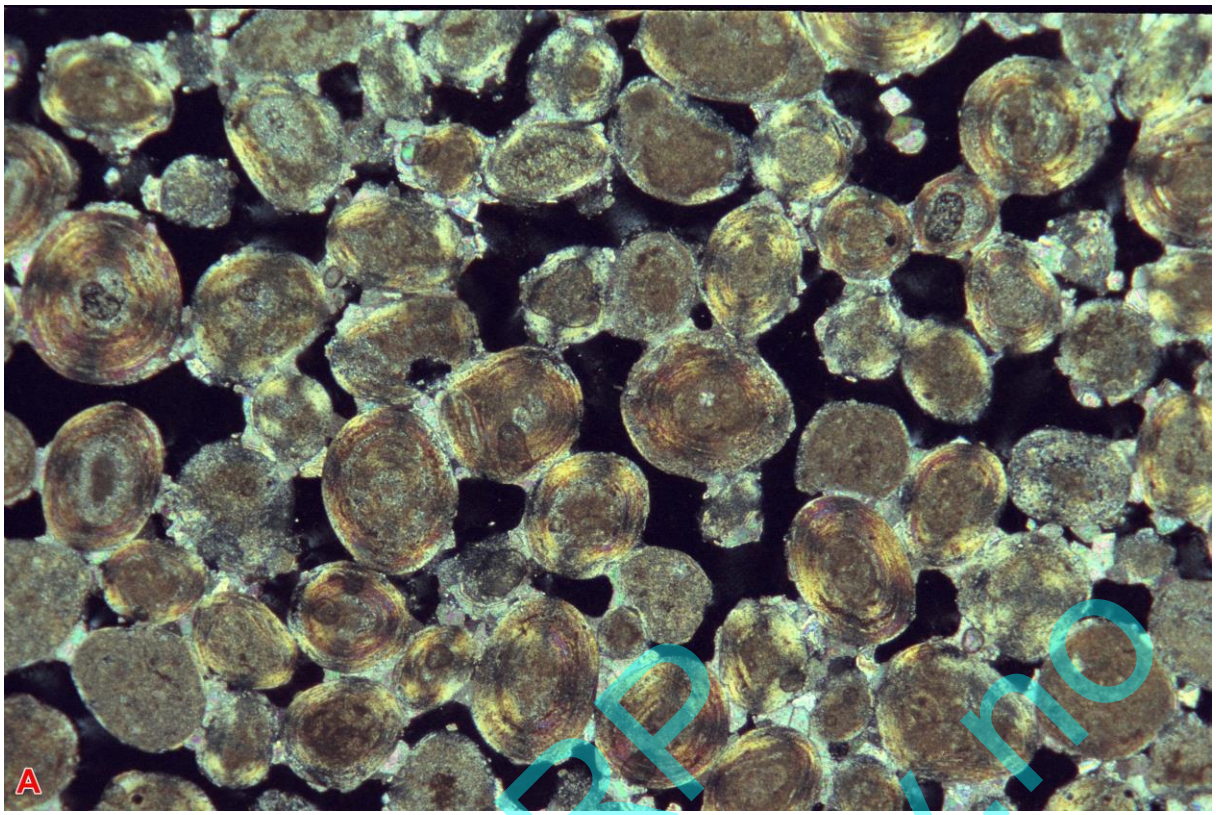

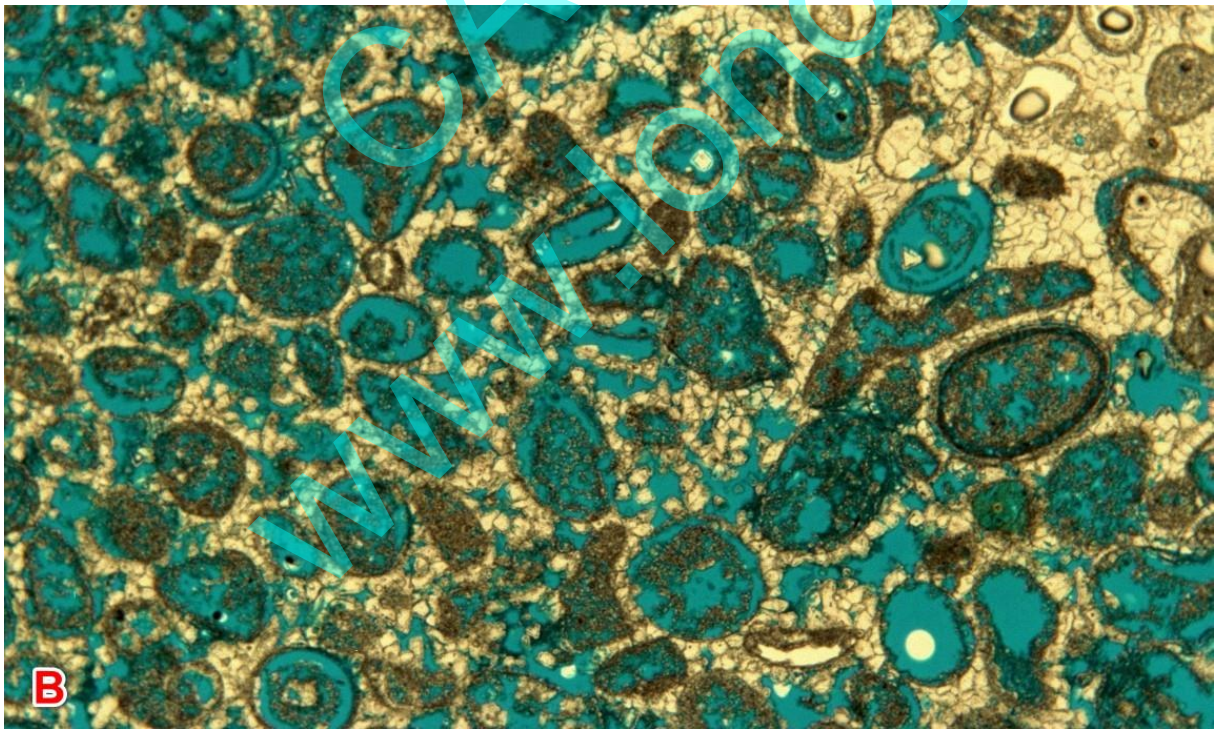

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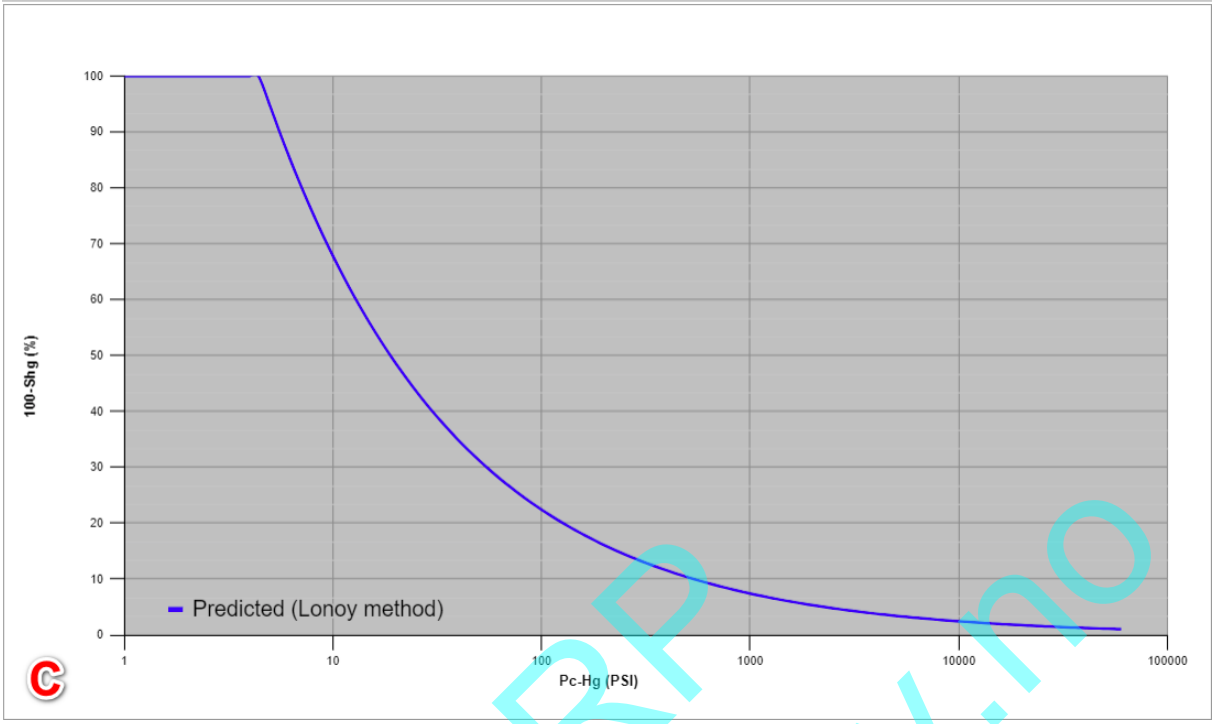
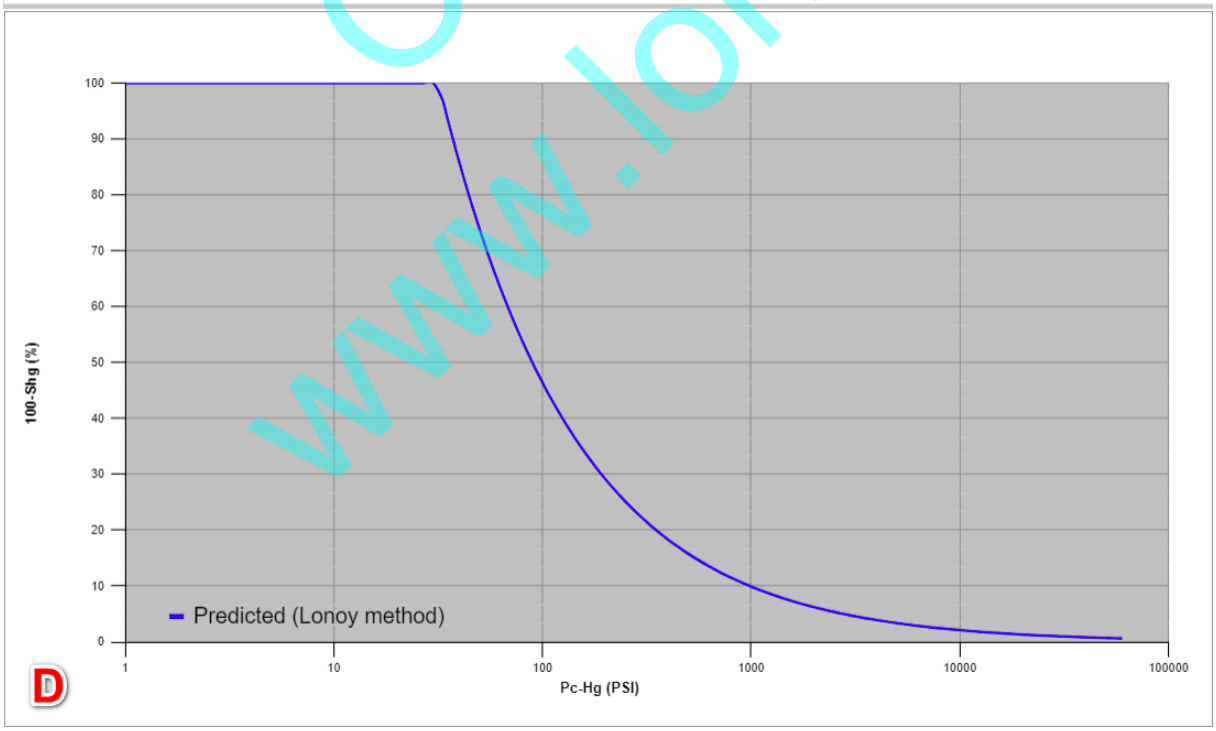
Demo, Sample A,
Pore Type 1.13, Porosity = 20% (Raw data)



Demo, Sample B,
Pore Type 3.13, Porosity = 20% (Raw data)



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3 Pore Types

3.1 Overview (post #5)

Pore type is the basic element of CARP. Combined with porosity and a few other parameters, pore types can be used for prediction of several different reservoir parameters, including permeability, effective porosity, porosity cut-off and associated net/gross, MICP curves, saturation, and OWC.

CARP applies the pore-type classification system of Lonoy (2006) with one additional pore type. The classification system is based on empirical optimization of global porosity-permeability relationships, and uses elements from the Choquette & Pray (1970) and Lucia (1983, 1995, 1999) pore-type classification systems, but also introduces many new elements. Please send an email to geoconsulting@lonoy.no if you would like a copy of Lonoy (2006).

The pore-type system includes 21 pore-type classes that show a predictable relation between porosity and permeability. It combines sedimentologic and diagenetic features with flow-related properties, and reservoir-critical parameters can thus be predicted using sedimentologic and diagenetic models.

Examples of different pore types, and their definition and origin will be presented in later weekly updates of CARP on LinkedIn.

The classification system consists of six main pore-type categories, labelled 1-6, four of which are subdivided in up to six subclasses. The pore types and assigned number codes are given in the table (screen shot from CARP).

3.2 Abbreviations & Pore Size (post #6)

The pore-type classification system applied in CARP is based on 3 main components: Pore geometry, pore size and porosity patchiness. These components define the pore-type number coding applied in CARP (see post #5). The pore-type number code is in the form A.BCD where the characters represent

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numbers. The pore types are always represented by A, whereas the presence of B, C or D depends on the pore type.

The following description applies to all pore types, except pore type 6 (will be discussed in a later post).

A represents the pore geometry and is an integer between 1 and 6.

D is only applied to interparticle (geometry 1) and intercrystalline (geometry 4) pore types, and refers to porosity patchiness. The presence/absence of D signifies patchy/uniform porosity distribution.

The last digit in each pore-type code (irrespective of whether this is C or D) gives the pore size: 1 = micro, 2 = meso, and 3 and 4 = macro.

Examples:
Pore type 1.11 = Interparticle micro w/uniform distribution
Pore type 1.112 = Interparticle meso w/patchy distribution
Pore type 4.13 = Intercrystalline macro w/uniform distribution
Pore type 3.11 = Moldic micro
Pore type 3.14 = Isolated moldic macro
Pore type 2 = Vuggy pores

Note that pore-size categories only apply to geometries 1, 3 & 4, and are different for the different geometries:

- Interparticle pores (geometry 1): 10-50µm (micro), 50-100µm (meso), >100µm (macro).
- Intercrystalline pores (geometry 4): 10-20µm (micro), 20-60µm (meso), >60µm (macro).
- Moldic pores (geometry 3): <20µm (micro), >20µm (macro).

Other pore-type classification systems, e.g. Lucia (1983), apply grain/crystal size rather than pore size for interparticle and intercrystalline pore geometries. Sometimes it doesn't make much difference because there often is a relation between the two. However, in many cases where the sediment is cemented, a sample may have large grains, but small pore sizes. Another example is packstone, which may be classified as coarse-grained but still have small pore sizes.

Examples of these are given in thin-section images A and B, where both samples are coarse grained but have interparticle micropores due to either packstone texture (A) or extensive cementation (B). Porosity is artificially stained blue/green. Some of the small interparticle pores in B are marked by red arrows, and this image additionally shows some intraparticle pores. It is the pore size, not the grain size, that controls the reservoir quality, and larger pore sizes give higher permeability for a given porosity.

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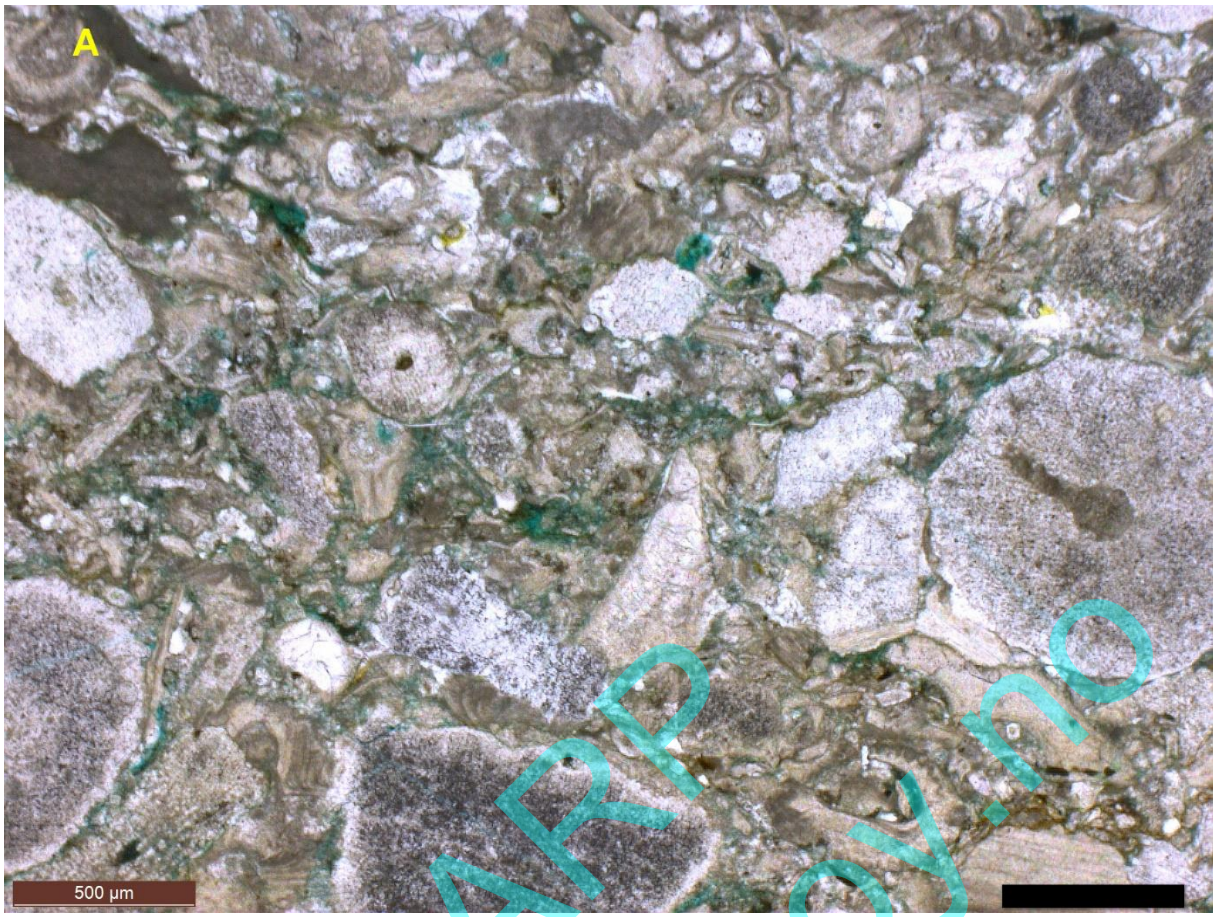

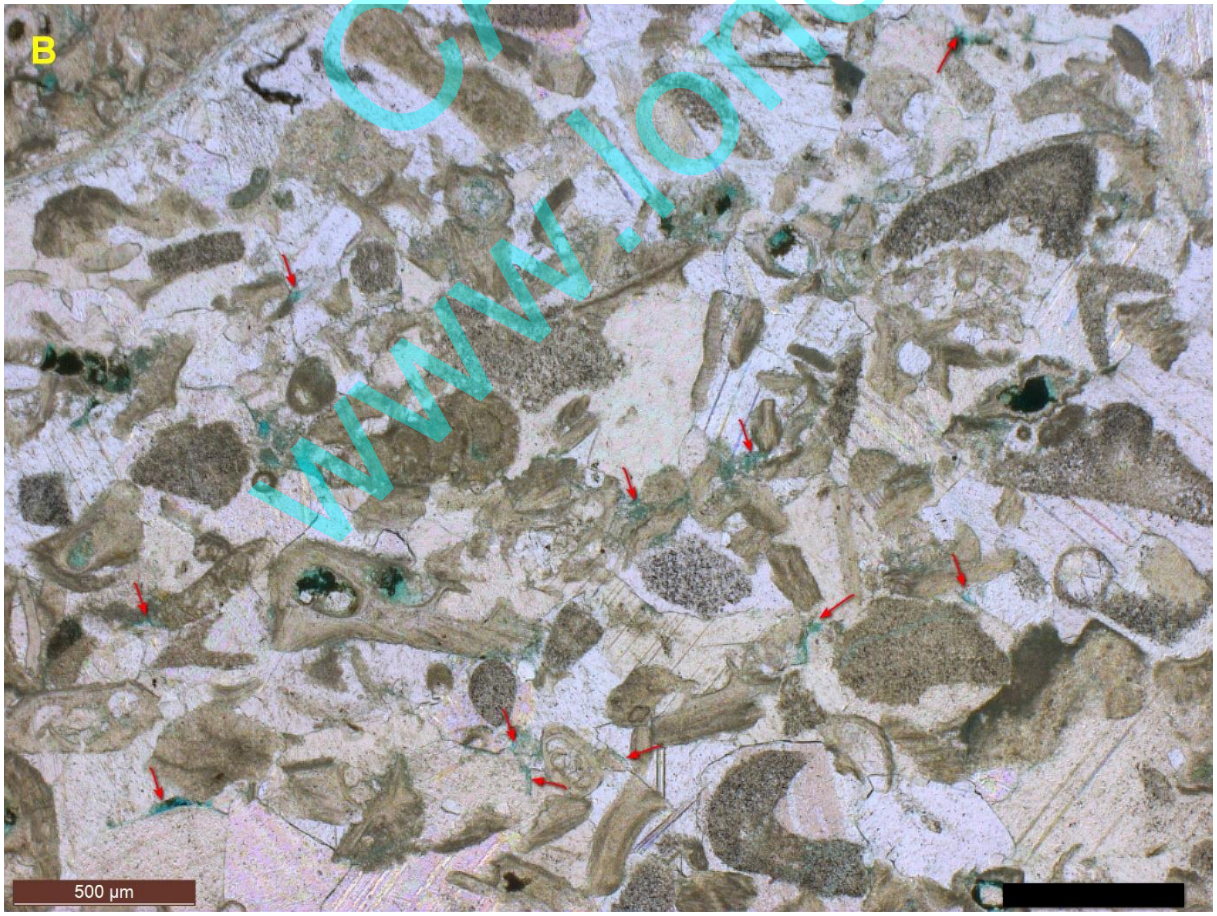

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3.3 Porosity Patchiness (post #7)

As discussed in last week's post, CARP is based on Lonoy's (2006) pore type classification system. The classification is based on three parameters: pore geometry, pore size and porosity distribution. This post #we will discuss the importance of porosity distribution, as illustrated in the two figures below. Porosity distribution as a controlling factor on porosity/permeability relationship was first published by Lonoy (2006).

FIGURE A (sample courtesy of Univ. of Tromsø)

The two thin-section micrographs "a" and "b" are identical samples and show a highly porous (green) oolite. In "b" we have artificially introduced a patch of cement (white), resulting in different porosity distributions in the two micrographs. "a" has a uniform and "b" has a patchy porosity distribution. Obviously, the cement patch strongly reduces porosity in "b". Pore-throat diameters are, however, the same in the two micrographs, and are not affected by the cement. Permeability is to a large extent controlled by pore-throat diameters, and the permeability is thus more or less the same in "a" and "b". Possibly there is an insignificant reduction in permeability in "b" due to slightly increased tortuosity. In any case, the cement patch has a significantly stronger impact on porosity than on permeability, and this changes the porosity/permeability ratio.

FIGURE B

The principles and conclusions derived from Figure A are illustrated in Figure B. The figure shows a porosity-permeability cross plot, with three red circles and a line representing artificial data points and associated trend line for samples with uniform porosity distribution. If we introduce cement patches to the samples, the porosity will be significantly reduced but permeability will almost remain the same, as illustrated by the black arrows. The new data points, representing the samples with patchy porosity distribution, are represented by blue circles, and an associated blue trend line. We see that the porosity-permeability trend line is shifted towards higher permeabilities.

CONCLUSION

For the same porosity, the permeability will be significantly higher when the porosity is patchily distributed than when it is more uniformly distributed. Porosity patchiness also affects porosity cut-off, capillarity, saturation and recovery factor. Patchy porosity distribution gives significantly lower porosity cut-off, higher pore-throat sizes, lower water saturation and higher recovery factor than for uniform porosity distribution, given the same pore geometry, pore size and porosity. This can have a tremendous effect on effective porosity and saturation, potentially giving more than a thousand percent difference in volume estimates (Lonoy, 2006). This is particularly the case in exploration. All of these parameters can be predicted in CARP.

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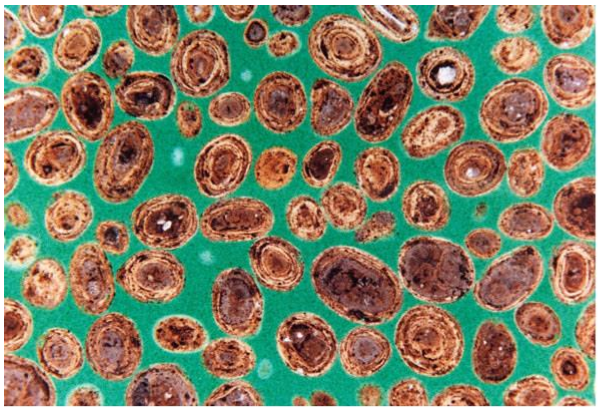
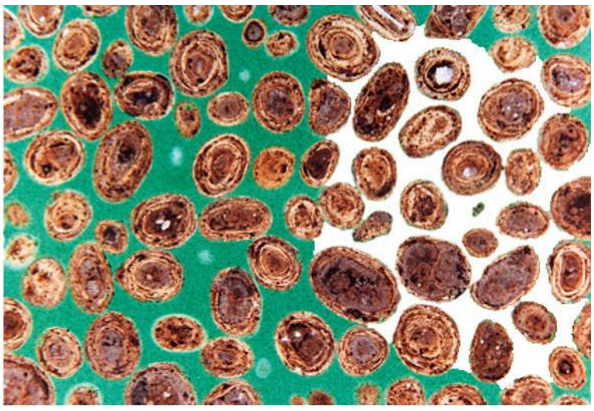


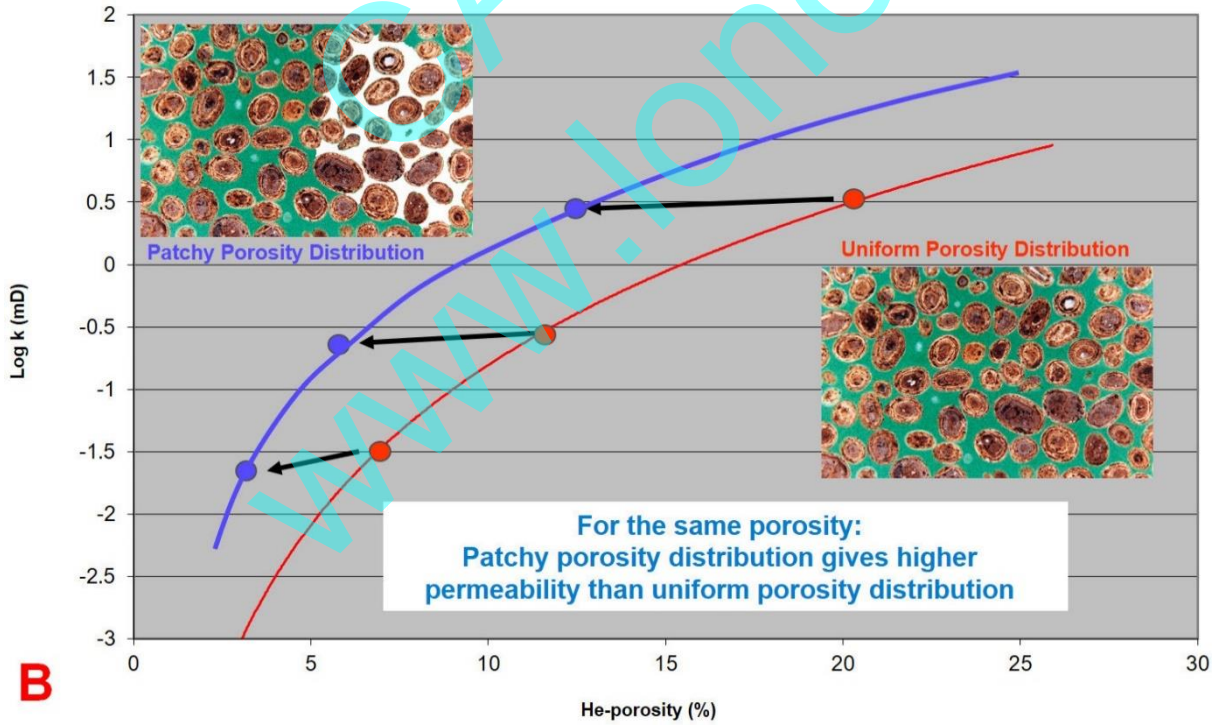
a) Uniform porosity distribution



b) Patchy porosity distribution controlled by cement patch (white)

A

Similar pore-throat diameters.
Insignificant permeability reduction in b).
Strongly reduced porosity in b).



B

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3.4 Interparticle (Pore Type 1)

3.4.1 Introduction (post #9)

Interparticle porosity, also called intergranular porosity, is pore spaces between grains. Interparticle pore types are some of the more common pore types in carbonates, and are by far the most common pore types in sandstones. Studies carried out on a North Sea sandstone reservoir suggest that poro-perm and MICP prediction tools in CARP also are applicable to sandstone reservoirs.

Interparticle porosity is commonly primary in origin, but may also be formed by secondary dissolution of cements or matrix. Pore shapes may vary significantly and are homogenous only when the enclosing particles are of uniform size and shape, e.g. well-sorted ooids. Porosity increases with better sorting and more irregular grain shapes, attaining values of up to approximately 60%.

Preservation of interparticle porosity during burial may relate to rapid burial, dry climate, protective seals of impermeable rocks (e.g. shales, evaporites or fine-grained limestones), early oil emplacement, or early partial cementation at grain contacts. Porosity may be high and the pores are generally well interconnected, yielding reasonable permeability. For a given porosity, permeability increases with increased pore size and patchy porosity distribution.

Interparticle porosity is subdivided into six subtypes based on pore size (3 sizes) and porosity distribution (uniform or patchy).

3.4.2 Interparticle w/uniform distribution (post #9)

Pore Type 1.11: Micropores
Description: Dominant pore size 10-50µm. Image A.
Main occurrences:
• Mud-lean packstones with recrystallized mud.
• Grain-supported textures composed of very small bioclastic fragments.
• Grain-supported textures which have been subjected to partial, finely-crystalline cementation.

Pore Type 1.12: Mesopores
Description: Dominant pore size 50-100µm. Image B.
Main occurrences:
• Grain-supported textures composed of small bioclastic fragments.
• Grain-supported textures which have been subjected to partial, finely-crystalline cementation.

Pore Type 1.13: Macropores
Description: Dominant pore size >100µm. Image C.
Main occurrences:
• High-energy depositional settings where all fine particles have been washed out by wave, tide or current activity.

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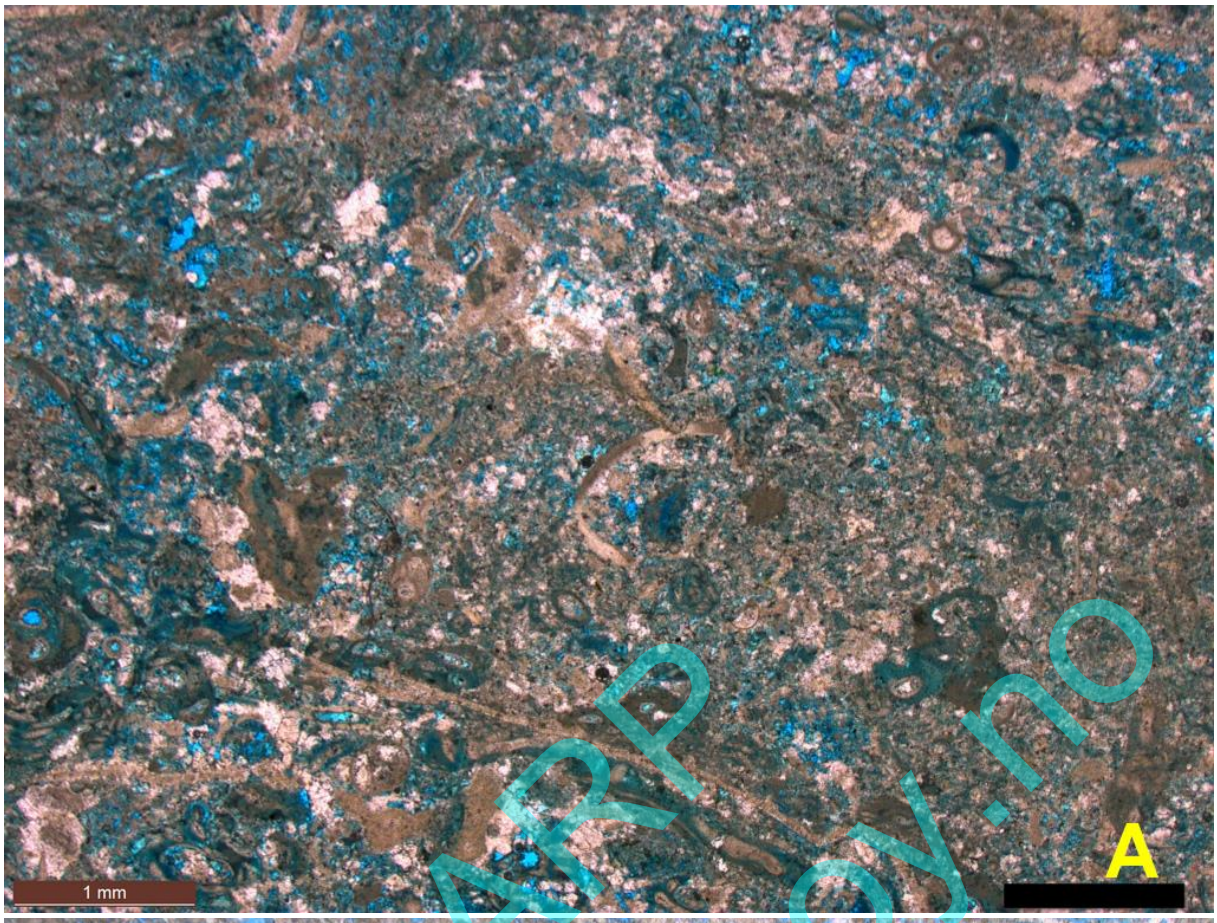

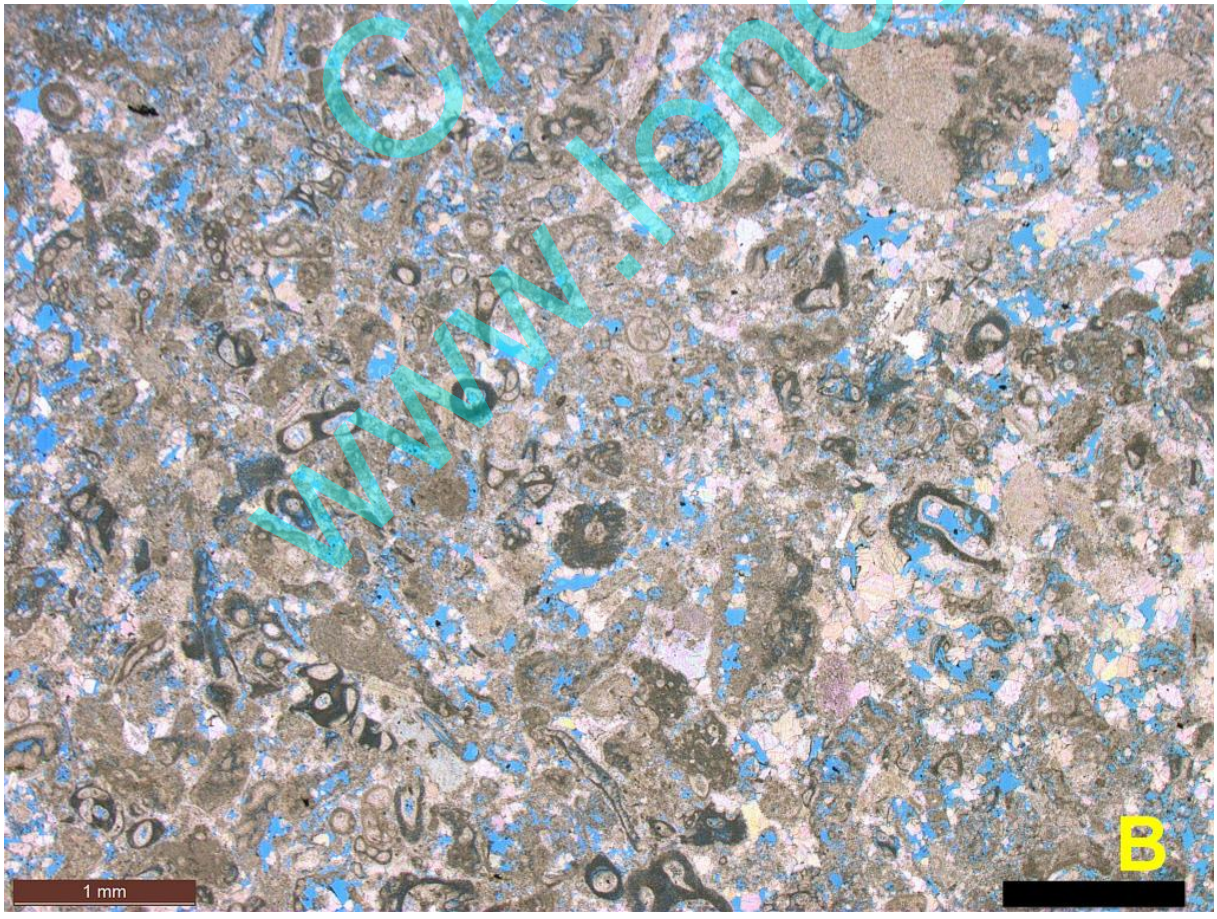

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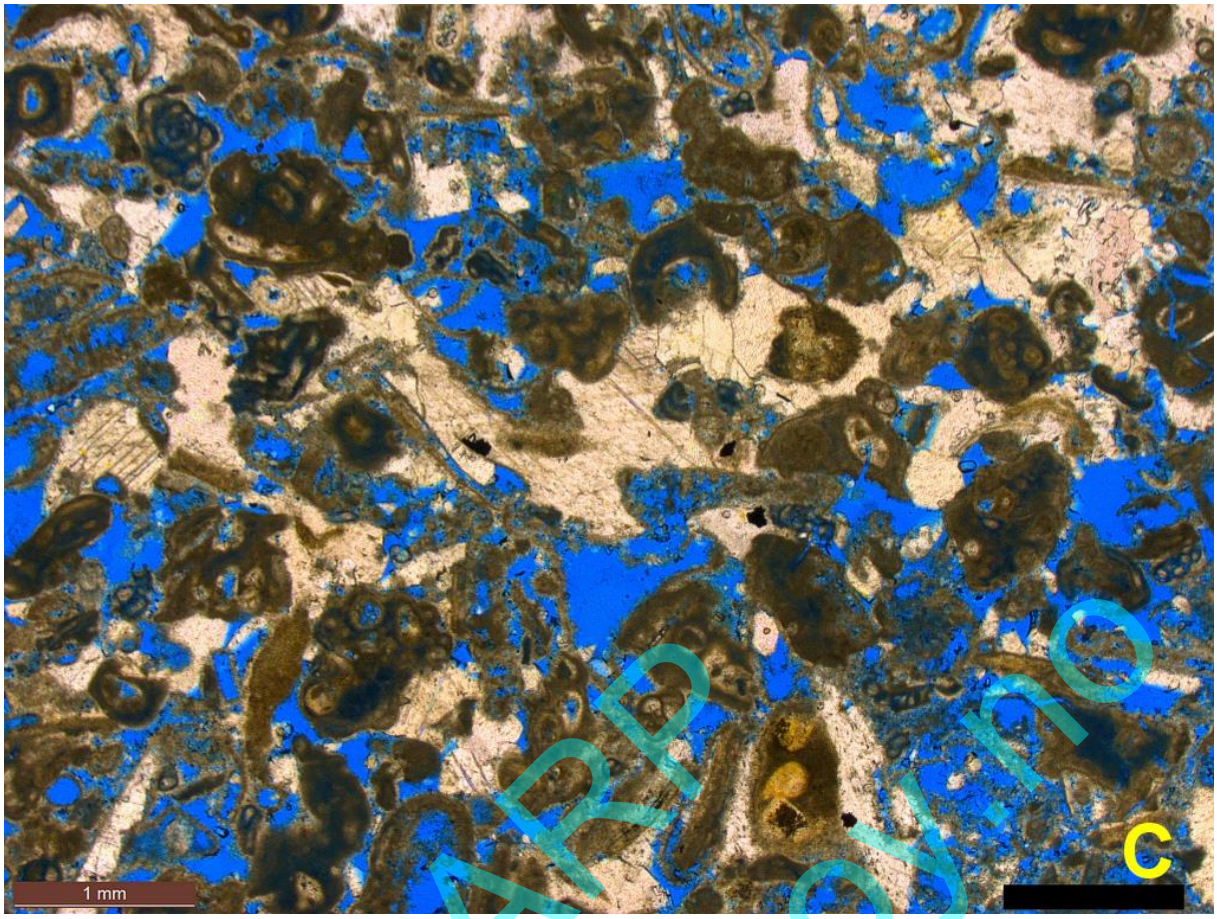

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3.4.3 Interparticle w/patchy distribution (post #14)

Each of the 3 interparticle pore size categories can have a uniform or patchy porosity distribution. This means that patchily-distributed interparticle porosity consist of 3 pore types: micro- (pore type 1.111; Image A), meso- (pore type 1.112; Image B) and macro- (pore type 1.113; Image C).

Patchy porosity distribution is defined at the scale of core plugs and/or thin sections. A plug showing patchy porosity distribution may show uniform porosity distribution within the associated thin section, depending on the location of the section. A thin section may, by itself, sometimes not be sufficient to evaluate the porosity distribution.

Patchy porosity distribution is usually caused by patchy cement distribution, burrows, dis-integration of fossils or by the presence of very large, dense grains:

- Large grains can be grain-supported or occur as scattered grains. Interparticle porosity in e.g. conglomerates, breccias and coquinas will thus usually be classified as patchy even though no/limited cements are available. It could be argued that mega-pores occurring in such coarse-grained samples have a uniform porosity distribution. However, they have more or less the same petrophysical properties as patchy macropores. In order to reduce the number of pore types, patchy porosity is thus defined at a thin-section and/or core plug scale.

- Patchy cement distribution is often controlled by selective precipitation of syntaxial calcite cement overgrowths on single-crystal grains (typically echinoderm fragments), or by different mineralogical composition within the sediment. The cement can be of any mineralogy, and most commonly the patchy cement distribution is due to few mineral nucleation points. This is usually the case when the cement has a different mineralogy to the grains/matrix, e.g. evaporite/silica precipitation within a lst/dol, or carbonate cementation within sst.

Patchy porosity is usually primary in origin, but can also be secondary and related to selective dissolution of interparticle cements/matrix. Distribution of secondary interparticle porosity is strongly controlled by fluid migration pathways, often yielding a patchy pore distribution in the early stages of dissolution. The patchy and more "channelized" porosity distribution commonly give significantly higher permeability at lower porosity than for other interparticle pore types. At higher porosity the porosity tends to have a less patchy distribution, but the secondary origin of the pore spaces is often more obvious.

Patchy porosity distribution gives higher permeability/porosity ratio and lower water saturation, as compared to uniformly-distributed porosity. Failure to recognize the patchy distribution may thus greatly underestimate the reservoir performance.

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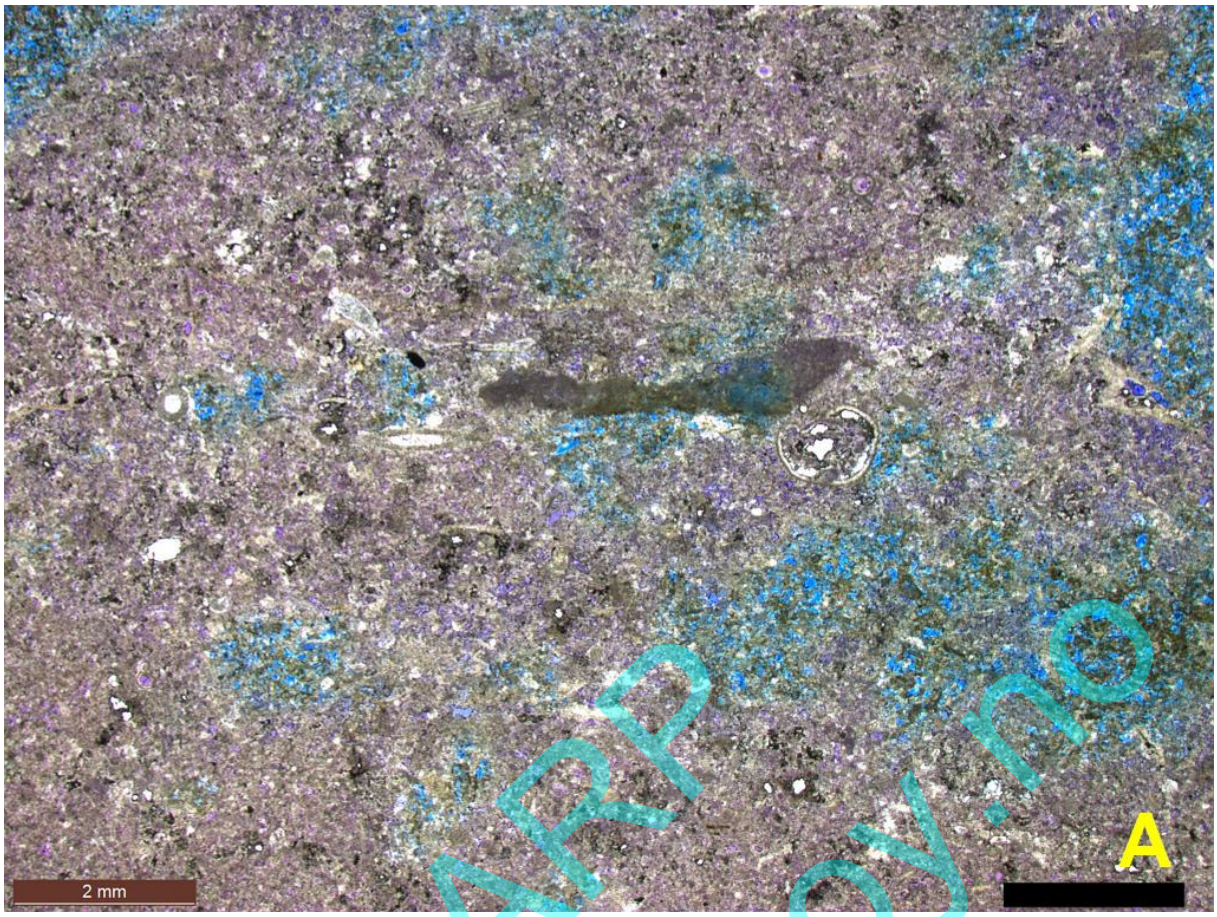

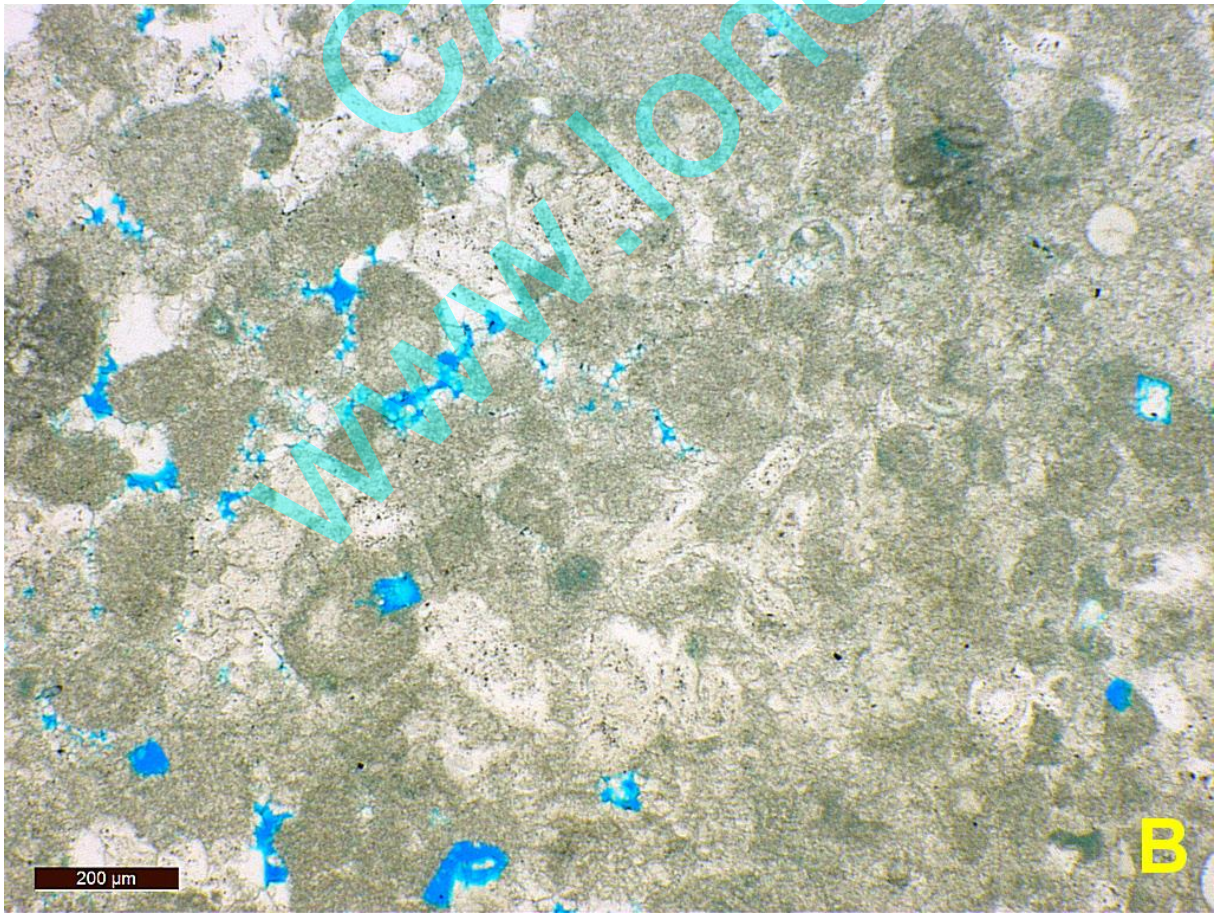

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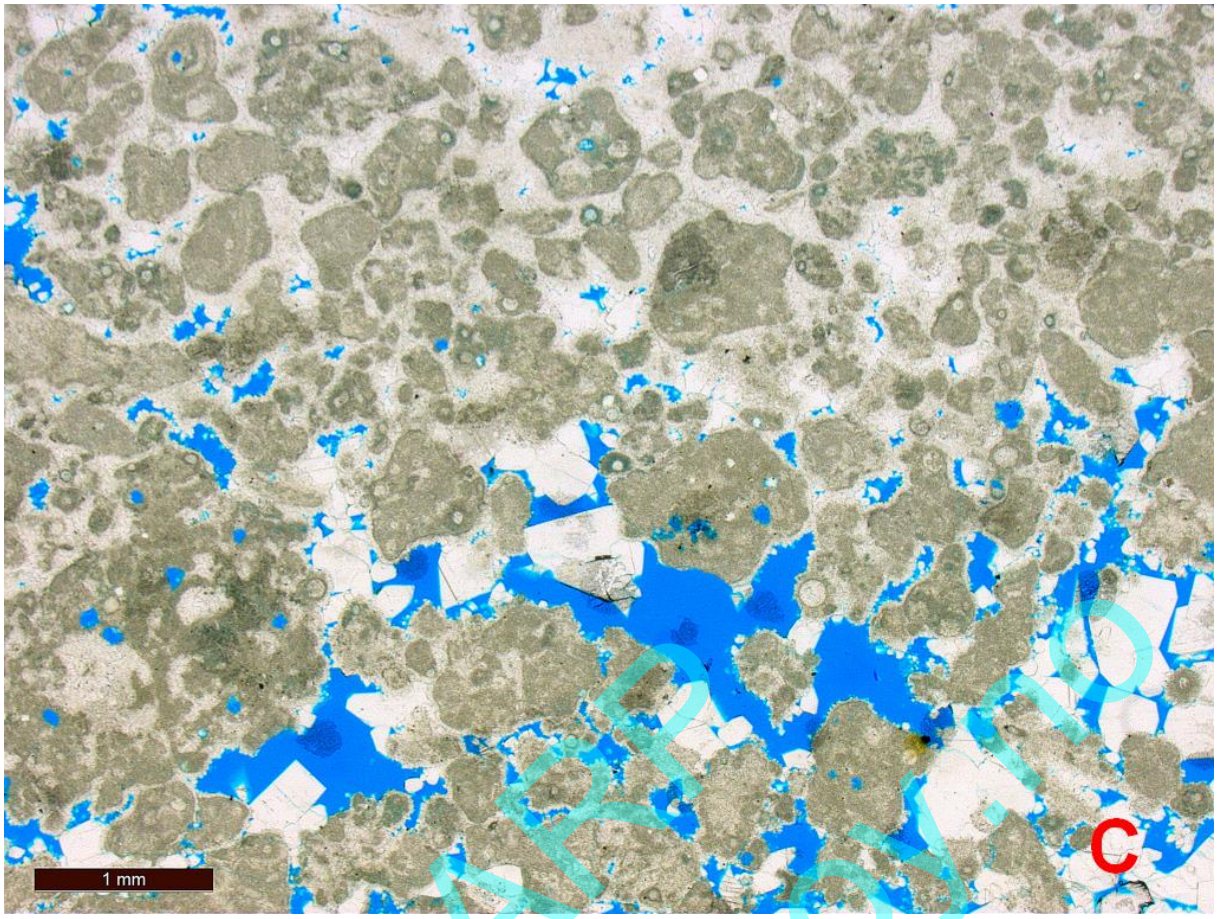

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3.4.4 Secondary Interparticle (post #30)

Interparticle porosity is usually primary in origin, but can also be secondary related to dissolution of interparticle cement. This is observed in both carbonates and sandstones. More frequent observations in sandstones can be due to stronger mineral contrasts (carbonate vs. quartz) or that the process is more difficult to observe in carbonates.

Secondary interparticle porosity tend to have a patchy distribution at various scales, giving rise to pore types 1.111, 1.112 and 1.113, of which the latter is the most common in the CARP database. The patchy distribution gives a significant enhancement of permeability as compared to primary interparticle pore types with more uniform porosity distribution.

This post was planned for later, but was preponed due to DNO's recent North Sea gas condensate discovery (Norma). My only info from Norma is published data, but it would be no surprise if the reservoir resembles the Martin Linge reservoir when it comes to diagenesis and associated porosity development.

Martin Linge & Norma similarities:
- Good reservoir quality in deeply buried (4-5km) sst
- High temperature & pressure
- Gas condensate

Good reservoir quality sandstones are not common at these depths due to common extensive quartz cementation and illitization. This is addressed in my 1986 paper on the diagenesis of the deeply buried Hild Field (renamed Martin Linge). A short summary focusing on the secondary interparticle porosity development follows below.

The Martin Linge reservoir is dominated by low porosity, extensively quartz-cemented sandstones, with abundant authigenic kaolinite related to kaolinization of feldspar, mica and clay minerals. However, some intervals have porosities of up to 30%, with excellent permeability, at over 4km burial depth (Image A). High porosity, calcite-cemented and quartz-cemented intervals form distinctive intervals, but are tightly integrated (Image B). High porosity appears to be located below gas chimneys. Both the porous and calcite-cemented intervals are characterized by the total absence of quartz cement and authigenic kaolinite, suggesting that the interparticle pores were calcite-cemented at an early stage, before quartz cementation and kaolinization was initiated. The close association with calcite-cemented intervals suggest that the high-porosity intervals are related to late calcite dissolution, creating patchily-distributed secondary interparticle porosity with excellent permeability. Calcite dissolution is likely to have been initiated by influx of CO_2-rich gas derived from underlying coal beds.

Secondary interparticle reservoirs need careful evaluation of the spatial distribution of the porosity, in order to understand flow performance & reservoir volume.

Image B: Note high minus-cement porosity in the calcite-cemented (stained blue) intervals (lower left) and the extensive quartz cementation where calcite is absent (upper right). Porosity is green.

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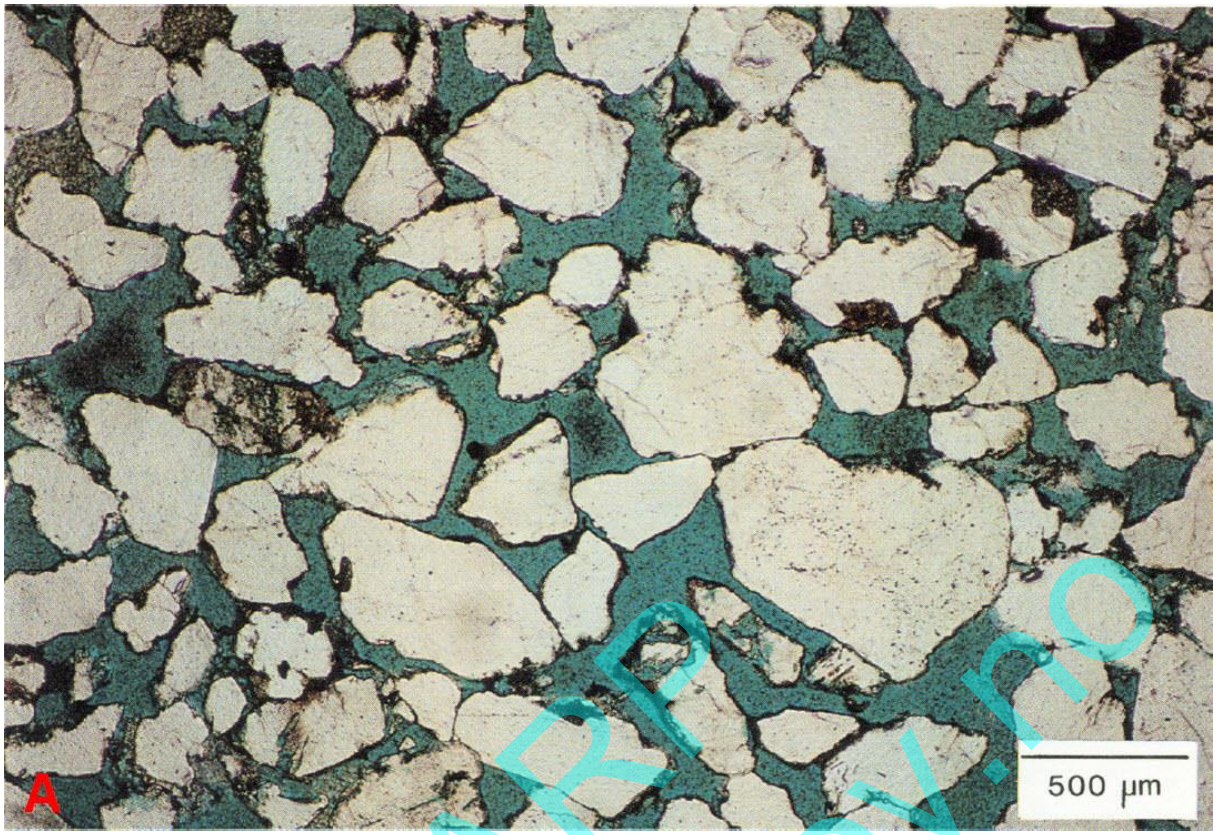

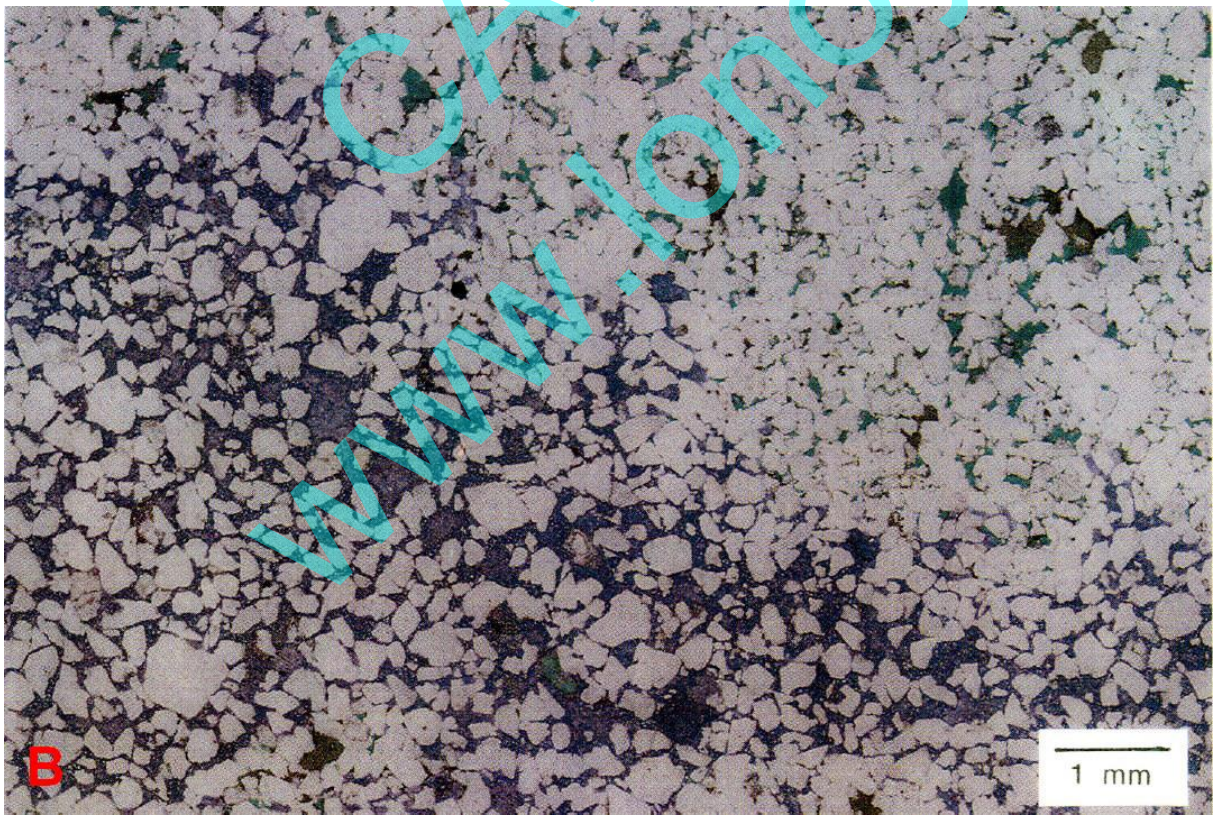

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3.5 Vuggy (Pore Type 2) (post #17)

Vuggy Porosity - Images A (thin section) and B (core; from Lønøy, 2006).

Vuggy porosity is secondary solution porosity that is not fabric selective, i.e. it cuts across grain and/or cement boundaries. The pores are of irregular size and shape and may or may not be interconnected. Many vugs are solution-enlarged molds where evidence of the precursor grain has been destroyed by enlargement. Vuggy pores are commonly from approximately 1mm to 1m in diameter.

Total porosity and permeability of vuggy pores may vary considerably and depend on the size and number of vugs. Vuggy porosity is thus among the pore types showing the highest data scatter along the porosity-permeability trend line. They are also among the pore types showing the best flow properties. Plug-derived porosities and permeabilities are often strongly dependent on the location of core plugs because of large vug sizes (e.g. Image B). Representative measurements will often require whole-core analysis.

Plug-measured porosity and permeability of samples dominated by connected vuggy porosity are usually unreliable and show scattered distributions on cross-plots. One way of dealing with vuggy reservoirs is to measure the micro to macro porosity in core plugs, either from selected RCA measurements or from image analyses from thin-section micrographs. Additional mega-vuggy porosity can be measured by use of image analysis of slabbed cores. Combining these can give a more reliable total porosity than plug measurements alone, and permeability can be estimated from CARP's global porosity-permeability trendline curves. Image analysis of slabbed cores will be discussed in a later post.

RCA measurements of vuggy reservoirs often strongly underestimate porosity and permeability due to common RCA practices where the most permeable pores are sealed off. This will be discussed in a later post.

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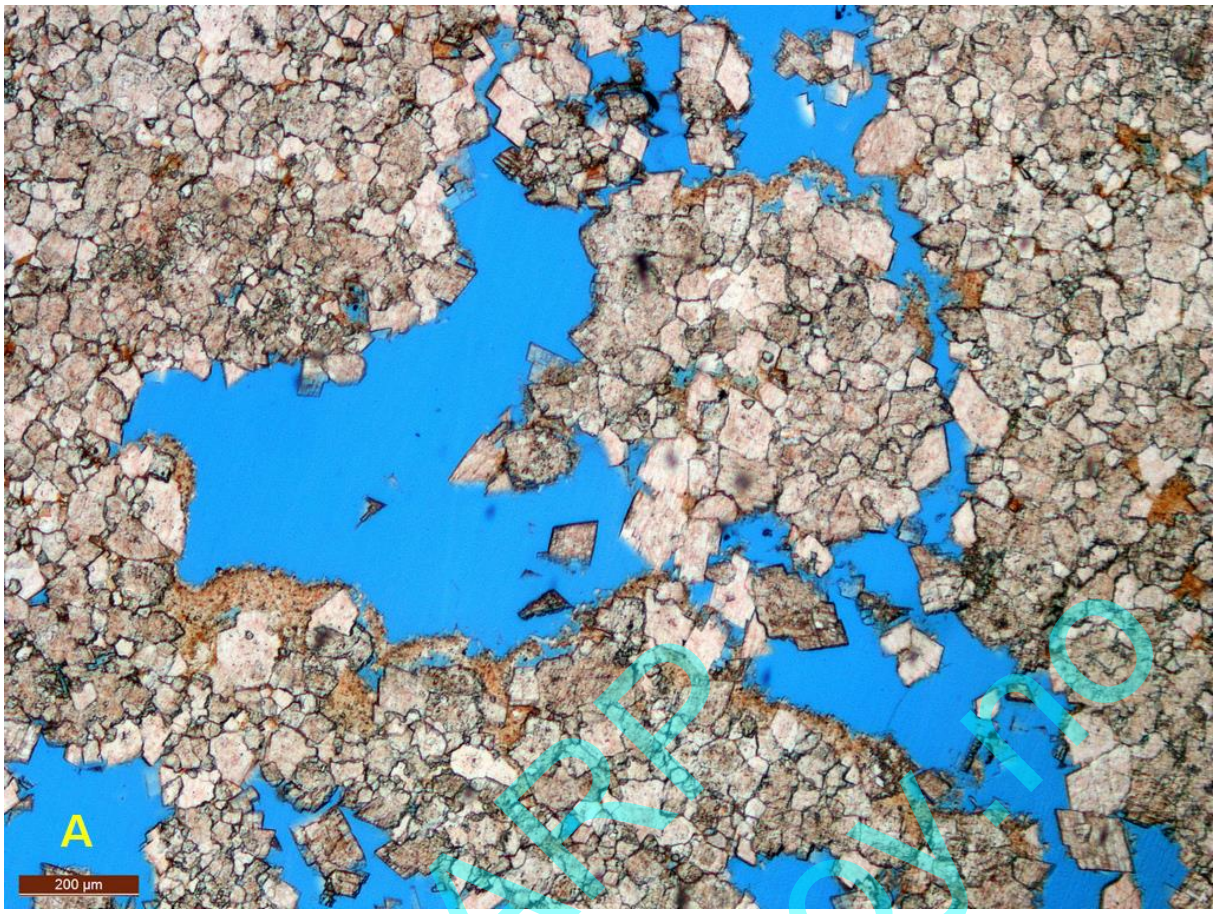

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3.6 Moldic (Pore Type 3)

3.6.1 Introduction (post #27)

Moldic porosity is secondary porosity formed by the selective dissolution of grains or crystals, such as ooids, bivalves, corals and evaporite minerals. A distinctive difference in solubility between grains/crystals and framework is needed and is commonly related to mineralogical differences, e.g. aragonite vs. calcite, calcite vs. dolomite, or dolomite vs. gypsum/anhydrite. Differences in solubility may also be related to differences in primary porosity, permeability and crystal size. Moldic pores have highly variable size. The pores are recognized by their shape, size and relict features (e.g. remains of a fossil) that indicate the former presence of a grain or crystal.

Effective porosity and permeability is strongly controlled by the size and number of connections between the molds. Even though total porosity may be high, recovery efficiency may be poor if molds are not in direct contact. However, in combination with other pore types, e.g. intercrystalline or fracture pores, or with good connections between moldic pores, recovery efficiency increases considerably.

Moldic porosity is subdivided into three subtypes based on intra-mold pore sizes and connectivity between the molds: pore types 3.11 (micro), 3.13 (macro) and 3.14 (isolated macro). The pore types are to some extent formed under different sedimentologic/diagenetic controls.

3.6.2 Pore type 3.11 (moldic microporosity) (post #27)

See image.

Dominant pore size: <20um.

Description: Secondary small intra-mold pores related to dispersed mud or small crystals within the molds. This pore type is generally associated with partially dissolved peloids, ooids and foraminifera with microgranular structure. Pore type 3.11 may also be generated by mud infiltration into moldic macropores.

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3.6.3 Pore type 3.13 (moldic macroporosity) (post #28)

Images A & B.

Dominant pore size: >20um.

Description: Secondary large pores that are formed through selective dissolution of grains and/or crystals. The pores commonly have relatively small inter-mold pore-throat diameters, although the pores themselves can be relatively large. The pores have relatively minor preserved mud or fine crystals. Dissolution is commonly controlled by mineralogical differences between grain/crystal and the surrounding sediment. Mold distribution is often controlled by faunal composition, with aragonitic fossils being more prone to dissolution.

3.6.4 Pore type 3.14 (moldic isolated macroporosity) (weeks 28 & 41)

Image C.

Dominant pore size: >20um.

Description: Secondary large pores formed through selective dissolution of grains, commonly ooids. The dissolution is commonly controlled by mineralogical differences between the grains and the surrounding sediment. The molds have extremely small inter-mold pore-throat diameters, giving very low permeabilities even at high porosities.

Moldic pore types 3.13 and 3.14 are differentiated on the basis of how well stained epoxy enter into the pore system. Compare images B and C; both samples have been impregnated with blue-stained epoxy. The epoxy has only entered into molds in image B, leaving molds in image C white. Although staining to some degree probably is dependent on laboratory conditions, this is the only criteria that has shown to be useful in the visiual differentiation of pore types 3.13 and 3.14. Interestingly, all the 47 pore type 3.14 samples in the CARP database are oolites.

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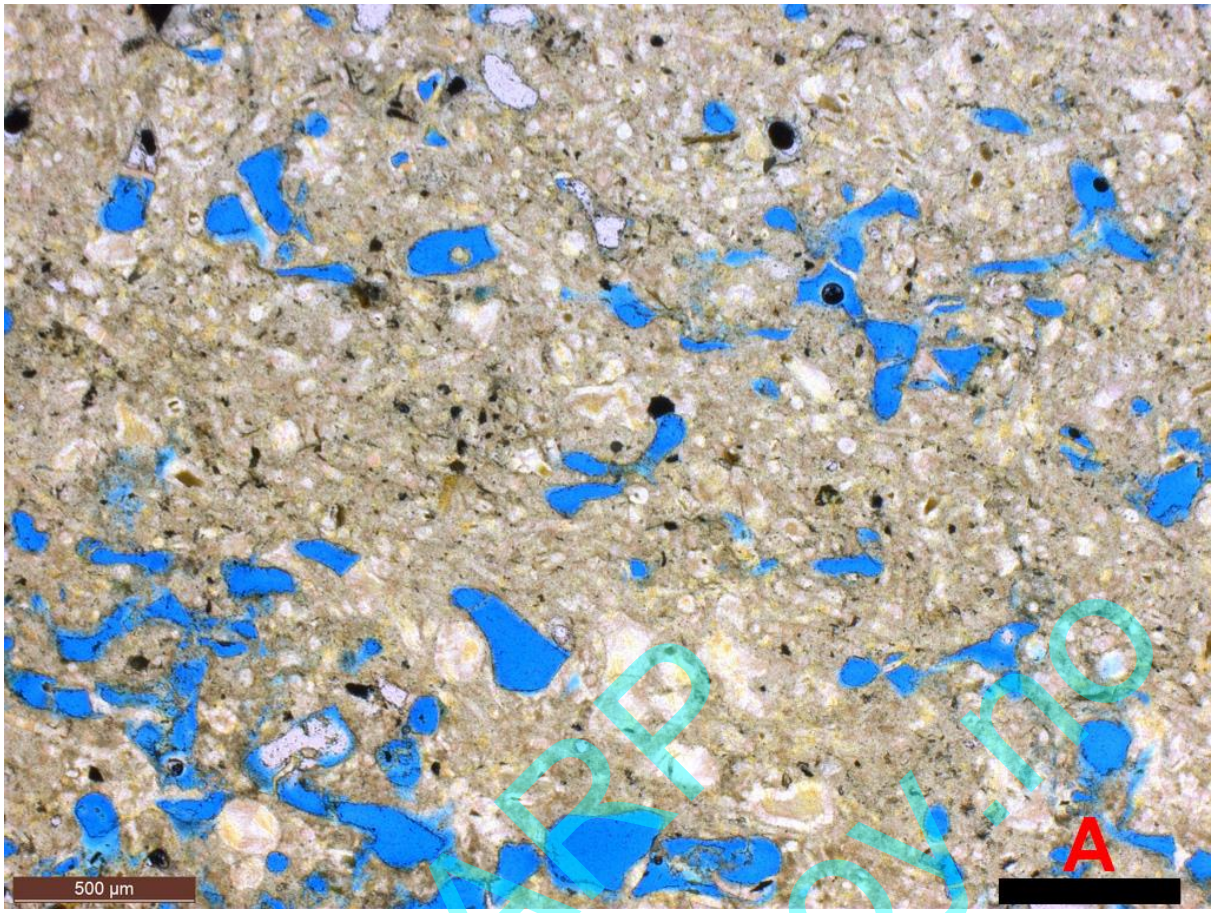

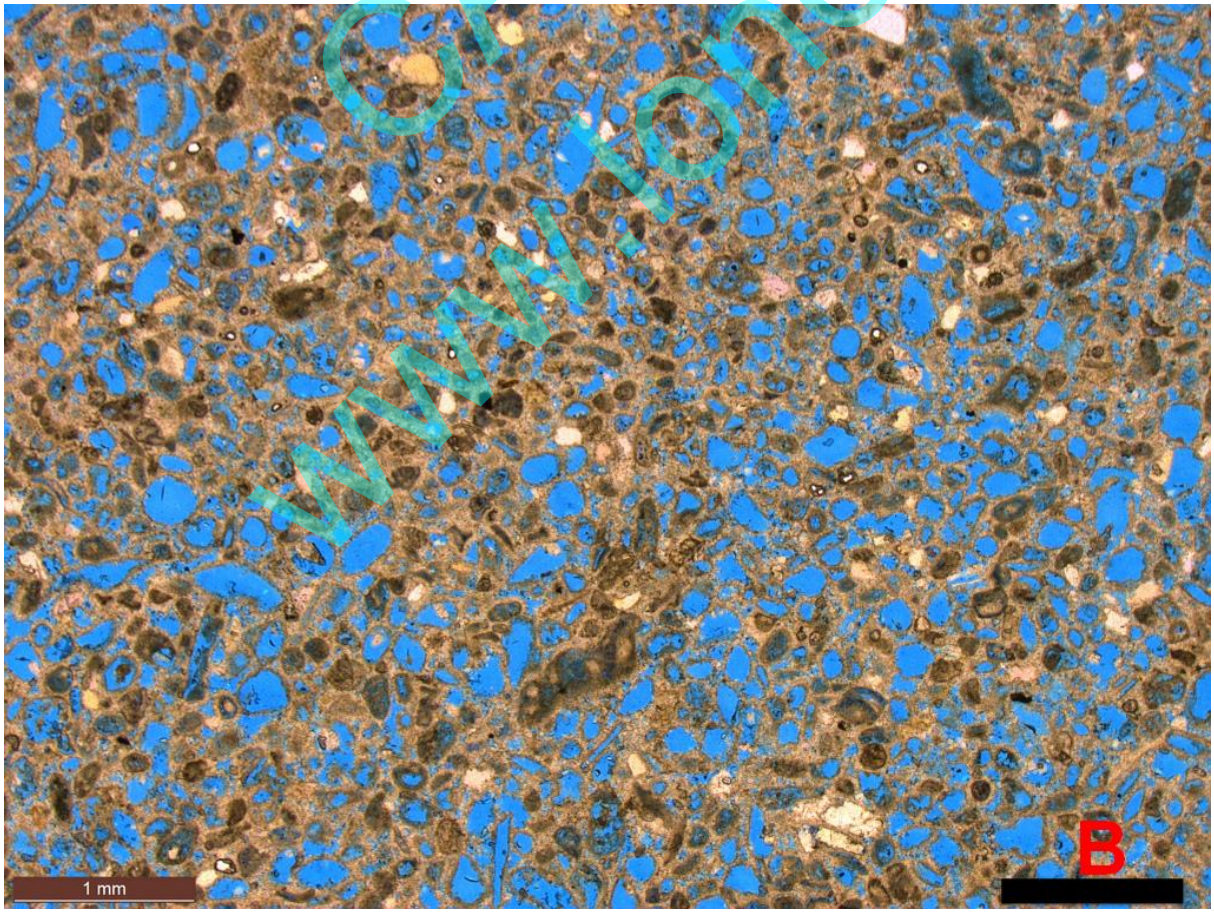

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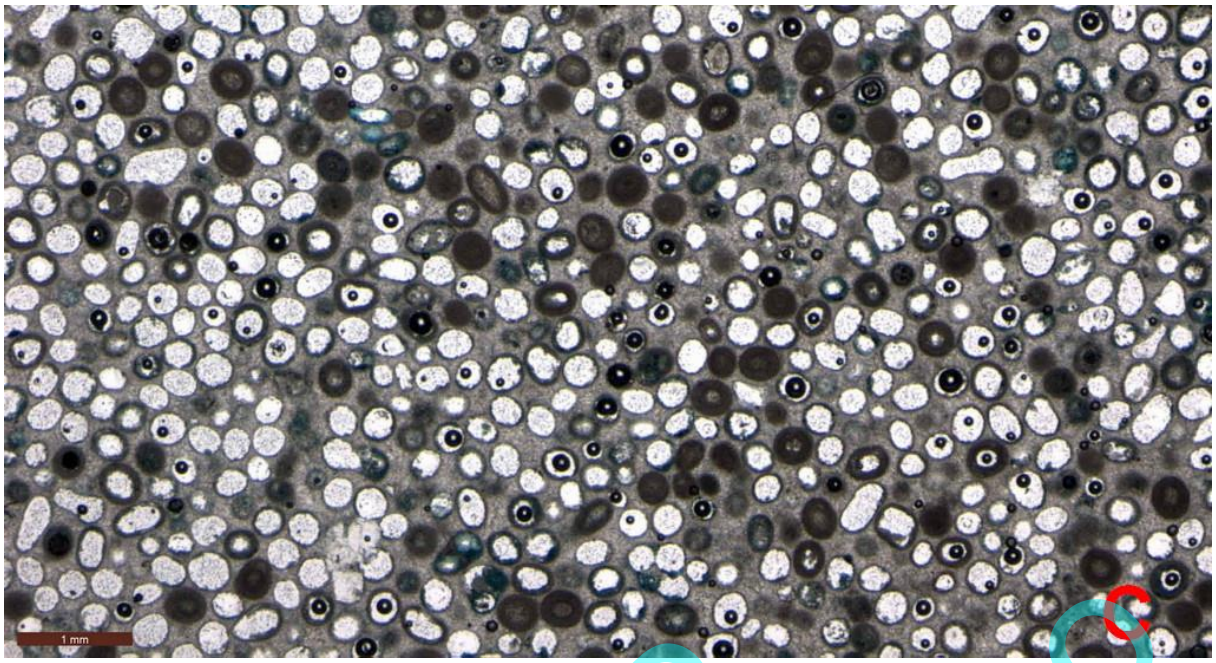

Secondary macro-moldic porosity (blue/green), pore type 3.13, can occur in a wide range of lithologies and mineralogies:

Figure A: Lime packstone with pore type 3.13 related to dissolution of fossil fragments (mainly bivalves). Width of micrograph: 960um.

Figure B: Spiculite with pore type 3.13 related to dissolution of siliceous sponge spicules.

Figure C: Dolomite with pore type 3.13 related to dissolution of gypsum crystals. Note the presence of gypsum (now dissolved) swallowtail twins, some of which are marked by red arrows.

Figure D: Sandstone with pore type 3.13 related to dissolution of feldspar grains (probably plagioclase, many of which are marked by red arrows). The secondary pores are lined by authigenic illite. Width of micrograph: 4 mm

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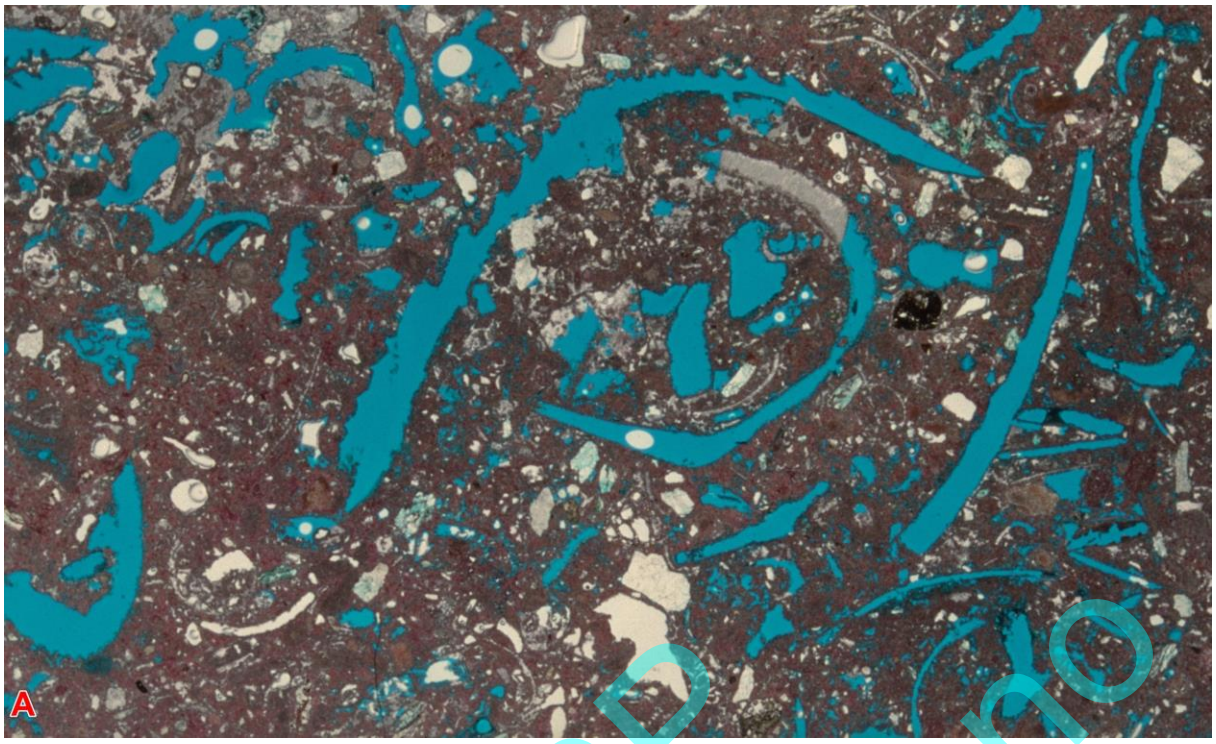

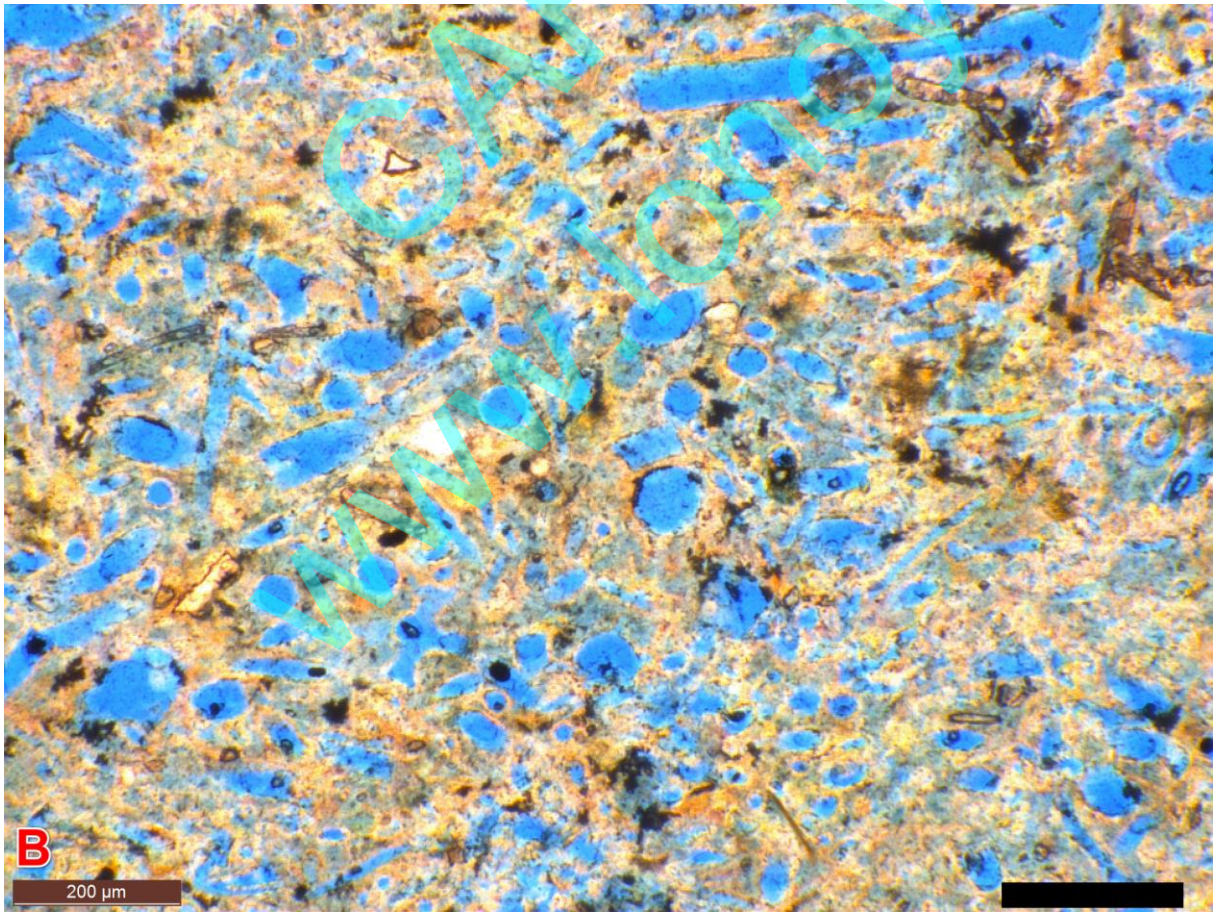

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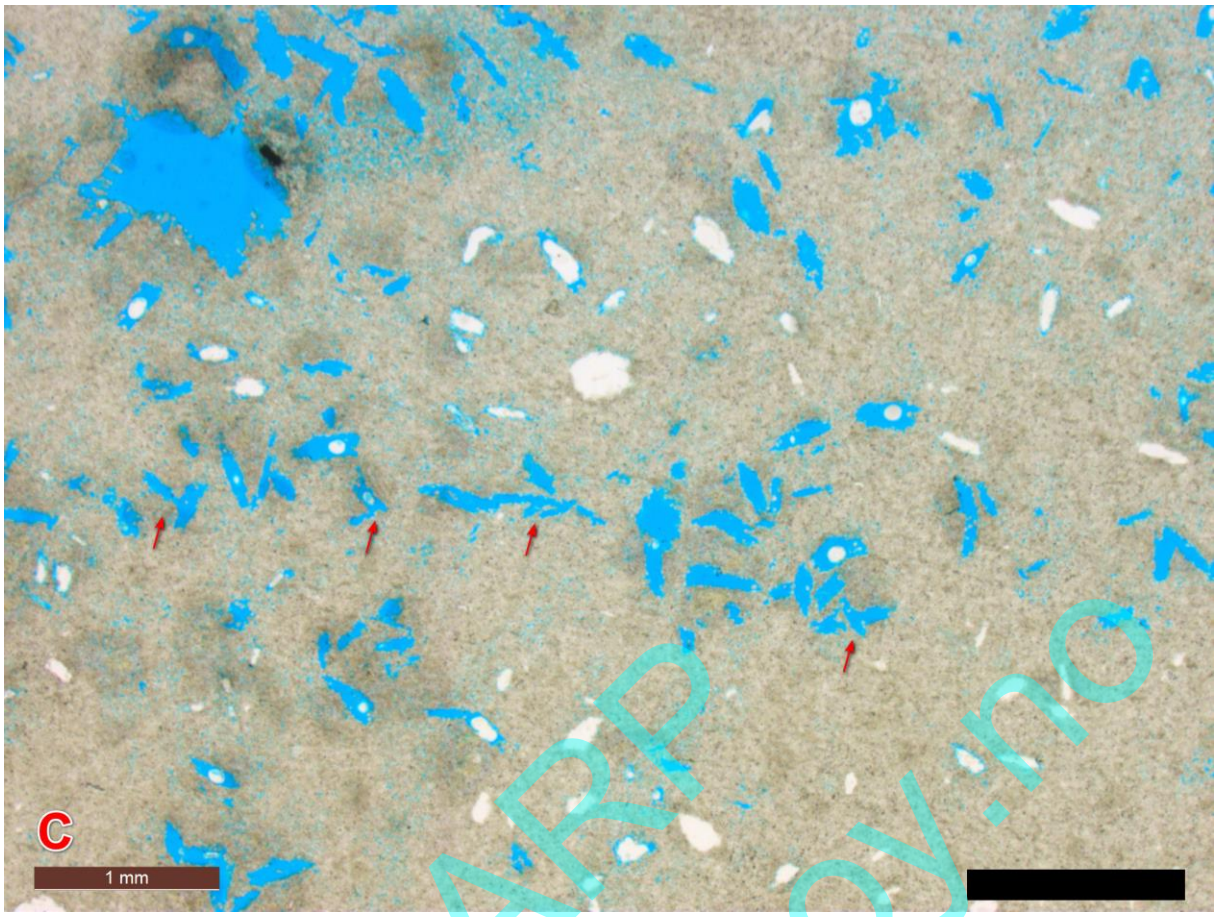

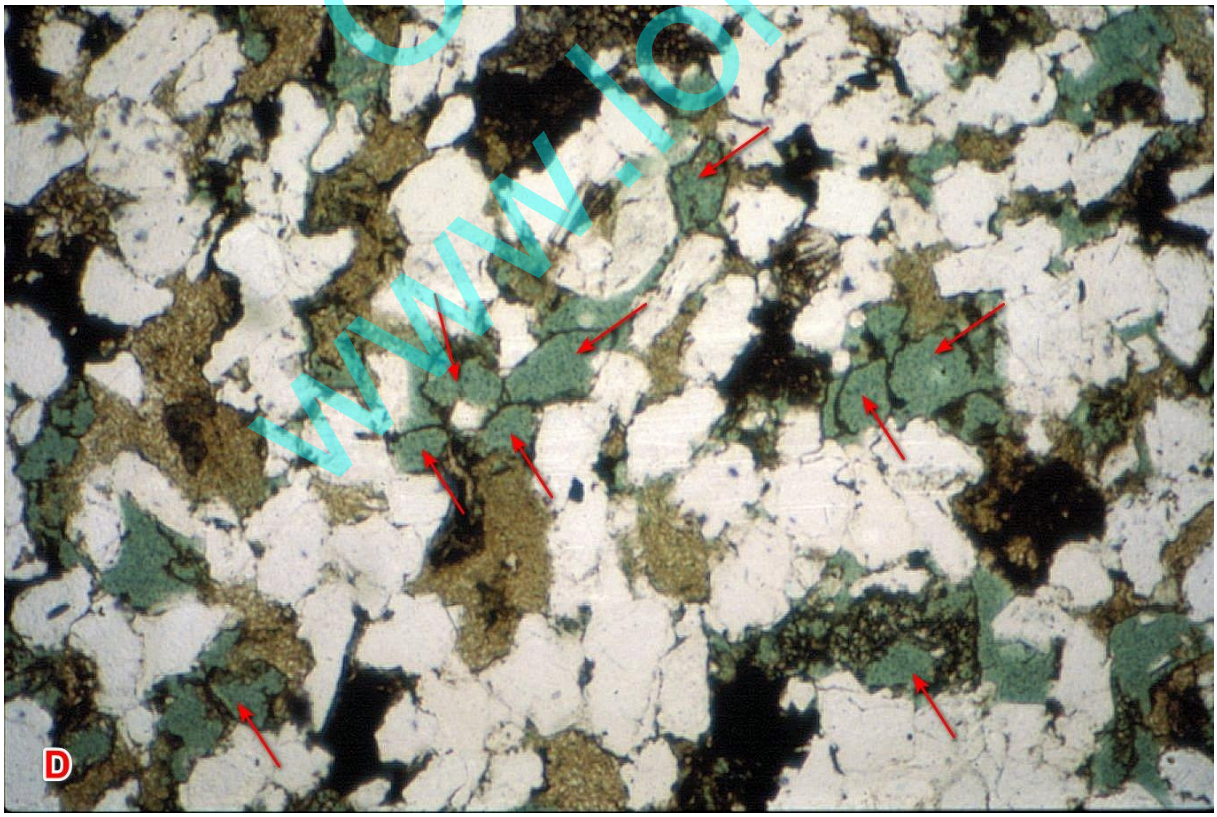

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3.6.5 Porosity-permeability (post #28)

Pore types 3.11 and 3.13 show partly overlying data plots on porosity-permeability cross-plots, whereas pore type 3.14 shows significantly lower permeability for a given porosity. Cross-plots for pore type 3.11 show significantly less data scatter than for pore types 3.13 and 3.14, and there are also differences in tredline type. Pore type 3.11 shows an exponential trendline, whereas pore types 3.13 and 3.14 show 3rd order polynomial and power trendlines, respectively. The reason for these differences is not known.

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3.7 Intercrystalline (Pore Type 4)

3.7.1 Introduction (post #37)

Intercrystalline porosity is the porosity between crystals that may be of either primary or secondary origin. Most pores are secondary in origin and occur between crystals that have grown more or less in place by calcite recrystallization or dolomitization. Pores are usually relatively uniform in size within a sample and have small pore-to-throat size ratios. Crystals are commonly of uniform size, resulting in a typically good correlation between crystal size and pore size. In some cases, notably within microporous, argillaceous dolomites, the pore size is smaller than expected from the dolomite crystal size alone because clays partially fill the porosity.

In grain-rich dolostones, porosity may be classified as either intercrystalline or interparticle, depending on the dominant control on pore structure. When depositional grains (allochems) are the dominant control, the porosity is classified as interparticle. Where pore structures are controlled by dolomite crystals, they are classified as intercrystalline.

Intercrystalline porosity is one of the most important within carbonate rocks, especially within dolomites, both in terms of permeability and total porosity. Porosity varies considerably but may attain values of more than 30%. Permeability is also highly variable and is often strongly controlled by crystal size and the abundance of compromise boundaries. Smaller crystals and more compromise boundaries usually give lower permeability.

Intercrystalline porosity is subdivided into six subtypes based on pore size and porosity distribution (uniform or patchy).

3.7.2 Intercrystalline w/uniform distribution (post #37)

Pore Type 4.11: Micropores
Description: Dominant pore size <20µm. Image A.
Formation: Pores are commonly formed by rapid dolomitization of micrite during early diagenesis.
Main occurrence: Low-energy, restricted to hyper-saline depositional settings.

Pore Type 4.12: Mesopores
Description: Dominant pore size 20-60µm. Image B.
Formation and main occurrence as for pore type 4.11.

Pore Type 4.13: Macropores
Description: Dominant pore size >60µm. Image C.
Main occurrences: High-energy depositional settings where grains have been subjected to dolomitization. The pores may, however, occur in any depositional setting, and distribution is often controlled by late diagenetic fluid pathways (fractures, faults and high-permeable matrix).

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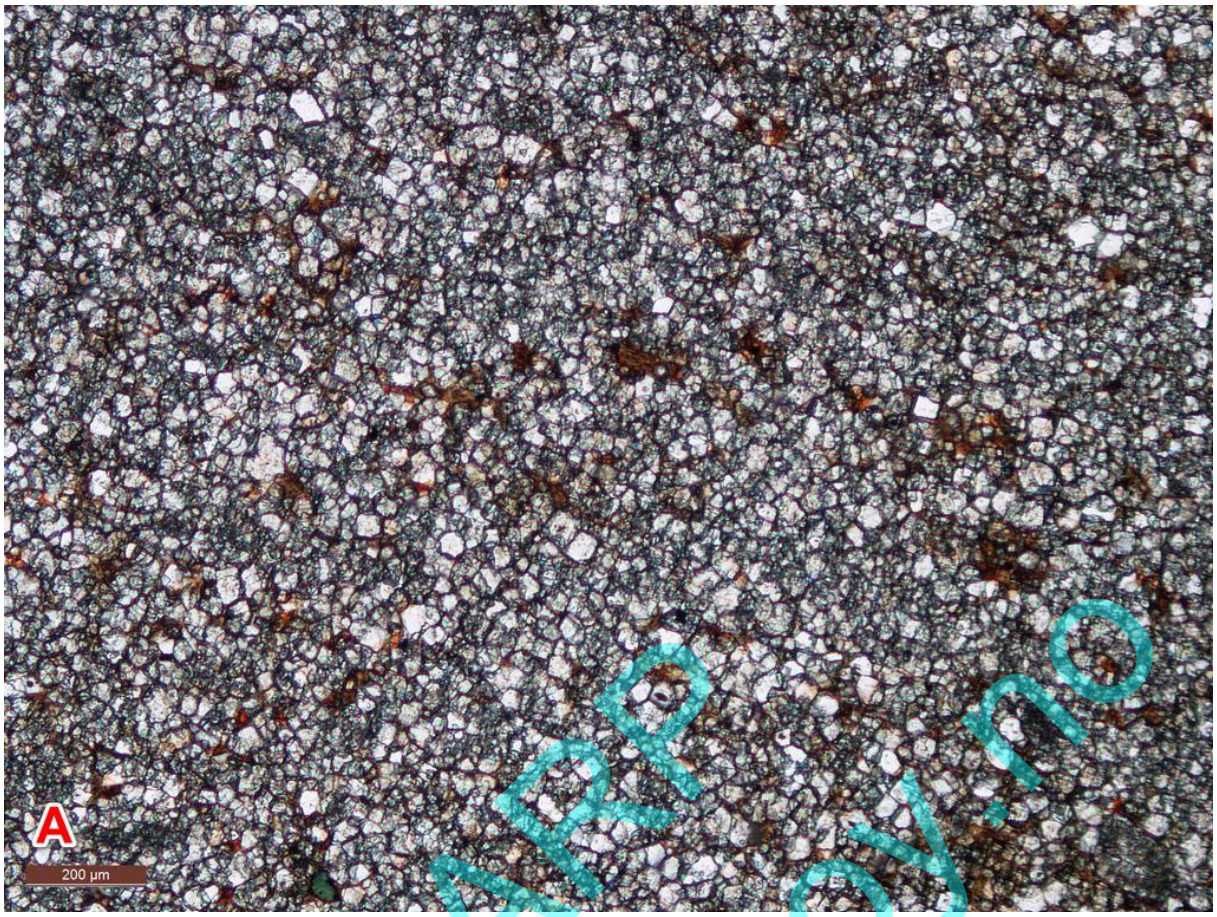

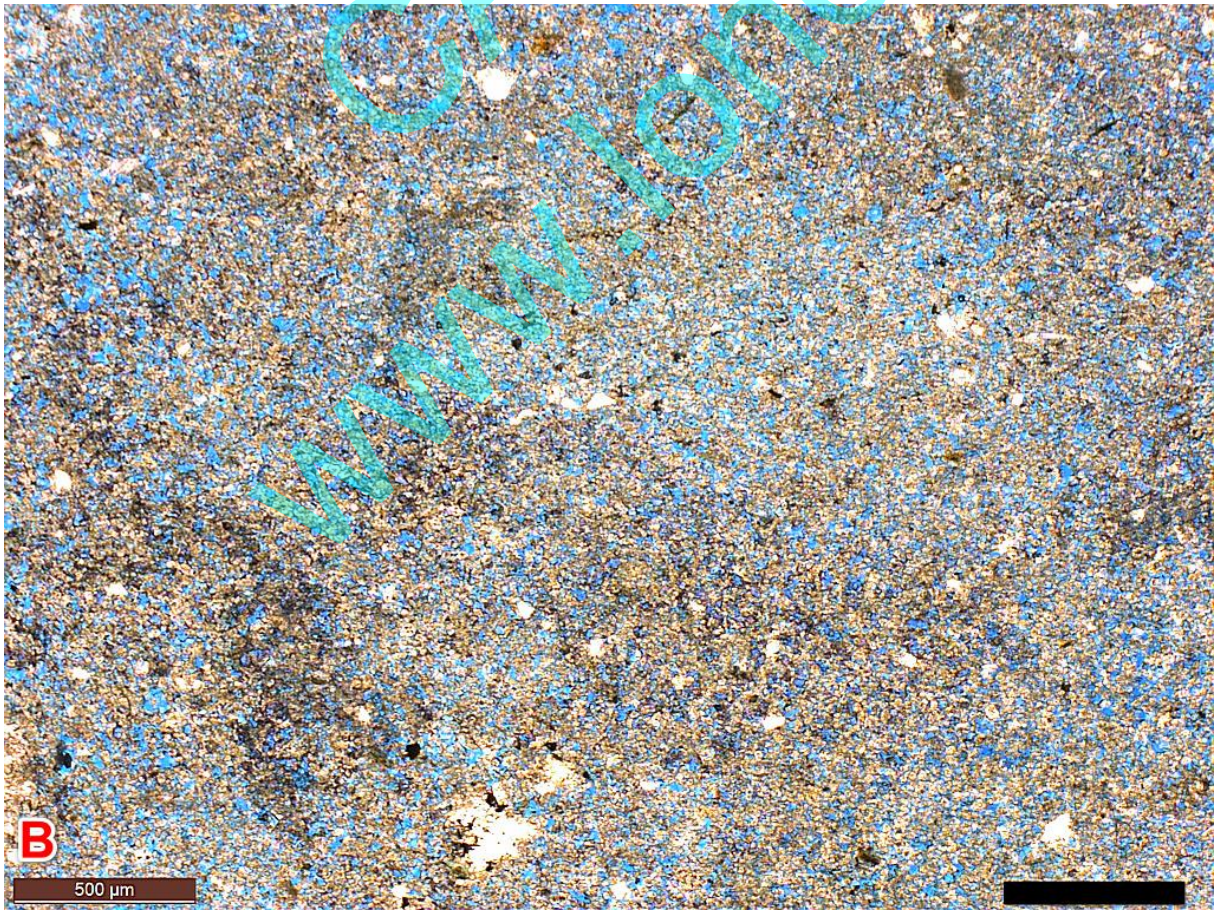

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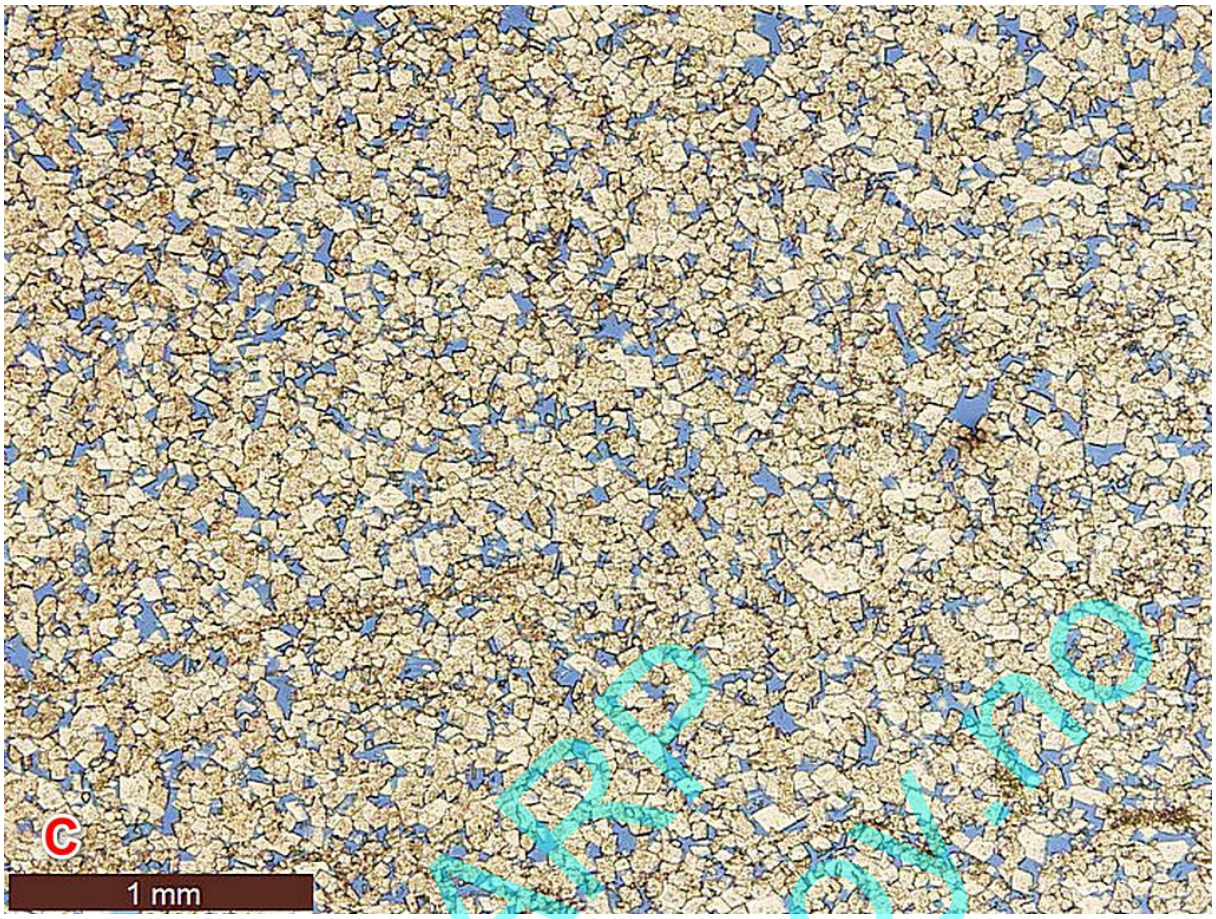

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3.7.3 Intercrystalline w/patchy distribution (post #52)

Description
Patchily-distributed secondary porosity occurring between crystals.

Formation
These pore types are commonly related to patchy cementation of intercrystalline pores. Patchy cementation is usually due to few and scattered nucleation points for the cement, or permeability pathways controlled by e.g. fractures, burrows etc. The cements are typically various forms of calcite, evaporites or silica. The patchy cement has a significant effect in reducing porosity, but has less or insignificant effect on permeability. The cement thus significantly affects the permeability/porosity ratio, as compared to uniformly-distributed intercrystalline porosity. Furthermore, the cement has limited effect on pore-throat diameters, and MICP curves are thus insignificantly affected in spite of a significantly reduced porosity.

For a given porosity and capillary pressure, the permeability is significantly higher and the water saturation and capillary entry pressure significantly lower when porosity is patchily distributed (as compared to uniformly-distributed porosity). As a guideline, the permeability and Hg capillary pressure (for a given porosity and saturation) show about one order of magnitude difference between patchily- and uniformly-distributed porosity.

Example for a given pore-size category, porosity and saturation:

- Uniformly-distributed porosity: 10 mD permeability and a capillary pressure of 1000 PSI.
- Patchily-distributed porosity: 100 mD permeability and a capillary pressure of 100 PSI.

PT 4.111: Micropores. Dominant pore size 10-20µm. Image A.
PT 4.112: Mesopores. Dominant pore size 20-60µm. Image B.
PT 4.113: Macropores. Dominant pore size >60µm. Image C.

Artificial colours on thin-section micrographs:
Blue/green: Porosity
Red: Calcite
Other colours (natural): Mainly dolomite

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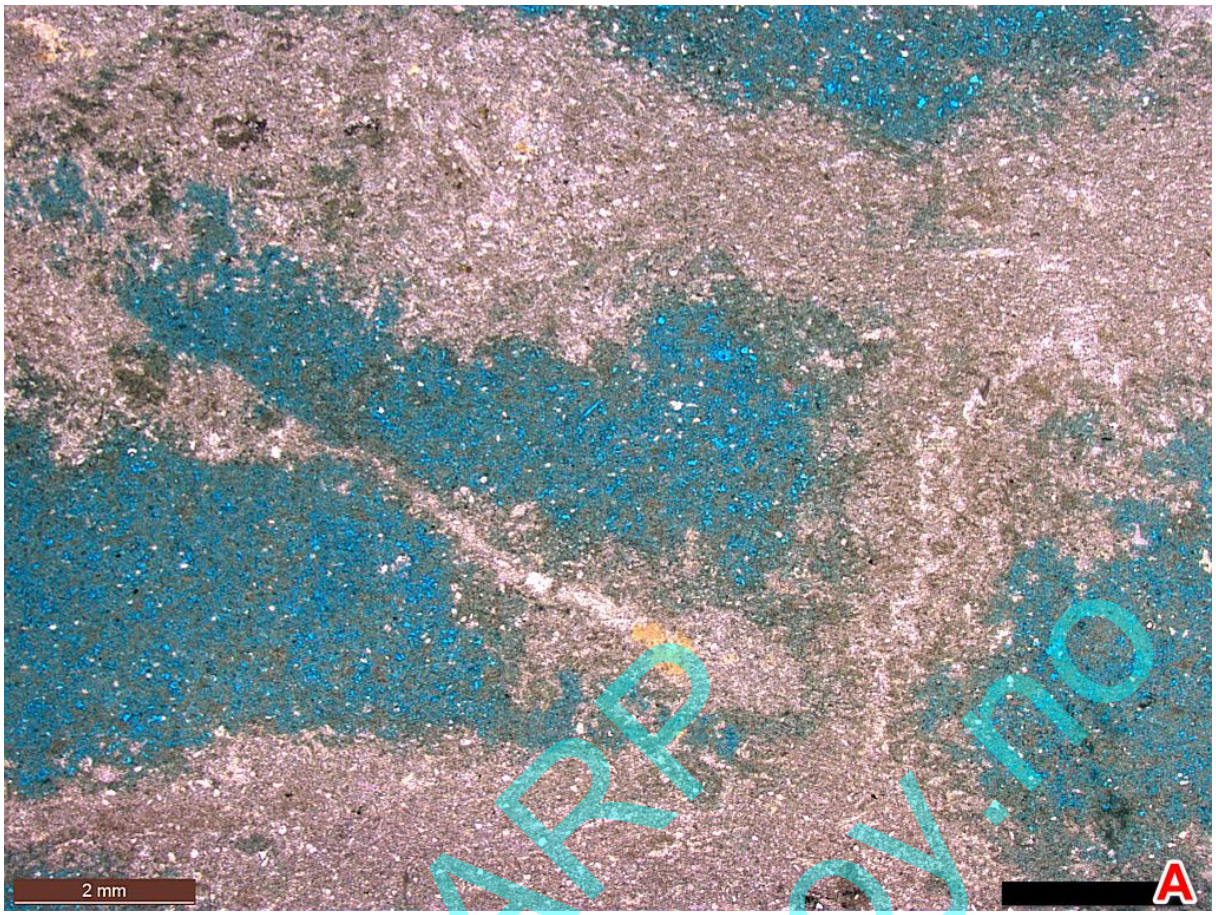

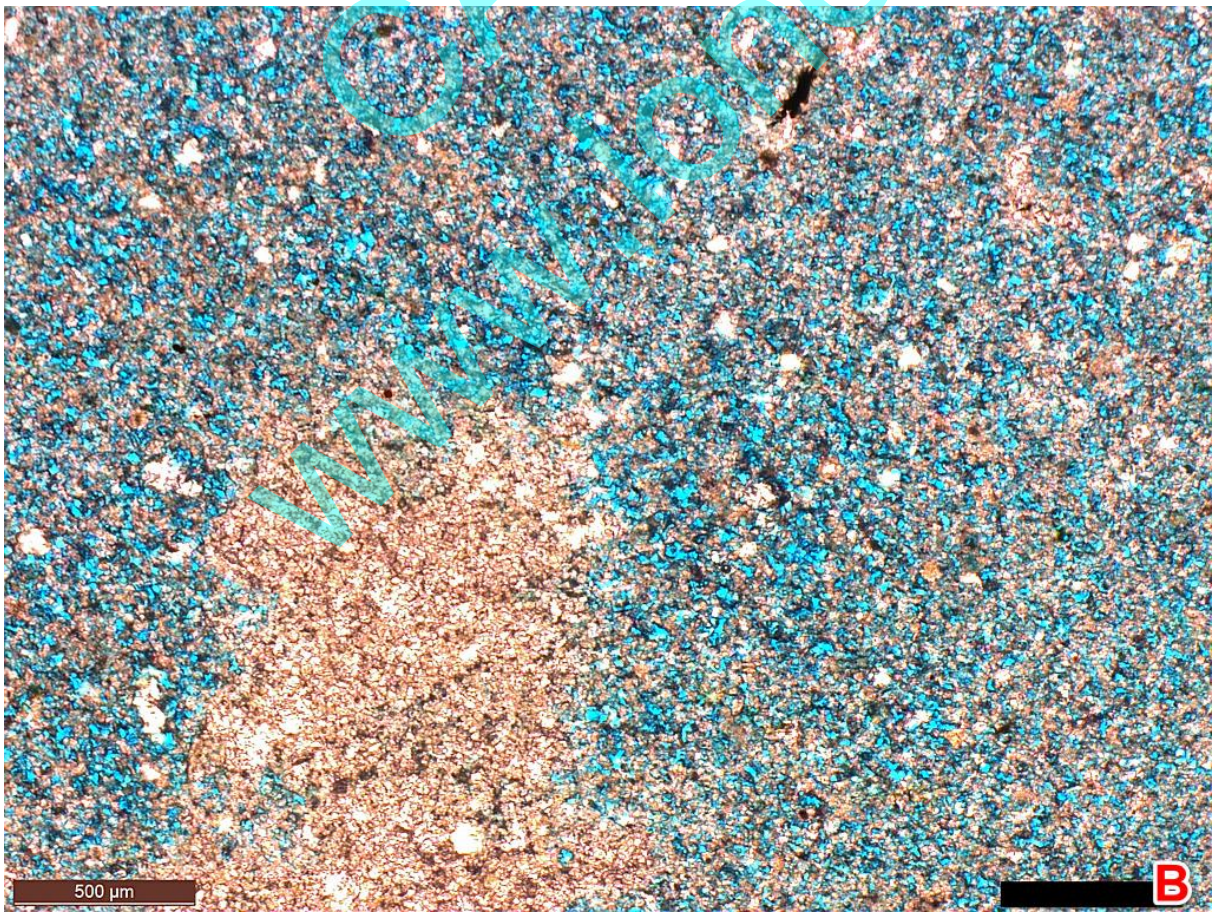

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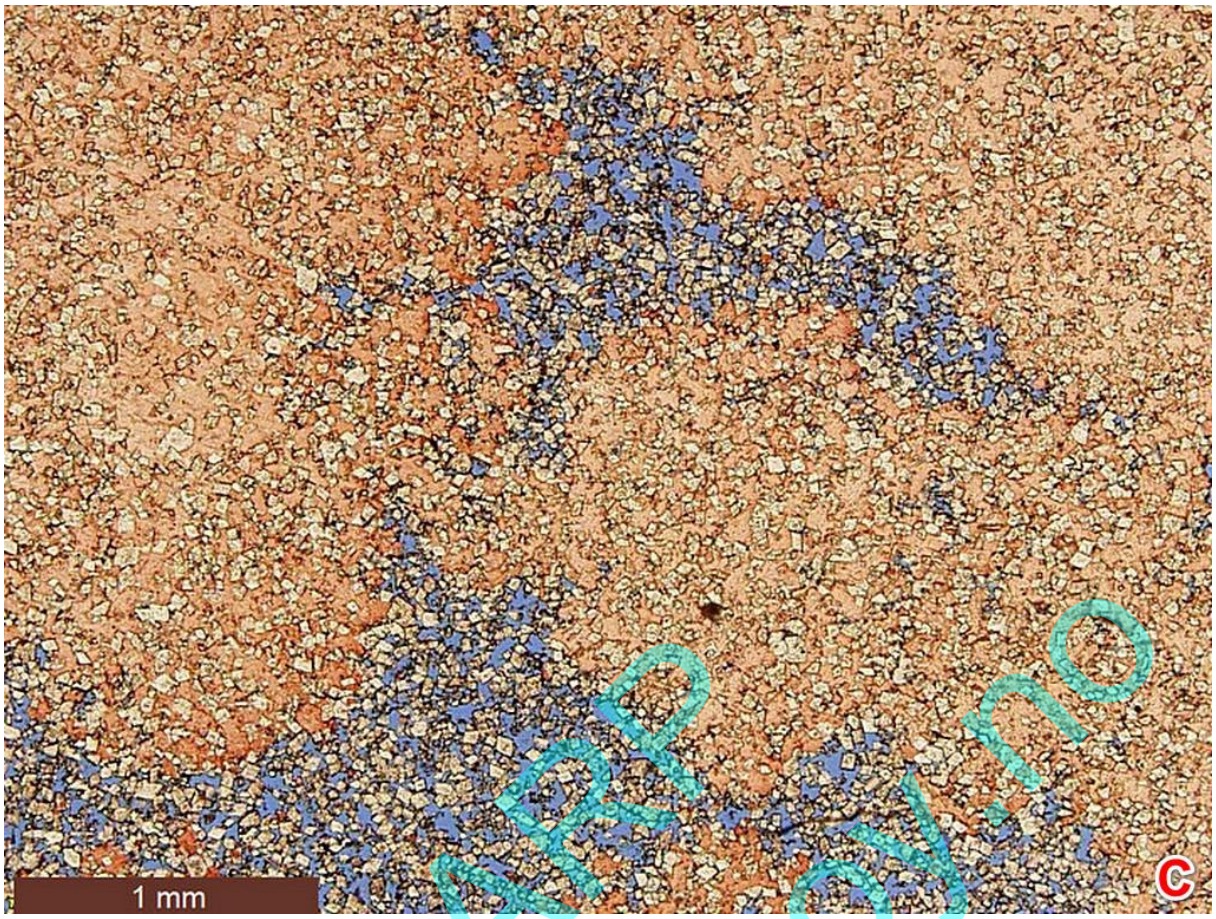

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4 Porosity

4.1 Effects of Pororosity Patchiness (post #53)

This is a follow up to post #50, based on comments relating to differences/similarities in reservoir properties by the introduction of a patchily-distributed cement. Two identical samples were presented in the post (reposted as image 1), with the only difference being a cement artificially introduced into sample 1b.

In the comments, it was questioned why the MICP curves for the samples would be the same in spite of differences in porosity and permeability/porosity ratios. The cement reduces the Hg-porosity, but pore sizes, pore-throat diameters and pore geometries remain the same.

MICP curves do not deal with porosity, but applies Hg-saturation as a function of capillary pressure. Hg-porosity refers to a percent of the rock volume, and Hg-saturation is a percent of porosity. To give an example: For a sample with 20% porosity, 10% porosity is intruded by Hg at a given capillary pressure. This amounts to 50% of the total pore volume and is given as Shg=50%. This is what is applied in a MICP plot.

Although porosity is reduced, the relative volume at each capillary pressure step remains the same because the pore-throat size distribution is the same for the two samples.

Based on this, the geometry of the MICP curve will remain the same for the two samples, although porosity and permeability/porosity ratio are different. The Leverett J-function heavily rely on this ratio, and will fail in this situation where the geometry of the curve remains the same in spite of changing permeability/porosity ratios. In fact, many commonly used petrophysical equations that are based on porosity and permeability fail in carbonates.

To illustrate the effect of the cement, let's do a test of the samples given in image 1. No porosity or MICP measurements are performed on the samples, but image analysis show that images 1a & 1b have porosities of 27% and 19%, respectively. The pore types (PT) in images 1a and 1b are 1.13 (interparticle macropores, uniform distribution) and 1.113 (interparticle macropores, patchy distribution), respectively. The MICP curves can be predicted for the samples using CARP's global database (illustrated in post #45). According to the discussion above (and in post #50) the two samples (PT 1.13 with a porosity of 27% and PT 1.113 with a porosity of 19%) should have more or less identical MICP curves. As the CARP predictions are based on the average of globally-derived MICP curves, and not on the actual samples given in images 1a and 1b, we may not expect identical but very similar curves. The CARP-predicted MICP curves are presented in images 2 and 3.

The images show that the Lonoy MICP curves for samples 1a and 1b are very similar, and this also applies to Thomeer. However, the Leverett MICP curves show significant differences between 1a and 1b, because Leverett is strongly dependent on the permeability/porosity ratio.

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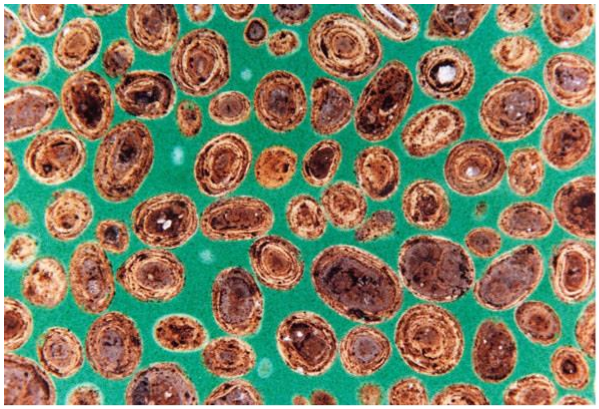
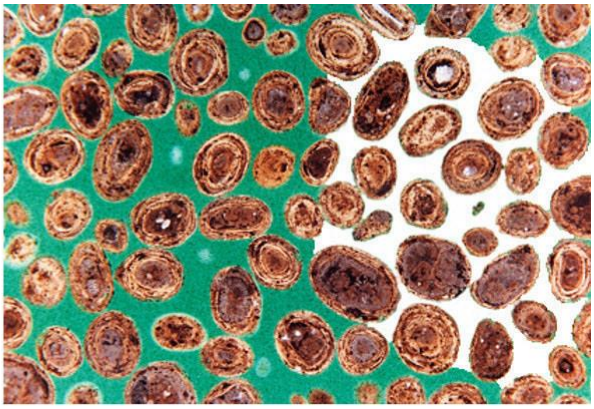


a) Uniform porosity distribution



b) Patchy porosity distribution controlled by cement patch (white)

Identical pore-throat diameters	Different pore types
Identical pore sizes	Different porosities
Identical pore geometries	Different permeability/porosity ratio (applied in Leverett J-function)
Similar permeabilities	
Similar MICP curves	

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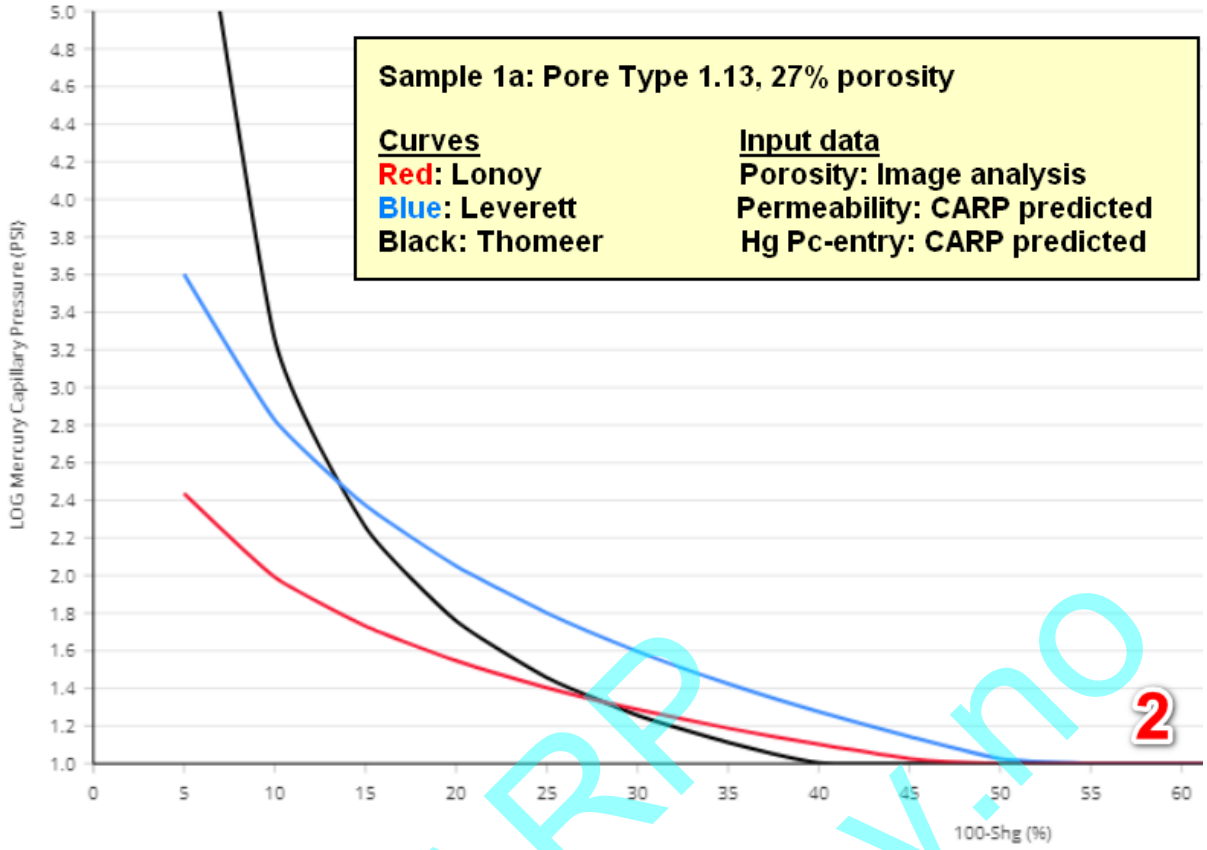

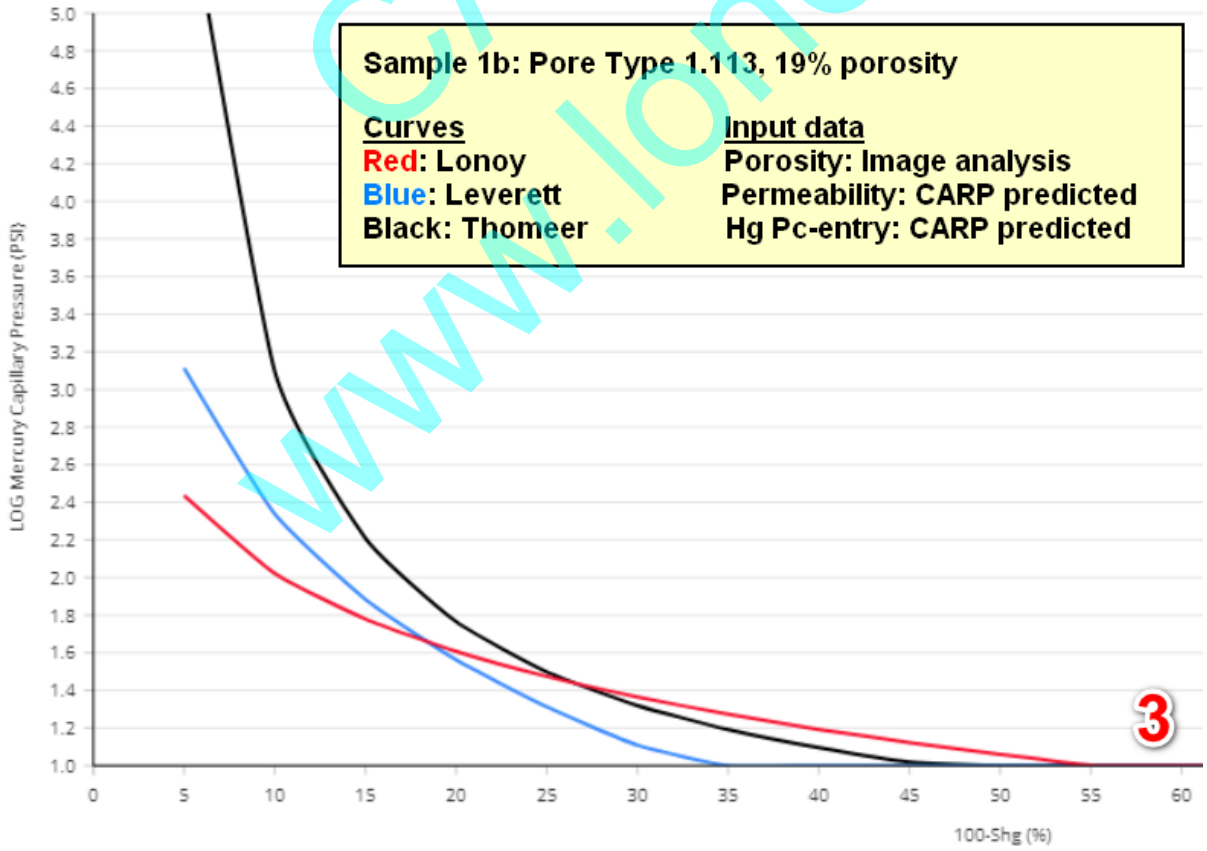

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5 Methods

5.1 MICP (Mercury-Injected Capillary Pressures)

5.1.1 Introduction to new methodology (post #31)

This will be the first of a series of posts on mercury injection capillary pressure (MICP) porosimetry. CARP can predict MICP curves based on a new methodology presented by Lonoy Geoconsulting AS, which only requires pore type and porosity as input; i.e. parameters that can be derived from porosity-distribution and sedimentologic/diagenetic facies maps. Such maps are usually applied as input to reservoir models, and MICP curves and associated saturations can thus be predicted at cell grid resolution. The method will be presented in detail and compared to Leverett J-function and Thomeer methods. This first post will give a general introduction to MICP.

MICP porosimetry is frequently used for determining saturation and pore-throat size distribution within a reservoir. The technique may thus be used for understanding the pore-system structure in the reservoir. Pore systems consist of pores and pore throats (smaller channels) connecting the pores. Pore throats, in conjunction with pore-system geometry and topology, control the movement of fluids between pores.

MICP porosimetry is based on pore-throats and the volume distribution of associated pores within the rock. The method depends on forcing mercury into voids within the rock. Pore throats control access to larger voids (pores) and greater pressures are required to force mercury (or other non-wetting fluids) into smaller spaces. Pore throats are therefore bottlenecks in the system, and it is necessary to exceed their critical capillary pressure in order to inject mercury into pores. By injecting mercury at incrementally higher pressures, and allowing time for equilibration between pressure increments, mercury is injected into increasingly smaller pores. It is then possible to calculate the size distribution of pore throats, to determine how pore-throat size is affected by increasing confining stress to approximate reservoir conditions, and to determine how permeability is affected by reduction in pore-throat size. MICP curves are also used for determining the saturation conditions within a reservoir.

Different methodologies for averaging MICP curves are applied in the oil & gas industry, of which the Leverett J-function and Thomeer methods are the most common. A new averaging method, denoted as the Lonoy method, is presented in CARP. This method applies global empirical functions based on pore type and porosity. The thin-section micrographs show four samples with different pore types, 20% porosity and contrasting MICP curves. CARP can predict MICP curves for any combination of pore type and porosity.

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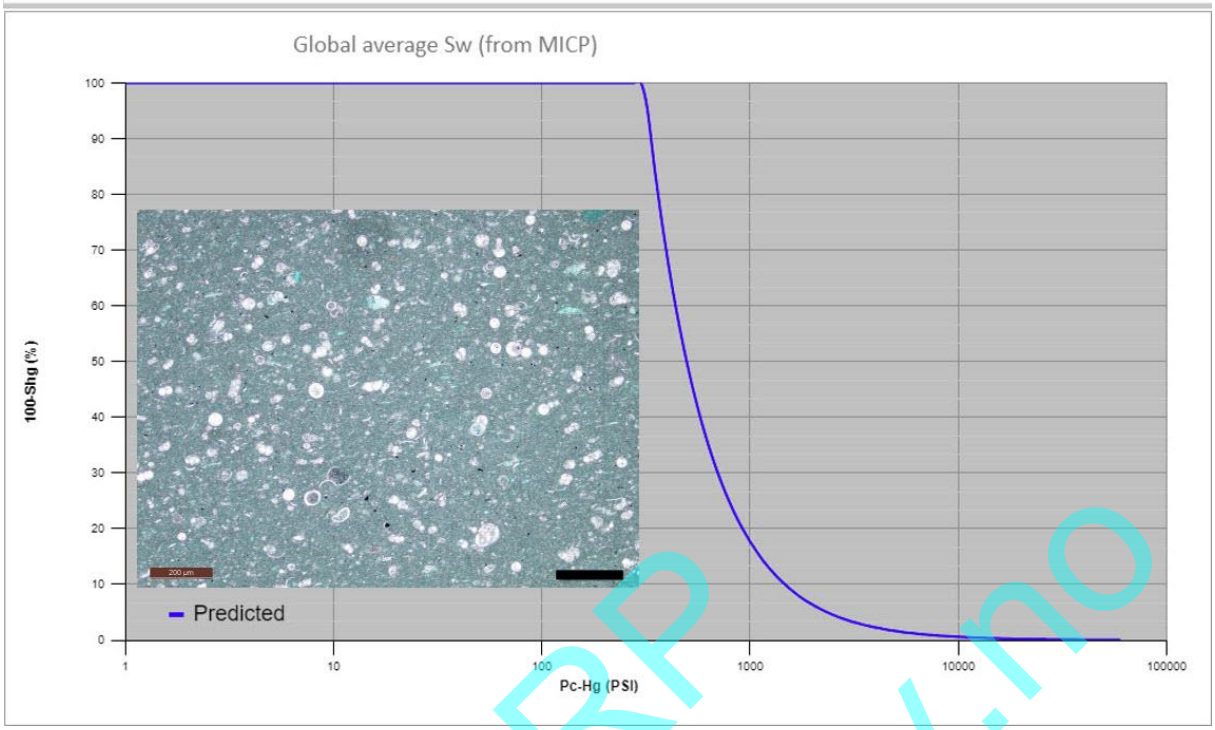
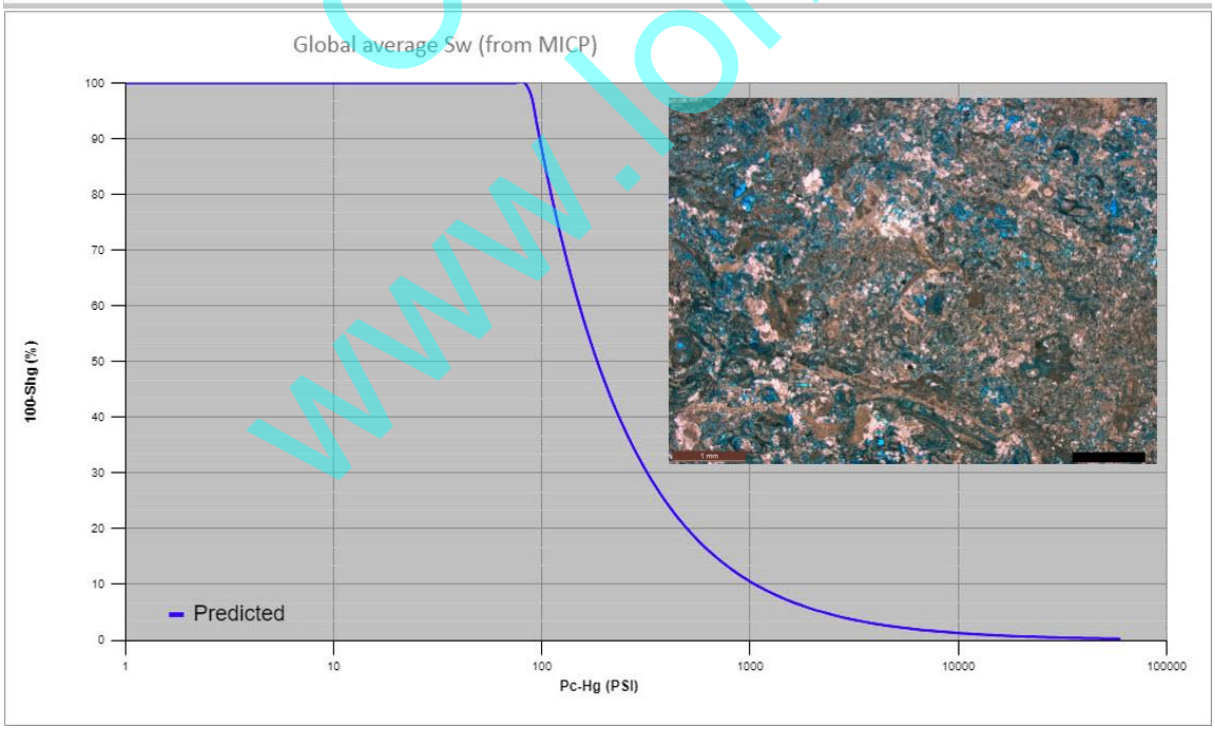
Typical MICP curve, global average,
Pore Type 6.02, Porosity = 20% (Conformance corrected)



Typical MICP curve, global average,
Pore Type 1.11, Porosity = 20% (Conformance corrected)



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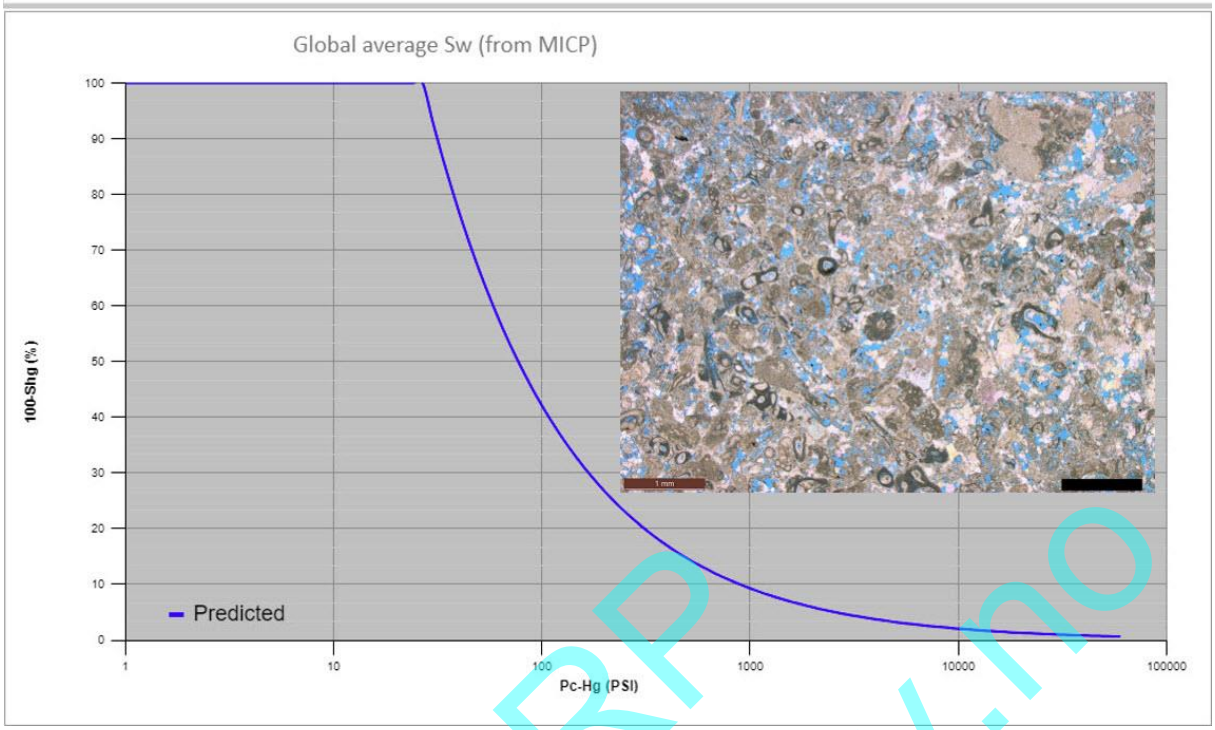
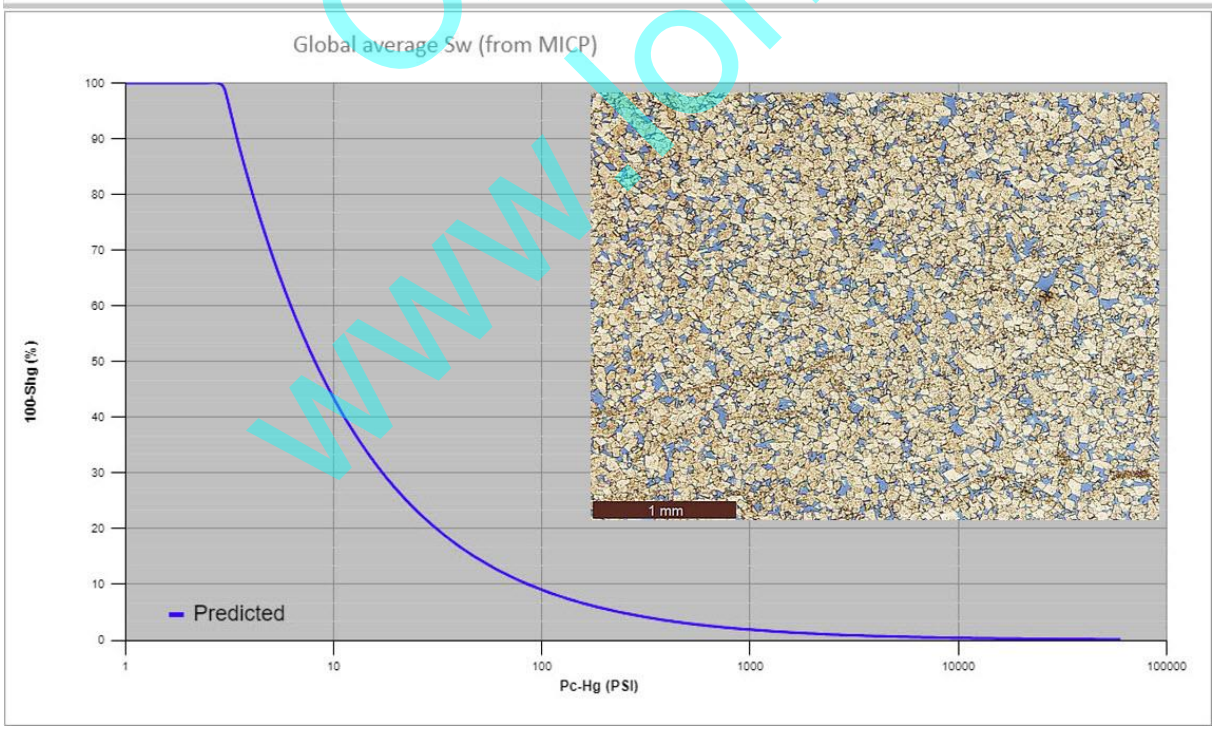
Typical MICP curve, global average,
Pore Type 1.12, Porosity = 20% (Conformance corrected)



Typical MICP curve, global average,
Pore Type 4.13, Porosity = 20% (Conformance corrected)



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5.1.2 The Lonoy Method (posts 32 & 33)

The Lonoy method is based on a large global MICP database, currently consisting of 696 measured MICP curves, which shows the empirical relation between pore types, porosity, capillary pressure and mercury (Hg) saturation. The database covers 19 of the pore types published by Lønøy (2006) and includes samples that are strongly dominated by only one pore type. Mixed pore-type systems are thus not included in the database, but can be inferred from the end pore-type members. Pore type 4.12 (intercrystalline mesopores with uniform distribution) will be used for illustration purposes of the method.

CALIBRATION

The MICP curves are calibrated before averaging:

- All curves are conformance corrected in order to exclude the effect of surface-connected pores (see figure for more details).
- Standardized capillary pressure points are defined. Any samples that have different pressure points are calibrated by interpolation, in order to have identical pressure points for all samples.

GROUPING

Samples in the database are grouped according to pore type and Hg-porosity interval. Porosity intervals are from 0-5%, 5-10% and usually up to 25-30% or 30-35% (i.e. usually 6-7 groups for each pore type). For chalk, the porosity interval extends up to 45-50%. The number of samples within each group may vary considerably, from no samples to tens of samples.

TRENDLINES

The MICP curves within each group are averaged, and a POWER trendline and an associated trendline equation for each group is defined (Figure 1). The trendline is only defined for part of the MICP curve, from Hg capillary entry pressure to 2000 PSI. There are two reasons for ending the trendline at 2000 PSI:

- MICP curves typically show a significant increase in curvature as the Hg-saturation gets high (often at Hg saturations >75%, but this may vary). This makes it difficult to achieve a good trendline fit, and the high-saturation part of the curve may have a strong impact on the remainder of the curve.
- A Pc-Hg of 2000 PSI equals a Pco (oil capillary pressure) of approx. 145 PSI. Higher pressures are believed to be close to a potential Swirr (irreducible water saturation in an oil-water system). There is no reason to involve this part of the MICP curve in the trendline, mainly because it has insignificant impact on the producible reserves.

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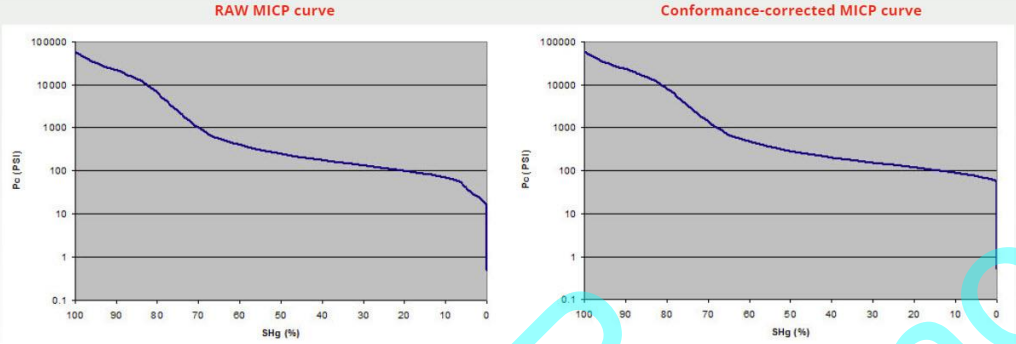
Hg-INJECTION POROSIMETRY: CONFORMANCE CORRECTION

The raw MICP curves should undergo a conformance correction (closure correction) before being applied in reservoir evaluation. Conformance correction is a function of the mercury volume required to fill the external voids and surface irregularities on a core sample. The high contact angle and non-wetting characteristics of mercury require an applied pressure to initiate the injection process. External vugs and irregularities that fill initially at very low pressures are not necessarily indicative of the sample's entry or displacement pressure and should be removed from the injection volume. The conformance correction is highest for small samples because of their high surface area relative to the sample volume.

Conformance correction is based on the geometric mean of the capillary entry pressure for each porosity class, where the mean value defines the pressure where all external voids and surface irregularities are filled with mercury. The porosity class is defined by pore type and each 5% porosity increment, and the applied conformance correction is therefore identical for all samples within a porosity class. An example of raw and conformance-corrected MICP curves is given below.



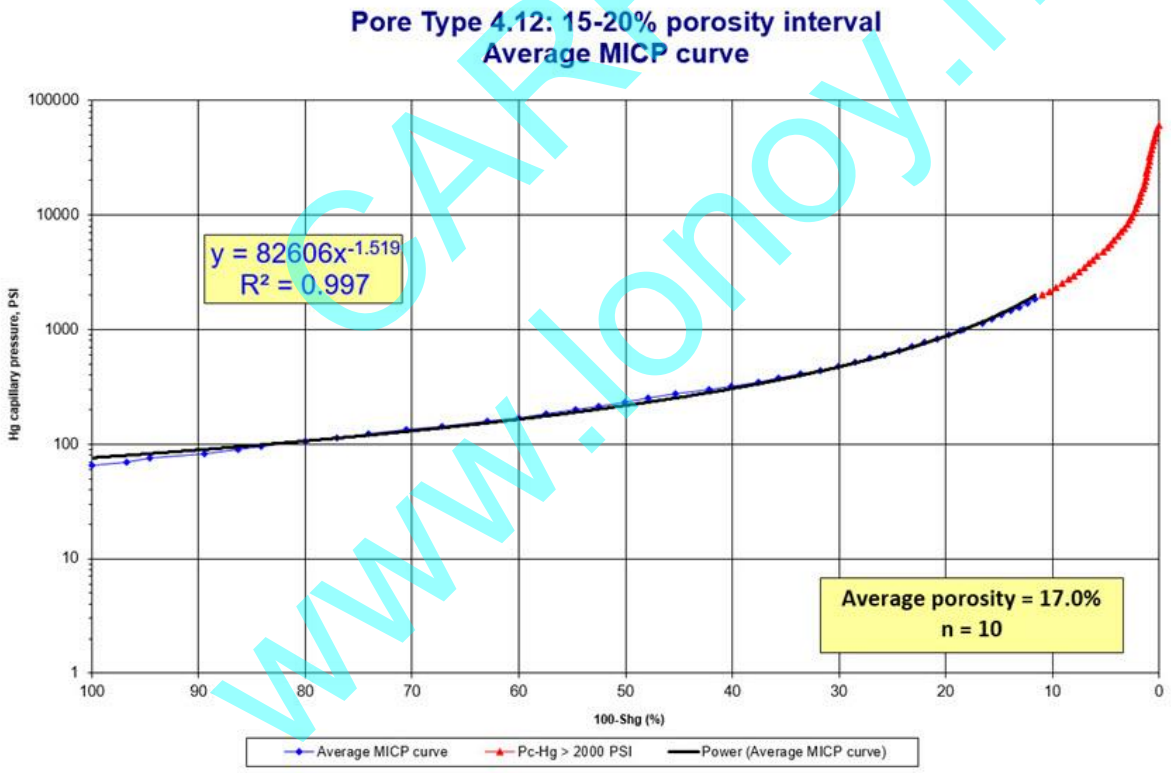


Figure 1:
Average MICP curve (blue and red) for pore type 4.12 in the porosity interval 15-20%. The average curve is based on 10 measured MICP curves, and the average Hg-porosity of the samples is 17.0%. The red part of the curve corresponds to Pc-Hg > 2000 PSI, which is approx. equivalent to Pco > 145 PSI. At these pressures, saturation is probably within Swirr of an oil-water system. A POWER trend line (black) is defined for the blue part of the average MICP curve (i.e. Pc-Hg < 2000 PSI). The trend line has the general form y = A*x^B. LOG A and B for each porosity interval are applied in the plots given in Figures 2 and 3.

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TRENDLINE EQUATIONS

The trendline equations are in the general form of:

y = A*x^B (Eq. 1)

where
y = Pc-Hg (PSI)
x = 100-Shg (%)

A & B are constants that vary based on pore type and porosity.

COMPOSITE EQUATIONS

In order to reduce the number of equations and to apply porosity as a continuous variable parameter, a single optimal composite equation was calculated for each pore type. The composite equation is based on the trendline equations for the pore type's different porosity intervals, using the average porosity and the equation constants A & B for each porosity interval. This is achieved by defining porosity-controlled trendlines for the equation constants A & B (Fig. 2 and 3), resulting in 3 constants (a1, a2 and a3) defining A and 3 constants (b1, b2 and b3) defining B.

The optimized composite equations involve 6 constants, that vary for the 19 pore types, and porosity (PHI):

A = 10^(a1*PHI^2+a2*PHI+a3)
B = b1*PHI^2+b2*PHI+b3

A & B go into Eq. 1, forming one composite equation for each pore type.

The equation constants for pore type 4.12 are (Fig. 2 and 3):

a1 = 0.0057
a2 = -0.3514
a3 = 8.8546
b1 = -0.0033
b2 = 0.1805
b3 = -3.4463

The constants are dynamic and will change as new measured MICP curves are added to the database.

Creating composite equations sometimes imply strange effects near end points, i.e. at low and high porosities (typically below 5-10% porosity and above 25-30% porosity, depending on the min. and max. values in the data set). A required condition during optimization was therefore that the trendline equation should give reasonable results throughout the porosity specter, i.e. increasing porosity within a pore type should give a progressive increase in Hg-saturation at constant capillary

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pressure. This was achieved by inserting artificial values at the end of the porosity specter (1 and 35% in Fig. 2 and 3) to control the trendline curvature.

Updating the database and equations is quite simple once a work procedure has been set up.

Pore type is one of the most important parameters controlling reservoir quality. Pore types are controlled by sedimentologic/diagenetic processes, and pore-type distribution can thus be inferred regionally from facies maps. This means that MICP curves can be applied at grid cell resolution in reservoir models, based on facies (or pore type) distribution maps and porosity distribution.

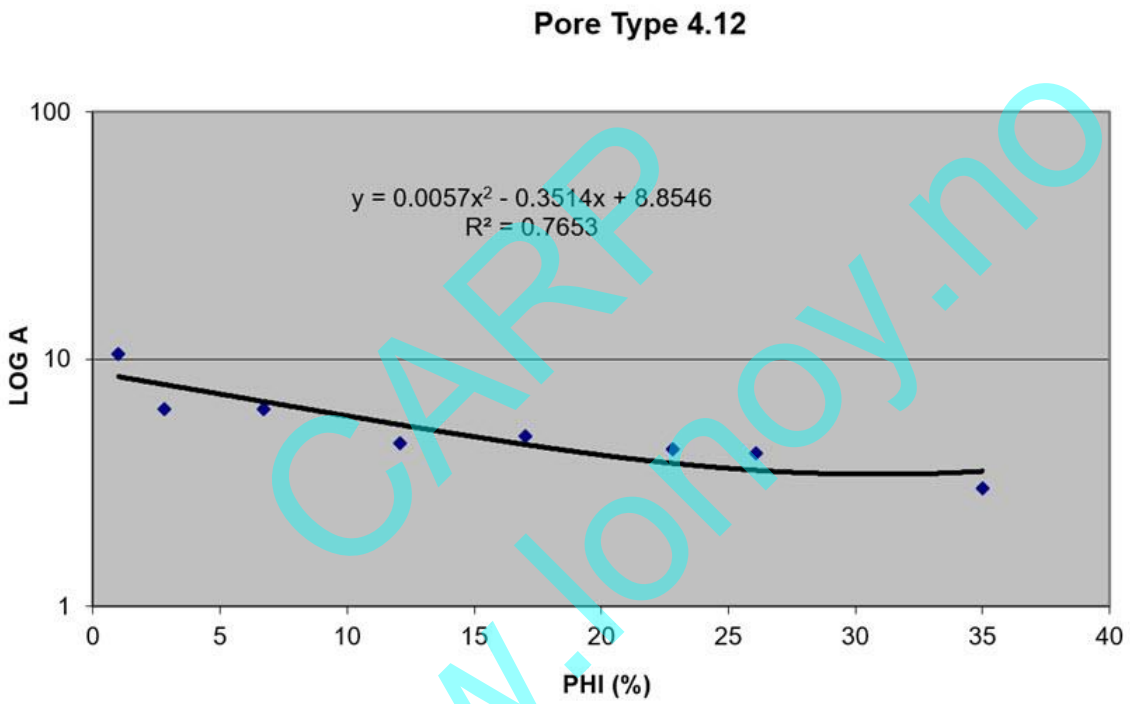

Figure 2.
Cross-plot of LOG A and porosity for pore type 4.12. Each data point represents an average value for each 5% porosity interval. The A value for the porosity interval 10-15% is derived from the trend-line equation in Figure 1. The end points at 1 and 35% porosity are artificial and are included in order to control the trend-line curvature so that the final trend-line equation should give reasonable results throughout the porosity specter, i.e. increasing porosity within a pore type should give a progressive increase in Hg-saturation at constant capillary pressure. The constants in the trend-line equations in the figure represent a1, a2 and a3 in the final pore-type equation.

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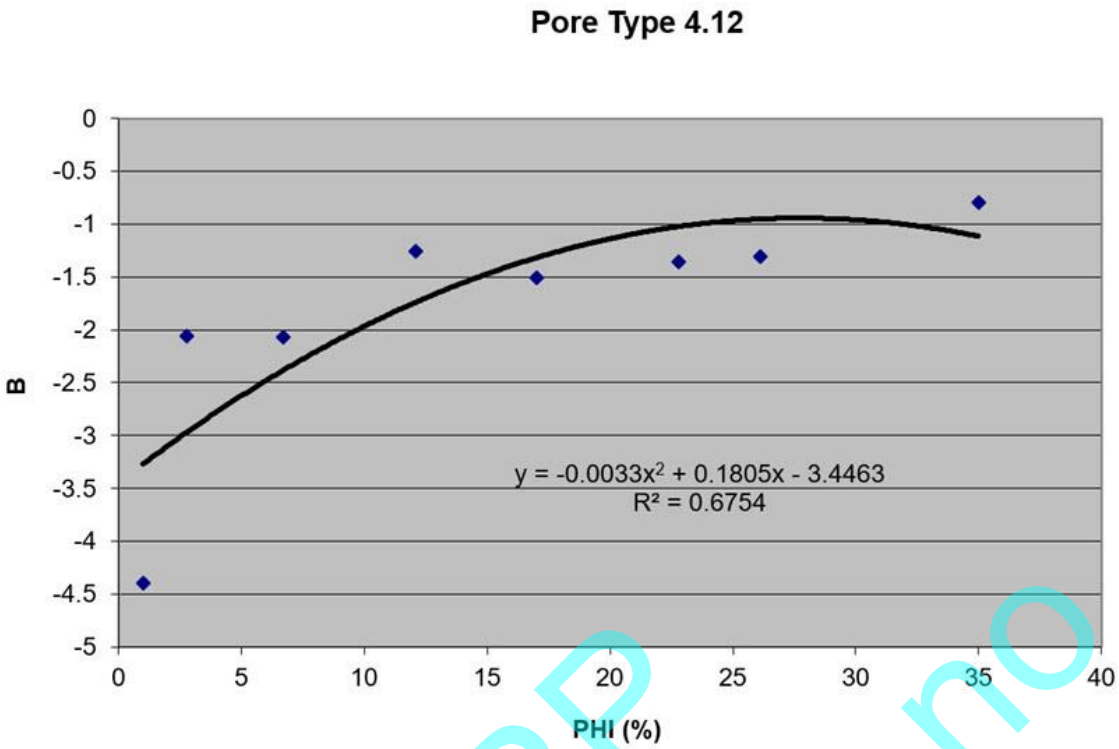

Figure 3.
Cross-plot of B and porosity for pore type 4.12. Each data point represents an average value for each 5% porosity interval. The B value for the porosity interval 10-15% is derived from the trend-line equation in Figure 1. The end points at 1 and 35% porosity are artificial and are included in order to control the trend-line curvature so that the final trend-line equation should give reasonable results throughout the porosity specter, i.e. increasing porosity within a pore type should give a progressive increase in Hg-saturation at constant capillary pressure. The constants in the trend-line equations in the figure represent b1, b2 and b3 in the final pore-type equation.

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5.1.3 Comparison of Methods (post #34)

This will give an introductory comparison of the Leverett J-function, Thomeer & Lonoy methods.

Leverett and Thomeer are based on the assumption that MICP curves for similar rock types will be controlled by porosity (Leverett), permeability (Leverett & Thomeer) and capillary entry pressure (Thomeer). A rock type can be defined in many ways. The Lonoy method is based on pore types (which can be considered as rock types) and porosity.

The main differences between the methods are:

- Permeability and capillary entry pressure are not involved in the Lonoy method.
- Only one mathematical equation is involved in the Leverett & Thomeer methods, covering all rock types, whereas the Lonoy method has one equation for each of the 19 pore types involved.
- The equations involved in Lonoy's method are dynamic and change as the global MICP database increases. At one point the global database will be so large that the equations become more or less static.
- The Lonoy method is based on a more limited set of input variables than for the two more commonly applied MICP averaging methods, and is based on parameters that go into standard reservoir models.

Pore-type and porosity distribution (the only inputs to the Lonoy method) are controlled by sedimentary/diagenetic facies, and pore-type probabilities within different facies can be derived from empiric relations. In wells, porosity (and in some cases pore-type) can be derived from wire-line logs. Sedimentary/diagenetic facies maps and porosity distribution are common input parameters to reservoir models, and this means that MICP curves can be predicted at cell-grid resolution of reservoir models using the Lonoy method. The prediction accuracy will, of course, depend on the accuracy of porosity distribution and facies model.

The Leverett & Thomeer methods are difficult to use in reservoir models as the permeability and capillary entry pressure have to be predicted. Thomeer and Leverett methods thus depend on additional sets of predictions, which create additional uncertainty in prediction of MICP curves, as compared to the Lonoy methodology.

Fig. 4 & 5 show differences between Lonoy, Leverett & Thomeer curves for a sample with 21.1% porosity and dominated by pore type 4.12. Permeability & Hg capillary entry pressure are measured in Fig. 4, and predicted (using other prediction tools in CARP) in Fig. 5.

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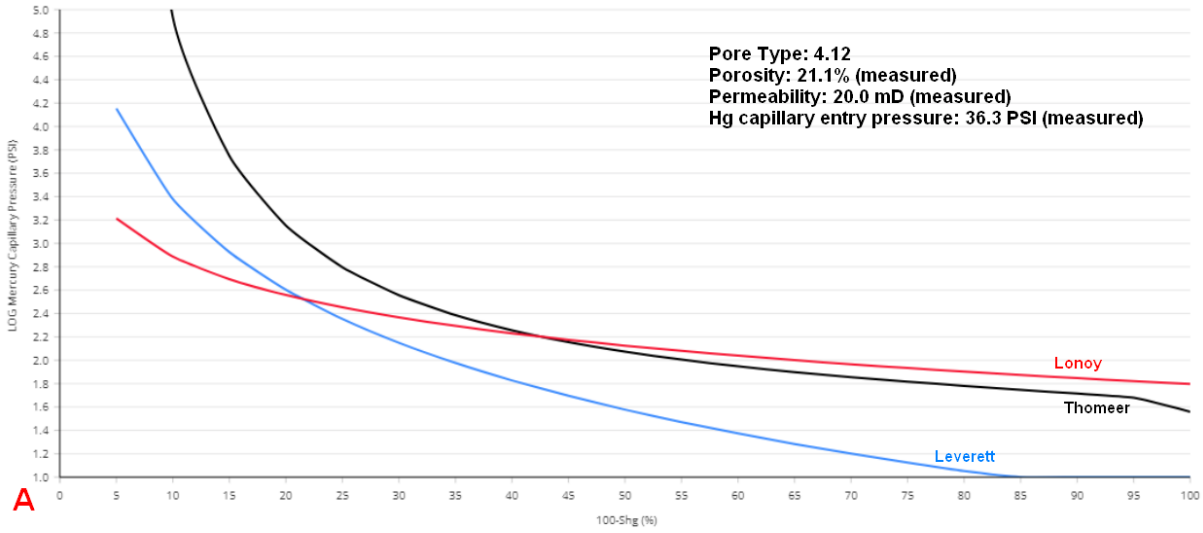

Figure 4:
Comparison of Hg capillary pressure curves for Thomeer, Leverett and Lonoy methodologies. Permeability and Hg capillary entry pressure are measured.

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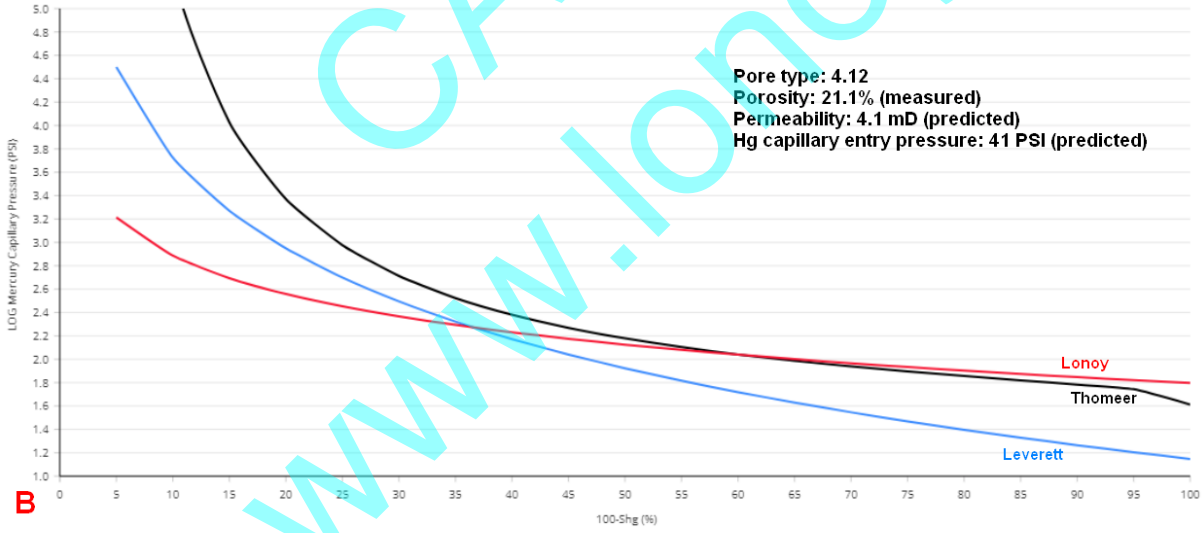

Figure 5:
Comparison of Hg capillary pressure curves for Thomeer, Leverett and Lonoy methodologies. Permeability and Hg capillary entry pressure are predicted from different CARP tools.

5.1.4 MICP Prediction vs. Classification (post #39)

MICP PREDICTION

The most useful application of MICP curves is to be able to predict saturations at any location within the reservoir, based on geological knowledge. This includes predictions in cored sections lacking analyses, uncored wells or parts of wells, and in inter-well locations. In these parts of the reservoir, permeability and capillary entry pressure are largely unknown and have to be predicted. This represents a very high degree of uncertainty in the saturation prediction using the Thomeer and Leverett averaging methods.

The Leverett averaging method depends on porosity and permeability, whereas the Thomeer method depends on permeability and capillary entry pressure. Although porosity is not part of the Thomeer equation, this parameter is often required for prediction of permeability and capillary entry pressure. For predictive purposes, both methods have to be related to rock types.

The Lonoy method only depends on porosity & pore type. These are controlled by sedimentologic and diagenetic processes, and as such can be predicted from sedimentary facies maps. The Lonoy method is thus based on a more limited set of input variables than for the two more commonly applied MICP averaging methods, and is based on parameters that go into standard reservoir models. MICP curves can therefore be predicted at cell-grid resolution of a reservoir model. The prediction accuracy will be controlled by the accuracy of porosity distribution and facies model.

MICP CLASSIFICATION

For MICP classification/grouping, permeability and capillary entry pressure are available from core measurements.

The Leverett and Thomeer averaging methods may be useful for grouping samples into rock types, but the methods have limited predictive ability beyond cored intervals because they depend on permeability (Leverett & Thomeer) and capillary entry pressure (Thomeer). Furthermore, rock typing based solely on MICP curves may be detached from sedimentology and diagenesis, and as such, may have poor predictive ability.

Classification for Leverett and Thomeer are controlled by the MICP curves, whereas in the Lonoy method classification is based on sedimentology (pore type and porosity). The Lonoy method was developed for prediction, not classification.

The images below are from three randomly chosen samples from two different oil-producing Middle East fields. User data, as referred to in the image text, is measured data. Note the significantly lower prediction error for the Lonoy methodology, as compared to Leverett and Thomeer.

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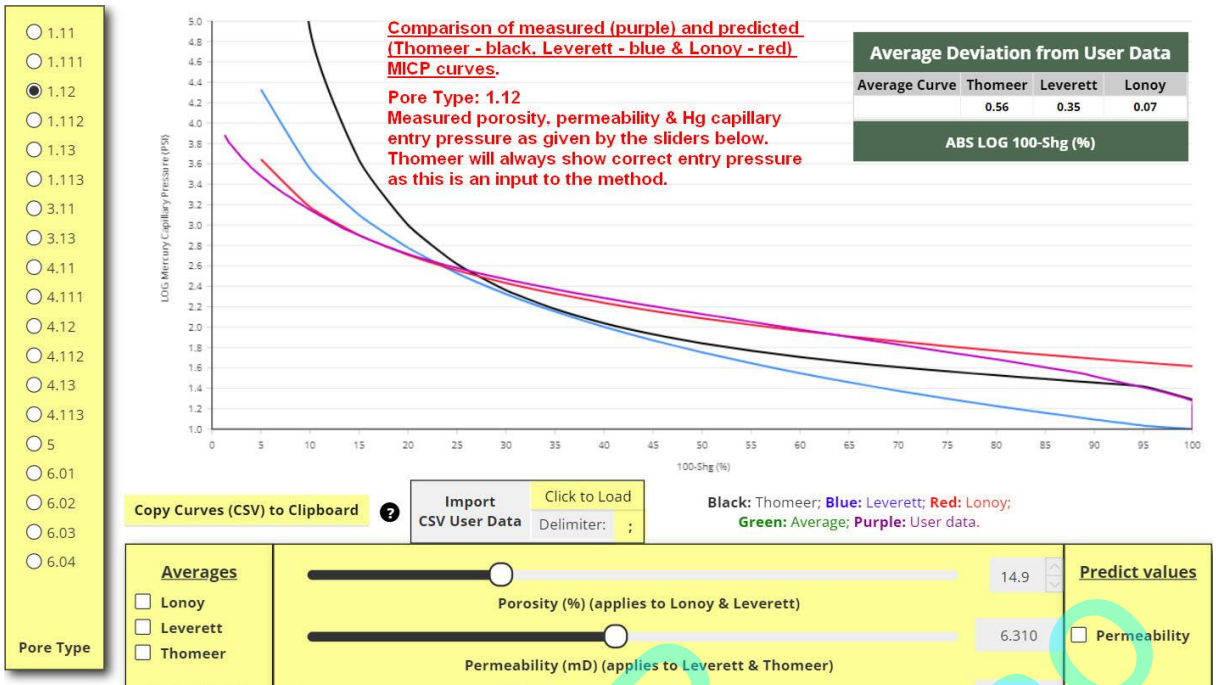

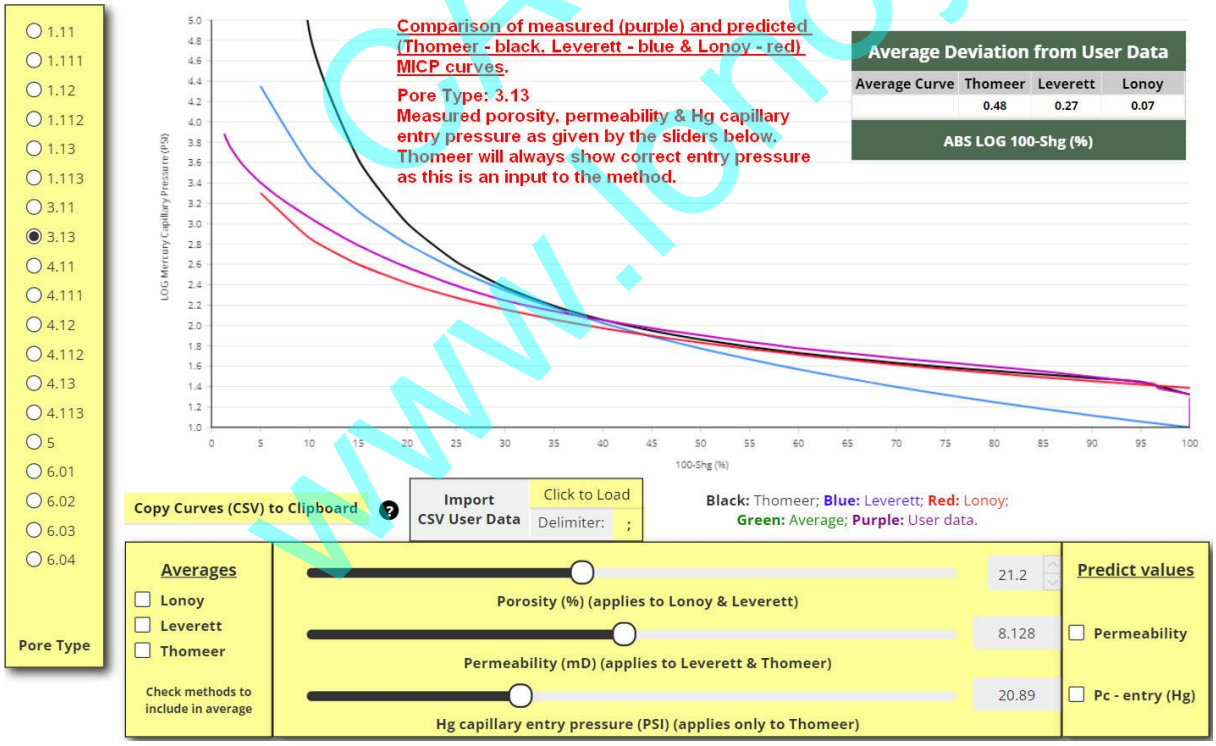

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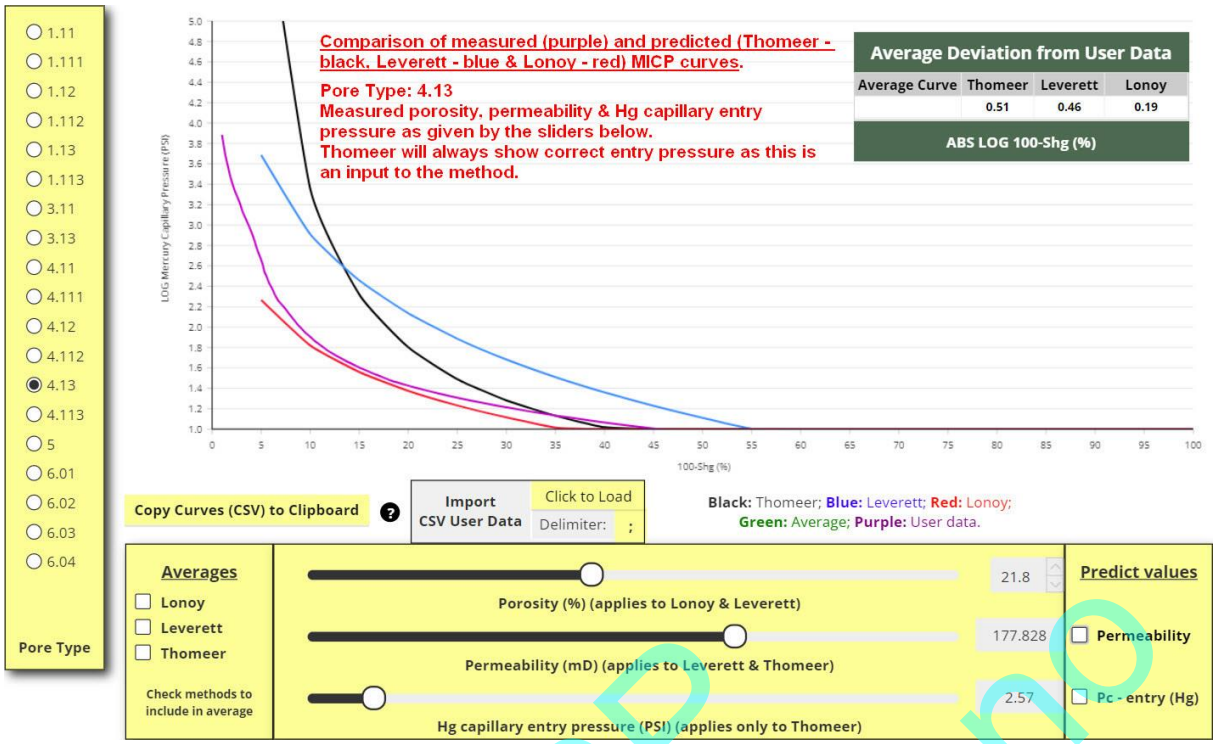

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5.1.5 Prediction Error (post #40)

The prediction error of the different methods (Leverett J-function, Thomeer & Lonoy) is calculated by comparing the predicted MICP curves for each method with measured MICP data (Figure A). The error comparison can be carried out for both MICP prediction and MICP classification (post #39), of which the former is the most useful. The difference between these is that for MICP prediction some of the input parameters (permeability and capillary entry pressure - Pc-entry) are unknown and have to be predicted. For MICP classification, permeability and Pc-entry are available from core measurements. The results presented in this post are based on MICP prediction.

The prediction error can be given both as the average and absolute average pressure deviation (LOG PSI) for different pore types, measured in the Hg pressure interval of Pc-entry to 2000 PSI. The advantage of the average deviation is that it shows the average as minus (overall overestimation of Sw) or plus (overall underestimation of Sw). The disadvantage is that deviations which are symmetric across the measured MICP curve tend to have an average close to 0 (e.g. Figure A).

The advantage of the absolute average deviation is that under- and over-estimated saturations do not equalize, resulting in an overall low average deviation, but gives the true overall deviation. However, there is no information on the overall tendency in the prediction error. The results presented here are based on average absolute prediction error. Figure B shows the differences in average prediction errors for the Thomeer, Leverett & Lonoy methods based on ca. 600 samples.

The results show that the Lonoy averaging method gives significantly better results for 18 of the 19 pore types, as compared to the Leverett & Thomeer methods. Overall, for all pore types combined, the prediction errors are 0.18 for Lonoy, 0.41 for Leverett, and 0.47 for Thomeer. All prediction errors refer to the absolute value of LOG Pc (PSI), with measured global averages (ca. 600 samples) used as reference. It turns out that the poor performance of the Thomeer method often relates to strong underestimation of Hg saturation at high pressures, as demonstrated for the porosity interval 15-20% of pore type 4.12 (Figure C).

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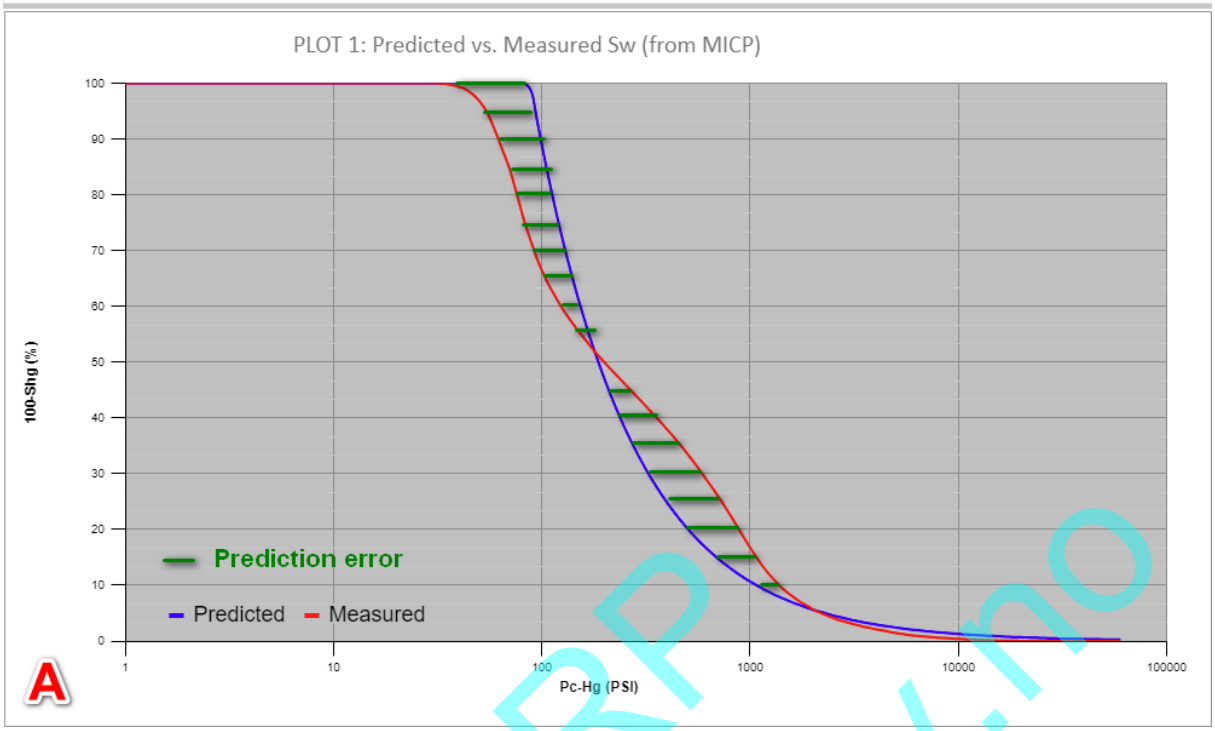
DemoWell #1, Plug #3,
Pore Type 1.11, Porosity = 19.9% (Conformance corrected)



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	Prediction error (LOG PSI)		
Pore Type	Lonoy	Leverett	Thomeer
1.11	**0.22**	0.43	0.29
1.111	**0.12**	0.23	0.27
1.12	**0.15**	0.30	0.38
1.112	**0.30**	**0.30**	0.32
1.13	**0.23**	0.25	0.37
1.113	**0.23**	0.31	0.31
3.11	**0.08**	0.43	0.54
3.13	0.19	0.39	**0.16**
4.11	**0.13**	0.33	0.22
4.111	**0.27**	0.60	1.92
4.12	**0.11**	0.28	0.30
4.112	**0.12**	0.29	0.40
4.13	**0.24**	0.46	0.47
4.113	**0.20**	0.46	0.57
5	**0.18**	0.42	0.29
6.01	**0.08**	0.48	0.51
6.02	**0.10**	0.66	0.74
6.03	**0.22**	0.78	0.55
6.04	**0.33**	0.37	0.38
Total	**0.18**	0.41	0.47

Based on ca. 600 globally-derived samples

B

Average absolute pressure deviations (LOG PSI) for different pore types, using Lonoy, Leverett and Thomeer prediction methods. Deviations are relative to measured MICP curves at variable mercury saturations, and are measured at pressures from mercury capillary entry pressure to 2000 PSI. For each pore type, the method(s) giving the least and highest prediction error are marked with bold and underlined numbers, respectively.

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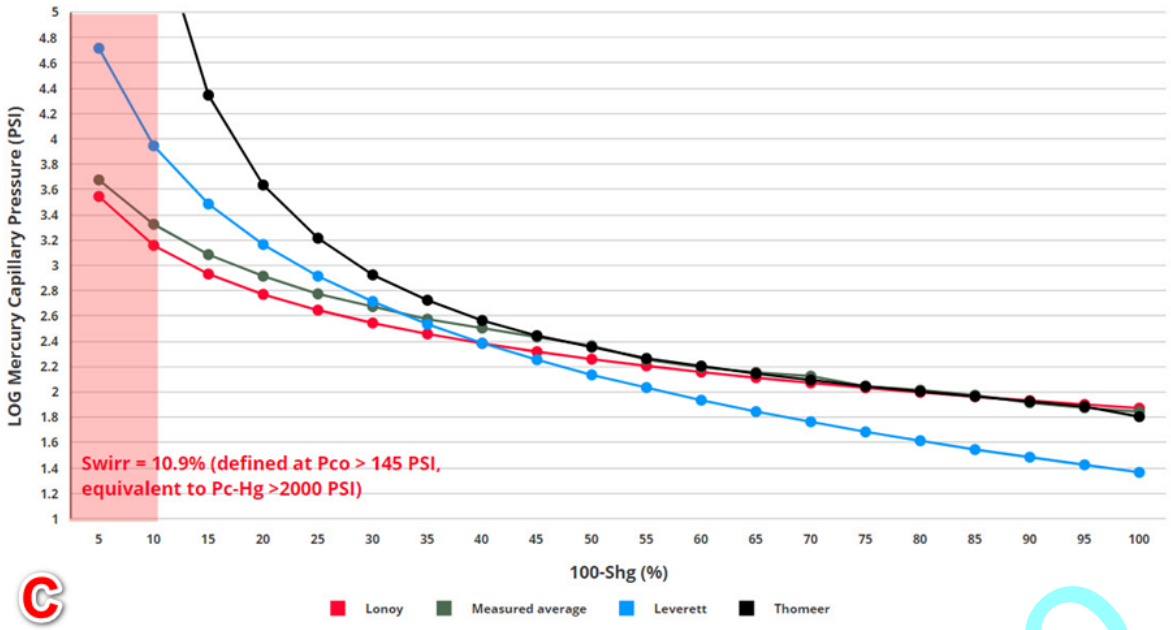

Measured and predicted MICP curves for pore type 4.12, porosity interval 15-20%. Measured, average global MICP curve (green curve) is based on 10 samples with an average porosity of 17.0%. Predicted MICP curves are based on Lonoy (red curve), Leverett (blue curve) and Thomeer (black curve). Typical for Thomeer is that the mercury saturation, for most pore types, is strongly underestimated at high pressures. Prediction errors are given as the average absolute pressure deviation to the measured average, given as Log PSI. For this pore type and porosity interval, at Pc-Hg < 2000 PSI, the deviation is 0.07 (Lonoy), 0.28 (Leverett) and 0.19 (Thomeer). Quite typical, the Thomeer method gives significantly improved prediction at lower mercury saturations. This is logical, as the Thomeer averaging method is dependent on the capillary entry pressure.

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5.1.6 MICP Controlling Parameters (posts 43 and 51)

Some of the most important parameters controlling MICP curves (many of which are inter-related) are:

- Pore type
- Pore-throat diameter
- Porosity
- Porosity patchiness
- Pore size
- Pore geometry
- Permeability

Pore types are controlled by sedimentologic processes and diagenesis, and are mostly defined based on pore size and pore geometry. They are also partly based on porosity patchiness which, in combination with pore size and porosity, control pore-throat diameters. Pore sizes also give important information on pore volume at MICP increments. All these parameters directly contribute to both permeability and MICP curves, which makes pore types the ideal rock type to apply in reservoir characterization. Other forms of rock typing, such as e.g. sedimentary facies or texture, only work optimally when there is a 1:1 relation to pore types.

As noted above, pore-throat diameters are controlled by various parameters (some of which are involved in pore-type definitions), and are calculated from MICP measurements.

Permeability is an important input to the Leverett and Thomeer MICP averaging methods, but is not involved in the Lonoy method. How can the Lonoy method do without this parameter?

The reason for this is that in the Lonoy method, rock typing is based on pore types. There is a close correlation between pore type, porosity and permeability, as demonstrated in previous posts in LinkedIn and in Lonoy (2006). The only inputs to the Lonoy method are pore type and porosity, and permeability is not required as this is a function of these two parameters. In most cases for Leverett and Thomeer, the permeability would have to be predicted, e.g. from porosity-permeability cross-plots.

This explains how the Lonoy method can do without permeability as input, but how can this method on average perform better than Leverett and Thomeer? The reason for this lies in the empirical derivation of equations for each pore type. The Leverett and Thomeer methods attempt to explain MICP curves using one single equation, whereas the Lonoy method uses one equation for each of the 21 pore types. This, in itself, gives more detailed prediction of the MICP curves. Unless Leverett and Thomeer apply pore type controlled rock types, these methods will lack important information related to pore size, porosity distribution and pore geometry. These parameters are included in Lonoy's pore type classification, and are vital for understanding MICP curves.

The images show the average deviation of the Lonoy, Thomeer and Leverett MICP curves as a function of height above FWL for oil-producing fields in the Middle East: Miocene (image 1) and Cretaceous (image 2).

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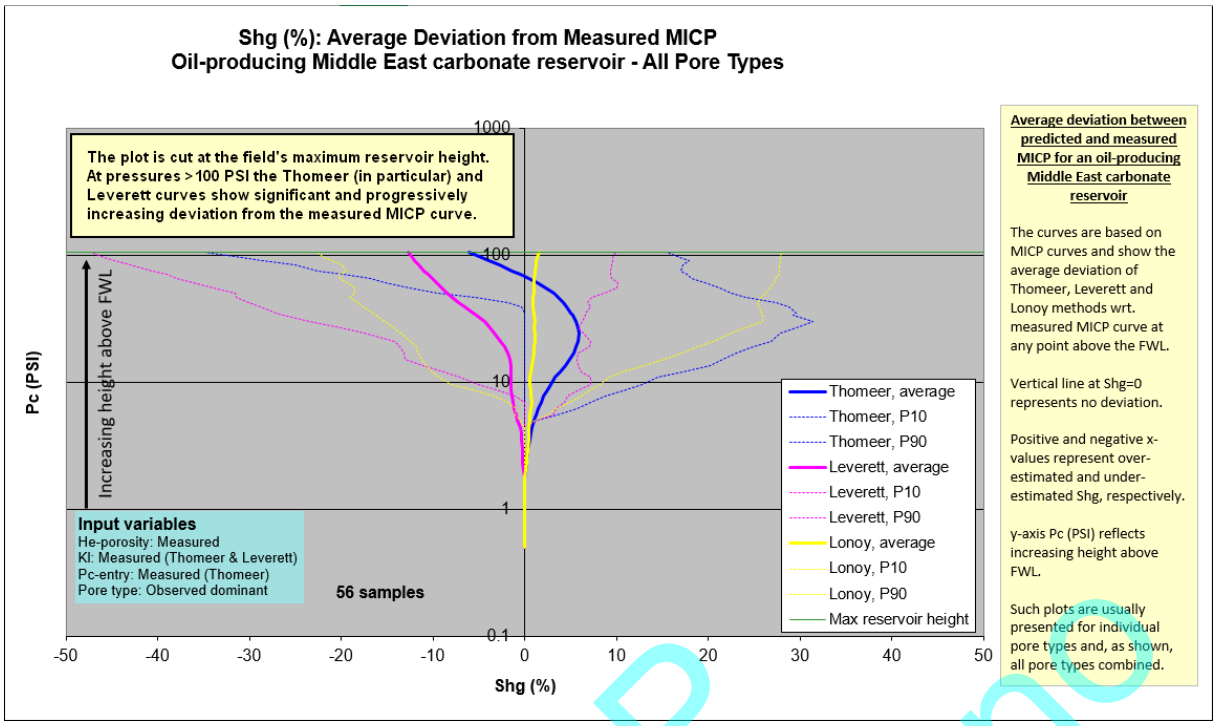

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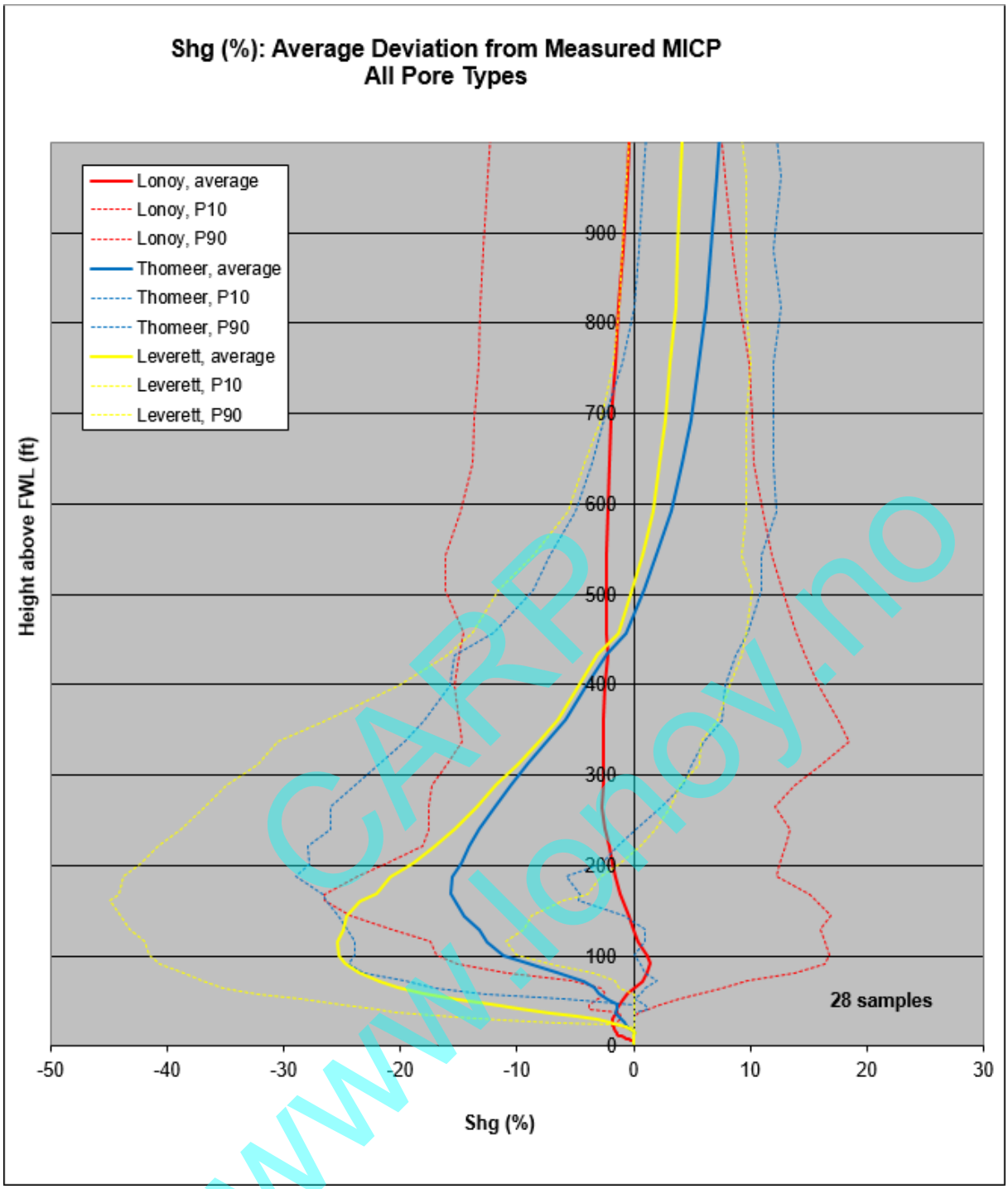

The curves on the graph are based on MICP curves and show the average deviation of Thomeer, Leverett and Lonoy methods wrt. measured MICP curves at any point above the FWL. The vertical line at Shg=0 represents no deviation. Positive and negative x-values represent over-estimated and under-estimated Shg, respectively. Y-axis reflects increasing height above FWL. The dashed lines show the P10 and P90 curves. The graphs are usually presented for individual pore types and, as shown, all pore types combined.

5.1.7 MICP curve fitting (post #50)

Several MICP-related methods apply curve fitting in an attempt to generate mathematical equations for defining measured MICP curves. Some geoscientists apply curve fitting to single MICP curves. This may generate excellent results, but has limited predictive properties.

Other geoscientists apply curve fitting to groups of MICP curves, where the groups represent petrophysical rock types. This is a slight improvement to individual curve fitting, but once again has limited predictive properties because there is no way to reliably populate the properties across the field.

Yet others apply curve fitting to geologically-defined rock types, quite often defined by similar depositional setting or sedimentary texture. This is a huge improvement as geological features can be predicted field-wide based on geological models. It is, however, not the optimal solution as illustrated by the images.

The images illustrate how diagenesis can affect MICP curves. The images are identical except for an artificially induced white cement in image b). The cement has no impact on pore sizes or pore throat diameters, insignificant impact on permeability and MICP curves, but a significant impact on porosity and the permeability/porosity ratio. These differences are captured by pore types, but not by depositional setting or sedimentary textures.

Optimally, curve fitting should be applied to rock types that define the pore structure of the sediment and which are related to geological processes captured by sedimentary and diagenetic facies maps. My experience is that pore type is the best rock type to apply in order to capture reservoir-critical parameters such as pore size, pore geometry, permeability, pore-throat diameters, permeability/porosity ratio etc (see chapters 5.1.6 and 2.2). Pore types are related to sedimentological processes and diagenesis, and can therefore be integrated into geological models.

Overall, a "perfect" petrophysical fit to measured data is not the most important, and is probably only attainable for single samples. Petrophysical evaluations are restricted to wells, and have limited predictive properties between wells unless related to geological models. Wells constitute far less than 0.0001% of the total rock volume in a field, and petrophysical properties must therefore be related to geological models.

The critical issue is to achieve a model that on average optimally replicate the reservoir properties. Of equal importance is to have a reliable geological model. If the geological model is wrong, the petrophysical prediction will be wrong, no matter how good the petrophysical model is.

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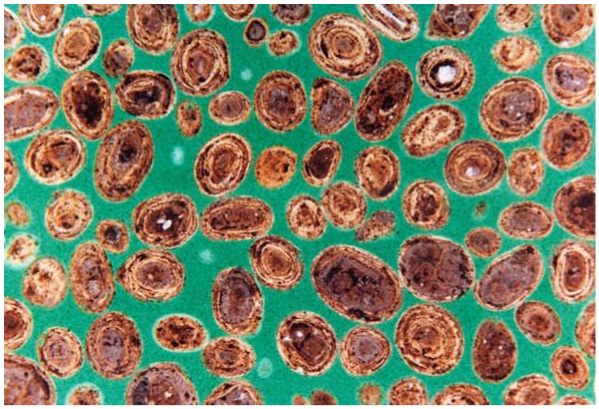
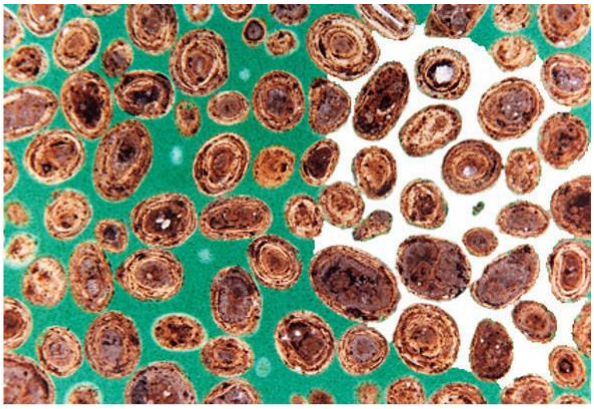


a) Uniform porosity distribution



b) Patchy porosity distribution controlled by cement patch (white)

Identical pore-throat diameters	Different pore types
Identical pore sizes	Different porosities
Identical pore geometries	Different permeability/porosity ratio (applied in Leverett J-function)
Similar permeabilities	
Similar MICP curves	

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6 Database

6.1 General Database (post #8)

The database consists of roughly 10.000 samples derived from a wide range of geological time periods, formations and depositional settings globally. The data range from samples that only have a pore type defined, to samples that also have a wide range of measured petrophysical properties.

The CARP tool shown in the video below shows the geographic distribution of the total CARP database, with geological age, formation, depositional setting and dominant pore-type distribution. The database is continuously being updated. Databases for different reservoir parameters will be illustrated in later postings.

The dominant pore-type composition is important for the local and global statistical prediction of pore types in carbonates from different geological time periods and depositional settings. The database illustrated in the video can, as such, be applied to distribute pore types in various depositional settings based on the local statistical pore-type distribution. This would typically be done when other local data is limited, e.g. during exploration, and may have a significant impact on predicted flow properties and volume estimates. In fact, wrong pore types may account for several hundred percent difference in volume estimates, as published by Lonoy (2006). The statistical dominant pore-type distributions can be used to spatially populate pore types and associated reservoir properties, e.g. into grid cells of a reservoir model.

The YouTube video link below illustrates how the CARP overall database is presented.

Video link: https://youtu.be/eyOU9wqeulM

6.2 Porosity-Permeability Database

6.2.1 Overview (post #10)

Porosity-permeability relationships are important for predicting permeability from porosity, and for defining porosity cut-offs.

Wireline borehole tools usually cannot measure permeability, and in uncored wells the permeability is therefore commonly predicted from porosity-permeability relationships defined from cored wells. Porosity cut-offs are most commonly applied in exploration, and is often defined at an assumed flow-critical permeability of 1 mD for oil reservoirs.

Porosity-permeability relationships are often well established in siliciclastic reservoirs, and permeabilities and porosity cut-offs are therefore normally well defined. In carbonate reservoirs, however, such relationships are commonly poorly developed due to the significantly more complex pore geometries. In order to better define porosity-permeability relationships in carbonate reservoirs it is thus necessary to evaluate different pore types.

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The porosity-permeability database in CARP is illustrated in the video below, showing how pore types have a strong impact on porosity-permeability relationships. The equation-based trend lines for the different pore types can be applied in reservoir models to predict permeability (and porosity cut-off) in every cell of the grid. This is accomplished by combining sedimentary facies maps and porosity distribution in the model, and by assigning pore types according to statistical global or local distributions within different facies. This is possible because the pore types are controlled by sedimentologic and diagenetic processes.

Sensitivity testing of the reservoir model can be carried out by applying CARP's equation-based probability curves (user-defined P10 to P90 in 10% increments). In the video, the P10 and P90 trend lines are given as dashed lines, whereas the expected trend line is given as a solid line.

Porosity cut-offs vary considerably for different pore types and this may have a severe effect on estimating hydrocarbon reserves in a field. Some practical examples based on data from various fields (Lønøy, 2006) show that STOOIP may vary with several hundred percent just based on pore type and associated changes in porosity cut-off.

Pore types also have an important control on water saturation, which may account for STOOIP variations of additional several hundred percent.

Video link: https://youtu.be/8XWaZAbx5Vw

6.2.2 Deviations From Global Trendlines (Part 1) (post #11)

The CARP porosity-permeability database is based on matrix properties and on samples that are dominated by one single pore type. Most of the samples have been quality controlled. This gives low scatter in data points along the trend lines for individual pore types.

There are many reasons why user data show a wider scatter in porosity-permeability data points, and these may be grouped into two categories: Features that are dependent or independent on orientation. This post will be on features that may result in deviations from the global porosity-permeability trendlines, dependent on orientation. Orientation referred to is relative to the length of the core plug, and effects on porosity-permeability refers to plug-derived values.

Features oriented perpendicular to plug length usually cannot be observed in thin sections, assuming that the thin section is made from the plug or end trim of plug. Those with an oblique orientation may or may not be observed, whereas those parallel to plug length always will be observed in thin sections.

- Open Fractures.
  Perpendicular/oblique: Insignificant effect on permeability.
  Parallel: CCA (Conventional Core Analysis) may overestimate matrix permeability, depending on the lateral continuity of fractures. IMAGE A.

  Open fractures have insignificant effect on porosity unless the matrix porosity is low.

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- Cemented fractures and stylolites.
  Perpendicular/oblique: May create permeability barriers, and CCA underestimates matrix permeability.
  Parallel: Minor to no effect on permeability. Stylolites may in some cases significantly increase permeability due to flow along stylolite (artificially induced fracture along stylolite), and CCA thus overestimates matrix permeability. IMAGE B and C.

  Cemented fractures have variable effect on porosity depending on fracture width. Stylolites usually have a minor effect on porosity unless pressure dissolution has resulted in increased cementation along stylolite.

- Bedding.
  Perpendicular/oblique: May result in significant reduction in permeability, and CCA represents a paleo-vertical plug.
  Parallel: No or limited effect on permeability. IMAGE D.

  Bedding has no effect on porosity when parallel to plug length. It may have an effect when bedding is perpendicular or oblique to plug length, depending on variability in porosity/cementation in different laminae.

Note the patchy porosity distribution of samples A, B and C.

CONCLUSION:
If samples have a strong deviation from global porosity-permeability trendline curves, the core plug should be carefully examined for effects that may have affected the measured RCA results. RCA plug measurements are not always recording the matrix properties.

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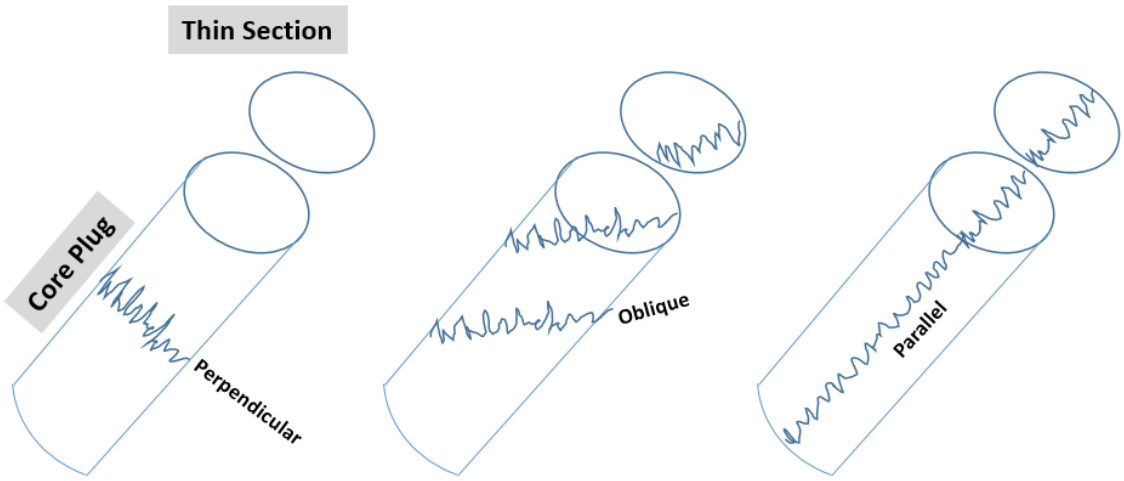

Left: Stylolite perpendicular to plug length. Usually not present in thin section. Reduces permeability.
Middle: Stylolite oblique to plug length. May or may not be observed in thin section. Reduces permeability.
Right: Stylolite parallel to plug length. Present in thin section. Usually limited effect on permeability.

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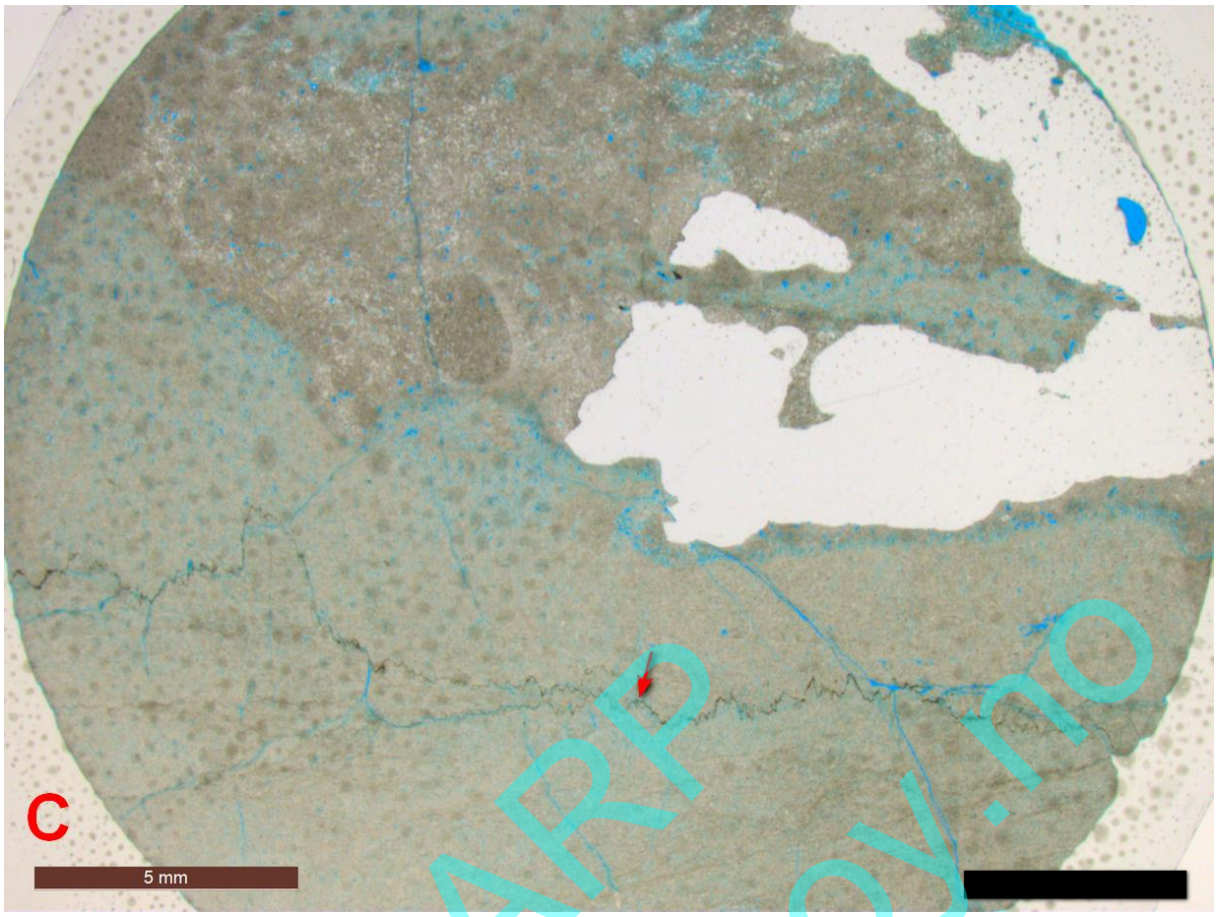

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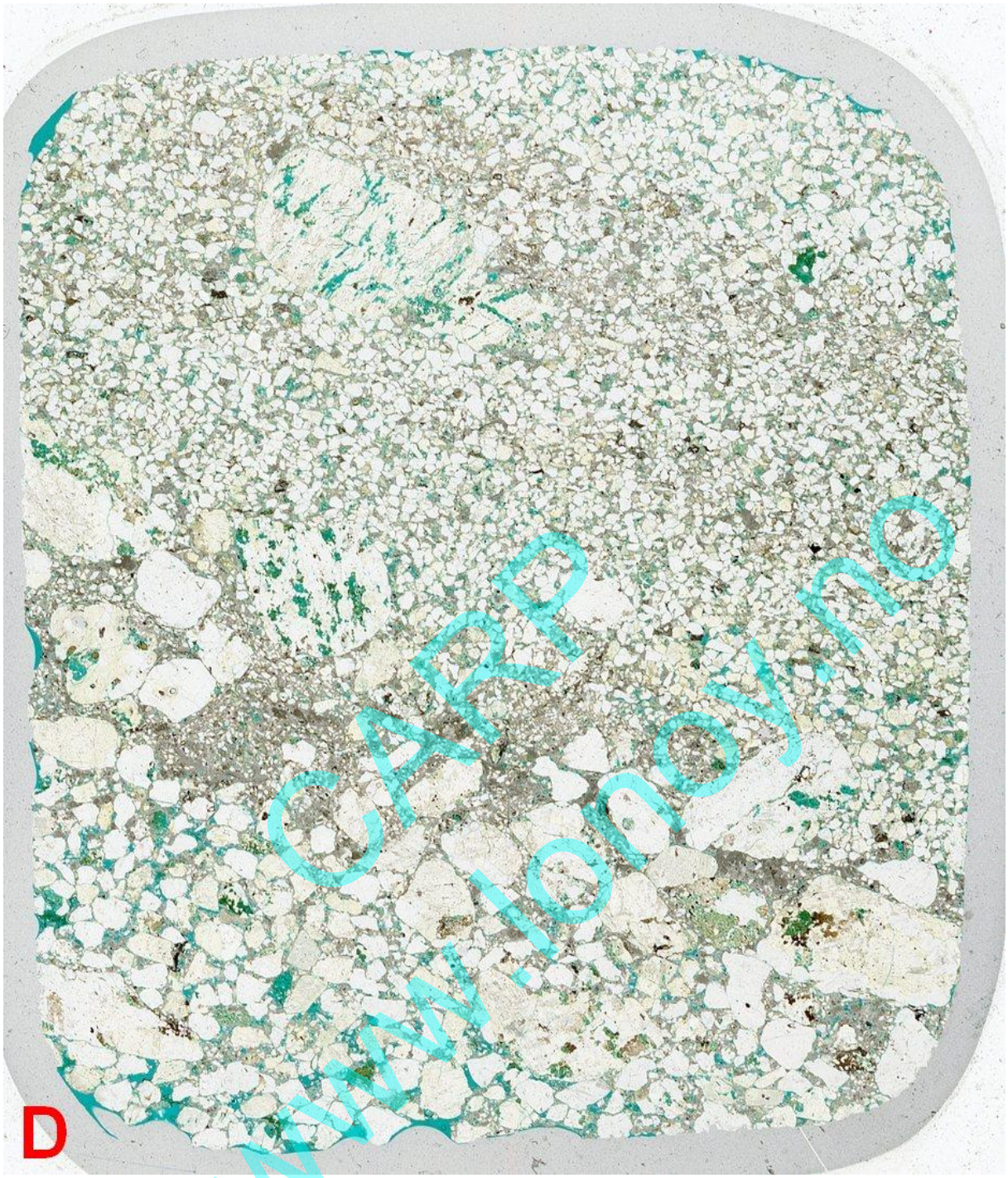

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6.2.3 Deviations From Global Trendlines (Part 2) (post #12)

This post will be a follow up from last post #on why some data deviate from the global poro-perm trends. This will be exemplified by published data from the South Pars Field offshore Iran (https://lnkd.in/dRYBR8Sx).

Based on images from the publication, we are able to define pore types and plot the reported poro-perm (given on the images) on the global pore-type dependent cross-plots (see screen dumps from CARP). South Pars samples are red on the plots.

Dominant pore types are:
Image A: 3.11 - moldic micro (3.13 is subordinate); porosity is black
Image B: 3.13 - moldic macro; porosity is white
Image C: 4.13 - intercrystalline macro (based on crystal size)
Image D: No porosity observed
Image E: Open fractures
Image F: Fenestral, which is not included in CARP. Pore type 2 (vuggy) is most representative in this case
Image X-ray left: 1.113 (interparticle, patchy macro)
Image X-ray right: 3.13

Based on similarities in texture to A and B, D and E are plotted with pore type 3.13.
We see from the cross-plots that all samples, except D and E, closely follow the global trendlines.

There are no pore types, except open vugs and fractures, that can explain the poro-perm properties of D and E. In fact, open fractures are seen in the lower part of image E. Failure to recognize the effect of open fractures on plug-measured poro-perm can lead to a significant overestimation of the matrix properties. Given that the fractures are natural, and not artificially induced during drilling, the reservoir scale permeability is to a large degree controlled by the fractures. However, in this case the fractures should be included as a separate layer in the reservoir model where fracture spacing, orientation and lateral continuity would play active roles.

In some cases global poro-perm relationships for individual pore types give more accurate matrix permeabilities than plug measurements.
The effect of open fractures on porosity-permeability plug measurements is most easily recognized in low porosity samples. Our experience is that open fractures are most common in low porosity samples, probably because these samples usually are more brittle.

South Pars photo links: https://lnkd.in/dhvRb-kY and https://lnkd.in/dmqtRx-x

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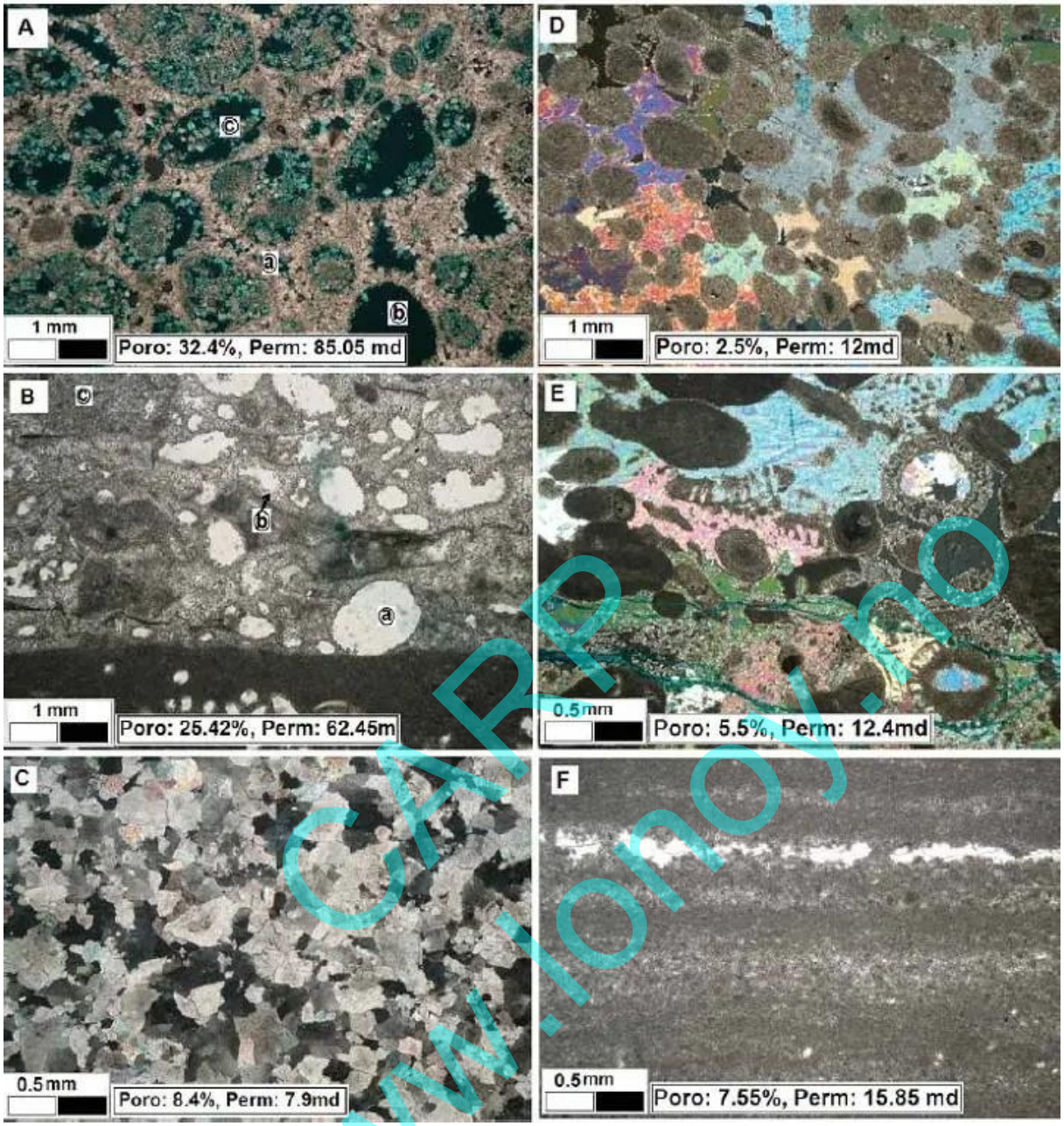

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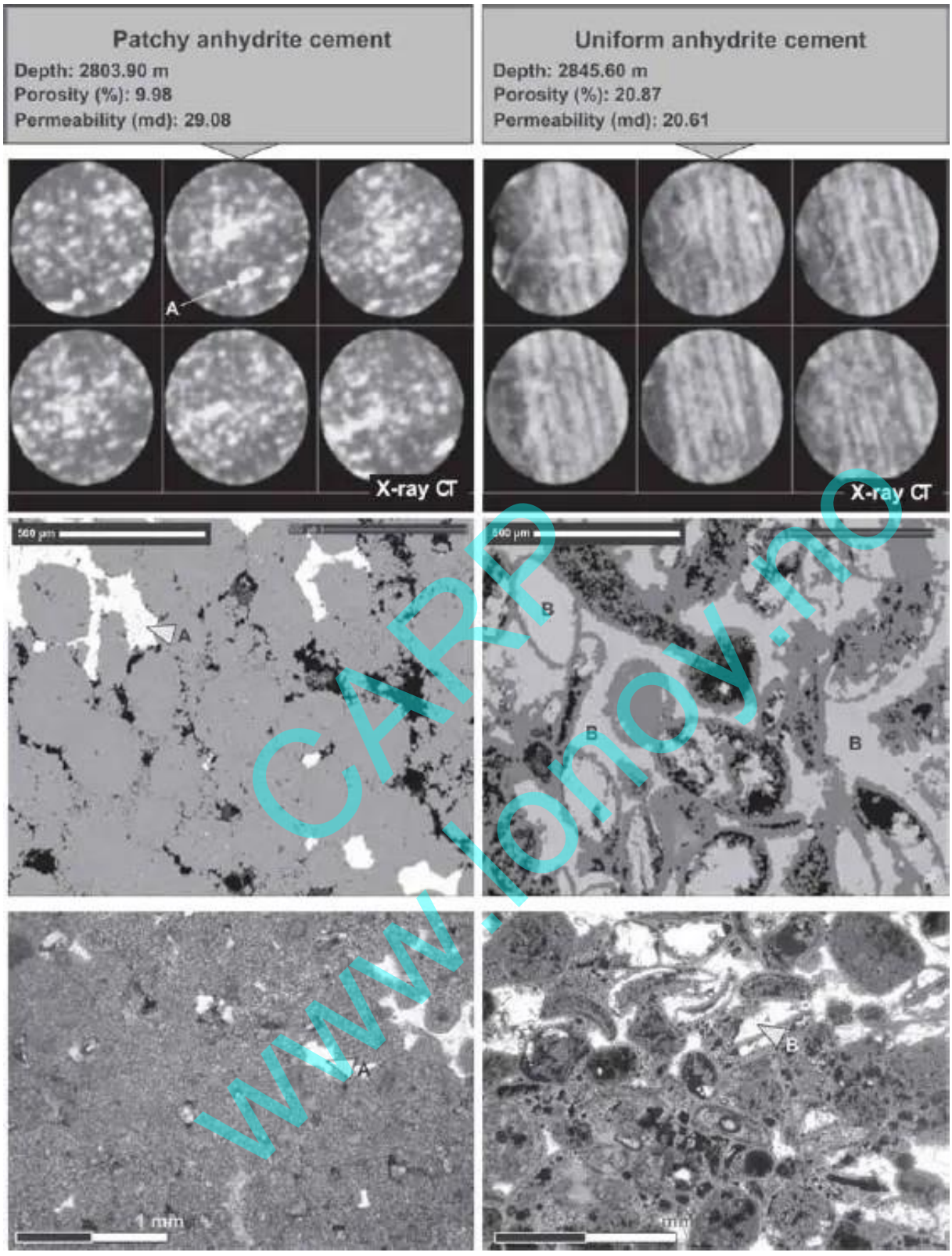

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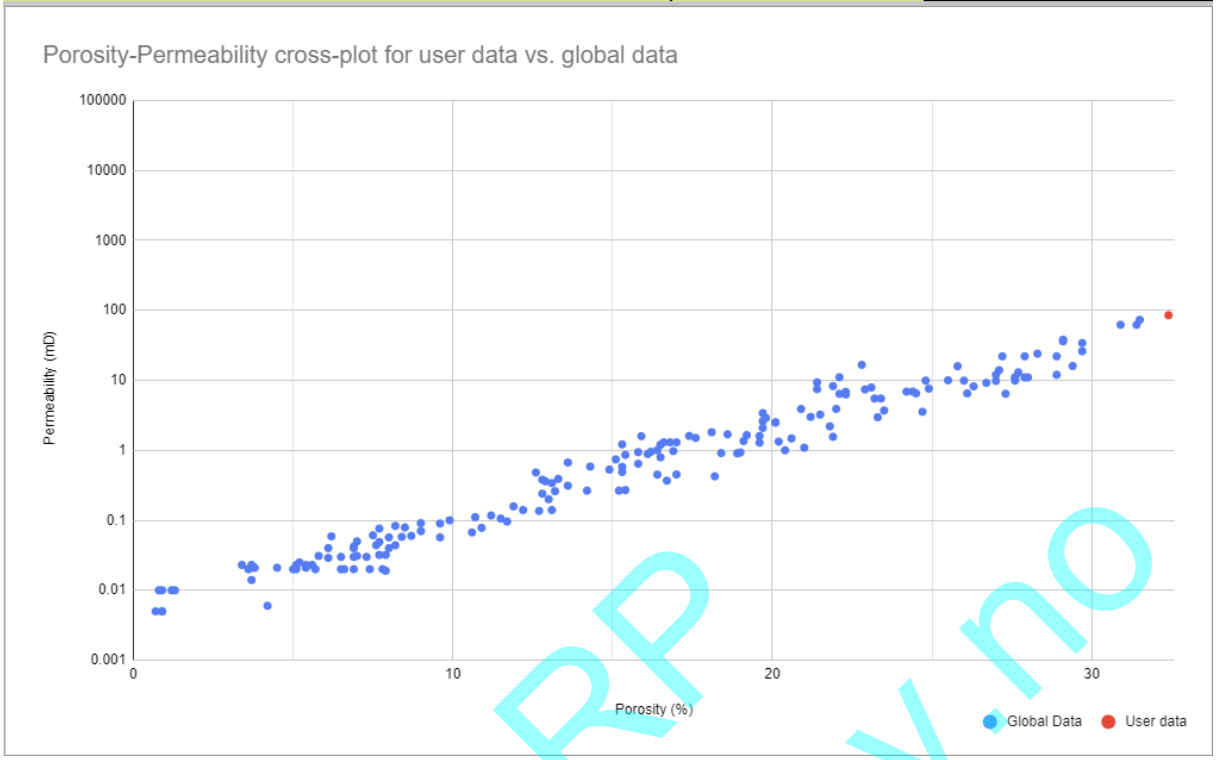
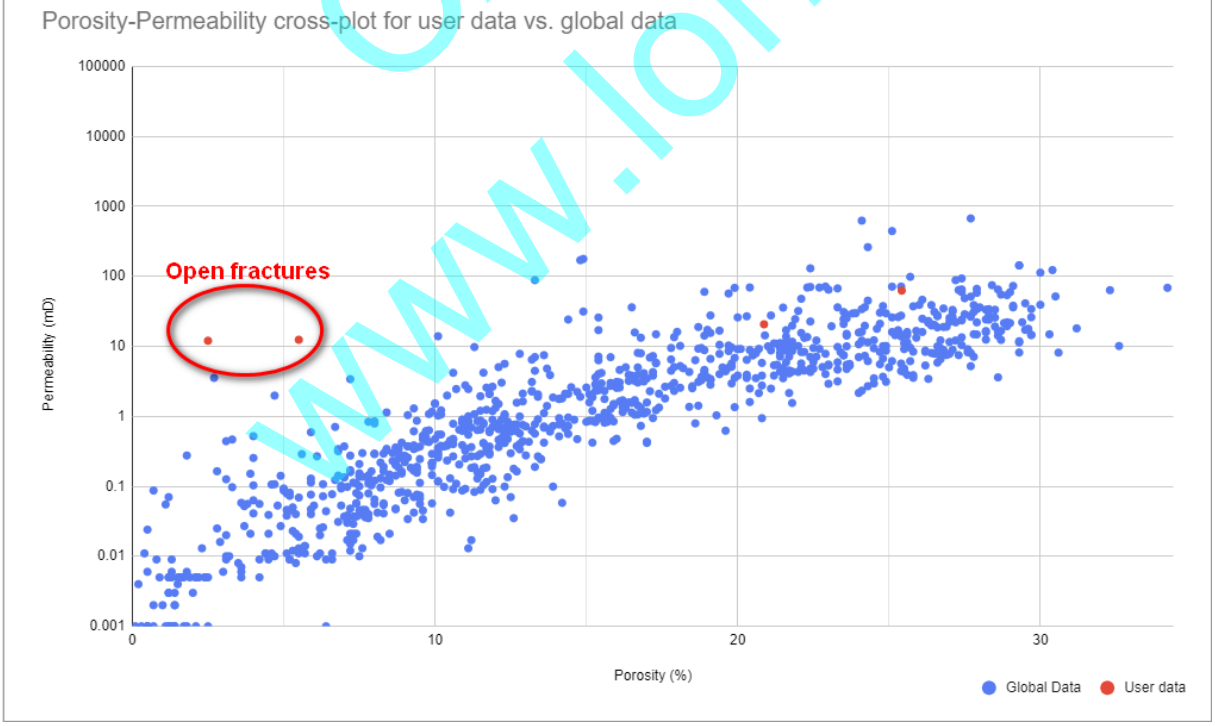
PORE TYPE TO PLOT

Global Data Set Pore Type	Pore Type: Global = User
3.11	☑



PORE TYPE TO PLOT

Global Data Set Pore Type	Pore Type: Global = User
3.13	☑



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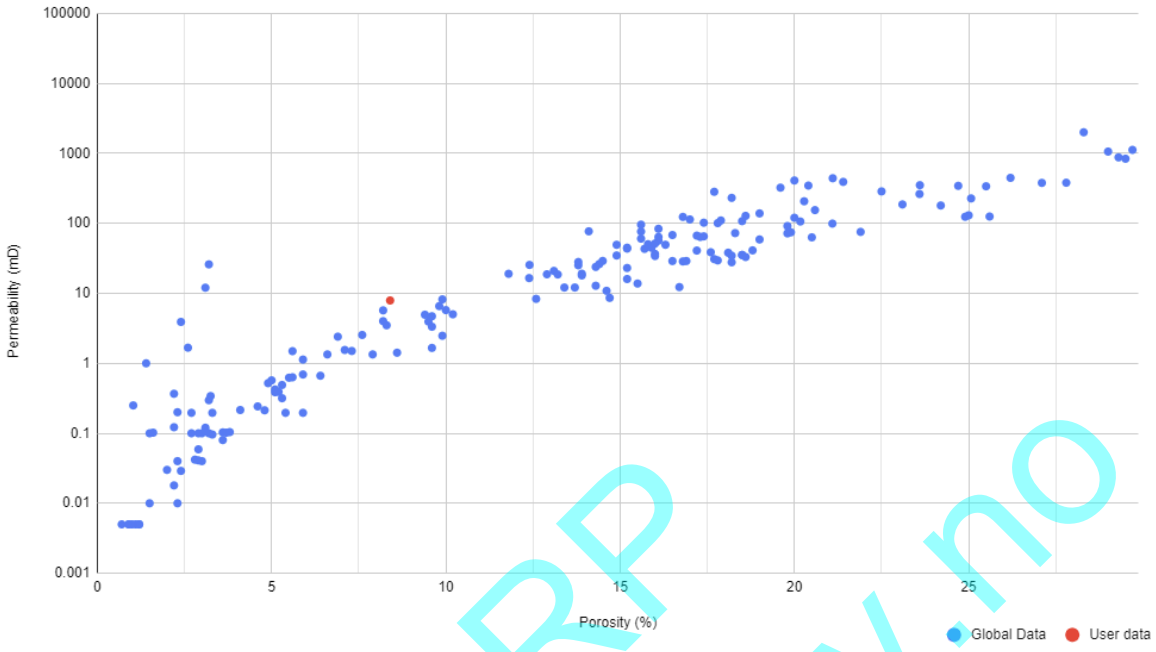
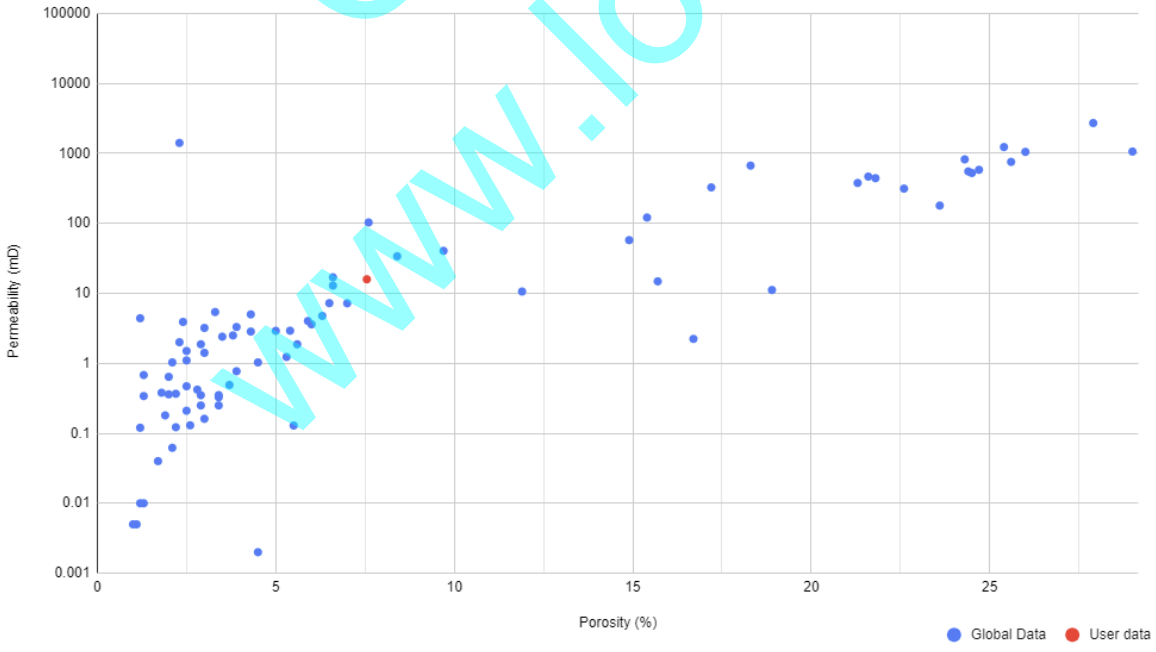
PORE TYPE TO PLOT	
Global Data Set Pore Type	Pore Type: Global = User
4.13	☑

Porosity-Permeability cross-plot for user data vs. global data



PORE TYPE TO PLOT	
Global Data Set Pore Type	Pore Type: Global = User
2	☑

Porosity-Permeability cross-plot for user data vs. global data



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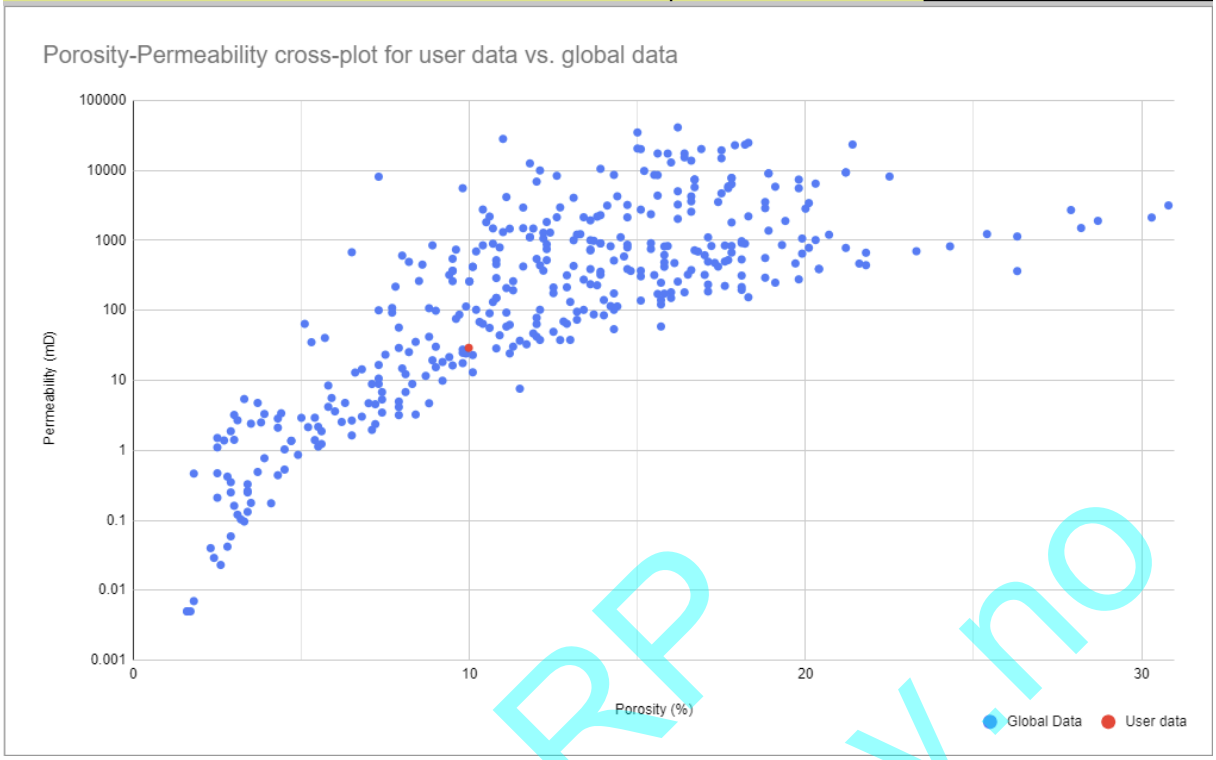
PORE TYPE TO PLOT		
Global Data Set Pore Type	Pore Type: Global = User	
1.113	☑	



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6.2.4 Deviations From Global Trendlines (Part 3) (post #18)

This post will be a follow up from weeks 11 & 12 on why some data deviate from the global poro-perm trends.

There are many reasons why user data show a wider scatter in poro-perm data points, and these may be grouped into 2 categories: Features that are dependent or independent on plug orientation. This post will be on one of the features that are independent on orientation: Dual pore-type systems (see post #15).

Dual pore-type systems may or may not cause deviations from the global poro-perm trends. Deviations are prominent when there is a significant difference in flow properties between the dominant and subordinate pore types, but may be insignificant when the flow properties are similar. In the latter case, it doesn't make much difference whether the dominant or the subordinate pore type is applied in the model as they give almost the same result.

The latter case will be exemplified by published data from the Lower Lekhwair Fm. in UAE (poster presented by Santerre et al., IAS conference in Toulouse, 2017). Three groups of data are presented in the poster, along with measured poro-perm and representative thin-section micrographs (images A-C; presented by permission). Based on the images we are able to define pore types and plot the reported poro-perm on the global pore-type dependent cross-plots (see screen dumps from CARP, images D-G). Lower Lekhwair samples are red on the plots.

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Group 1 (image A)

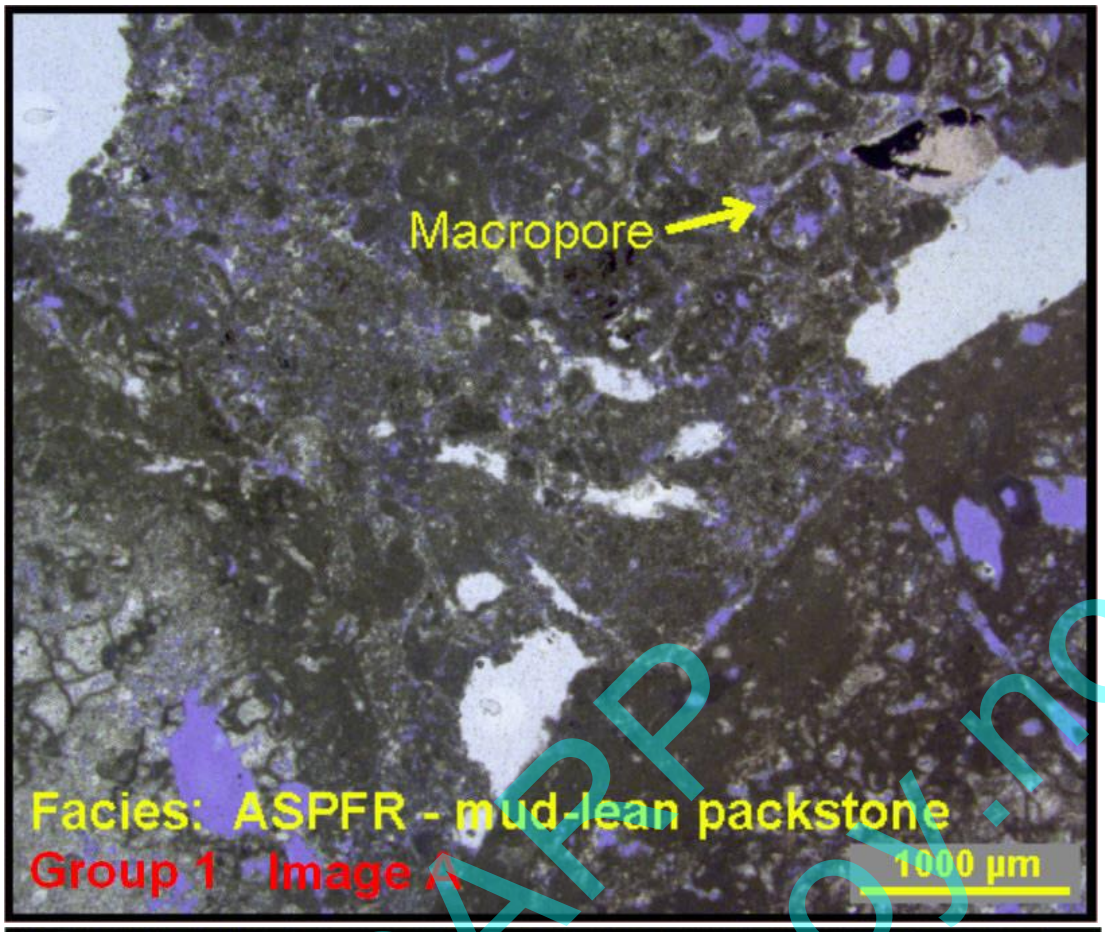
Pore types are 5 (intraparticle) & 1.12 (interparticle meso uniform distr.). Either of them can be dominant or subordinate, depending on sample.

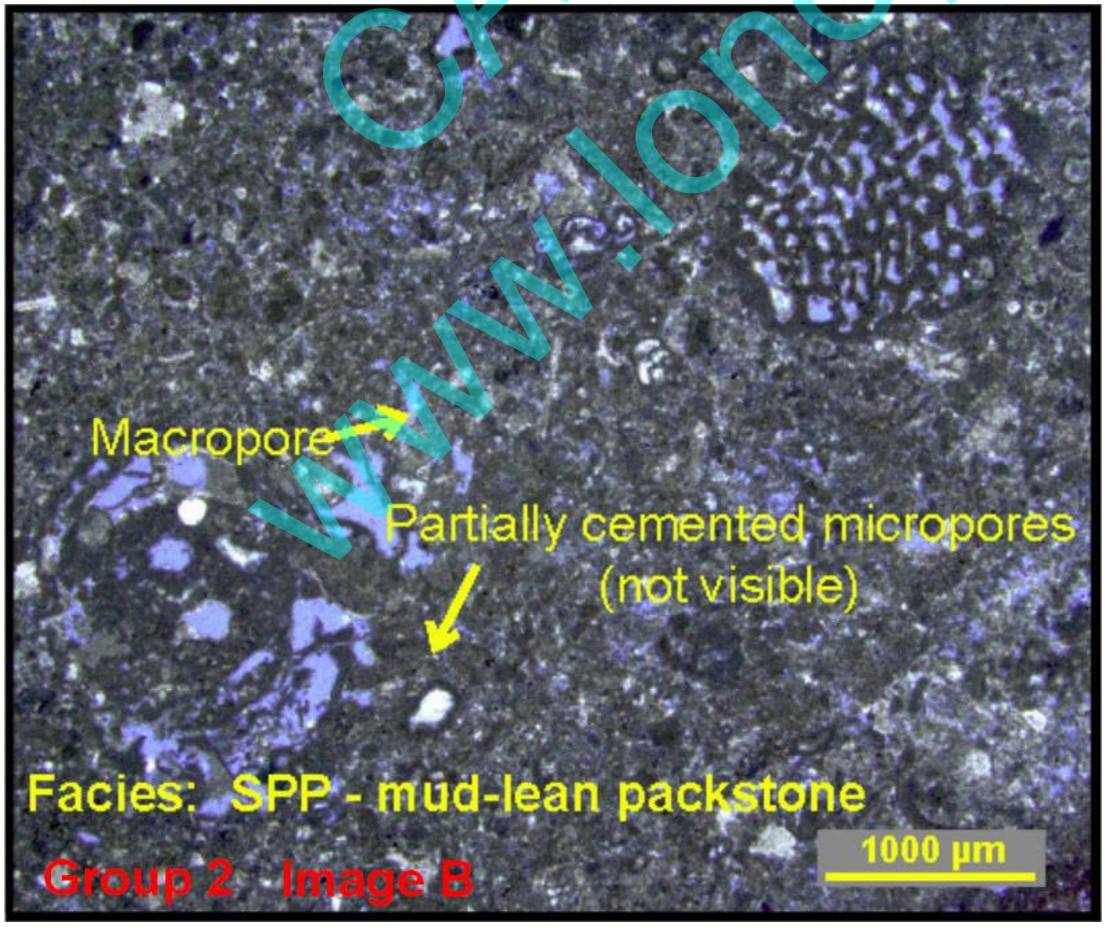
Poro-perm data from Group 1 are plotted along with CARP global poro-perm data for pore types 5 (image D) and 1.12 (image E). We see that Group 1 poro-perm data fit well with both pore types of the global data set.

Groups 2-3 (images B & C)

Pore types are 5 & 1.11 (interparticle micro uniform distr.). Either of them can be dominant (mostly pore type 1.11) or subordinate, depending on sample. Poro-perm data from Groups 2-3 are plotted along with CARP global poro-perm data for pore types 5 (image F) and 1.11 (image G). We see that Groups 2-3 poro-perm data fit well with both pore types of the global data set, but fits slightly better pore type 1.11.

This illustrates that defining a dominant AND a subordinate pore type may not be important if their reservoir properties are fairly similar. In this case, selecting either of them (or both) has insignificant effect on the predictions. There are, however, strong reasons why we don't want to combine these pore types in order to minimize the number of pore types. We will come back to that next week.





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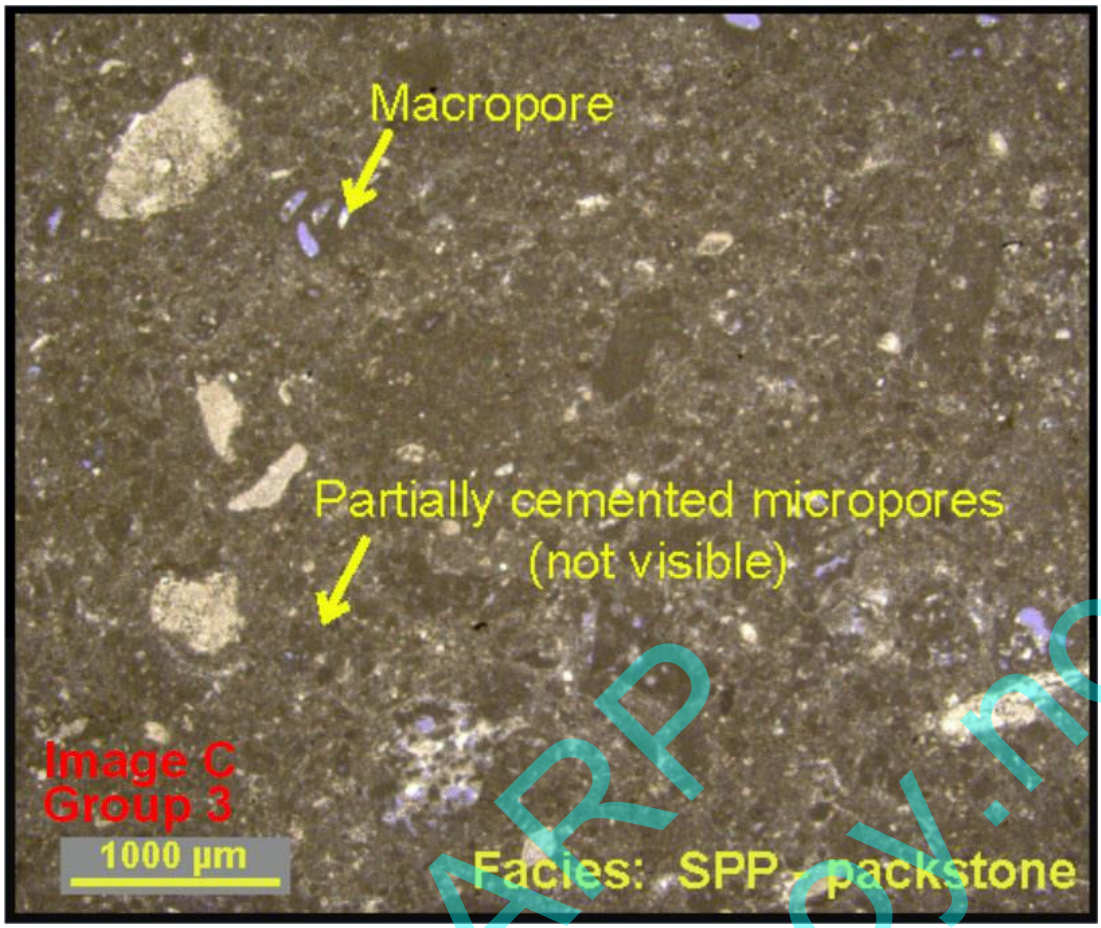

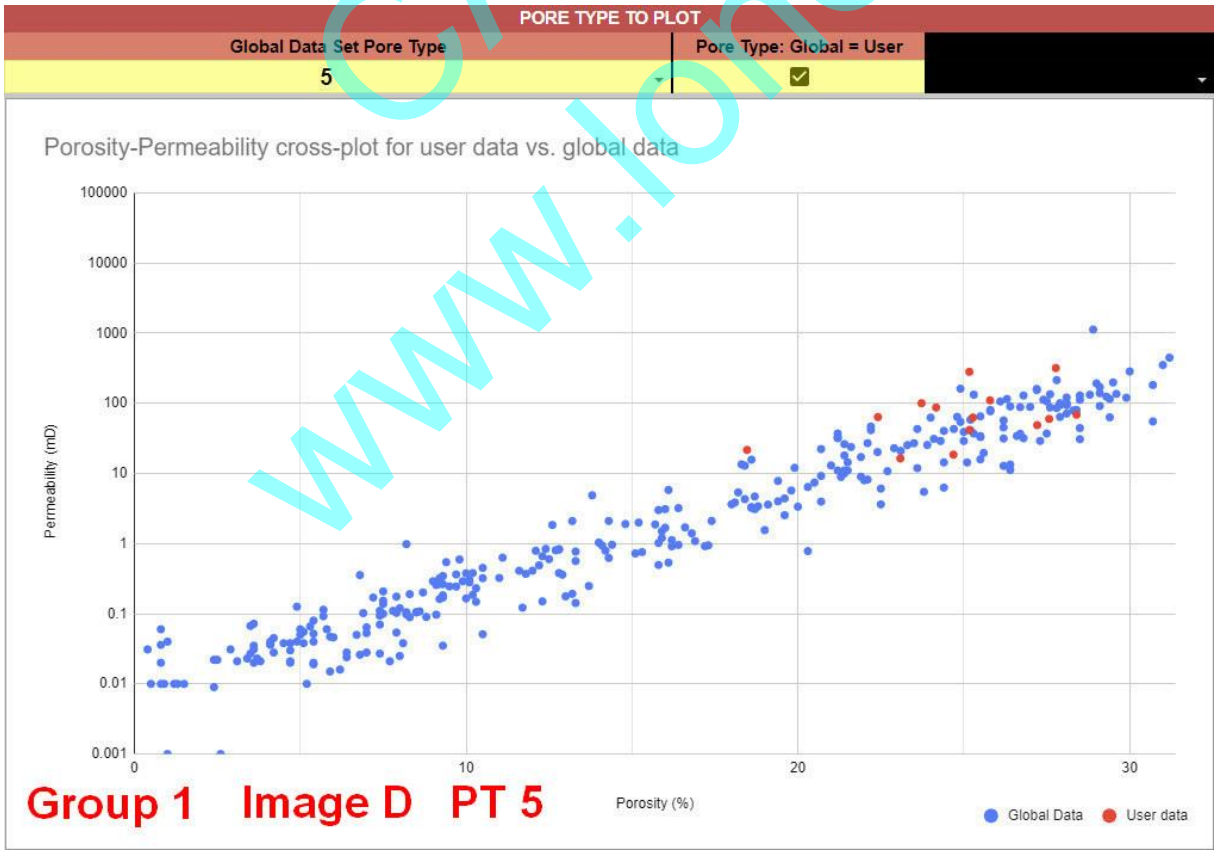

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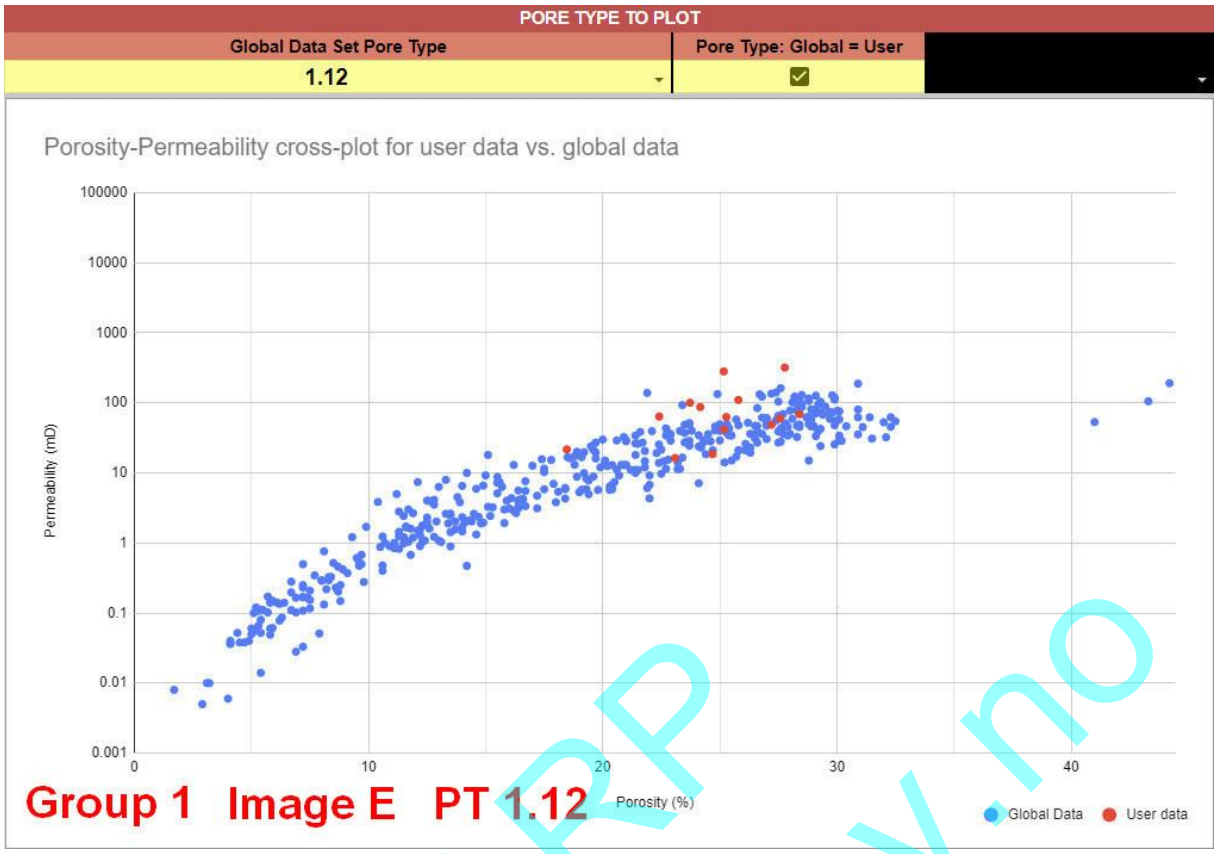

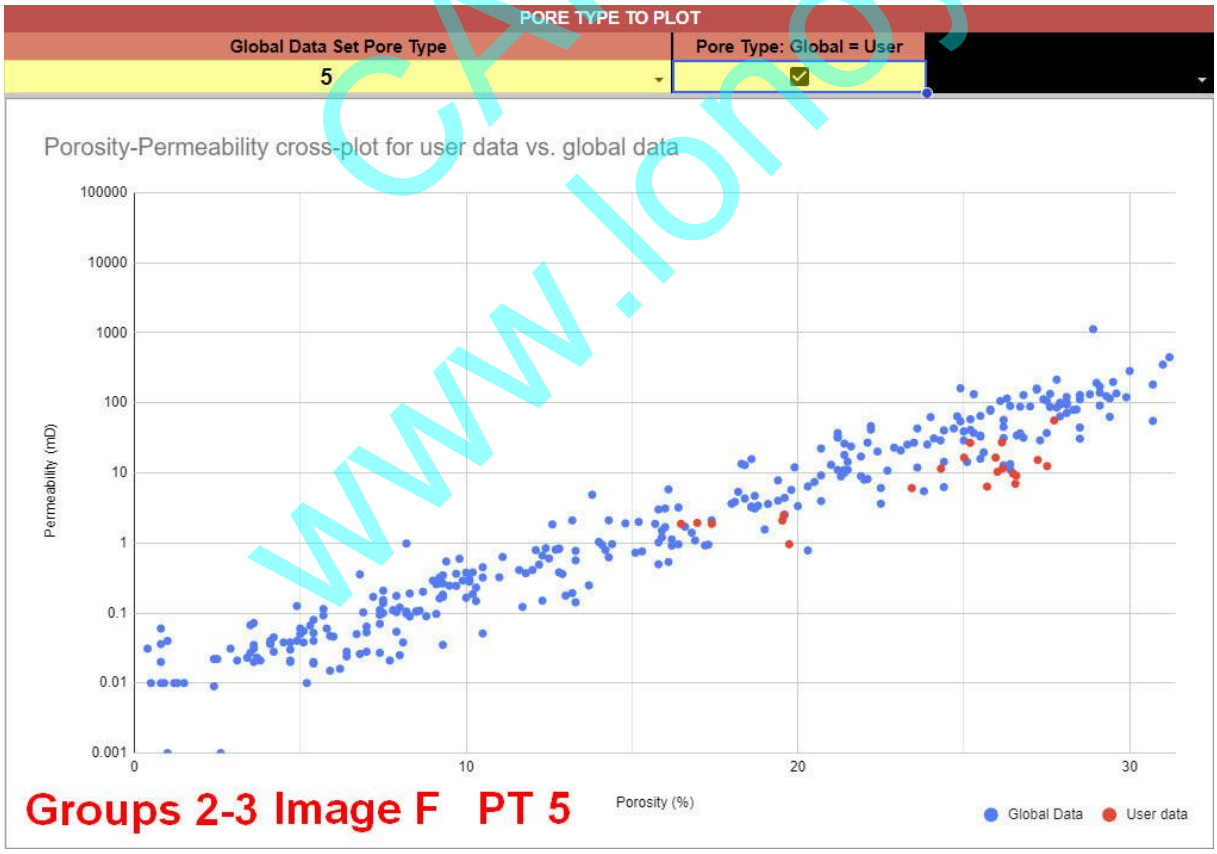

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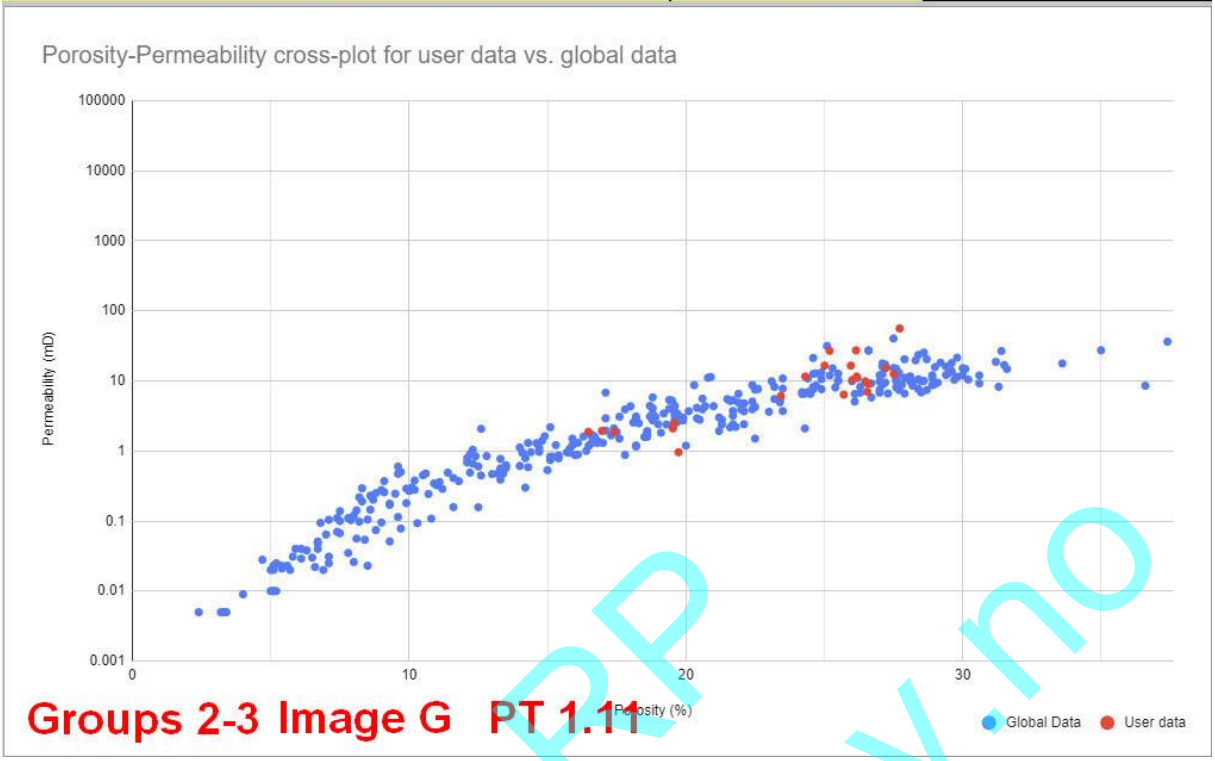
PORE TYPE TO PLOT		
Global Data Set Pore Type	Pore Type: Global = User	
1.11	☑	



Groups 2-3 Image G PT 1.11

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6.2.5 Deviations From Global Trendlines (Part 4) (post #21)

This post will be a follow up from weeks 11, 12 and 18 on why some data deviate from the global poro-perm trends.

There are many reasons why user data show a wider scatter in poro-perm data points, and these may be grouped into 2 categories: Features that are dependent or independent on plug orientation. This post will be on one of the features that are independent on orientation: Unrepresentative thin section.

There are two reasons why thin-section observations may not be representative for the poro-perm measured core plug: a) Heterogeneous core plug and/or b) Thin section staining technique.

a) For heterogeneous samples, what you see in the thin section may not be representative for the entire plug.

b) Standard porosity staining techniques of thin sections will often not stain microporosity, and the porosity is invisible. The dominant pore type may therefore be incorrectly defined from the observable porosity, and the poro-perm data will not follow the global trendline (wrong pore type is defined). There is an alternative technique that will stain microporosity.

If the measured porosity is significantly different to what is observed in the thin section, this may give an indication that the thin-section observation may be unrepresentative for the core plug. An experienced geologist will easily see this, but the porosity difference may also be quantified using image analysis.

The above discussion will be exemplified by samples from the Paleocene-Eocene Khurmala Fm. in Northern Iraq, kindly supplied by the Univ. of Olomouc in the Czech Republic. Thin-section micrographs for three of the supplied samples are shown in images A-C. They all show a silty limestone with small moldic pores (blue, pore type 3.13). However, measured poro-perm data (given on the images) deviate to some extent from the global trendline for pore type 3.13, as seen in image D (red data points are Khurmala samples). We also see that the thin-section porosities (given on images A-C; derived from image analysis), show significantly lower values than the measured values. This suggests that the thin-section observations are unrepresentative. If this is related to unstained microporosity, we would expect the dominant pore type to be chalky microporosity (pore type 6.03). In fact, the poro-perm data fit almost perfect to pore type 6.03, as seen in image E, suggesting that this pore type is dominant rather than the observed pore type 3.13.

It is recommended to always compare measured and visual thin-section porosity. If the difference is significant, the visual porosity in the thin section may not be representative and a wrong dominant pore type may be defined.

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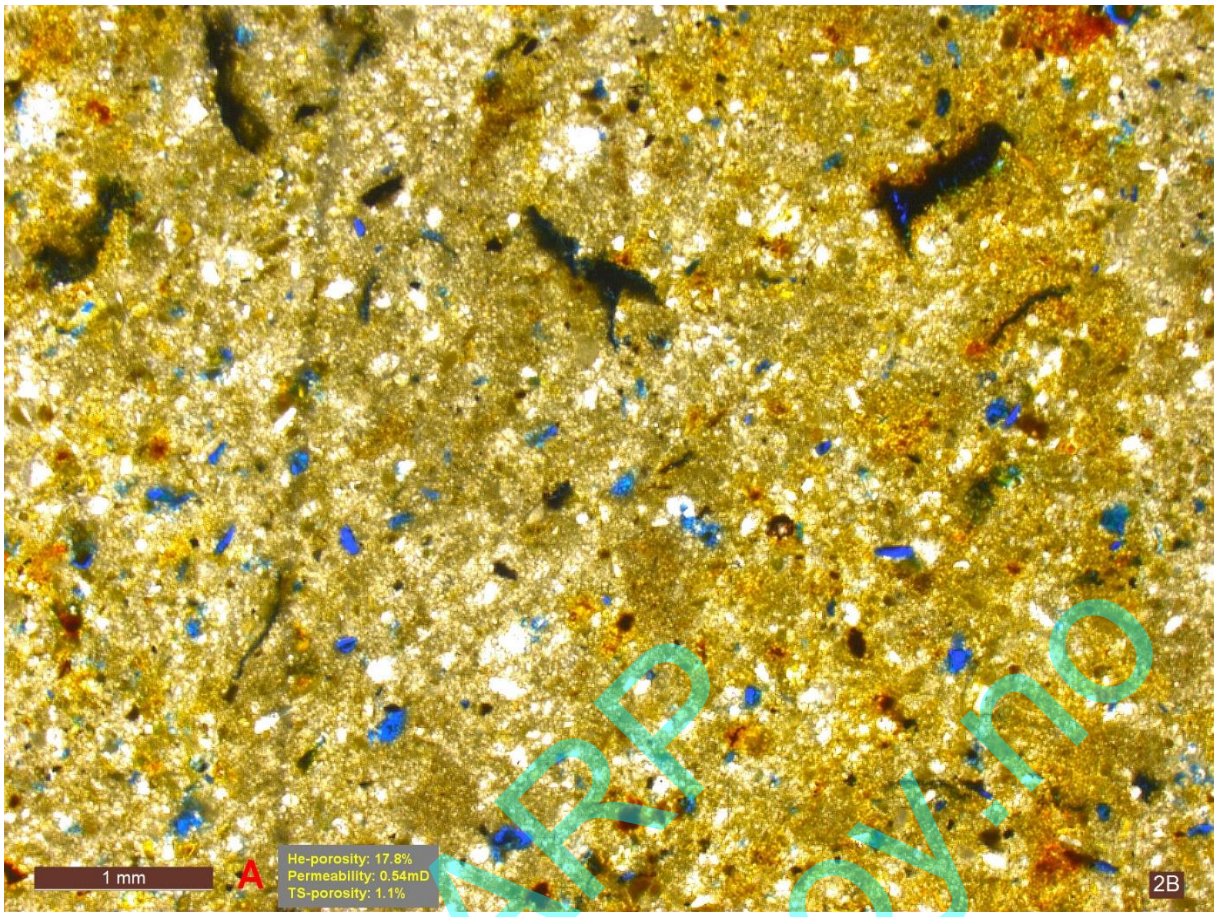

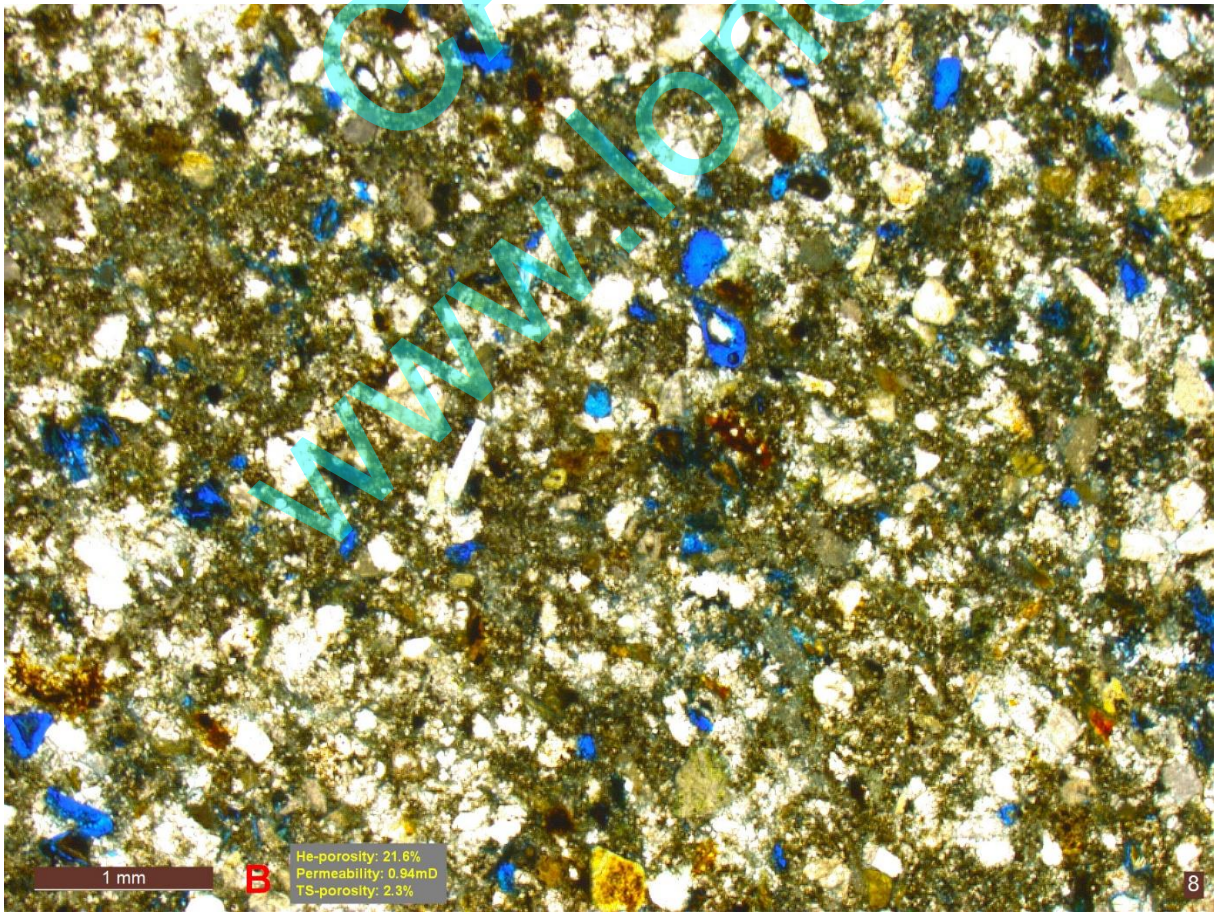

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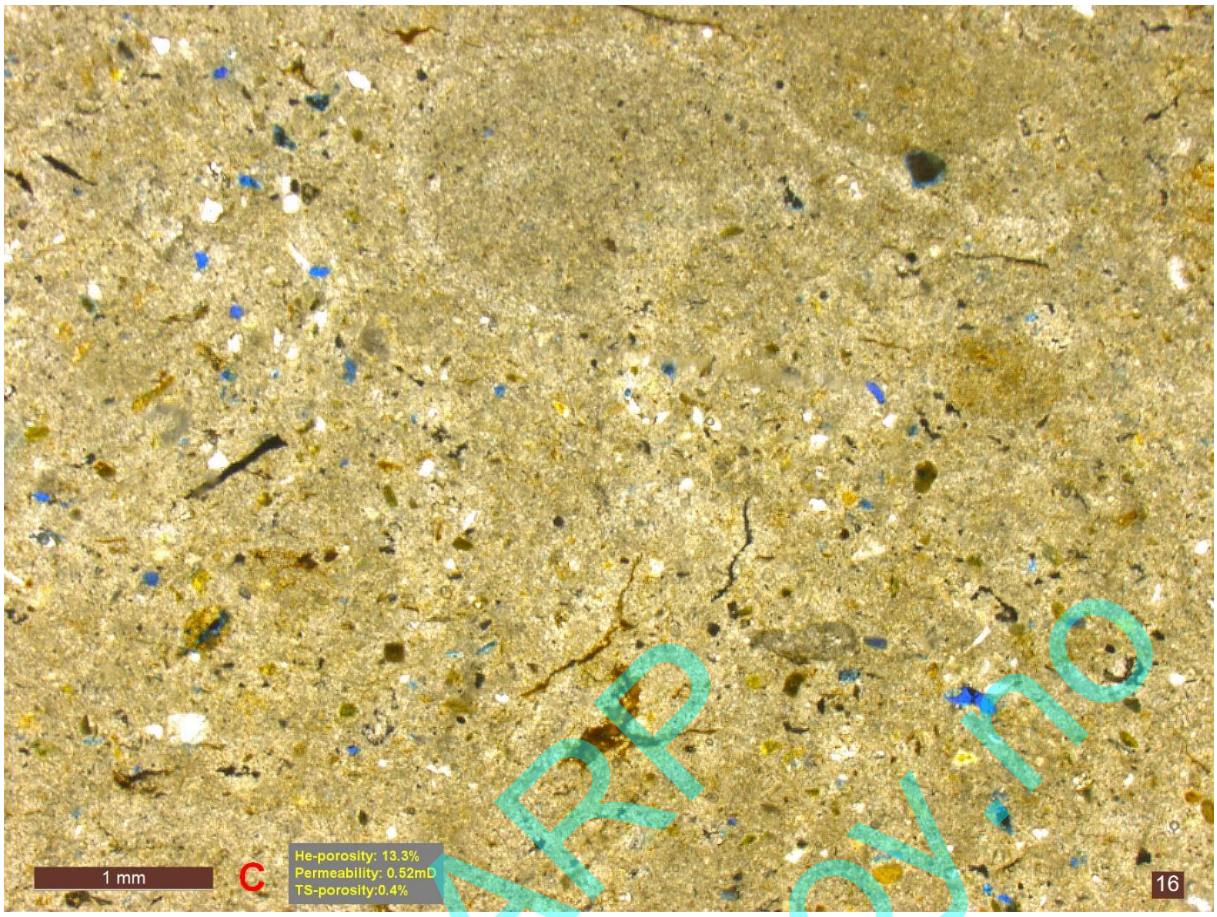

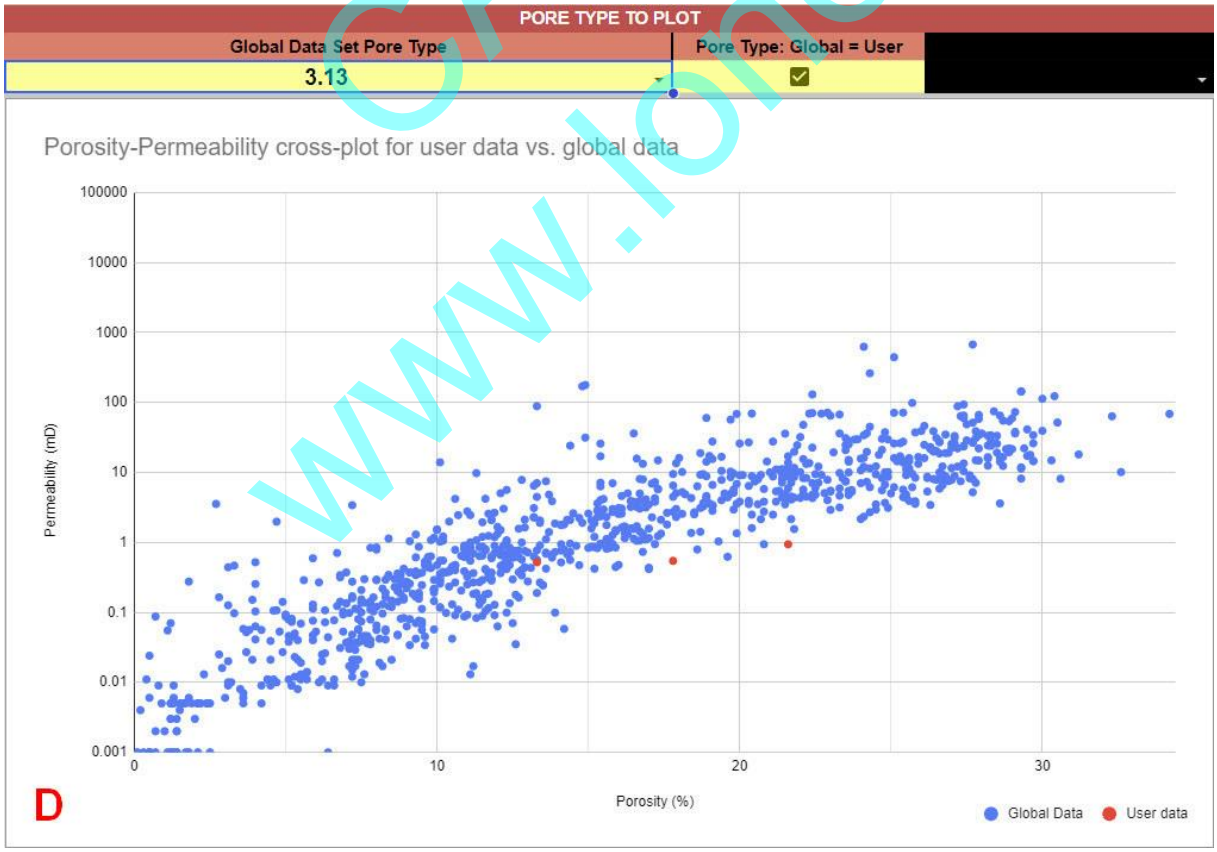

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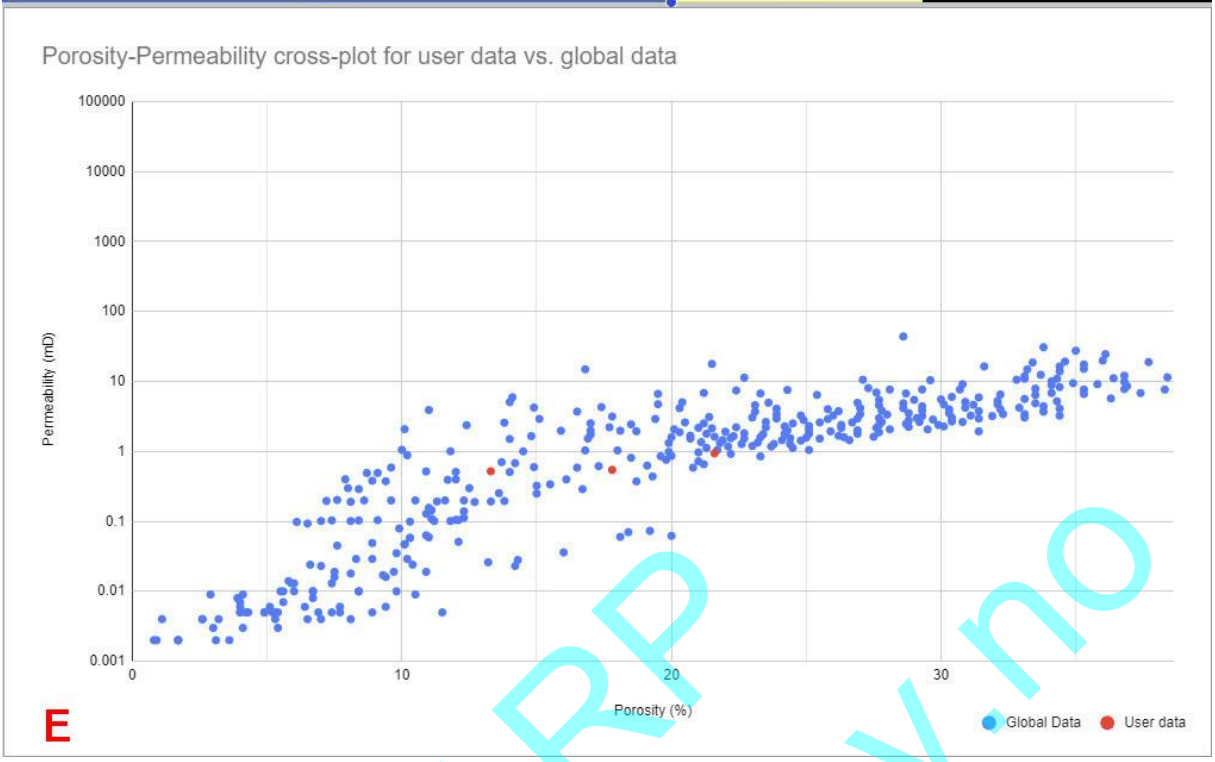
PORE TYPE TO PLOT		
Global Data Set Pore Type	Pore Type: Global = User	
6.03	☑	



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6.3 MICP Database (post #35)

The MICP database in CARP that forms the basis for the Lonoy methodology is presented in the linked YouTube video. The video also gives a summary of the methodology.

Video link: https://youtu.be/X3Sy-BpZ48k

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7 Prediction Tools

7.1 Permeability

7.1.1 Single (Dominant) Pore-Type Systems (post #13)

Permeability is an important parameter for understanding flow of water and hydrocarbons in the subsurface. When rock samples are unavailable for direct measurement, permeability is usually predicted from porosity-permeability cross-plots derived from core plugs. These cross-plots show excellent coefficient of determination when plots are made for individual pore types, and the trendline equations are applied in generating prediction tools. These equations can also go into reservoir models to predict permeability from facies and porosity distribution maps, and predictions can be made at grid cell resolution.

Several tools for predicting different reservoir parameters are available in CARP. This post will be on the permeability prediction tool for single pore-type systems (dominant pore type). The tool predicts permeability for different pore types based on porosity. Predicted permeabilities are given as expected and percentile values (P10 to P90 in 10% increments).

The prediction tool shows that the expected permeability may vary between 0.18mD and 2763mD at 20% porosity, depending on pore type. At 10% porosity, the expected permeability may vary between 0.01mD and 105mD.

The functionality of the tool is shown in the video.

Video link: https://youtu.be/KpSzD3v31yM

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7.1.2 Dual Pore-Type Systems (post #15)

Samples that have a mixture of several pore types may need a dual pore-system evaluation. The two most volumetrically important pore types are classified as dominant and subordinate. A subordinate pore type should only be defined when it constitutes at least 25% of the pore volume, and a dominant pore type usually constitutes more than 50% of the pore volume. Empirical data indicate that most of the reservoir quality information is achieved from the dominant and subordinate pore types, and that additional pore types are not required. Volumetric evaluations of pore types are carried out by visual estimates.

When the dominant and subordinate pore types have almost identical pore volumes, the most permeable pore type should be defined as the dominant and the least permeable should be defined as the subordinate.

The pore-volume percentages should only be taken as a guideline, as it is the pore connectivity that really matters. This requires an experienced geological evaluation of the sample. Occasionally a pore type may be classified as dominant even though it is not the volumetrically most important. This may be the case when a better quality (more permeable) pore type forms a continuous network through the sample, even though not being the volumetrically most important pore type. An extreme example of this is fractured plugs. Fractures may not be volumetrically important, but they may control the permeability.

Our experience is that most samples only need a dominant pore type. Less frequently, a subordinate pore type needs to be defined. In any case, using both a dominant and a subordinate pore type is difficult to implement into reservoir models. In cases where the dominant and the subordinate pore types have fairly similar flow properties (i.e. belong to the same pore-type group - I will come back to this in a later post), it doesn't make much difference whether the dominant or the subordinate pore type is applied in the model as they give almost the same result.

CARP has a tool that can predict the expected and percentile permeability of dual pore-type systems, as shown in the video.

Video link: https://youtu.be/DX4Cg6CNpiw

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7.1.3 Pore-Type Groups (post #19)

Currently there is a total of 21 pore types defined in CARP. This may seem a lot to include into a reservoir model. However, our experience is that there normally are only 6-8 common pore types present within a reservoir, and usually this can easily be incorporated into a static reservoir model. The pore types vary between reservoirs and are dependent on depositional setting and diagenesis.

Dynamic reservoir models can often not handle 6-8 pore types, and the geologist may be requested to reduce the number of pore types. In order to accomplish this, pore types with similar petrophysical properties have been grouped into four limestone and four dolomite classes (see below). A simpler pore-type grouping may also be preferred due to poor data quality.

Pore types give the highest prediction accuracy and is optimally integrated with sedimentology and diagenesis. The disadvantage of the pore-type grouping is that the connection to depositional setting and diagenetic processes is lost. Pore-type groups can thus not be applied in spatial prediction of reservoir properties.

The following recommendations are given:

- Apply pore types in static reservoir models, where only the most common pore types are incorporated. Rare pore types are included with pore types formed under similar depositional and diagenetic conditions, and/or with similar reservoir properties.
- If necessary, group pore types before application in a dynamic reservoir model.
- Repeat the process if the static model is updated.

By combining a pore-type based static model with a pore-group based dynamic model, it is possible to preserve most of the depositional/diagenetic control on reservoir performance. This makes it easier to understand and predict reservoir performance. In order to apply a dynamic model based on pore-type groups, prediction models for pore-type groups have to be developed. This is incorporated into CARP, and an example of permeability prediction for pore-type groups is shown in the video.

LIMESTONES

Group 10 - Pore types 1.113 & 2
Group 20 - Pore types 1.111, 1.112 & 1.13
Group 30 - Pore types 1.11, 1.12, 3.11, 3.13, 5 & 6.04
Group 40 - Pore types 3.14, 6.01, 6.02, & 6.03

DOLOMITES

Group 110 - Pore types 2 & 4.113
Group 120 - Pore types 4.112 & 4.13
Group 130 - Pore types 3.13, 4.111 & 4.12
Group 140 - Pore type 4.11

Reservoir performance decreases with increasing group number within each lithology.

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Video link: https://youtu.be/H_XmGp7uoQE

7.1.4 Sedimentary Facies (post #23)

Permeability prediction from sedimentary facies can be carried out in CARP based on the global poro-perm trendline curves for individual pore types. The CARP tool predicts dominant pore types and related permeabilities from sedimentary facies and porosity. Predictions can be carried out on pre-defined and/or user-defined facies and associated pore-type probabilities. Pre-defined facies and associated pore-type probabilities are based on a large global database showing the empirical relation between sedimentary facies, pore-type probability, porosity and permeability.

User-defined sedimentary facies control on pore-type distribution is based on local experience and can be entered into the prediction tool.

Dominant pore types for sedimentary facies are predicted from their respective global and/or local pore-type probabilities. E.g. a sedimentary facies with dominant pore-type probabilities of 20% (pore type 1.11), 30% (pore type 1.12) and 50% (pore type 1.13) will randomly predict one of these pore types according to their probabilities. Both expected and probability (P10 to P90 in 10% increments) permeabilities for each pore type are predicted.

Video link: https://youtu.be/5rUTH0iPDug

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7.1.5 Petrophysical Methods (post #25)

Most interactive permeability prediction tools in CARP are based on porosity-permeability relationships for different pore types and pore-type groups, i.e. the permeability prediction is based on sedimentology and diagenesis. This post #I will present a group of permeability tools that predicts permeability based on published petrophysical methods.

The methods included are Wyllie & Rose (both medium gravity oil and dry gas), Timur, Coates-Dumanoir and two NMR methods (SDR and Coates). The prediction methods are integrated into one single CARP tool and can handle both single and multi-data entries. For the latter, user data can be uploaded to the tool and the resultant predictions can be exported back to the user. The user data and the resultant predictions never leave the user's computer, thus preserving data confidentiality. A video link illustrating the tool is given below.

Petrophysical methods may be able to predict permeability in boreholes, at varying degree of accuracy. However, a borehole is just a pinhole penetrating the reservoir and is therefore only a minor contributor in reservoir modelling. Petrophysical methods are useful for calibrating sedimentologic/diagenetic models at well locations, but have limited use in inter-well predictions. In my opinion, all reservoir models should be based on geological modelling. A reservoir model based solely on petrophysical properties tend to be developed based on various forms of interpolation, and this can go really wrong.

I have tested many of the petrophysical permeability models, along with pore-type controlled prediction models, in blind test wells. The petrophysical models in general predict significantly poorer than the pore-type derived models. This also applies to NMR logs, which often are applied in permeability prediction. In fact, using an average pore type as input (i.e. a constant porosity/permeability relationship) performs significantly better than NMR-predicted permeabilities. I will come back to this in a later post.

Video link: https://youtu.be/qXsVwtv63Gg

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7.1.6 Permeability prediction – Summary (post #26)

Permeability is an important parameter for understanding flow of water and hydrocarbons in the subsurface. When rock samples are unavailable for direct measurement, permeability is usually predicted from porosity-permeability cross-plots derived from core plugs. These cross-plots show poor coefficient of determination unless plots are made for individual pore types.

The CARP interactive prediction tools predict matrix permeability for different pore types or pore-type groups based on porosity. Predicted permeabilities are given as expected and percentile values (P1O to P90 in 10% increments). The tools can handle both single and dual pore-type systems. Permeability can also be predicted from sedimentary facies based on empirical or expected pore-type probability within each facies, where pore types are assigned randomly according to pore-type probability.

The video shows a summary of the different CARP tools for predicting matrix permeability. All these tools have been presented in more detail in previous LinkedIn posts.

Video link: https://youtu.be/FEGVbXJ6Nvg

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7.2 Calibration of Wire-Line Log Porosities (post #16)

A tool has been developed by Lonoy Geoconsulting AS to calibrate petrophysical-derived porosities (PHI) in order to optimize permeability prediction. The tool is included in CARP, and a video illustrating the tool is presented below.

PHI represents the average porosity over a depth interval, which is determined by the reading interval of the wireline log tool. The averaging does not affect the overall pore volumes, but may have a severe effect on permeability prediction and flow properties.

Permeability is usually predicted from porosity-permeability transforms based on core plug measurements, and these represent spot measurements. Plug-derived He-porosities show a wider range than porosities derived from wire-line logs (PHI) because the spikes are lost in the PHI averaging process. In a He-porosity vs. PHI cross-plot, the He-porosity therefore often show higher values in the higher porosity ranges and lower values in the lower porosity ranges, as compared to PHI.

The use of average porosities (PHI) implies the prediction of average permeabilities, and interval averages are compared to spot-measured data. The flow properties in a reservoir is usually not controlled by an average permeability, but rather by laterally continuous high-permeable pathways represented by the high-porosity spikes. Uncalibrated PHI values therefore tend to underestimate permeability and flow properties in the best reservoir intervals and overestimate permeability across permeability barriers.

The PHIE calibration tool in CARP is a method for calibrating PHI to measured He-porosities so that the high-permeable pathways are better represented in the data set. Permeability prediction based on porosity-permeability transforms after PHI calibration is believed to better represent flow properties within the reservoir. Permeability predictions based on porosities derived from wire-line logs should therefore be carried out on the adjusted porosities, and using porosity-permeability transforms for core-plug data.

The calibration does not affect the average porosity within the data set, but may slightly affect the average porosity when applied to uncored intervals (effects on average porosity is calculated and presented in the tool). It is recommended to perform calibration before spatially populating porosities in the reservoir in order to better preserve the effects of permeability spikes.

Video link: https://youtu.be/f3H-lFNaTJA

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7.3 Porosity Cut-Off & N/G Prediction

7.3.1 Introduction (posts 29 & 36)

Porosity cut-offs are usually applied in net-to-gross (N/G) evaluations, where porosities below a specified value are defined as non-effective. Quite commonly, especially in exploration, one cut-off value is applied for the entire reservoir section. However, this is misleading because N/G is dependent on permeability rather than porosity. A fixed permeability cut-off, giving variable porosity cut-offs for different pore types, should thus be applied. Applying a fixed porosity cut-off, rather than a fixed permeability (variable porosity) cut-off can have significant impact on estimates of producible reserves. In a study of a producing Devonian carbonate field in Russia (Lonoy, 2006), the pore-type control on porosity cut-off resulted in a 370% increase in predicted reserves.

CARP includes several interactive tools for predicting porosity cut-off and associated N/G for different pore types or pore-type groups. Predictions are based on a user-defined permeability critical to flow. Predicted porosity cut-offs and N/G are given as expected and percentile values (P10 to P90 in 10% increments). The tools can handle both single (dominant) and dual (dominant & subordinate) pore type systems.

7.3.2 Single Pore-Type Systems (post #29)

This post is on the prediction of porosity cut-off and associated N/G for single pore-type systems. Porosity cut-off can be predicted for individual samples, whereas N/G requires multi-data entries. The prediction tool is presented in this video:

https://youtu.be/B2lX4lbAz9E

7.3.3 Dual Pore-Type Systems (post #36)

This post focuses on the prediction of porosity cut-off and associated N/G for dual pore-type systems. Porosity cut-off can be predicted for both individual samples and multi-data entries, whereas N/G requires multi-data entries. The prediction tool is presented in this video:

https://youtu.be/SKApPk5Kgdk

7.3.4 Pore-Type Groups (post #42)

This post focuses on the prediction of porosity cut-off and associated N/G for pore-type groups. Porosity cut-off can be predicted for both individual samples and multidata entries, whereas N/G requires multidata entries. The prediction tool is presented in this video:

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https://youtu.be/L-yzQcMHLhU

It is strongly recommended in a static reservoir model to apply pore types, as these are related to sedimentologic & diagenetic processes. Pore types can be populated based on facies maps and diagenetic principles. In some cases, however, a simpler petrophysical classification may be needed, either due to poor data quality or for easier application in dynamic reservoir models. In such cases, the 21 pore types are grouped into 8 pore-type groups (4 for limestones and 4 for dolomites), characterized by their petrophysical properties. Be aware that once pore-type groups are applied, the connection to sedimentary facies and diagenesis is lost, making it extremely difficult to make spatial predictions across the field. A static reservoir model should thus preferably be made based on pore types. If a reduction in number of parameters is required in the dynamic model, there are two options:

- Reduce the number of pore types by merging rarely occurring pore types with pore types from comparable depositional settings and petrophysical properties.

- Convert from pore types to pore-type groups before exporting the static model to a dynamic model. The pore-type based static model should always be preserved for later updates.

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7.4 Pore Type

7.4.1 Dominant Pore Type (post #20)

Dominant pore types are usually defined from thin-section studies. When thin sections or cores are unavailable, dominant pore types and pore-type groups can be predicted using various tools in CARP.

These include:

- Prediction from measured porosity and permeability (e.g. RCA studies)
- Prediction from sedimentologic and diagenetic models (based on global or local pore-type distributions)
- Prediction from wire-line logs using locally-derived ANN models

This post will be on CARP prediction of dominant pore types when porosity-permeability data are available and core material or thin sections are inaccessible. This may be the case when RCA are derived from external companies. The prediction uncertainty can be high and the tool should thus only be applied when no better solution exists. Furthermore, geological evaluation of the predictions should be carried out based on local experience.

The prediction uncertainty is particularly high when there is no or limited knowledge about the sedimentologic and diagenetic settings. However, when local geological experience can limit the number of pore types to a minimum, and associate these to specific sedimentologic/diagenetic facies, the prediction accuracy can be significantly improved.

Pore type is predicted from measured porosity and permeability by calculating the sample's deviation from empirical porosity-permeability trendlines for different pore types. The pore-type predictions are ranked, with the most likely pore type ranked as 1. Lithology scenarios can be selected and allow for less uncertainty in pore-type prediction by eliminating pore types that are unlikely to occur. E.g. if dolomites and/or chalk are known to be absent in the studied sequence, these can be automatically excluded from the predictions.

Pore-type predictions are based on matrix properties, and fracture-affected plugs should therefore be avoided. The multi-data version of the tool marks samples that are likely to be fractured.

A video illustrating the tool is given at: https://youtu.be/srRzxOIecco

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7.5 MICP Curves

7.5.1 Introduction (post #45)

CARP has two interactive prediction tools for MICP curves: MICP Global and MICP User.

7.5.2 MICP Global (post #45)

This tool, which is presented in the video linked to below, predicts MICP curves for different pore types using the Leverett, Thomeer and Lonoy averaging methods. The average of the curves is also presented.

All methods require pore type as input for comparison of results. The Leverett method additionally requires porosity and permeability as input, and the Thomeer method requires permeability and Hg capillary entry pressure. The Lonoy method only requires porosity.

The applied capillary entry pressure, permeability and porosity is derived from user input (measured data). Capillary entry pressure and permeability can also be predicted based on prediction tools in CARP.

User data (measured MICP curves) can be imported into the tool to visualize how well the different predicted MICP curves fit the measured data.

A video illustrating the tool is given at: https://youtu.be/3gWr-taJF90

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8 Techniques

8.1 Staining of Porosity (post #22)

CARP includes a section on different techniques applied in reservoir description and characterization. One of the techniques, which will be presented here, is staining of micro-porosity. This is a follow-up of last week's post.

Standard staining techniques for thin sections will often not stain micro-porosity because the permeability is too low. This porosity is essentially invisible, the dominant pore type may therefore be incorrectly defined, and the poro-perm may deviate from the global trendline curves. There is an alternative technique that will stain microporosity and make it visible. The technique is given in CARP.

The thin-section micrograph shown is from a sample that has been stained using this alternative technique. Chalky microporosity is seen as weak blue-stained areas. Individual pores are difficult to discern because the pore sizes are smaller than the thickness of the thin section. However, the staining clearly shows the presence and distribution of the micro-porosity.

If stained by traditional techniques, the micro-porosity of the sample would probably be invisible because the permeability is too low for epoxy to penetrate deep into the pores. The visible porosity would therefore be significantly lower than the measured porosity. A significant difference between measured and observed porosity could, as such, be indicative of abundant micro-porosity.

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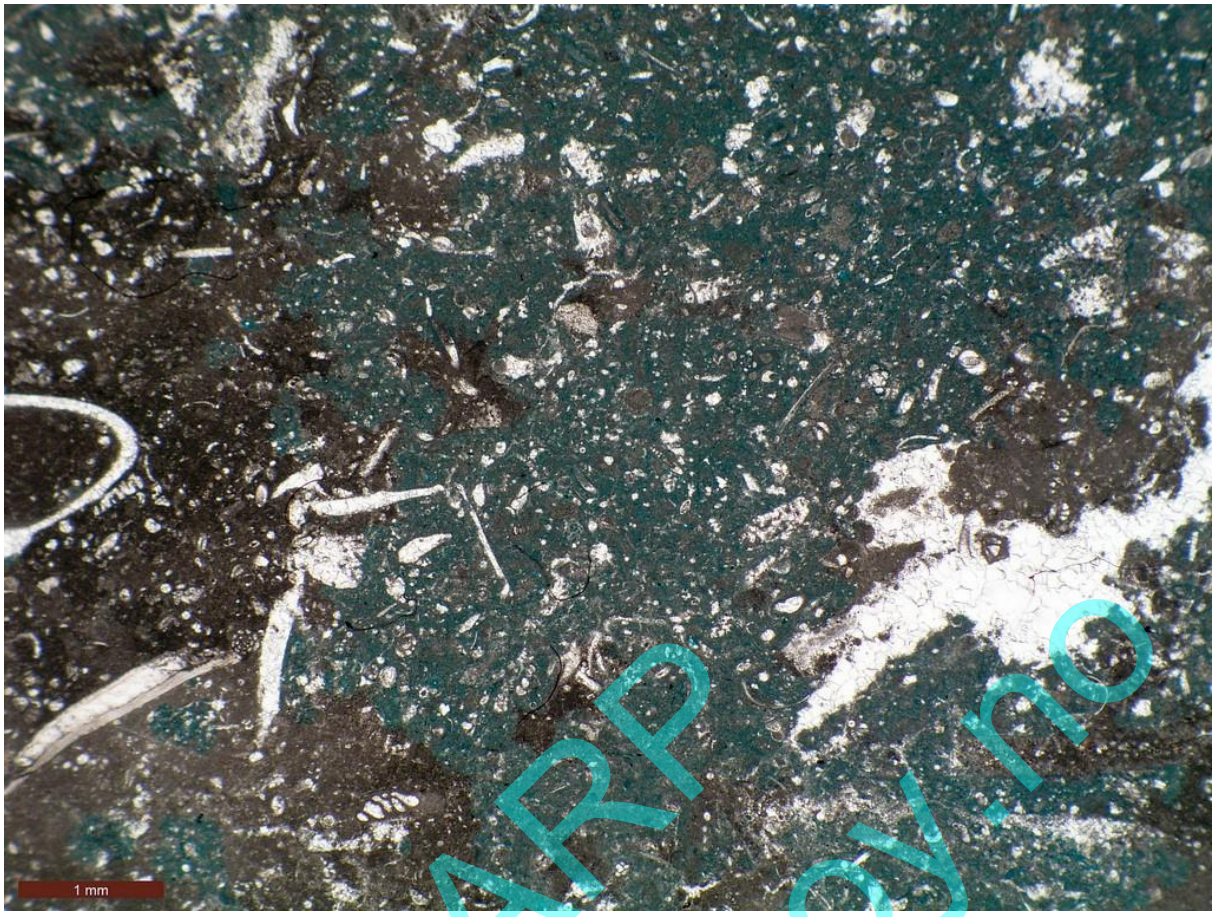

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8.2 Fluorescence Microscopy Applied to Core (posts 38 and 49)

8.2.1 Introduction

CARP includes a section on different techniques applied in reservoir description & characterization. One of the techniques is fluorescence microscopy applied to core.

Fluorescence occurs when ultraviolet (UV) light of a specific wavelength is directed to a thin section or core. The light excites electrons causing them to temporarily jump to a higher orbit in the atomic structure. Fluorescent light is emitted when electrons jump back to their original orbit.

Fluorescence images are often delivered as part of standard RCA studies. However, these images cover the whole length of the core and have poor resolution. More detailed images can be taken on thin sections using a microscope. The technique described below gives a microscopic resolution applied directly to core, without the need of a thin section.

8.2.2 New Technique

The technique applies a microscope which is the size of a lighter. This can be connected to a computer or cell phone. It can easily be applied in the field if connected to a cell phone. It is ideal to use on slabbed cores, but can also be applied to un-slabbed cores and cuttings, and can be hand-held or mounted either on a fixed stand or on a roller-stand for easy movement along the core at a fixed focal distance. Potentially the technique can be applied to cores at rig site. The microscope can easily switch between normal light and UV light, and data sampling is a very quick and non-destructive process. Photos give significantly improved resolution as compared to standard core photos. The camera also has a video function. It can zoom into small details, at a microscopic scale, but can also zoom out to cover larger areas (as seen in the enclosed images).

The technique has mainly been tested on carbonates, where it reveals details on core which otherwise would require thin sections. These include visualization of textures and grain components, mineral compositions and clast variations. In a test of a North Sea sandstone the technique was able to detect oil inclusions within quartz cement, without the need of a thin section.

8.2.3 Textures & Grain Components

Image A shows a core slab seen in normal light. No internal details can be observed. The same slab seen in UV light is shown in Image B. Details observed: Bryozoan fragments (red arrows), two generations of radiaxial marine dolomite cements (yellow & green arrows) and late diagenetic pale blue barite cement.

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Image A shows a core slab seen in normal light. No internal details can be observed. The same slab seen in UV light is shown in Image B.

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Image B is the same core slab as seen in image A, but seen in UV light.
Details observed: Bryozoan fragments (red arrows), 2 generations of radiaxial marine dolomite cements (yellow & green arrows) and late diagenetic pale blue barite cement.

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8.2.4 Mineral Compositions

Image A shows a small core slab seen in normal light. The same slab seen in UV light is shown in Image B. Details observed: Bryozoan fragments, 2 generations of radiaxial marine dolomite cements, late diagenetic cements of galena (red arrow), fluorite (yellow arrow) and barite (blue arrow).

Image C shows a small core slab seen in normal light. The same slab seen in UV light is shown in Image D. Late diagenetic cements observed are: saddle dolomite (strongly fluorescent pale blue) and ferroan calcite (weaker, dark blue fluorescence). Yellow fluorescence is dolomite (grains).

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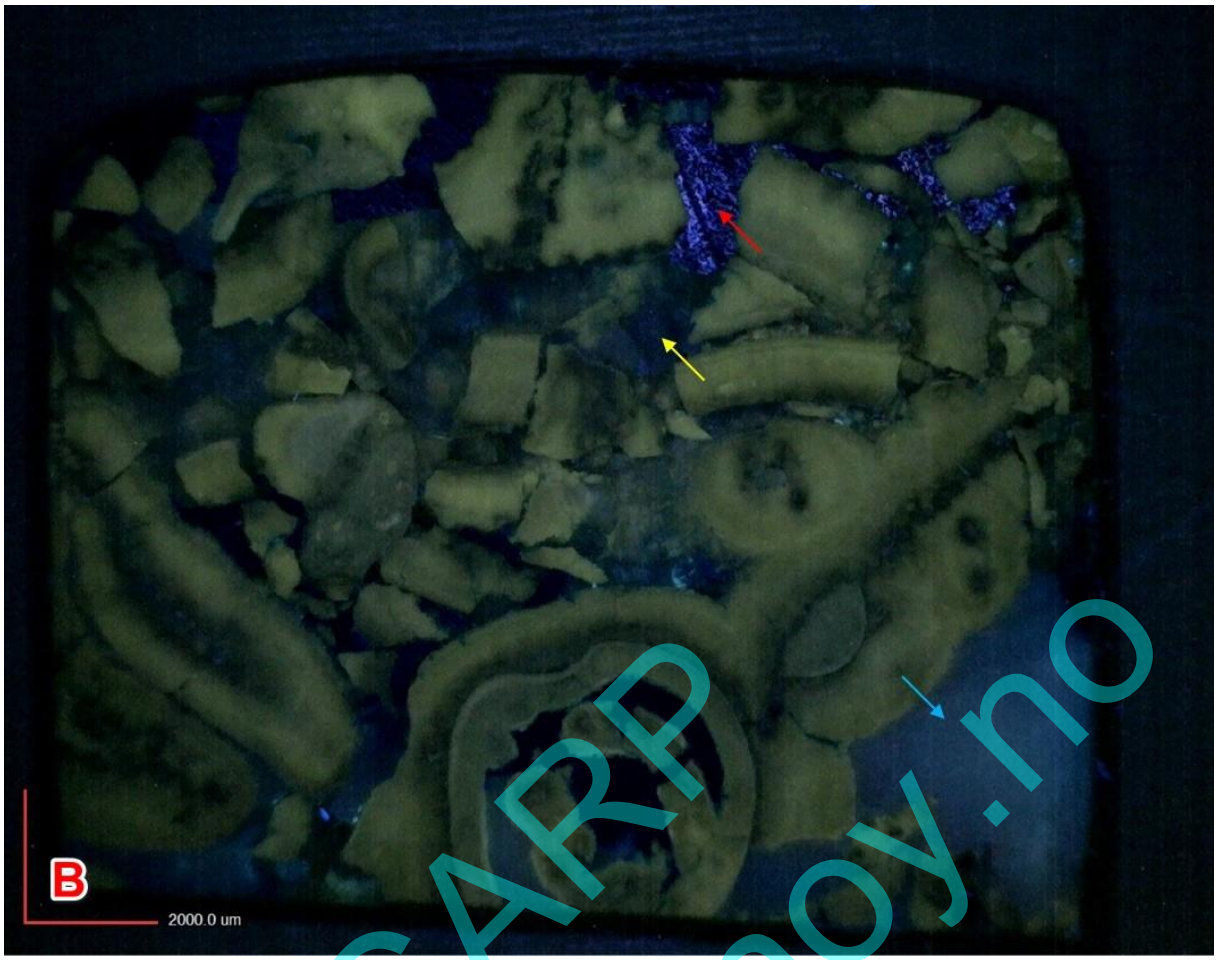

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9 Method Testing

9.1 Introduction (post #46)

CARP has a section where the reliability of different methods is tested. We test the accuracy or predictive properties of different methods applied to carbonates, based on measured values. In many cases we also investigate the pore-type control on the predictions, and how pore types potentially may improve prediction accuracy.

In some cases, the available samples are insufficient to come up with reliable conclusions, but the tests may give some insight on the controlling factors on predictions.

9.2 NMR (weeks 46 & 47)

9.2.1 Database and Methodology (posts 46 & 47)

NMR measurements were carried out on 100% brine-saturated carbonate core plugs. A total of 40 globally-derived plugs, representing 13 of the 21 pore types defined in CARP, were included in the study. Pore types were defined from thin sections made from the end-chip of the core plugs. All analyses were carried out at the same reputable laboratory.

9.2.2 NMR Porosity (post #46)

Measured He-porosities and laboratory-reported NMR porosities were applied in the study. He-porosities were compared to NMR porosities (both Tl and T2), and the comparisons were carried out for individual pore types as well as for the total database.

The images show plots of He-porosity versus NMR-T1 and NMR-T2 porosity for all samples. NMR porosities, both Tl and T2, show a close match to measured He-porosities. However, T2 shows a 2-5% porosity unit underestimation at porosities above 30%. There is insufficient number of samples to conclude if this is a general trend. There is no significant difference between the pore types, and the plots thus show all pore types combined.

The outlier on the T1-plot at ca. 24.5% He-porosity is not typical for its pore type, and the sample plots on the trendline for the T2-porosity.

Overall conclusion.
NMR porosities give, as expected, a very good representation of the measured He-porosities, regardless of pore type. This implies that NMR porosities are unaffected by pore size, pore-throat diameters and pore geometry.

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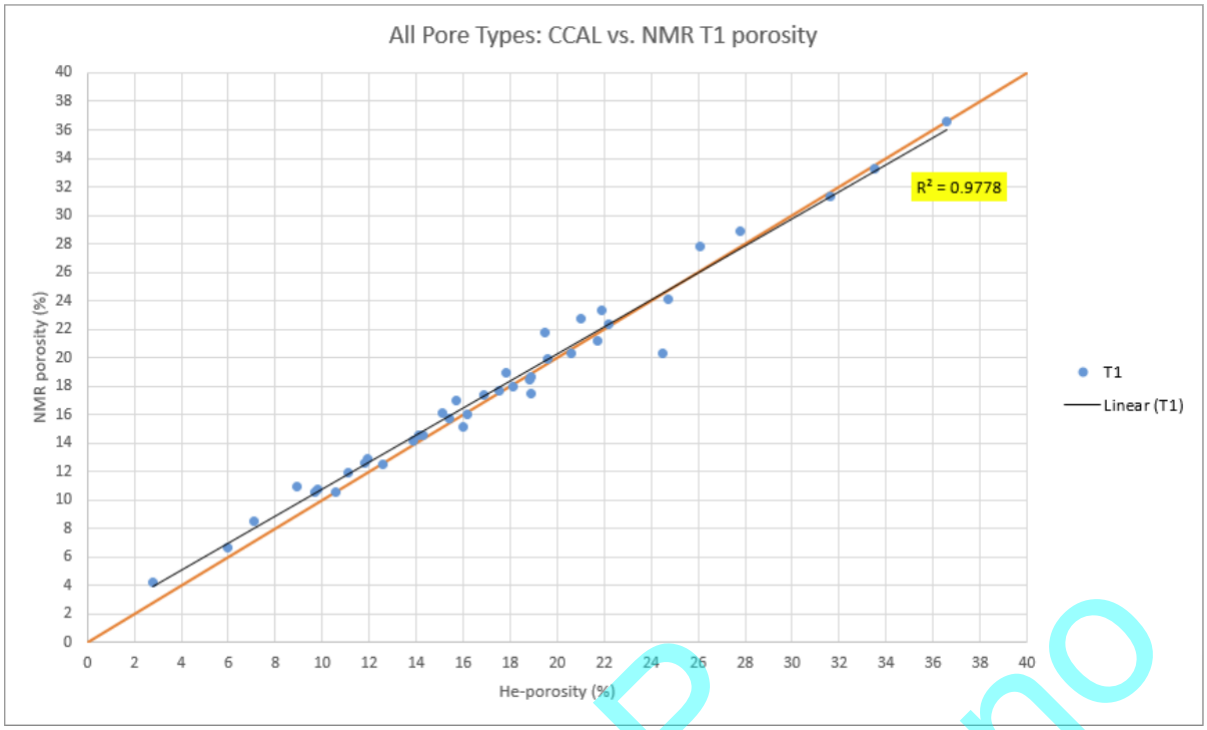

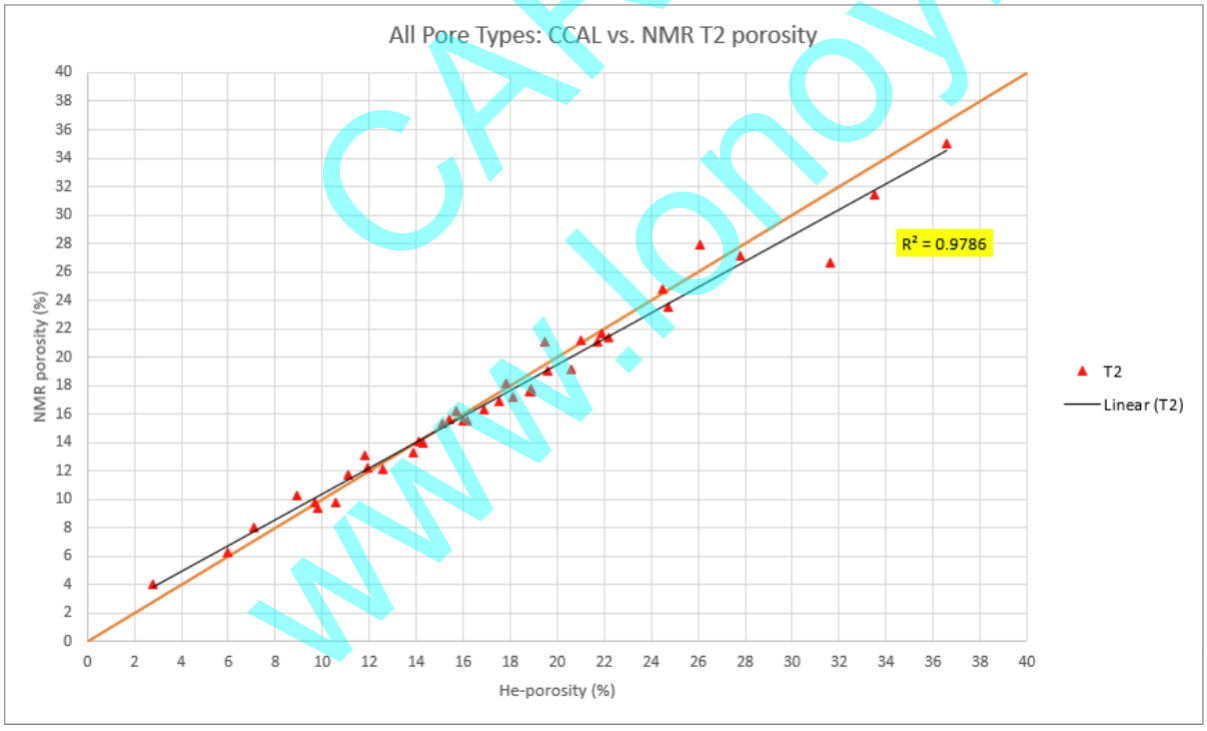

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9.2.3 NMR Permeability (post #47)

Plug-measured (CCAL), NMR-derived (Coates & T2ml) and CARP-derived (pore-type dependent) permeabilities were compared for individual pore types and for the total database. A standard Coates constant of 0.1 for carbonates was applied, as well as a variable, empirical, pore-type dependent constant. The pore-type dependent constants were derived by optimizing the permeability prediction for each pore type. In order to test the pore-type dependent CARP permeability in a situation where it is not possible to define pore types, the porosity-permeability transform of a global average pore type (pore type 1.112) was applied to all samples.

The NMR & CARP-derived permeabilities are compared to see how well the different methods perform relative to measured CCAL permeability. This is done by measuring the average absolute deviation (logarithmic values) between predicted (T2ml, Coates, CARP) and measured CCAL permeability. The deviations were calculated for individual pore types and for all pore types combined. The latter is shown in the figures.

Results (as compared to measured CCAL permeability).
The results are shown in figures A (Coates constant = 0.1) and B (pore-type dependent variable Coates constant) and can be summarized as follows:

- NMR permeabilities are in general significantly overestimated.
- Generally, Coates performs better than T2ml in limestones, and T2ml performs better in dolomites.
- Variable Coates constants, empirically optimized for each pore type, varies between 0.055-0.75 for the different pore types. This is significantly higher than the laboratory-standard of 0.1 usually applied in carbonates. Using a pore-type dependent, variable Coates constant significantly improves NMR permeability prediction, although the deviation is still high.
- CARP-derived permeabilities perform significantly better than NMR-derived permeabilities, even when applying a fixed, global average pore type.

Conclusion.
NMR-predicted permeabilities show extremely high deviations from plug-measured values, regardless of pore type. Global porosity-permeability trend lines for pore types show significantly better permeability prediction, even when a global average pore type trend line is applied. Based on these results NMR-derived permeabilities cannot be trusted in carbonates, and using a global average porosity-permeability trend line performs significantly better.

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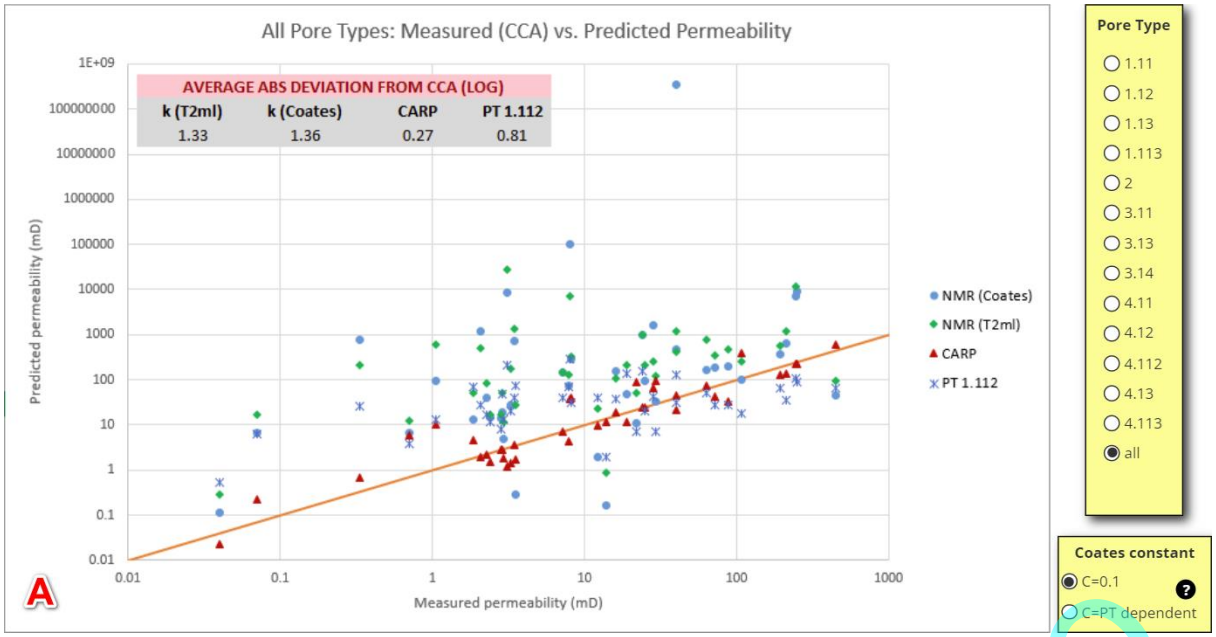

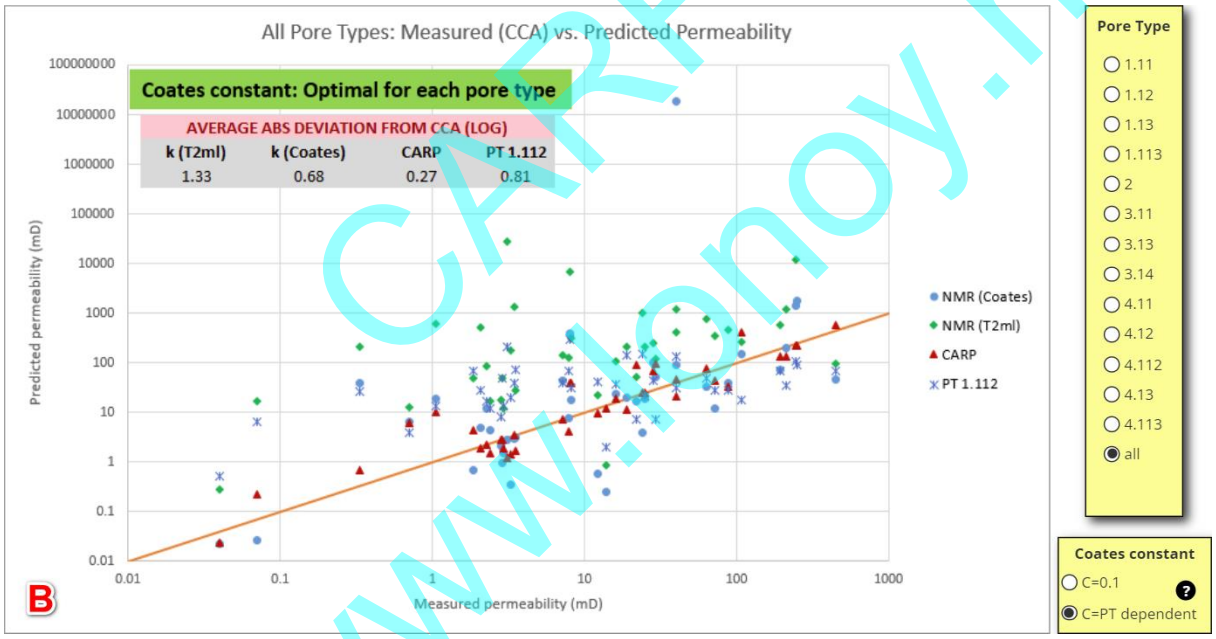

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9.2.4 Leverett J-function (post #48)

The Leverett J-function is applied to MICP data to optimize prediction of Sw. The function is strongly dependent on the permeability/porosity ratio. The principle of the J-function is that samples with similar pore type will have the same J(Sw) curve for different porosities and permeabilities. For a given pore type, the dimensionless J(Sw) curve removes discrepancies in the MICP curves by reducing them into a common curve, and the J-function defines the geometry of a pore type's MICP curve.

We will test the accuracy/reliability of the J-function by applying the function to a pore type with an excellent porosity/permeability transform. Pore type 1.11 will be applied as this pore type also is very common within siliciclastic sediments. The porosity-permeability cross-plot for pore type 1.11 is given in the figure.

Given the close relationship between porosity and permeability for pore type 1.11 (and other pore types), the permeability parameter in the J-function can be replaced by an equation involving only porosity. The resulting J(Sw) will represent the average for the pore type.

Based on the assumptions of the Leverett J-function, a pore type should have more or less the same J(Sw) value for a given saturation regardless of the porosity (remember that permeability is a function of the porosity). This is what we will test.

For each 5% porosity increment we have calculated J(Sw) at 10%, 50% and 90% saturation (100-Shg). The results are given in the table, showing that for a given saturation, J(Sw) decreases significantly with increased porosity. The assumption of the J-function thus fails.

The variable J(Sw) at fixed saturation (100-Shg) gives deviation in curve geometry between MICP and J(Sw). This can be resolved by performing a mathematical-based curve fit, although this is not a part of the Leverett J-function. Different pore types would require different curve fits, and an additional fit may be required for relating J(Sw) to Pc.

Overall, the Leverett J-function can be simplified by removing permeability as an input parameter, but will require pore-type controlled curve fits for each pore type. This resembles the Lonoy methodology, with the only difference being that the Lonoy method is completely based on empirically-derived equations.

Curve fitting should always be carried out as an average of multiple samples belonging to the same pore type, in which case the fit has global significance, as demonstrated by the Lonoy method. Curve fits based on individual samples has limited predictive properties.

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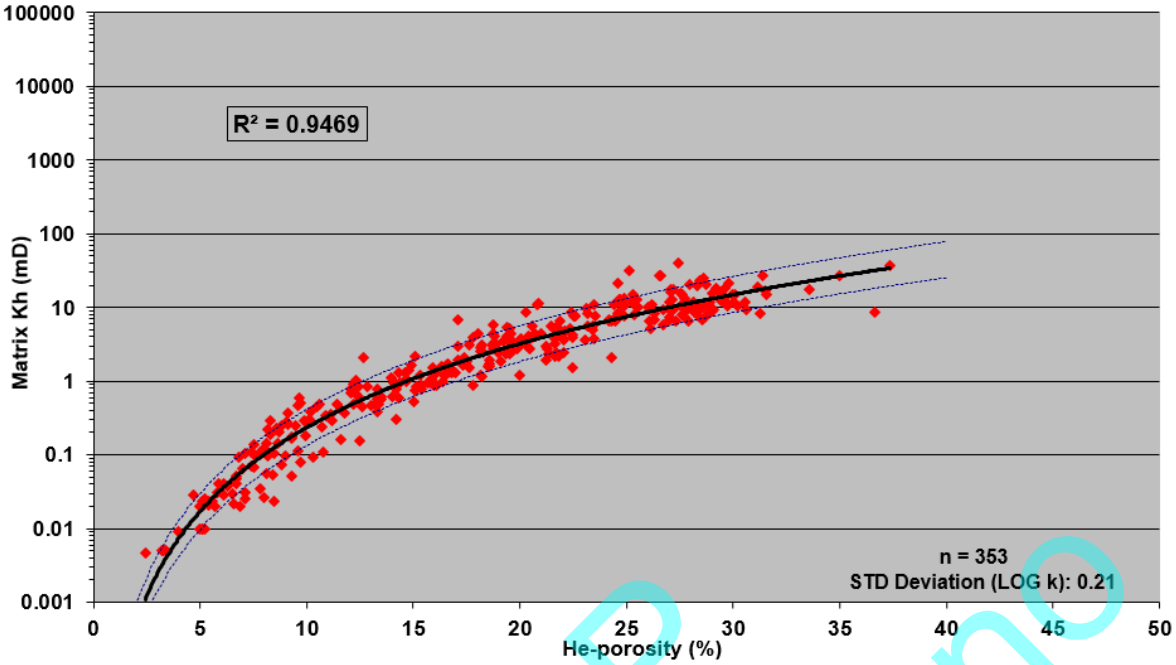
Pore Type 1.11: Interparticle Microporosity with uniform distribution



Porosity (%)	J(Sw) @ Water Saturation (100-Shg)		
	10 %	50 %	90 %
1	5.57	3.76	3.11
5	4.59	2.79	2.13
10	4.18	2.37	1.72
15	3.93	2.13	1.47
20	3.76	1.96	1.3
25	3.62	1.82	1.16
30	3.51	1.71	1.05
35	3.42	1.62	0.96
40	3.34	1.54	0.88

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10 Outcrop Studies

10.1 Introduction

Occasionally, I will present geological outcrop photos from various parts of the world. The photos have been taken during field trips I have attended, and the main focus will be on reservoir characterization.

10.2 Spitsbergen (post #54)

The post this week shows photos from Spitsbergen between mainland Norway and the North Pole (approximate location: 78°31'16.04" N; 17°25'58.50" E). Because of the arctic climate, there is hardly any vegetation, the exposed surfaces are relatively fresh, and the exposures are excellent. The only factors affecting the exposures are snow (best time to visit is July) and scree-covered intervals.

The exposures sometimes give a first impression on reservoir quality. Well-exposed, steep surfaces are often indicative of low porosity, whereas more gentle, scree-covered slopes occasionally may be underlain by rocks of better reservoir quality. Not all scree-covered intervals have good reservoir quality, though, especially not those occurring at the base of steep cliffs, and scree-covered intervals may represent contrasting lithologies. However, if good reservoir-quality rocks are present, my experience is that they are more likely to occur below scree-covered intervals. Outcrop studies are thus often biased towards low-porosity intervals. If possible, the scree-covered intervals should be followed laterally in an attempt to reveal their potential good reservoir quality.

The images show different parts of the Upper Carboniferous to Lower Permian sequence in central Spitsbergen. Image A shows an Asselian-Sakmarian carbonate sequence of variable reservoir quality, reflected by variable exposure. The best reservoir qualities are usually associated with intervals of poor exposure.

Image B is a close-up of the Asselian-Sakmarian sequence from a nearby locality.

Image C shows a well-exposed Moscovian sequence to the east (right) of the glacier seen in image A. Apparently there is a fault below the glacier with the eastern part being uplifted. The steep, well-exposed surface reflects the poor reservoir quality. Lateral facies changes are often associated with a significant improvement in reservoir quality, giving gentler slopes and poorer exposures.

Image D shows a well-exposed Artinskian sequence from the same area (slightly further south). The steep, well-exposed outcrops coincide with very poor reservoir quality.

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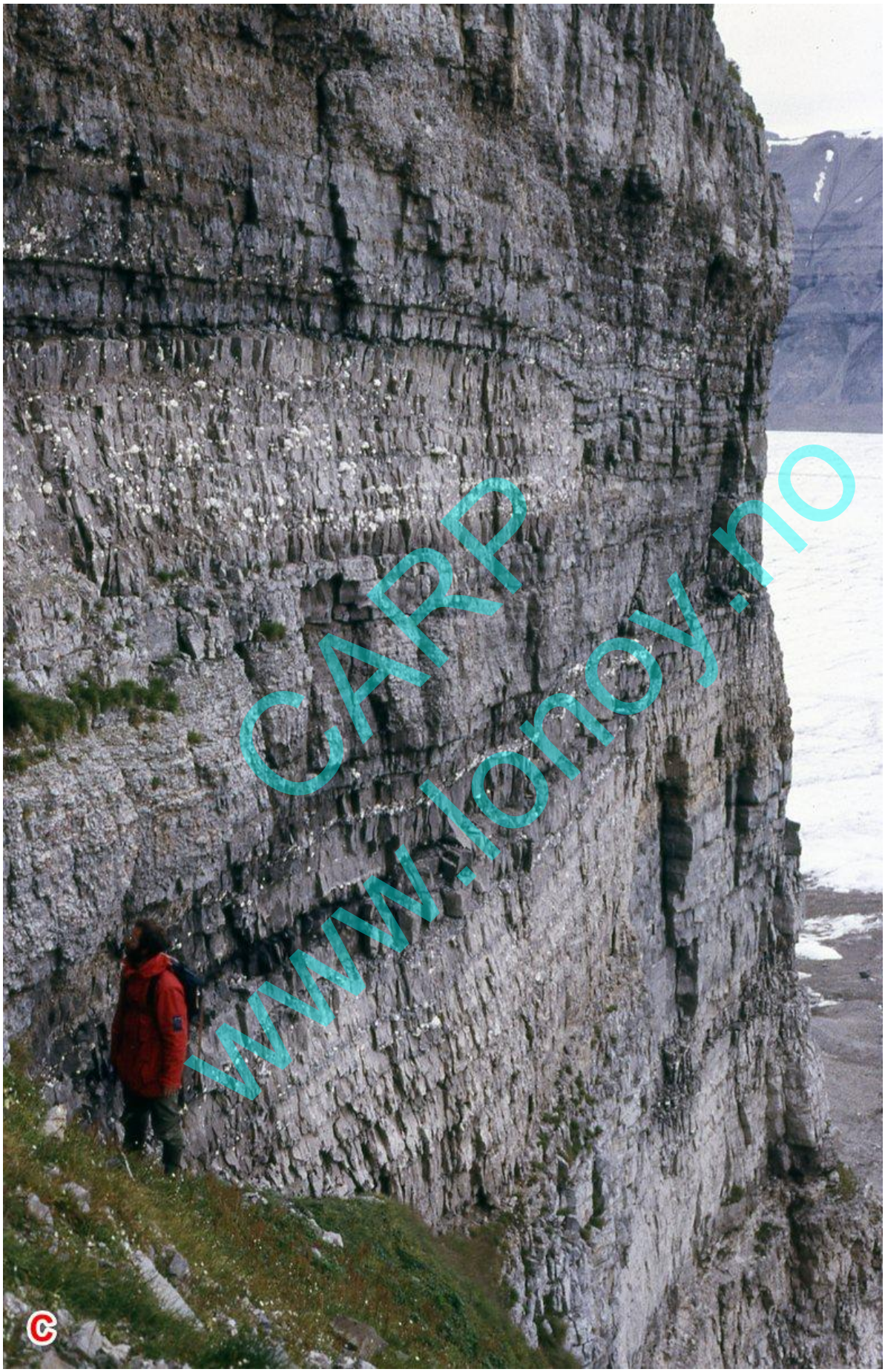

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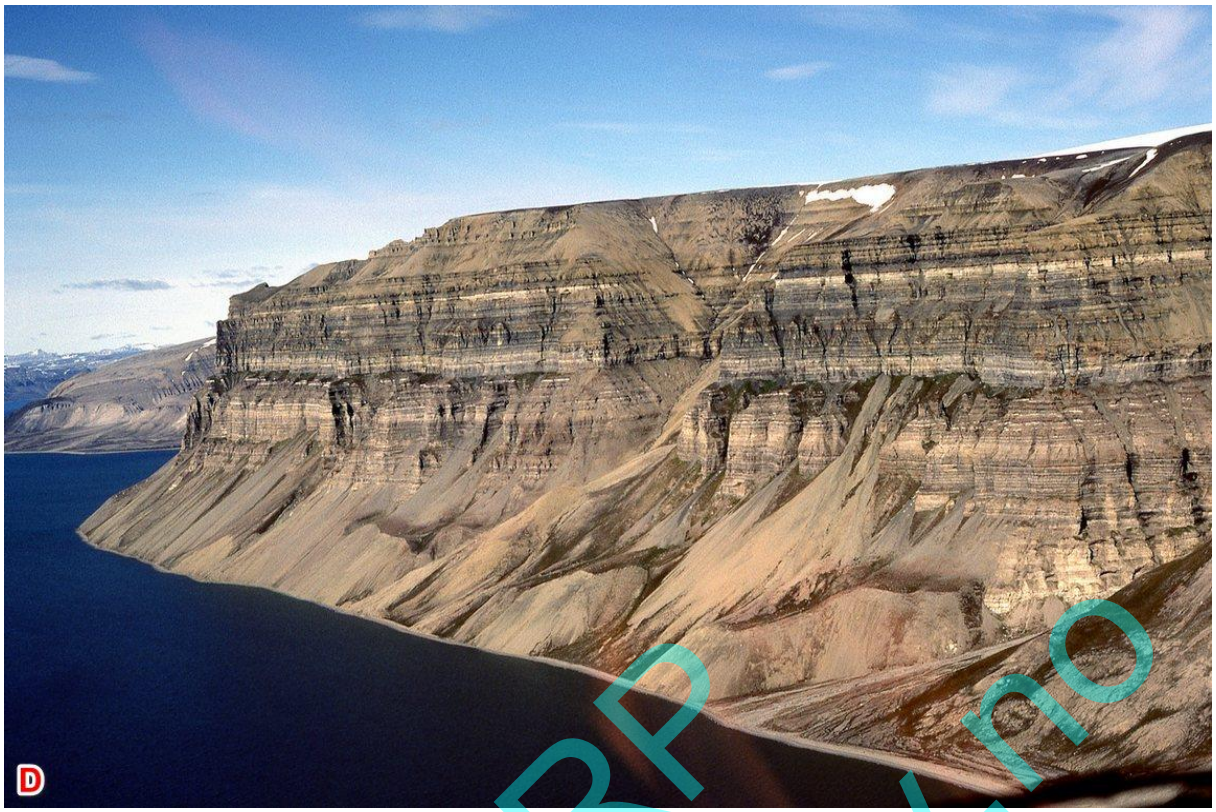

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11 Summer Break (post #24)

CARP weekly info will take a summer break until mid/late August, and Part 23 will be the last posting before the break. We promise to be back with postings on reservoir characterization of carbonates covering a wide range of parameters, including:

- Overview, description and examples of different pore types.
- Additional permeability prediction tools.
- Porosity cut-off and net/gross prediction tools.
- Fracture porosity and permeability prediction tools.
- Prediction of pore types.
- Prediction of effective porosity.
- Prediction of subordinate mineral composition.
- Synthetic wire-line log curves.
- Prediction of MICP curves based on a new methodology developed by Lonoy Geoconsulting, and which only requires porosity and pore type as input.
- Prediction of capillary entry pressures.
- Tool for optimization and prediction of core-to-log depth shifts.
- Prediction of water saturation and Swirr.
- Prediction tools for water resistivity.
- Tools for predicting height of HC contacts above FWL.
- Tools for predicting total organic carbon.
- Tools for predicting shale volume.
- A new method for defining flow zone units based on thin-section micrographs.
- Different reservoir quality tools.
- Prediction tools for different reservoir parameters at confining pressures.
- Different tools for predicting micro-porosity.
- Tools for predicting cementation exponent and formation resistivity factor.
- Acoustic velocities for different pore types.
- Reliability testing of NMR permeabilities.
- Testing of Winland method.
- Additional techniques applied in reservoir characterization.
- Calculation of cm-scale partial STOOIPs, based on pore types, which add up to total STOOIP.

....and much more.

The thin-section micrograph shows how pore-type geometries can reveal information on depositional settings and precursor mineralogy. The blue-stained moldic pores (pore type 3.13) occur within a finely crystalline dolomitic matrix and are the result of dissolved gypsum crystals. This is clearly shown by the discoidal pore geometries, some of which form swallow-tail twins (arrows). This signifies early-diagenetic precipitation of gypsum in a saline depositional setting, probably in a restricted or semi-restricted lagoon. The white in the lower left is chert.

I wish you all a great summer holiday and see you back in late August.

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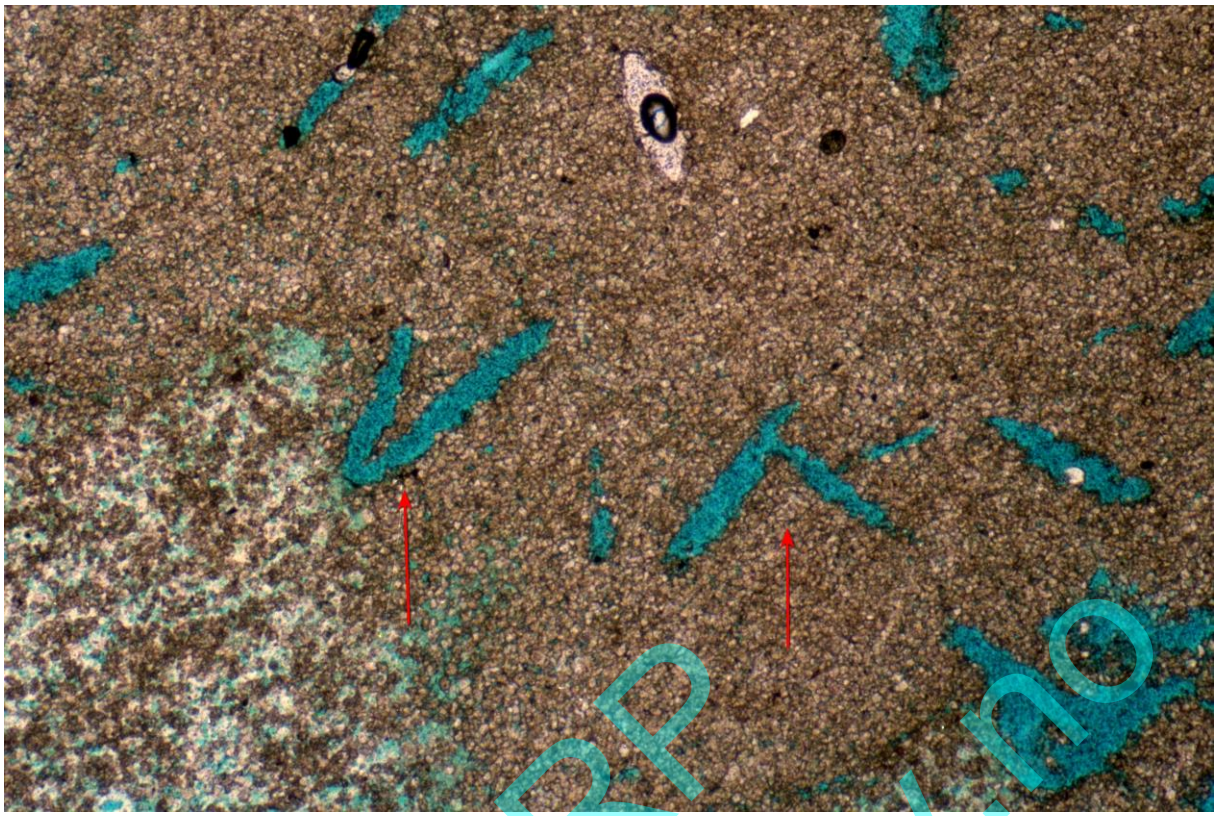

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