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1 **Petrophysical properties of greensand as predicted from NMR measurements**

2

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17

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23 **Abstract**

24

25 Nuclear magnetic resonance (NMR) is a useful tool in reservoir evaluation. The objective
26 of this study is to predict petrophysical properties from NMR T_2 distributions. A series of
27 laboratory experiments including core analysis, capillary pressure measurements, NMR
28 T_2 measurements and image analysis were done on sixteen greensand samples from two
29 formations in the Nini field of the North Sea. Hermod Formation is weakly cemented,
30 whereas Ty Formation is characterized by microcrystalline quartz cement. The surface
31 area measured by BET method and the NMR derived surface relaxivity are associated
32 with the micro-porous glauconite grains. The effective specific surface area as calculated
33 from Kozeny's equation and as derived from petrographic image analysis of
34 Backscattered Electron Micrograph's (BSE), as well as the estimated effective surface
35 relaxivity is associated with macro-pores. Permeability may be predicted from NMR by
36 using Kozeny's equation when surface relaxivity is known. Capillary pressure drainage
37 curves may be predicted from NMR T_2 distribution when pore size distribution within a
38 sample is homogeneous.

39

40 **Keywords:** Greensand, glauconite, porosity, permeability, capillary pressure, NMR

41 Greensands are glauconite bearing sandstones composed of a mixture of stiff clastic
42 quartz grains and soft glauconite grains. Glauconite grains are porous and composed of
43 aggregates of iron-bearing smectitic or illitic clay. Porosity is thus found at two scales:
44 macro-porosity between grains and micro-porosity within grains (Fig. 1). Greensand
45 petroleum reservoirs occur world-wide, e.g. the mid-Cretaceous Safaniya Sandstone
46 Member in Saudi Arabia (Cagatay *et al.* 1996), the Cretaceous Mardi Greensand in
47 Australia (Hocking *et al.* 1988), the Lower Cretaceous Glauconitic sandstone in Alberta,
48 Canada (Tilley & Longstaffe 1984), the Upper Cretaceous Shannon sandstone in
49 Wyoming, USA (Ranganathan & Tye 1986), a lower Cretaceous Greensand offshore
50 Ireland (Winn 1994) and a late Paleocene Greensand in central part of the North Sea
51 (Slot-Petersen *et al.* 1998). However, evaluation of greensand reservoirs has challenged
52 geologists, engineers and petrophysicsts. Glauconite has an effect on porosity,
53 permeability and elastic properties of reservoir rocks (Diaz *et al.* 2003). Glauconite is
54 also ductile (Ranganathan & Tye 1986) so it can cause non-elastic deformation of
55 greensand (Hossain *et al.* 2009) and affect the reservoir quality. Greensands generally
56 show low resistivity in the reservoir zone due to the large amount of bound water in the
57 glauconite, yet free hydrocarbons can be produced because glauconite rather than being
58 pore-filling is part of the sand grain framework (Slot-Petersen *et al.* 1998). Core analysis
59 of greensand thus shows a poor relationship between porosity and permeability.
60 Furthermore, greensand paramagnetic glauconite or pore filling berthierine may induce
61 magnetic gradients on the pore level causing the NMR T_2 relaxation time to be shortened
62 dramatically (Rueslåtten *et al.* 1998).

63 Nuclear Magnetic Resonance (NMR) is a non-invasive technique, and NMR
 64 measurements on reservoir core samples are done to obtain an improved interpretation of
 65 logging data. NMR measures the net magnetization of a hydrogen atom (^1H) in the
 66 presence of an external magnetic field. Hydrogen has a relatively large magnetic moment
 67 and is abundant in both water and hydrocarbons in the pore space of a sedimentary rock.
 68 NMR spectrometry involves a series of manipulations of the hydrogen protons found in
 69 fluids. A measurement sequence starts with proton alignment to a magnetic field followed
 70 by spin tipping, and decay. The quantities measured include signal amplitude which is
 71 proportional to the number of hydrogen nuclei and decay, also called relaxation time
 72 (Kenyon *et al.* 1995). Longitudinal relaxation time (T_1) measures the decay of spin
 73 alignment; transverse relaxation time (T_2) measures the decay of precession. Although T_1
 74 measurements are more common in the literature, they are more time consuming than T_2
 75 measurements. Hence, pulsed NMR logging tools preferentially measure T_2 for faster
 76 logging speeds (Straley *et al.* 1997). NMR transverse relaxation (T_2) of fluids confined in
 77 a porous rock is affected by pore surface, by the bulk relaxation process in the fluid and
 78 additionally by dephasing in case of molecular diffusion. T_2 may be expressed by the
 79 fundamental equation governing the NMR relaxation spectrum (Coates *et al.* 1999):

80

$$81 \quad \frac{1}{T_2} = \frac{1}{T_{2\text{Surface}}} + \frac{1}{T_{2\text{Bulk}}} + \frac{1}{T_{2\text{Diffusion}}} \quad (1)$$

82

83 Surface relaxation ($T_{2\text{Surface}}$) is the dominating mechanism in porous media, controlled by
 84 pore surface area. The relation between NMR relaxation and pore surface area results

85 from strong interaction between the protons and the surface because the surface
86 relaxivity (ρ) causes rapid alignment of hydrogen protons on the pore wall, perhaps only
87 a monolayer or two thick, while protons in the remaining fluid decay through itself (bulk
88 relaxation), which is much slower (Howard *et al.* 1993). Bulk relaxation (T_{2Bulk}) is thus
89 significantly smaller than the surface relaxation and so where relaxation of diffusion
90 ($T_{2Diffusion}$) is slow, the relaxation ($\frac{1}{T_2}$) may be related to surface relaxivity and surface to
91 volume ratio of pores (S_p):

92

$$93 \quad \frac{1}{T_2} = \rho_2 S_p \quad (2)$$

94

95 NMR measurements provide information about the pore structure (S_p), the amount of
96 fluid in-situ and interactions between the pore fluids and surface of pores. Thus,
97 laboratory NMR measurements can be used to obtain porosity and correlate pore size
98 distribution, clay bound water, and to estimate permeability and potentially predict
99 capillary pressure curves from longitudinal relaxation time (T_1) and transverse relaxation
100 time (T_2) distribution (Kenyon 1997). Numerous authors have explored the link between
101 NMR measurements and petrophysical properties, e.g. the wettability investigation by
102 NMR measurements by Al-Mahrooqi *et al.* (2003, 2006).

103

104 Porosity is one of the key parameter for hydrocarbon reservoir evaluation, and NMR is an
105 effective tool to determine the porosity. However, several authors reported that there exist

106 significant differences between NMR porosity and core analysis porosity. Factors
107 influencing the T_2 measurements include paramagnetic minerals in the reservoir rock
108 which may cause $T_{2Diffusion}$ and hence reduce the T_2 relaxation time (Xie *et al.* 2008).
109 Additionally, iron and other paramagnetic minerals affect the surface relaxivity and
110 produce a shift of the relaxation distribution to shorter times (Dodge *et al.* 1995).
111 Rueslåtten *et al.* (1998) studied NMR of iron-rich sandstone from the North Sea and
112 found a detrimental effect of iron bearing minerals on porosity estimation by NMR T_2 .
113
114 Specific surface area is another significant petrophysical parameter for understanding the
115 physics of porous media and for permeability prediction. It was never fully integrated
116 into standard or special core analysis programs due to lack of petrophysical
117 understanding and concepts for correct evaluation (Riepe 1998). Nitrogen adsorption
118 methods (BET) yield high specific surface value as nitrogen enters the pores in the
119 sample. By using image analysis to determine the specific surface area, usually a much
120 smaller value is derived, and the value depends upon the resolution (Solymar *et al.* 2003).
121 The results of different methods reflect the different properties of pores at different
122 scales. By using a high resolution BET surface or a highly smoothed surface derived from
123 image analysis, the calculated permeability can be varied several orders of magnitude
124 (Riepe 1998). This is a concern because specific surface plays a vital role in
125 understanding and calibrating the T_2 spectra by estimating surface relaxivity (equation
126 (2)).

127

128 NMR relaxation is thus not only affected by the pore dimensions but also by the
129 relaxivity of the rock surface. Quantitative knowledge of the surface relaxivity is needed
130 when T_2 distributions are interpreted. Surface relaxivity is required in order to convert T_2
131 distribution into specific surface area, to calculate permeability and to convert T_2 time to
132 capillary pressure curves. However, to measure surface relaxivity directly is not easy.
133 Surface relaxivity may be estimated by scaling the normalized capillary pressure curve to
134 the normalized T_2 distribution (Kleinberg 1996); or by comparing NMR T_2 distributions
135 to specific surface area from nitrogen BET adsorption (Hidajat *et al.* 2002). Alternatively,
136 it can be estimated by comparing NMR pore size distribution to pore size distribution
137 from image analysis of thin sections (Howard *et al.* 1993; Kenyon 1997). Kleinberg
138 (1996) concluded that the NMR effective specific surface area is closely associated with
139 hydraulic radius of the sedimentary rock and calculated effective surface relaxivity from
140 capillary pressure curves and T_2 distribution.

141

142 Permeability is a difficult property to determine from logging data, yet it is essential for
143 reservoir characterization. Laboratory measurements provide absolute permeability at
144 core scale which could be different from reservoir permeability. NMR is the only tool
145 that attempts to estimate *in-situ* formation permeability (Hidajat *et al.* 2002; Glover *et al.*
146 2006). One of the most popular NMR derived permeability correlations is the Timur-
147 Coates formula (Coates *et al.* 1999), and is implemented as:

148

149
$$k_{NMR} = (C\phi)^m \left(\frac{FFI}{BFI} \right)^n \quad (3)$$

150

151 where, ϕ is the porosity, FFI is the free fluid volume and BFI is the bound irreducible
 152 fluid, as determined from NMR measurements. Formation dependent constants C , m and
 153 n may be assumed to be 10, 4 and 2 for sandstones respectively, where NMR
 154 permeability, k_{NMR} is given in mD. However, this equation is simply an empirical derived
 155 relationship that links various NMR-derived parameters to permeability. Especially for
 156 diagenetically altered consolidated reservoir rocks, the complicated internal pore
 157 structures may not be described by this model, causing unrealistic permeability estimates,
 158 unless empirically calibrated parameters are used, which have no general physical
 159 meaning and thus are only valid for special facies types and for local investigations.

160 Timur-Coates formula also indicates that porosity or pore volume strongly controls the

161 permeability together with the effective specific surface area as expressed by $\frac{FFI}{BFI}$ in

162 accordance with the equation of Kozeny (1927). For homogeneous sediments like chalk,

163 the effective specific surface is equivalent to the one measured by nitrogen adsorption

164 (BET) and Kozeny's equation works well without introducing empirical factors

165 (Mortensen *et al.* 1998). However, for less homogenous sediments, like greensand, we

166 can calculate an effective surface area ($Sp(Kozeny)$) from permeability and porosity by

167 using Kozeny's equation. We infer that it is this effective surface that controls

168 permeability.

169

170 Capillary pressure (P_c) curves can be determined only from core analysis, but NMR
171 derived P_c curves provide a fast, cheap and non-destructive estimation. However, up to
172 now, most authors have focused on the relation between T_2 distribution and P_c curves
173 (Kleinberg 1996; Grattoni *et al.* 2003; Marschall *et al.* 1995; Volokitin *et al.* 1999) and
174 the general conclusion is that, if the bulk relaxation and diffusion effects are ignored, a
175 simple relationship between P_c and T_2 becomes:

176

$$177 \quad P_c = \frac{K}{T_2} \quad (4)$$

178

179 where, K is an empirical scaling factor introduced to predict capillary pressure curves.
180 However, several authors, e.g. Kleinberg (1996) concluded that the match between
181 capillary pressure and NMR relaxation curves are not universal. The simple relationship
182 (equation (4)) reflects that both the T_2 distribution and P_c curves are affected by pore
183 structures but overlooks the difference between the physics of the processes. Kewan &
184 Ning (2008) discussed that in a pore and throat model of the pore space, the capillary
185 pressure is sensitive to the pore throat, whereas the NMR measures the pore body size.
186 Thus, the technique gives same information only when there is a constant ratio between
187 them.

188

189 The combination of conventional core analysis, such as Helium porosity, Gas
190 permeability, specific surface area by BET and image analysis of thin sections
191 micrographs is proven to be very effective in the evaluation of normal reservoir rocks.

192 However, for glauconite bearing greensand where a high proportion of micro-porosity in
193 glauconite grains creates an uncertainty with respect to fluid distribution and fluid
194 saturation, an accurate determination of petrophysical properties by using conventional
195 core analysis is difficult (Rueslåtten *et al.* 1998). The objective of this study is to predict
196 petrophysical properties from NMR T₂ distributions which can be applied to *in-situ* well
197 logging. Estimates of porosity, permeability, irreducible water saturation derived from
198 NMR measurement were corrected with measurements from core analysis. The porosity
199 obtained by using the different methods was compared for the greensand samples. The
200 potential use of surface area data is also described and illustrated. Kozeny's equation was
201 used for NMR permeability prediction and P_c curves were estimated from NMR
202 measurements.

203

204 **Geological setting of Nini Field**

205

206 The Nini field is located in Siri Canyon which is part of a larger system of submarine
207 canyons in the Paleocene in the Norwegian-Danish Basin running in an E-W to NE-SW
208 direction towards the Central Graben (Fig. 2) (Stokkendal *et al.* 2009). The Nini
209 accumulation is defined by a combined structural and stratigraphic trap, the anticlinal
210 structure being induced through salt tectonics. The reservoir consists of sands deposited
211 in the Siri Fairway (Schjøler *et al.* 2007).

212

213 The glauconite bearing sandstone in the Nini field was recognized by stratigraphic work
214 in Statoil in the mid-1990s (Schjøler *et al.* 2007). It is formally included in the Hermod

215 Formation and in the older Ty Formation. These Paleocene reservoir sands are
216 characterized by glauconite rich (20-30 vol %) fine grained, well sorted sand, embedded
217 in hemiplegic to pelagic mud- and marl-stones, in which both quartz grains and
218 glauconite pellets are part of the load-bearing matrix. The greensand beds thus occur in a
219 shale-sequence. In the Nini wells, the Hermod sand was found to be more massive, more
220 porous and more permeable than Ty sand (Fig. 3).

221

222 **Method**

223

224 We studied sixteen one and half inch horizontal core plugs from the two greensand
225 formations of the Nini-1 well (7 samples from Hermod Formation and 9 samples from Ty
226 Formation). The samples had already been used for routine core analysis and were chosen
227 so as to cover the range of variation in porosity (25%-40%) and air permeability (60 mD-
228 1000 mD). All cores were cleaned from brine and hydrocarbons by soxhlet extraction
229 with methanol and toluene prior to analysis. Thin sections were prepared from the end of
230 each plug and material from the end trimmings were used for X-ray diffraction (XRD)
231 and BET analysis.

232

233 **Routine core analysis**

234

235 Helium porosity (ϕ_H) of the samples was measured by the gas expansion method. Helium
236 porosity is a good measure of total porosity, including porosity in clay minerals, as no
237 pores are so small that Helium cannot enter. Buoyancy of the cores in brine (Archimedes)

238 was also used to determine bulk volume on a fully saturated sample and pore volume was
 239 calculated from grain density as measured by the gas expansion method. Complete
 240 saturation was verified by comparing porosity measured by Helium expansion and by
 241 Archimedes method. As porosity data from the two methods are within experimental
 242 error, all samples were assumed to be fully brine saturated.

243

244 Klinkenberg corrected permeability was derived from permeability at a series of nitrogen
 245 gas pressures. Specific surface area of the grain (S_g) was measured by BET method by
 246 using nitrogen gas adsorption. Specific surface of pores from BET method ($S_p(BET)$) was
 247 calculated by dividing S_g by porous fraction, (ϕ_H) and multiplying by grain fraction, ($1-\phi_H$)
 248 as:

$$249 \quad S_p(BET) = S_g \left(\frac{1-\phi_H}{\phi_H} \right) \rho_g \quad (5)$$

250

251 where, ρ_g is grain density.

252 The effective bulk specific surface (S) was obtained from Klinkenberg permeability (k)
 253 and macro-porosity (ϕ) by using Kozeny's equation (Kozeny 1927) as:

254

$$255 \quad k = c \frac{\phi^3}{S^2} \quad (6)$$

256

257 where, c is Kozeny's factor which can be estimated from porosity via a simple model of
 258 linear 3D interpenetrating tubes (Mortensen *et al.* 1998):

259

260
$$c = \left[4 \cos \left\{ \frac{1}{3} \arccos \left(\phi \frac{8^2}{\pi^2} - 1 \right) + \frac{4}{3} \pi \right\} + 4 \right]^{-1} \quad (7)$$

261

262 According to equation (7), c increases from 0.15 to 0.25 as porosity increases from 0.05

263 to 0.5. Specific surface of pores from Kozeny's equation ($Sp(Kozeny)$) can then be

264 calculated:

265
$$Sp(Kozeny) = \frac{S}{\phi} \quad (8)$$

266 $\frac{1}{Sp(Kozeny)}$ is equivalent to hydraulic radius and thus should be related to capillary

267 pressure and T_2 relaxation, so we base the remaining analysis on $Sp(Kozeny)$.

268

269 **Capillary pressure**

270

271 The capillary pressure may be expressed by the fundamental equation:

272
$$P_c = \frac{2\sigma \cos \theta}{r_c} \quad (9)$$

273

274 where, r_c is the radius of pore throat, σ is the surface tension and θ is the contact angle.

275 For water-wet conditions $\cos \theta$ becomes one, and in terms of specific surface of pore (Sp)

276 equation (9) may be rewritten as:

277

278
$$P_c = S_p \sigma \quad (10)$$

279 Air brine drainage capillary pressure measurements were done on brine saturated
280 greensand samples by using the porous plate method at room temperature. Initially each
281 sample was saturated with simulated formation brine. The brine has a density of 1.06
282 g/cm³ and a viscosity of 1.054 cP. Irreducible water saturation (S_{wi}) including clay
283 bound water was determined from capillary pressure curves and macro-porosity was
284 calculated as porosity above irreducible water saturation (Fig. 4b).

285

286

287

288

289 **Image analysis**

290

291 Polished thin sections were prepared from all samples in a plane perpendicular to the
292 flow direction during core analysis. A Philips XL40 Scanning Electron Microscope was
293 used for acquisition of Back Scattered Electron (BSE) images. The images are 1024 x
294 1024 byte greyscale images with a pixel length of 1.78 μm . This magnification resolves
295 the intergranular macro-porosity and leaves the micro-porosity unresolved. Each image
296 was filtered to remove the noise and thresholded to create a binary image prior to
297 analysis. Porosity determined in the images is called image porosity (ϕ_{image}). The image
298 analysis procedure is sensitive to porosity threshold, so image porosity was determined when
299 they are equal to macro-porosity determined from P_C measurements. The macro-porosity
300 determined by image analysis is within a narrow range (± 2.5 p.u.) obtained by image analysis

301 along. The specific surface area or strictly speaking the specific perimeter ($S(image)$) of
302 the solid grains was determined by using the method of Borre *et al.* (1995). According to
303 Underwood (1970) and Solymar & Fabricius (1999) the specific perimeter ($S(image)$) may
304 be approximated to the 3-D specific surface (S) by:

305

$$306 \quad S = \frac{4}{\pi} S(image) \quad (11)$$

307

308 Image specific surface of pores ($S_p(image)$) is thus calculated by using equation (8) where
309 porosity is defined as macro-porosity determined from capillary pressure measurements.

310

311 **NMR measurements**

312

313 For NMR measurements all samples were saturated with brine (7.6 % NaCl). Complete
314 saturation was verified by using the dry weight, the saturated weight, grain volume by
315 Helium expansion, and brine density. All samples attained full brine saturation. All the
316 measurements were performed with the samples sleeved in PTFE heat shrink as several
317 were poorly consolidated. The weights and volumes of the heat shrink material were
318 accounted for in the measurements.

319

320 The laboratory NMR measurements were performed using a Resonance Instruments
321 MARAN 2 spectrometer at ambient pressure and 34°C at a proton resonance frequency of
322 2.2 MHz. T_2 relaxations was measured using Carr-Purcel-Meiboom-Gill (CPMG) pulse

323 sequence. The T_2 relaxation curves were measured by using a Recycle Delay (Repetition
324 Time) of 10 sec, Number of Echos 8000, CPMG inter echo spacing (τ) 200 μ s and 100
325 scans. The $\pi/2$ and π pulses were 14.8 μ s and 29.6 μ s, respectively.

326

327 NMR porosity of the fully saturated samples was determined by using the total signal
328 amplitude of each sample (by summing the amplitudes of the T_2 distribution) and known
329 standard of similar diameter. In this case the reference standard was a sealed glass vial,
330 containing 3cm³ of 50,000 ppm NaCl and 17cm³ of deuterium oxide. Deuterium oxide
331 does not have an NMR signal therefore this reference standard has an equivalent porosity
332 of 15%. The same number of scans was used for the reference and the sample. NMR
333 porosity is then calculated using the, total signal amplitude, the bulk volume, hydrogen
334 index of both plug and reference and the equivalent porosity of the reference.

335

336 For determining the macro-porosity and micro-porosity we need a cutoff value from the
337 T_2 distribution. For two samples (one from Hermod and one from Ty), the T_2 cutoff was
338 determined in the laboratory by obtaining the T_2 distribution at two saturations, fully
339 brine saturated and at irreducible water saturation as determined from capillary pressure
340 curves. The analysis of the air-water systems is relatively easy as there is no NMR
341 response from the air and the relaxation time is exclusively due to the protons in the
342 water. The cutoff time is defined as the relaxation time at the point where the cumulative
343 porosity of the fully saturated sample equals the irreducible water saturation (Fig. 4a). As
344 the T_2 cutoff is determined from capillary pressure equilibrium experiments includes
345 capillary bound fluid and trapped in micro-pores. A single T_2 cutoff value for each

346 formation was used for all samples of that formation. The cumulative porosity over the
347 range $T_2 > T_{2\text{cutoff}}$ was the macro-porosity and below the range $T_2 < T_{2\text{cutoff}}$ was the micro-
348 porosity or irreducible water saturation.

349

350 The NMR permeability model used in this work was obtained by combining equation (2),
351 (6), and (8):

352

$$353 \quad k = c\phi(T_2\rho_2)^2 \quad (12)$$

354

355 In a similar way the capillary pressure NMR model was obtained combining equation (2)
356 and (10):

$$357 \quad P_c = \frac{\sigma}{\rho_2 T_2} \quad (13)$$

358 The assumption of this model is that: 1- the pore structure controlling the T2 distribution
359 and capillary pressure is a bundle of capillary tubes and the drainage is controlled by the
360 hierarchy of pore sizes; 2- the surface relaxivity is constant overall the sample; 3-
361 diffusion relaxation is negligible.

362

363 **Results**

364

365 The Helium porosity of greensand ranges from 28 to 42 p.u. (porosity units) with a
366 maximum uncertainty 1.5 p.u. (Table 1). Klinkenberg corrected permeability ranges from

367 60 to 940 mD (Table 2). Permeabilities of Hermod samples are larger than Ty samples
368 and correlates with porosity, whereas Ty data are more scattered (Fig. 5).
369
370 Petrographic thin section analysis indicates that the studied Paleocene greensands are
371 well to very well sorted, dominated by grains of quartz but also large volumes of
372 glauconite (20-25 vol %) (Fig. 6). Samples from Hermod Formation contain glauconite
373 grains of size between 100 and 200 μm , some glauconite grains are larger (300 to 400
374 μm) (Fig. 1a). Samples from Ty Formation contain glauconite grains of size between 100
375 and 150 μm , although some glauconite grains are larger (200 to 300 μm) (Fig. 1b). The
376 grains are subangular to sub-rounded for the both Formations. Hermod Formation is only
377 weakly cemented, whereas samples from Ty formation contain cement of berthierine or
378 microcrystalline quartz cement resulting in relative in a low permeability (Table 2). In
379 both formations XRD analyses of separated glauconite grains show the presence of some
380 expanding layers in the predominantly illitic glauconite.
381
382 The capillary pressure was obtained assuming 72 mN/m for the brine surface tension.
383 Capillary pressure curves show that for the higher permeability Hermod Formation
384 samples, the P_c curves are shifted toward low irreducible water saturation, whereas P_c
385 curves for the lower permeability Ty Formation samples are shifted toward high
386 irreducible water saturation (Figs 7a, c). Irreducible water saturation from capillary
387 pressure was obtained at P_c 100 psi, and varied between 25% and 42% of the total
388 porosity (Table 2).

389

390 The NMR T_2 distributions are presented in graphical form for each sample and the
391 population is expressed in porosity units in Figures 7b, d. All T_2 distributions are
392 bimodal. Each T_2 time corresponds to a particular pore size. If the rock has a single pore
393 size then instead of a broader distribution there will be a single vertical line. Thus broader
394 distributions reflect greater variability in pore size. We have determined a time cutoff of
395 5.21 ms for the sample 1-4 from Hermod Formation and 3.68 ms for sample 1A-141 from
396 the Ty Formation. The short relaxation time component in a T_2 distribution of a rock is
397 attributed to the water in glauconite. For the present greensand samples a peak close to 1
398 ms should correspond to glauconite water, whereas all samples also present a second
399 peak close to 100 ms that corresponds to movable fluid. Higher permeability Hermod
400 Formation samples show larger amplitude in the movable fluid than samples from Ty
401 Formation; whereas lower permeability bearing Ty Formation sample show slightly
402 larger amplitude in capillary bound and glauconite water (Figs 7b, d).

403

404 **Discussion**

405 **Porosity**

406

407 Helium porosity, Archimedes porosity and NMR porosity are compared in Figure 8.
408 Helium porosity is associated with the total porosity of the sample including micro-
409 porosity in glauconitic and it shows the highest values among the three types of porosity
410 data. However, Archimedes and NMR porosity should also in principle represent the total
411 porosity of a sample, but could be lower if water saturation is below 100%. Although the

412 Archimedes porosity is close to Helium porosity, NMR porosity tends to be lower. Both
413 macro-porosity and micro-porosity are underestimated by the NMR measurements (Figs
414 8c, d). The discrepancy between Archimedes porosity and NMR porosity could be due to
415 several factors. First, NMR and Archimedes porosity depend on saturation condition of
416 the sample. So we cannot rule out that during NMR measurement the saturation condition
417 was lower than that at the Archimedes measurements. Second, paramagnetic iron-bearing
418 minerals in reservoir rock may be an important factor influencing T_2 measurements as
419 shown by Dodge *et al.* (1995). The presence of paramagnetic ions increases the rate of
420 relaxation of the hydrogen proton. This is expected for greensand because glauconite and
421 berthierine are iron-bearing. These clay minerals have large surface area and high
422 magnetic susceptibilities leading to large internal gradients and short T_2 (Straley *et al.*
423 1997). Rueslåtten *et al.* (1998) illustrated the influence of chlorite (berthierine) and
424 glauconite on the difference between Helium porosity and NMR T_2 derived porosity
425 (delta porosity) and found broad positive correlation between delta porosity and chlorite
426 content, whereas they found no correlation with glauconite content. Thus they pointed to
427 the detrimental effect of chlorite or berthierine on porosity estimated by NMR. However,
428 we found only a vague negative correlation between delta porosity and bulk mineral
429 composition (glauconite, clay coating and pores filling) (Fig. 8b).

430

431 **Specific surface area**

432

433 Specific surface area with respect to pore (S_p), determined by three methods are

434 compared in Figure 10a. We found a large difference between the specific surface areas

435 as measured by BET method ($Sp(BET)$, 76-141 μm^{-1}) and calculated by Kozeny's
436 equation ($Sp(Kozeny)$, 0.27-0.95 μm^{-1}) and determined by image analysis ($Sp(image)$,
437 0.32-0.46 μm^{-1}). Nitrogen adsorption has a very high resolution; therefore this method
438 determines the specific surface of the total porosity, including micro-porosity. Based on
439 the Kozeny's equation, we estimated $Sp(Kozeny)$ by using permeability determined on
440 the cores and macro-porosity. Sp by image analysis depends on the resolution of the
441 image (Solyman *et al.* 2003). However, Sp from image analysis at the present pixel size
442 and Sp from Kozeny's equation are in same order of magnitude which tells us that
443 resolution of image is sufficient and pixel size is small enough to determine Sp by image
444 analysis. The specific surface area of separated glauconite grains are in order of 1300-
445 1600 μm^{-1} , whereas the specific surface area of quartz grains is less than 1 μm^{-1} . So
446 rather than quartz grains, specific surface of glauconite grains are measured by BET
447 method. Thus, Sp by BET method is mainly reflected by the micro-pores of glauconite
448 grains and pore filling/lining clays, whereas Sp from Kozeny's equation and image
449 analysis is associated with effective surface and related to macro-porosity. We found that
450 Sp measured by BET method is well correlated with fraction of glauconite plus pore
451 filling clay minerals (Fig. 9c).

452

453 We found that irreducible water saturation ranges from 22% to 41% from capillary
454 pressure measurements and from 23% to 36% from NMR measurements. Considering
455 errors association with these two methods, irreducible water saturations are close to each
456 other. The high value of irreducible water saturation is due to the high specific surface of
457 glauconite. The micro-pores of glauconite remain brine filled even at a capillary pressure

458 of 100 psi. We found a positive correlation between irreducible water saturation
459 determined from P_c and NMR with S_p determined from BET method (Figs 9a, b). In
460 addition Figures 9a, b also show the tendency for low surface area samples to approach
461 minimum irreducible water saturation and for high surface area samples to remain more
462 saturated. A relationship between specific surface and irreducible water saturation has
463 been noted by several authors e. g. Hamada *et al.* (2001) where authors reported an
464 excellent correlation ($R^2=0.98$) between irreducible water saturation and specific surface
465 of pores.

466

467 **Surface relaxivity**

468

469 We compare four ways of estimating surface relaxivity in Figure 10b. Equation (2) shows
470 that surface relaxivity for NMR T_2 distribution is related to specific surface of pores.
471 Thus in absence of laboratory data, surface relaxivity may be evaluated by comparing T_2
472 distributions with $S_p(BET)$, $S_p(Kozeny)$ or $S_p(image)$. This results in relaxivity value
473 ranges in order of 2.7-4.2 $\mu\text{m/s}$ from $S_p(BET)$, 7-58 $\mu\text{m/s}$ from $S_p(Kozeny)$, and 10-35
474 $\mu\text{m/s}$ from $S_p(image)$. As an alternative, we used P_c curves and found that a surface
475 relaxivity of 20.4 $\mu\text{m/s}$ for Hermod and of 28.4 $\mu\text{m/s}$ for Ty Formation are needed to
476 generate P_c curves from NMR measurements. The surface relaxivity estimated based on
477 $S_p(BET)$ would be controlled by micro-porosity in glauconite. We found an average
478 surface relaxivity by $S_p(BET)$ of 3.42 $\mu\text{m/s}$, which is close to the 3.3 $\mu\text{m/s}$ for glauconite
479 reported by Matteson *et al.* (1996). Surface relaxivity estimated from $S_p(Kozeny)$ and

480 $Sp(image)$ also should be effective surface relaxivity as it was calculated from effective
 481 specific surface area.

482

483 **Permeability**

484

485 Kozeny's equation (equation (12)) was used to predict permeability from NMR T_2
 486 distributions. Before applying this equation we highlight the similarities and differences
 487 within T_2 distribution among samples (Fig. 11). The T_2 distribution of sample 1-18 peaks
 488 at longer time than for sample 1-6, thus the larger porosity of sample 1-18 is due to the
 489 larger pores which also cause higher permeability (Fig. 11a). The comparison of three
 490 samples with similar distributions at shorter times is shown in Figure 11b. When the
 491 larger peak (around 100 ms) becomes smaller and is shifted to larger times due to a small
 492 number of intermediate pores, there is a small increase of the number of larger pores.
 493 Thus, for these samples the permeability is not high although porosity is higher. We thus
 494 cannot use average T_2 time or final T_2 time in equation (12) for permeability calculation.
 495 So we modified the equation (12) by summing the total permeability among the T_2
 496 distribution and only including the macro-porosity. Thus resulting:

497

$$498 \quad k = c\phi\rho_2^2 \sum_{i=1}^N f_i (T_{2i})^2 \quad (14)$$

499

500 where, f_i is a fraction of the total amplitude of each T_{2i} . Kozeny factor c was calculated
501 using equation (7).

502

503 The predicted permeability distribution obtained by using equation (14) is shown in
504 Figures 11c, d. Below cutoff time, the amplitude of permeability is zero which means
505 micro-porosity does not contribute to fluid flow. From cutoff time to 100 ms, the
506 amplitude of permeability is small but above 100 ms the contribution of permeability
507 increases.

508

509 Predicted permeability and measured permeability are compared in Figure 12a by using
510 surface relaxivity from $Sp(Kozeny)$ (Average surface relaxivity for each depth interval),
511 in Figure 12b by using surface relaxivity from $Sp(image)$, in Figure 12c by using surface
512 relaxivity from equation (13), and in Figure 12d by using surface relaxivity from $Sp(BET)$.
513 Predicted permeability is close to 1:1 line of measured permeability for case 1 and 2. The
514 estimated permeability from Timur-Coates model is illustrated in Figure 12e. Predicted
515 permeability using this model works rather well if we use $C=8.3$ which was optimized in
516 a least-squares sense such that the sum of the squared error between the measured and
517 predicted permeability is minimized. Predicted permeability from image analysis and
518 measured permeability are compared in Figure 12f. Image permeability and NMR
519 predicted permeability by using surface relaxivity from $Sp(image)$ are equal.

520

521 **Capillary pressure curves**

522

523 We applied the value of surface relaxivity of 20.3 $\mu\text{m/s}$ and 28.4 $\mu\text{m/s}$ for Hermod
524 Formation and Ty Formation sample respectively to generate the capillary pressure
525 curves directly from the T_2 distribution by using equation 13 (Fig. 13). Capillary
526 pressure curves overlay each other for low permeability samples. However, we found
527 deviation between the P_c NMR and P_c lab for the high permeability sample from Hermod
528 Formation. A deviation is to be expected, because we assumed uniform surface
529 relaxivity within a sample and ignored diffusion relaxation. The calculated surface
530 relaxivity is shown in Figure 13e for a sample from Hermod Formation and in Figure 13f
531 for a sample from Ty Formation. A good match between P_c curves from laboratory and
532 NMR measurement is found when average surface relaxivity is equal to surface relaxivity
533 applied to predict P_c curves from NMR. In contrast, we found deviation between P_c
534 curves from laboratory and NMR measurements when average surface relaxivity is not
535 equal to the surface relaxivity need to match P_c curves. This variation of surface
536 relaxivity within the sample is probably due to the large pores and higher permeability in
537 the greensands of Hermod Formation.

538

539 **Conclusion**

540

541 The objective of this study is to predict petrophysical properties from NMR T_2
542 distributions. Based on laboratory experiments and image analysis on sixteen greensand
543 samples from the two formations in the Nini field of the North Sea, we found Hermod
544 Formation is only weakly cemented, whereas samples from Ty formation contain cement

545 of berthierine or microcrystalline quartz cement resulting in relatively to lower
546 permeability than Hermod samples.

547

548 We found that the total porosity measured by Archimedes method is to close to Helium
549 porosity, whereas NMR porosity tends to be lower. The discrepancy between Archimedes
550 porosity and NMR porosity may be due to a combination of several factors, including the
551 presence of glauconite grains in greensand.

552

553 This study shows that the surface area measured by BET method and the derived surface
554 relaxivity are associated with the micro-porous glauconite grains. The effective surface
555 area as calculated by Kozeny's equation and as determined from petrographic image
556 analysis of Backscattered Electron Micrographs and the estimated effective surface
557 relaxivity is associated with macro-pores. We found that S_p measured by BET method is
558 well correlated with fraction of glauconite plus pore filling clay minerals.

559

560 Irreducible water saturation in the studied greensands ranges from 22% to 41% and these
561 high values are due to the high specific surface area of glauconite. The micro-pores of
562 glauconite remain brine filled even at a capillary pressure of 100 psi.

563

564 We found that predicted permeability from NMR by using Kozeny's equation agrees well
565 when surface relaxivity is known. By using Timur-Coates model, predicting permeability
566 works rather well if we optimize the constant to $C=8.3$.

567

568 This study shows that predicted capillary pressure curves from NMR T_2 distribution
569 overlay on measured capillary pressure curves for low permeability samples. The
570 deviation between the P_c NMR and P_c lab for the high permeability samples is due to the
571 contrasting relaxivity on the surface of quartz and glauconite.
572

573 **Acknowledgements**

574

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576 core analysis. Sinh Hy Nguyen (DTU, DK) performed XRD and BET measurements,
577 Hector Ampuero Diaz (DTU, DK) prepared polished thin sections. DONG Energy A/S is
578 acknowledged for financial support.

579

580 **Appendix**

581 **Nomenclature**

582	<i>BFV</i>	Bound fluid volume
583	<i>C</i>	Formation dependent constant
584	<i>c</i>	Kozeny factor
585	<i>f_i</i>	Amplitude of each T_{2i}
586	<i>FFI</i>	Free fluid volume
587	<i>k</i>	Klinkenberg permeability,
588	<i>K</i>	Scaling factor
589	<i>S</i>	Specific surface area of bulk
590	<i>S_g</i>	Specific surface area of grains
591	<i>S_p</i>	Specific surface of pores
592	<i>T_{2Bulk}</i>	Relaxation of fluids
593	<i>T_{2Diffusionk}</i>	Relaxation of molecular diffusion
594	<i>T_{2Surface}</i>	Relaxation of surface

595

596 **Greek symbols**

597 ϕ Porosity (fraction)

598 ρ Surface relaxivity

599 τ Inter echo spacing.

600

601 **Unit conversion**

602

603 1 mD = $0.9869 \times 10^{-15} \text{ m}^2$

604 1 psi = 6.89 kPa

605

606 **References**

607

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707 **Figure captions**

708

709 **Fig. 1.** BSE images of greensand samples. (a) Sample 1-4 from Hermod Formation and
710 (b) sample 1A-142 from Ty Formation. Scale bar is 200 μm . Q: quartz; Gl: glauconite; H:
711 Heavy minerals, M: Mica; PF: pore filling clay minerals. Porosity, permeability and
712 irreducible water saturation are 37 p.u., 530 mD and 26% for sample 1-4 and 29 p.u., 150
713 mD and 38% for sample 1A-142.

714

715 **Fig. 2.** Location map showing the position of the Nini-1 well used in this study (arrow).
716 The margins of the Siri Canyon are shown by grey shading. An area of positive relief
717 within the canyon is also shown by grey shading. G, Germany; N, Norway; NL,
718 Netherlands; S, Sweden; UK, United Kingdom (Figure modified after Schiøler *et al.*
719 2007).

720

721 **Fig. 3.** Gamma ray, porosity and resistivity logs for wells Nini-1 (top) and Nini-1A
722 (bottom). The glauconite bearing reservoir intervals (Hermod sand and Ty sand) have
723 relatively low separation between neutron- and density porosity. Horizontal dashed lines
724 indicate the studied core intervals. Core data are shown for reference. Permeability is
725 higher in Hermod sand than in Ty sand.

726

727 **Fig. 4:** Macro-porosity and micro-porosity determination for sample 1-4 (a) from NMR
728 T_2 distribution (b) from the capillary pressure curve. The cumulative distribution for the
729 fully saturated sample is compared to the cumulative distribution after centrifuging at 100

730 psi. The cutoff time which separates the T_2 distribution into macro-porosity and micro-
731 porosity is defined as the relaxation time at the point where the cumulative porosity of the
732 fully saturated sample equals the irreducible water saturation. The dashed vertical line is
733 shown a cutoff of 5.21 ms. The capillary pressure of 100 psi corresponds to a micro-
734 porosity of 9.1%.

735

736 **Fig. 5.** Cross plot of macro-porosity from capillary pressure measurement and
737 permeability. Samples from the Hermod sand have similar porosity and permeability,
738 whereas the samples from Ty sand are more scattered. The reference lines represent equal
739 specific surface of pores (Sp (Kozeny)) in μm^{-1} as calculated by using Kozeny's equation.
740 The data indicate that Sp is lower in Hermod sand than in Ty sand.

741

742 **Fig. 6.** Bulk composition of investigated samples from Hermod and Ty Formations of the
743 Nini Field. Mineral composition was determined by point counting of 500 points across
744 each entire thin-section. Macro-porosity was determined by image analysis when porosity
745 threshold is equal to macro-porosity determined from P_c measurements. Micro-porosity is
746 the difference between Helium porosity and image porosity.

747

748 **Fig. 7.** (a), (c) Capillary pressure curves and (b), (d) NMR T_2 distribution curves of
749 greensand samples. (a) P_c curves of Hermod Formation samples are shifted toward low
750 irreducible water saturation, whereas (c) the Ty Formation samples have relatively high
751 irreducible water saturation. This pattern compares to the relatively high permeability of
752 Hermod sand relative to the low permeability of Ty sand (Fig. 3). T_2 distribution of all

753 samples shows two peaks. The peak close to 1 ms represents micro-porosity and the peak
754 close to 100 ms represents macro-porosity.

755

756 **Fig. 8.** (a) Helium porosity, Archimedes porosity and NMR porosity of investigated
757 samples. Helium porosity tends to be the highest, whereas NMR porosity is
758 underestimated due to iron bearing minerals in greensand. (b) Cross plot of delta porosity
759 (Archimedes porosity-NMR porosity) and minerals bulk composition (glauconite, pore
760 filling clay and clay coating). Cross plots of (c) macro-porosity and (d) micro-porosity
761 from NMR T_2 distribution and capillary pressure curves.

762

763 **Fig. 9.** Correlation between specific surface of pores as measured by BET ($Sp (BET)$) and
764 (a) irreducible water saturation as determined from NMR measurements, (b) irreducible
765 water saturation as determined from capillary pressure measure as well as (c) clay
766 minerals (glauconite, clay coating and pore filling clay) as percentage of bulk
767 composition.

768

769 **Fig. 10.** (a) Specific surface area with respect to pore (Sp) determined by BET nitrogen
770 adsorption ($Sp (BET)$), estimated from Kozeny's equation ($Sp (Kozeny)$) and determined
771 by image analysis of the BSE images ($Sp (image)$). (b) Surface relaxivity determined
772 comparing T_2 distribution with $Sp (BET)$, $Sp (Kozeny)$, and $Sp (image)$. For two samples,
773 surface relaxivity are also determined from capillary pressure versus NMR T_2
774 distribution.

775

776 **Fig. 11.** (a), (b) Porosity distribution and cumulative porosity for five greensand samples.
777 (c), (d) Permeability distribution of five greensand samples obtained from Kozeny's
778 equation.

779

780 **Fig. 12.** Measured permeability versus NMR predicted permeability by using surface
781 relaxivity from (a) $Sp(Kozeny)$, (b) $Sp(image)$, (c) $Sp(BET)$, (d) P_c versus NMR and (e)
782 from Timur-Coates model. (g) Measured permeability versus predicted permeability from
783 image analysis. Image permeability and NMR predicted permeability by using surface
784 relaxivity from $Sp(image)$ are equal.

785

786 **Fig. 13.** Air Brine capillary pressure curves including saturation error compared with
787 NMR derived capillary pressure including saturation error. Saturation error corresponds
788 to the error associated with porosity measurements. The NMR derived capillary pressure
789 curves are based on surface relaxivity value of 20.4 $\mu\text{m/s}$ for Hermod Formation and 28.4
790 $\mu\text{m/s}$ for Ty formation. Deviation between average surface relaxivity (solid line) and
791 surface relaxivity for predicting P_c NMR (dashes line) are shown (e) for Hermod
792 Formation and (f) for Ty Formation.

793

794 **List of tables**

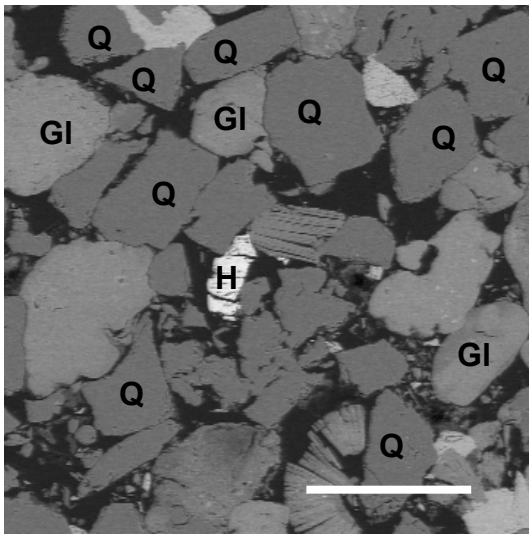
795

796 Table 1. *Core plug porosity data. Helium porosity was measured by Helium gas*
797 *expansion, Archimedes porosity was measured by immersing, and NMR porosity was*
798 *measured by the signal amplitude of T_2 measurements respectively. Archimedes macro-*
799 *porosity and NMR macro-porosity were determined from capillary pressure curves and*
800 *T_2 distributions respectively.*

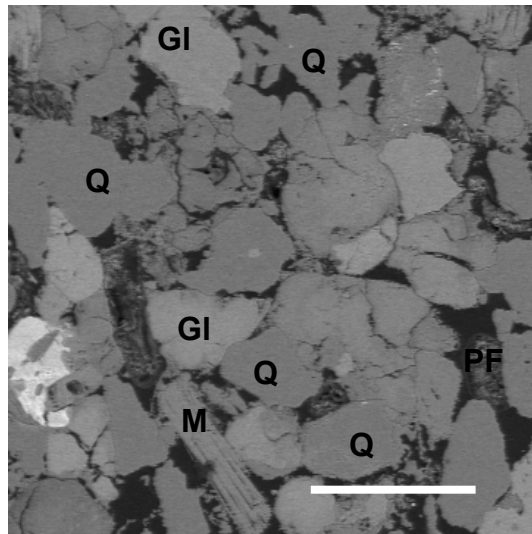
801

802 Table 2. *Core plug data. Specific surface area of grains (SSA) was measured by BET*
803 *method and effective specific surface of pores ($Sp(Kozeny)$) was calculated by using*
804 *Kozeny's equation. Image specific perimeter of pores ($Sp(image)$) was determined by*
805 *image analysis by using the method of Borre et al. (1997). The cutoff time which*
806 *separates the T_2 distribution into macro-porosity and micro-porosity is defined as the*
807 *relaxation time at the point where the cumulative porosity of the fully saturated sample*
808 *equals the irreducible water saturation.*

Fig. 1



(a)



(b)

Fig. 2

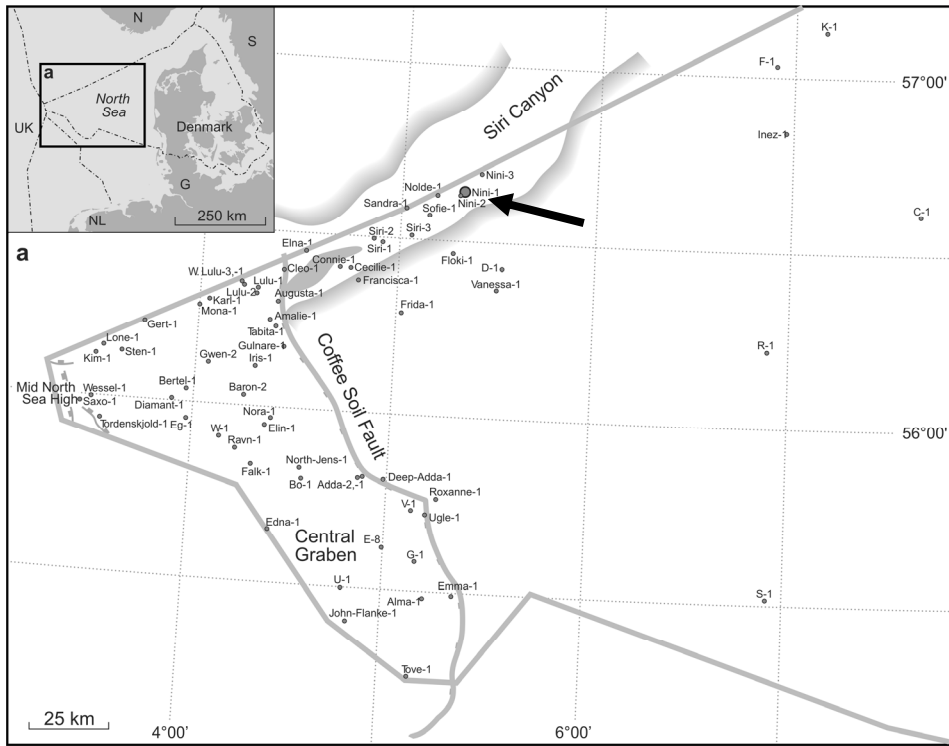


Fig. 3

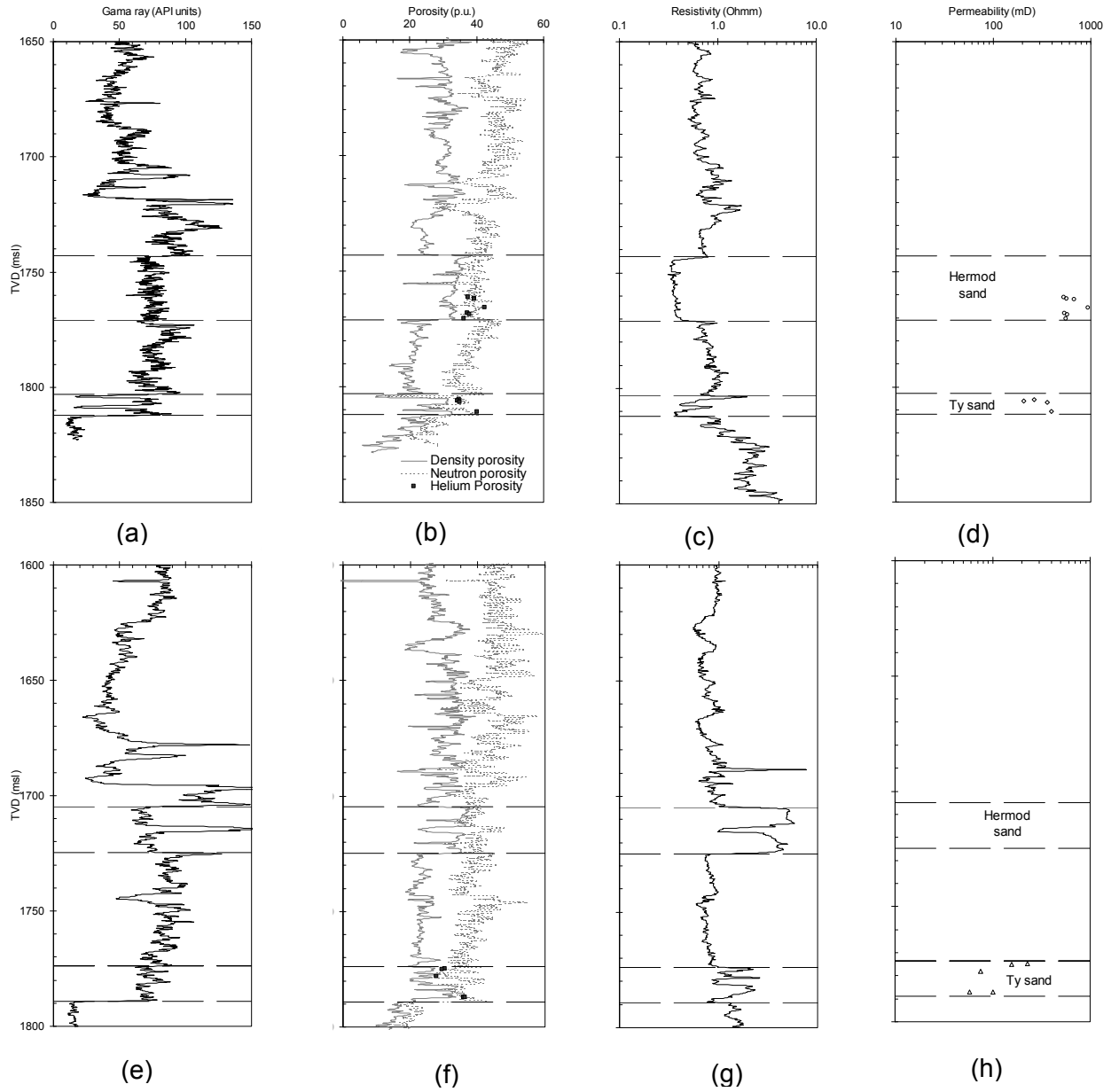


Fig. 4

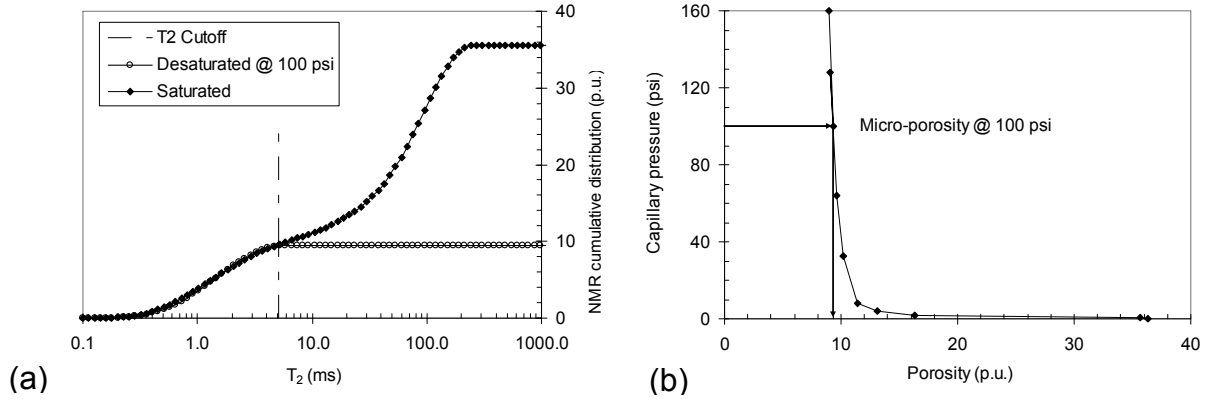


Fig. 5

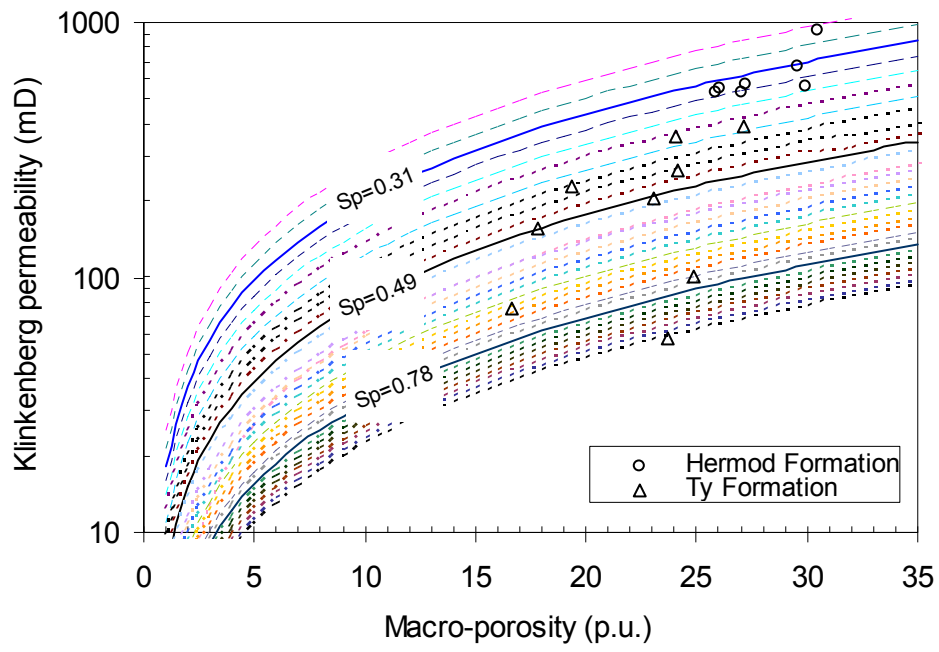


Fig. 6

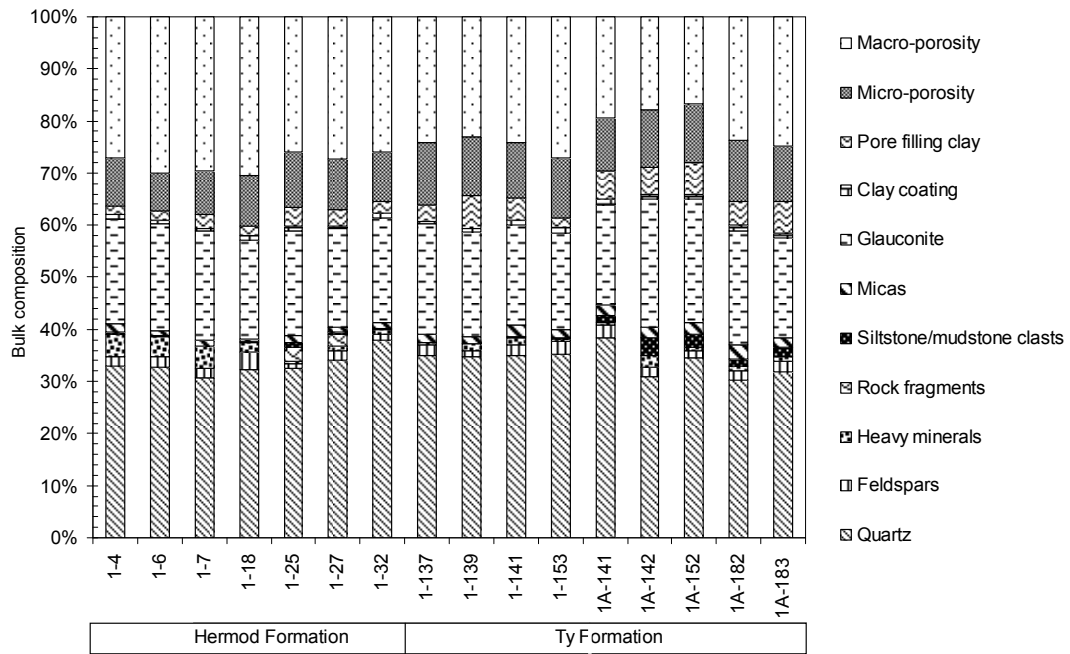
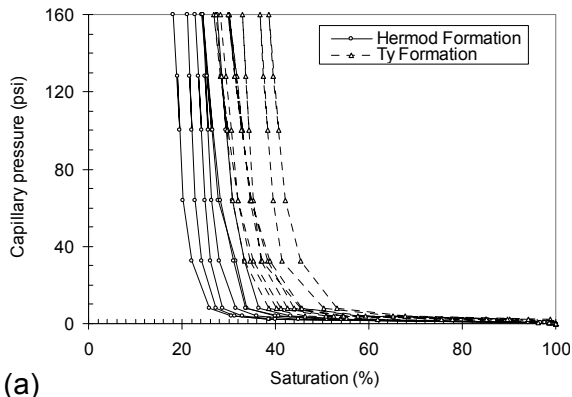
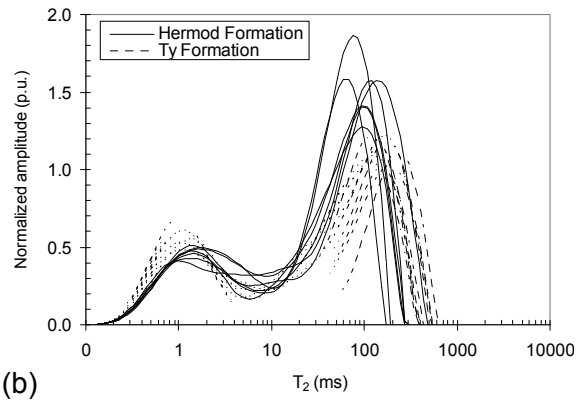


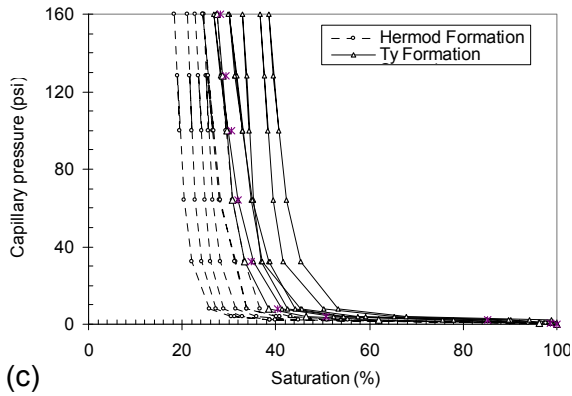
Fig. 7



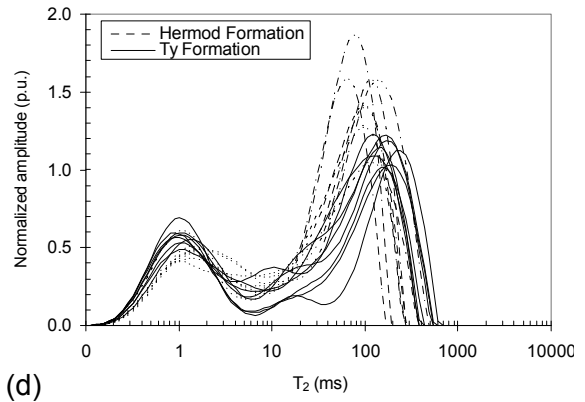
(a)



(b)



(c)



(d)

Fig. 8

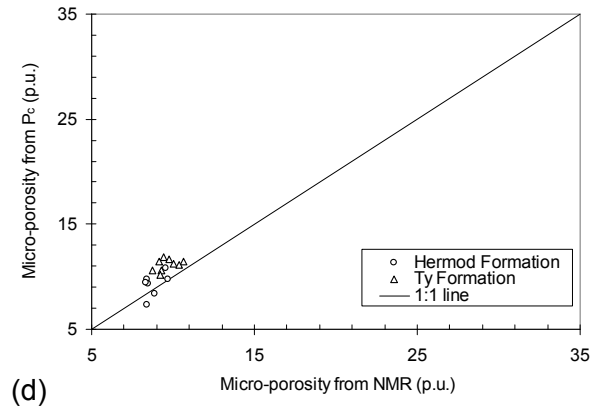
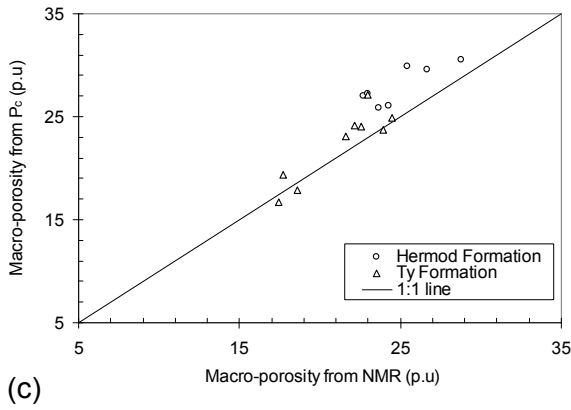
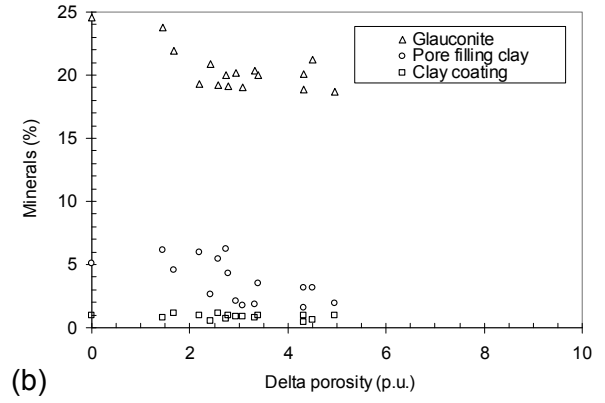
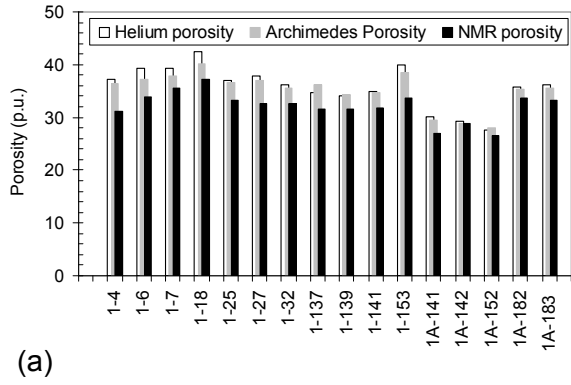


Fig. 9

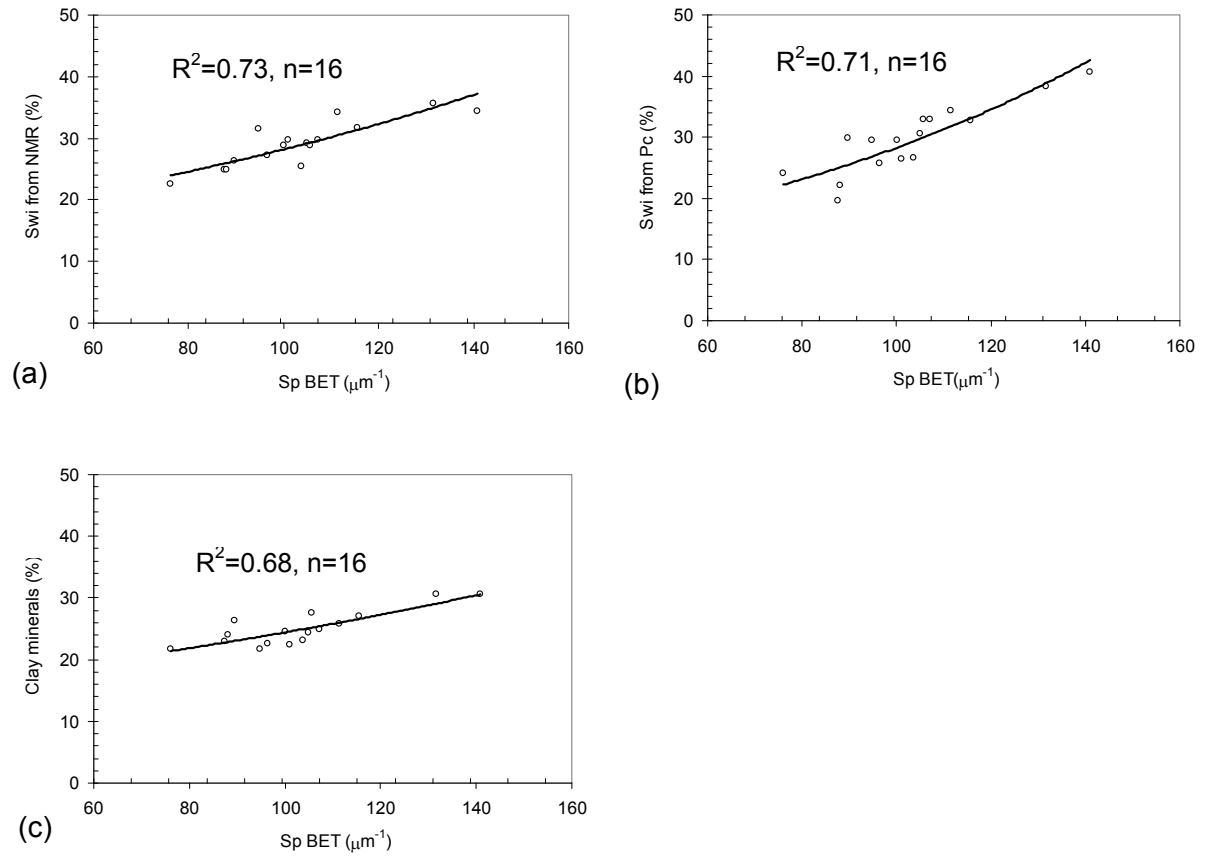


Fig. 10

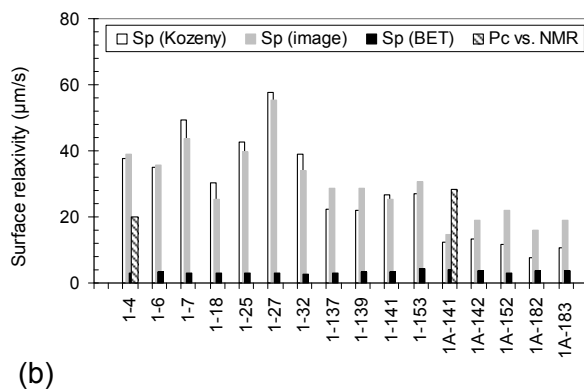
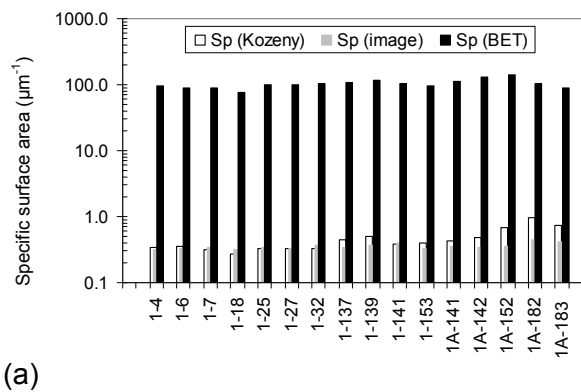


Fig. 11

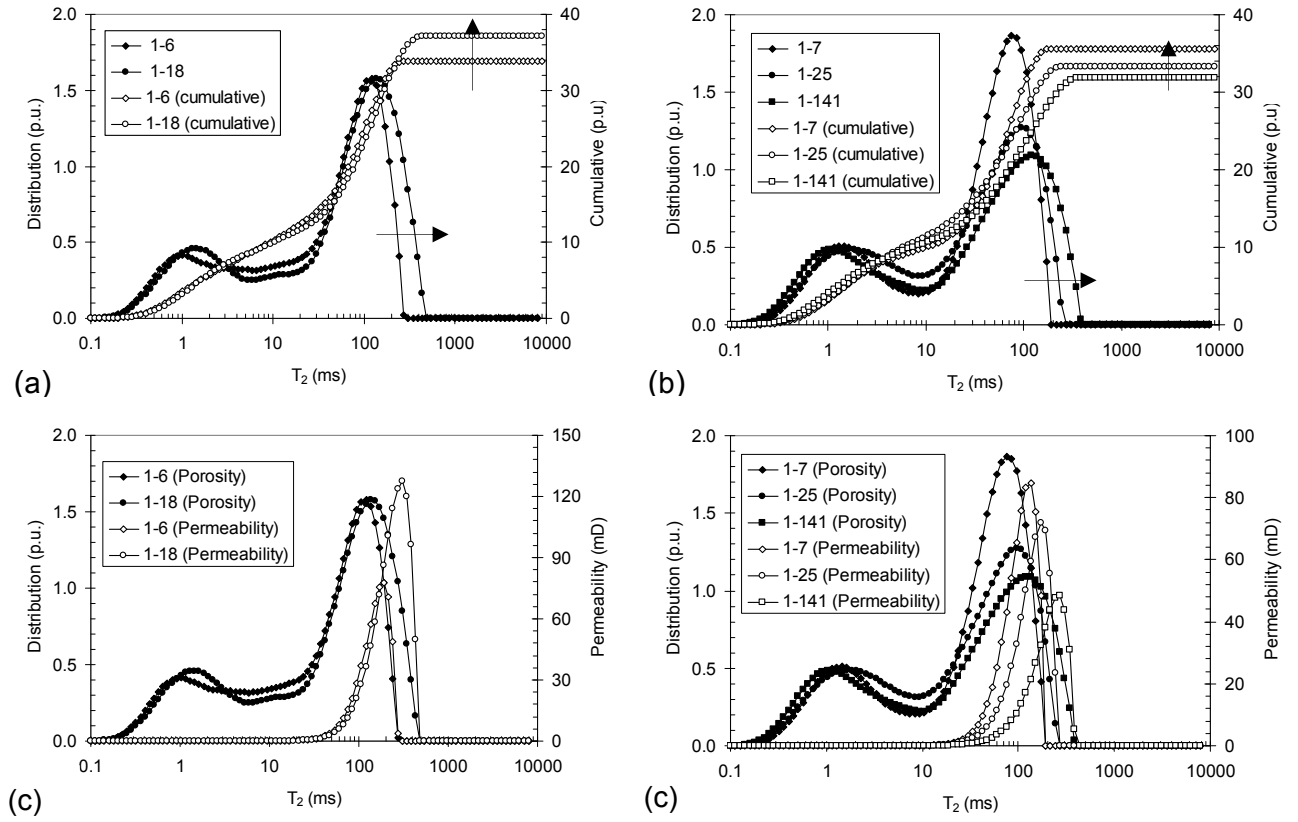


Fig. 12

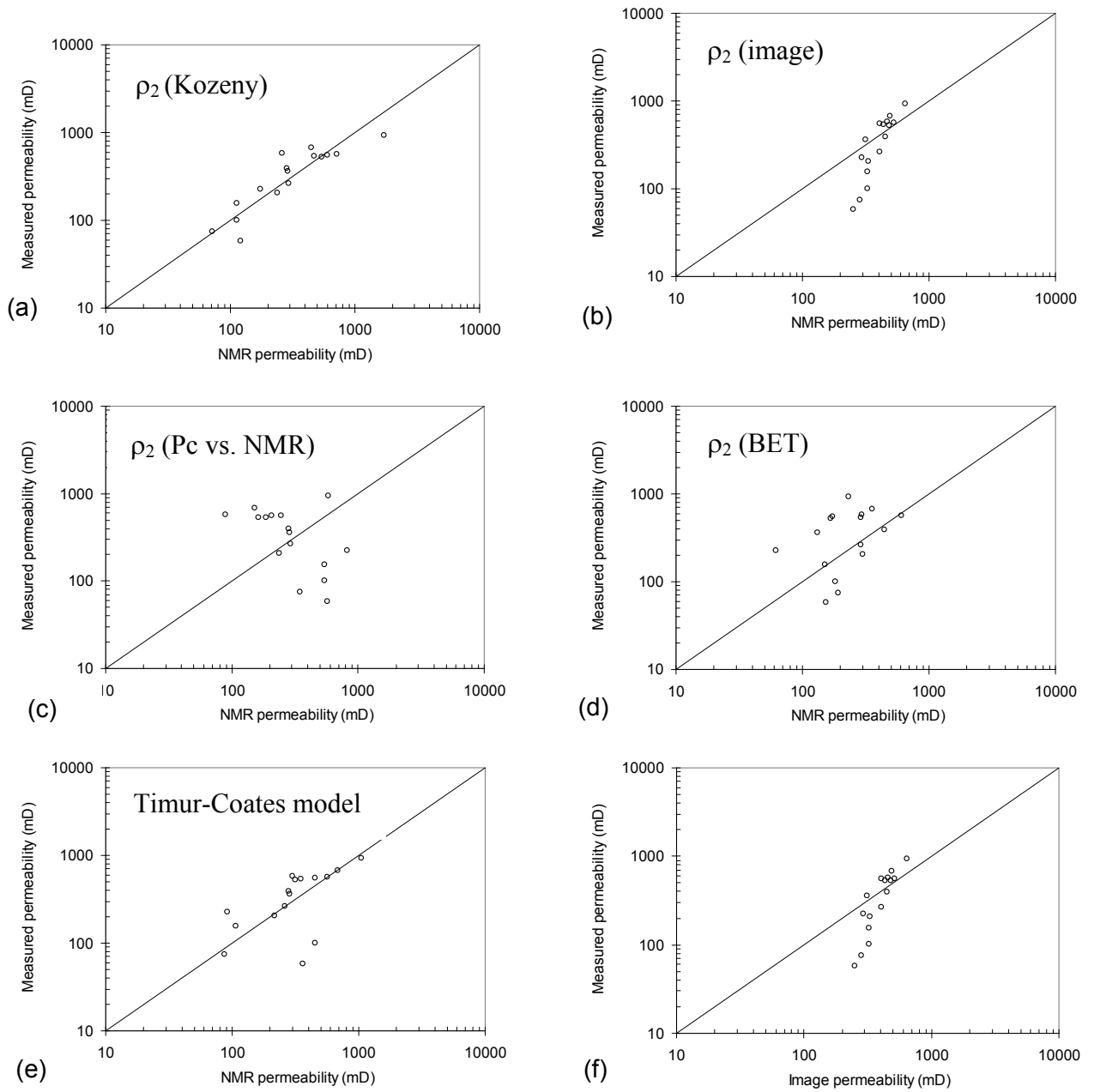


Fig. 13

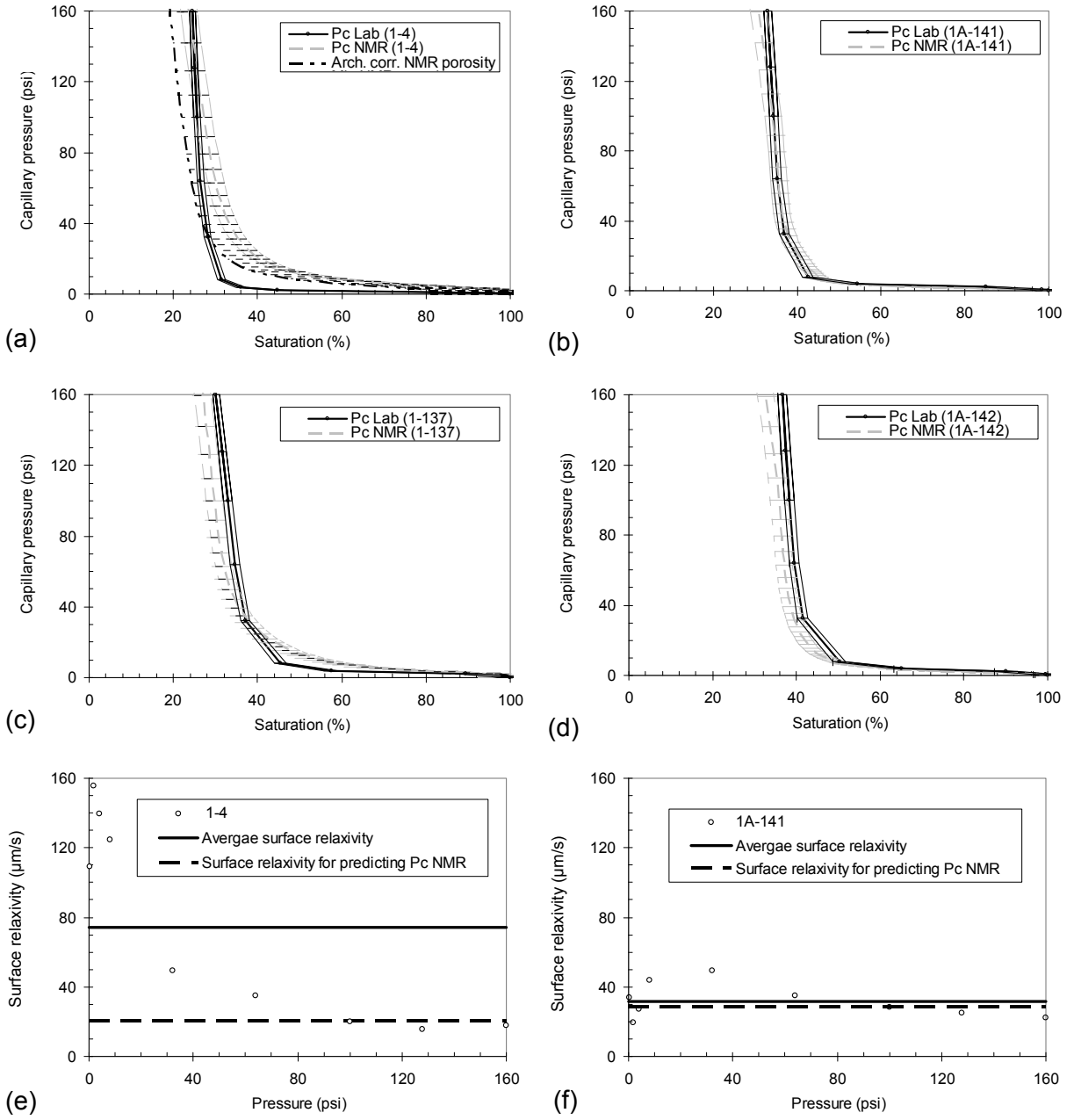


Table 1

Formation	Measured Depth (m)	TVD (msl)	Sample ID	Helium porosity (p.u.)		Archimedes porosity (p.u.)		NMR porosity (p.u.)		Archimedes macro-porosity (p.u.)	NMR macro-porosity (p.u.)
					Error ±		Error ±		Error ±		
Hermod	1761.1		1-4	37.3	1.5	35.5	1.1	31.2	0.4	27.0	22.7
	1761.7		1-6	39.3	1.3	37.2	1.1	33.8	0.5	29.9	25.4
	1762.1		1-7	39.2	0.4	37.9	1.1	35.5	0.5	29.6	26.7
	1765.7		1-18	42.4	0.5	40.2	1.2	37.2	0.5	30.5	28.8
	1768.1		1-25	37.1	0.5	36.7	1.1	33.3	0.5	25.9	23.7
	1768.7		1-27	37.8	1.1	37.0	1.1	32.7	0.5	27.2	23.0
	1770.4		1-32	36.2	0.9	35.5	1.1	32.6	0.5	26.0	24.3
Ty	1805.5		1-137	34.7	0.8	36.1	1.1	31.6	0.4	24.2	22.2
	1806.1		1-139	34.2	0.5	34.3	1.0	31.6	0.4	23.1	21.6
	1806.7		1-141	34.9	0.3	34.6	1.0	31.8	0.4	24.1	22.5
	1810.7		1-153	40.0	0.4	38.6	1.2	33.6	0.5	27.2	23.0
	1972.1	1774.7	1A-141	30.1	0.1	29.5	0.9	27.0	0.4	19.4	17.7
	1972.4	1775.0	1A-142	29.3	0.7	29.0	0.9	29.0	0.4	17.9	18.6
	1975.8	1778.1	1A-152	27.7	0.3	28.1	0.8	26.6	0.4	16.7	17.5
	1985.7	1787.0	1A-182	35.7	0.1	35.3	1.1	33.7	0.5	23.7	23.9
	1986.0	1787.2	1A-183	36.2	0.4	35.5	1.1	33.3	0.5	24.9	24.5

Table 2

Sample ID	Klinkenberg permeability (mD)	SSA (BET) (m ² /g)	Sp (Kozeny) (μm ⁻¹)	Sp (image) (μm ⁻¹)	T ₂ Cutoff (ms)	Irreducible water saturation from P _c (%)	Irreducible water saturation from NMR (%)
1-4	530	21	0.34	0.32	5.2	25.6	27.2
1-6	560	21	0.35	0.33		19.6	24.9
1-7	680	21	0.31	0.35		22.1	24.9
1-18	940	19	0.27	0.32		24.2	22.6
1-25	540	20	0.33	0.35		29.4	28.8
1-27	570	22	0.33	0.33		26.5	29.8
1-32	550	21	0.32	0.36		26.7	25.5
1-137	260	20	0.45	0.34		33.0	29.8
1-139	210	22	0.49	0.38		32.8	31.8
1-141	360	20	0.38	0.39		30.5	29.2
1-153	390	23	0.39	0.33		29.6	31.6
1A-141	230	17	0.43	0.35	3.7	34.4	34.2
1A-142	160	19	0.49	0.35		38.4	35.7
1A-152	80	20	0.68	0.36		40.7	34.4
1A-182	60	22	0.95	0.46		32.9	28.9
1A-183	100	19	0.74	0.41		29.9	26.4