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A statistical analysis of well production rates from UK oil and gas fields – Implications for carbon capture and storage

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Abstract

The number of wells required to dispose of global CO₂ emissions by injection into geological formations is of interest as a key indicator of feasible deployment rate, scale and cost. Estimates have largely been driven by forecasts of sustainable injection rate from mathematical modelling of the CO₂ injection process. Recorded fluid production rates from oil and gas fields can be considered an observable analogue in this respect. The article presents statistics concerning Cumulative average Bulk fluid Production (CBP) rates per well for 104 oil and gas fields from the UK offshore region. The term bulk fluid production is used here to describe the composite volume of oil, gas and water produced at reservoir conditions. Overall, the following key findings are asserted: (1) CBP statistics for UK offshore oil and gas fields are similar to those observed for CO₂ injection projects worldwide. (2) 50% probability of non-exceedance (PNE) for CBP for oil and gas fields without water flood is around 0.35 Mt/yr/well of CO₂ equivalent. (3) There is negligible correlation between reservoir transmissivity and CBP. (4) Study of net and gross CBP for water flood fields suggest a 50% PNE that brine co-production during CO₂ injection could lead to a 20% reduction in the number of wells required.

27 **Introduction**

28

29 There has been on-going discussion in the literature concerning the number of injection wells that
30 will be needed to store global CO₂ emissions in geological formations (Ehlig-Economides and
31 Economides, 2010; Cavanagh et al., 2010; 2011; Hosa et al., 2011; Gammer et al., 2011).
32 Confidence concerning estimates of number of wells required can be increased by consideration of
33 previous experience. However, commercial-scale CO₂ injection data remains scarce (Michael et al.,
34 2010; Michael et al., 2011; Hosa et al., 2011). Consequently, current estimates heavily rely on
35 numerical simulation (e.g., Pickup et al., 2011; Jin et al., 2012, Zhou et al., 2012). A particular issue
36 with numerical simulation concerns the excessive grid-resolution required to ensure numerically
37 converged results (Pickup et al., 2012). This in turn leads to prohibitive computational requirements
38 in the context of sensitivity analysis for uncertainty propagation (Mathias et al., 2013a; Hedley et
39 al., 2013) although this problem can be partially alleviated by the use of simplified analytical
40 solutions (e.g. Mathias et al., 2011b; Mathias et al., 2013b).

41

42 This article seeks to gain further insight concerning the estimation of CO₂ injection rates by
43 undertaking a statistical analysis of production data from 119 UK offshore oil and gas fields
44 (DECC, 2013) (see Figure 1). The conclusions from this work provide new information for
45 forecasting likely injection rates, and therefore numbers of wells, for future CO₂ storage projects
46 located on the UK continental shelf.

47

48 The article commences with an explanation concerning the need and methodology for converting
49 data for standard conditions (60°F and 14.7 psi) to an equivalent combined volumetric flow rate of
50 oil, gas and water at reservoir conditions. A discussion is then provided to explain the choice of
51 using the cumulative average production rate after 10 years. Production data statistics for UK
52 offshore oil and gas fields are compared with those for CO₂ injection projects world-wide. Water

53 flood data are used to gain further insights concerning the usefulness of brine co-production during
54 CO₂ injection. An investigation is then performed to look at how production statistics vary for
55 different reservoir types. Finally, the article summarises and concludes.

56

57 **Formatting of DECC production data**

58

59 Time series data for all UK offshore oil and gas fields can be obtained from DECC (2013) (UK
60 Department of Energy and Climate Change) including both monthly production and injection data
61 for oil, gas and water. An example of such a data set is shown for the Balmoral oil field in Figure
62 2a. The DECC (2013) data is reported at standard conditions (SC), i.e., 60°F and 14.7 psi (Ahmed,
63 2001, p. 33). Also note to obtain an average production rate per production well it is necessary to
64 divide the DECC (2013) data by the number of production wells in the field. For example, the
65 Balmoral field has 14 production wells (DECC, 2007).

66

67 Note that the number of production wells in a given field often increases with field life. However,
68 the history of well development for each field studied was not available for this investigation.

69

70 At reservoir conditions (RC) the solubility of gas in oil is much higher. Once the oil is brought to
71 SC, the gas solubility is significantly reduced and gas comes out of solution. Most of the gas
72 produced in UK oil fields has been derived by this process. In reservoir engineering it is typical to
73 quantify gas solubility in terms of a gas-oil-ratio at SC, R_s , which is measured in standard cubic ft
74 of gas per standard barrel of oil (SCF/BBL). Figure 3a shows a plot of R_s as a function of pressure
75 for the Balmoral field, assuming a correlation function presented by Glaso (1980) (see Eq. 2.73 of
76 Ahmed, 2001). Note that beyond 1460 psi, R_s remains constant. This critical pressure for a given oil
77 and gas is referred to as the bubble point, defined as the pressure at which a bubble of gas appears
78 on depressurising.

80 Also of interest is the gas expansion factor, E_g (-), defined as the volume of gas at SC divided by
81 the volume of gas at RC. Figure 3a also shows E_g (-) for Balmoral according to the Peng and
82 Robinson (1977) equation of state (EOS) assuming critical pressures and temperatures as calculated
83 using the correlations of Standing (1977) (see Eqs. 2.18 and 2.19 of Ahmed, 2001). Note that E_g
84 increases with increasing reservoir pressure due to the increase in gas density associated with
85 compression.

86

87 A unit volume of oil at RC results in a smaller produced volume at SC due to the loss of gas from
88 solution when the pressure is lowered. Also, at RC, once gas is dissolved an increase in reservoir
89 pressure leads to a slight reduction in oil volume due to compression of the oil phase. The oil
90 formation volume factor, B_o (-), is defined as the volume of oil at RC divided by the resulting
91 volume of oil at SC. Figure 3a shows a plot of B_o as a function of pressure for Balmoral, assuming
92 another correlation function presented by Glaso (1980) (see Eq. 2.87 of Ahmed, 2001), to account
93 for gas exsolution, in conjunction with the correlation of Spivey et al. (2007), to account for oil
94 compression. Above the bubble point, as pressure decreases, B_o increases because the volume of oil
95 is increasing in the reservoir due to decompression. However, once bubble point is reached, B_o
96 decreases with decreasing pressure because gas within the oil is coming out of solution.

97

98 Note that in principle, B_o should go to unity as pressure approaches 14.7 psi. This is not the case for
99 Glaso's correlation because the analysis is based only on experimental data observed at bubble
100 point pressure. Nevertheless, Glaso's correlation is considered to be one of the more accurate
101 correlations available (Ahmed, 2001, Chapter 2) and is pertinent to our study given that is based on
102 oils exclusively from the North Sea. Furthermore, in the analysis that follows, the formation volume
103 factors are applied at initial reservoir pressures, which are typically above or near bubble point.

104

105 The blue line in Figure 2b shows monthly oil production at RC. This was obtained by multiplying
 106 monthly oil production at SC by the formation volume factor, B_o , based on the initial reservoir
 107 pressure. Also of interest is the cumulative average rate (in green). This gives information
 108 concerning how the lifetime average rate changes with time. It is clear that there is a gradual decline
 109 in the cumulative average oil production rate, which is due to the depletion of the oil within the
 110 reservoir.

111
 112 However, to draw insights concerning CO₂ injection, it is of greater interest to consider an estimate
 113 of bulk (i.e., oil, gas and water) monthly fluid production at RC, V_b (BBL), found from

$$115 \quad V_b = B_o V_o + (V_g - R_s V_o) / E_g + B_w V_w \quad (1)$$

116
 117 where V_o (BBL), V_g (SCF), V_w (BBL) are the monthly productions of oil, gas and water,
 118 respectively, at SC and B_w (-) is the formation water volume factor (similar to B_o but for formation
 119 water). The formation water volume factor can be obtained by consideration of the density
 120 correlations presented by Batzle and Wang (1992).

121
 122 Cumulative average Bulk fluid Production, $\bar{V}_b$, (CBP) for Balmoral is shown as a red line in Figure
 123 2b. As can be seen, $\bar{V}_b$ is virtually independent of the oil production rate and dependent more on the
 124 water injection that occurs during the first 10 years (compare Figure 2a).

125
 126 Another quantity of interest is the net bulk fluid production, $V_{b,net}$ (BBL), which is found from

$$128 \quad V_{b,net} = V_b - V_{g,inj} / E_g - B_w V_{w,inj} \quad (2)$$

129
 130 where $V_{g,inj}$ (SCF), $V_{w,inj}$ (BBL) are the monthly injections of gas and water, respectively, at SC.

131

132 Cumulative average net bulk fluid production, $\bar{V}_{b,net}$, for Balmoral is shown as a turquoise line in
133 Figure 2b. Again it can be said that, $\bar{V}_{b,net}$ is virtually independent of the oil production rate.
134 However, net fluid production is negative at the beginning of operations due to large quantities of
135 water injection. But after 20 years, net fluid production starts to converge although still exhibiting a
136 moderate decline. This latter decline may be due to constraints associated with fluid production in
137 the reservoir associated with bulk transmissivity and compressibility of the reservoir as a whole.
138 Alternatively, it could also be case that the decline is due to increasing water cut in the producers,
139 thus increasing the gravity head in the well and thereby reducing the flow rates or even leading to
140 lift die out in some wells.

141

142 It is reasonable to compare the net CBP with an equivalent CO_2 injection rate. Assuming a CO_2
143 density of 629 kg/m^3 (quite representative of CO_2 density at reservoir conditions), it can be said that
144 1 Mt will take up a volume of 10 million barrels (MMBBL).

145

146 However, the following caveats should be understood:

147

148 (1) Although a correction has been made in terms of fluid density, the above analysis ignores effects
149 associated with differences (between CO_2 and the originally produced fluids) in fluid
150 compressibility and viscosity.

151

152 (2) For oil/gas production, production rates are often reduced with respect to the maximum possible
153 production rates for reservoir management reasons (such as avoiding early water or gas
154 breakthrough). It is not clear for how many of the 104 datapoints this is the case.

155

156 (3) For oil/gas production, the production could be well constrained (notably lift problems after
157 water breakthrough) rather than reservoir constrained. It is not clear for how many of the 104 fields
158 this is the case. Also, for production, a relatively small tubing size may have been selected to avoid
159 lift problems later on in the field life. For CO₂ injection, tubing size is still a consideration, but
160 optimal tubing size could be larger.

161

162 The Balmoral field is convenient in this context. However, the Ninian field represents a more
163 problematic example. Production history and estimates of cumulative average production rates for
164 Ninian are shown in Figure 4. The first issue is that, for the first ten years, the CBP is less than the
165 cumulative average oil production (compare red and green lines in Figure 4b). This is because no
166 gas production (or water production for that matter) was reported for that period (see green line in
167 Figure 4a) although gas must have been produced with the oil (consider the $(V_g - R_s V_o) / E_g$ term in
168 Eq. (1)). The next problem is that towards the end of the field life, as much fluid is being injected as
169 produced so as to continue oil production. Consequently the net CBP is virtually zero towards the
170 end.

171

172 Parameters required for the Glaso (1980), Peng and Robinson (1977), Standing (1977), Spivey et al.
173 (2007) and Batzle and Wang (1992) correlations include reservoir temperature, T (°F), initial
174 reservoir pressure, P (psi), specific gravity of the gas (relative to air at SC), γ_g (-), oil gravity, API
175 (°API), the gas oil ratio at bubble point, R_{sb} (SCF/BBL), and water salinity, SAL (ppm NaCl eq.).

176

177 For many of the fields listed in DECC (2013), most of the parameters described above can be found
178 from Abbots (1991) and/or Gluyas and Hichens (2003) (both of these documents are referred to
179 hereafter as AGH). However, special considerations include γ_g and R_{sb} .

180

181 For fields with a specified gas expansion factor, E_g , a value for γ_g is calculated by iterative solution
182 of the Peng and Robinson (1977) EOS, otherwise the AGH γ_g value is assumed.

183

184 A value of R_{sb} is obtained by assuming reservoir pressure is initially above bubble point and
185 calculating R_{sb} based on the mean of the first four months of SC oil and gas production data. The
186 Glaso (1980) correlation is then used to estimate the bubble point pressure. If the estimated bubble
187 point pressure is less than the initial reservoir pressure, the aforementioned value of R_{sb} is accepted.
188 Alternatively, the reported bubble point pressure from the AGH dataset is used with the Glaso
189 (1980) correlation to calculate an alternative estimate of R_{sb} . If none of the above is possible, the R_s
190 value reported in AGH is assumed to be R_{sb} .

191

192 Where pressure data is absent, a hydrostatic pressure gradient is assumed. Where reservoir
193 temperature is absent, a geothermal gradient of 0.0179 °F/ft with a surface temperature of 52.8 °F is
194 assumed (obtained by linear regression of the AGH temperature and depth to crest data). Where γ_g ,
195 API and SAL are absent, mean values for the AGH dataset are assumed. Mean values of γ_g , API
196 and SAL for all the fields reported in AGH are 0.794, 36.9°API and 126,000 ppm NaCl eq.,
197 respectively.

198

199 Note that this mean value of salinity is not realistic for some reservoirs. The Permian and some of
200 the Upper Jurassic are near salt saturation whereas some other reservoirs in the Upper Jurassic are
201 much less at around 70,000 ppm and the Brent is less saline than sea water (Warren and Smalley,
202 1994). However, the SAL parameter is only required for calculation of B_w , the sensitivity of which,
203 in comparison to expansions associated with the oil and gas, is virtually negligible. It was necessary
204 to apply the mean value of salinity to 20 of 104 reservoirs.

205

206 **Statistical analysis of DECC production data**

207

208 Cumulative distributions for the CBP data from DECC (2013) are shown in Figure 5. The data have
209 been separated out into oil fields without water flood, gas fields and oil fields with water flood.
210 Note that for the fields with water flood, both gross and net production data are presented (Figs 5c
211 and d, respectively). Also note that these data are production rate per well. This has been obtained
212 by dividing the field-scale data, as discussed in the previous section, by the number of production
213 wells in the field. The number of production well data has been obtained from DECC (2007) and
214 the AGH dataset. Probability of non-exceedance (PNE) has been calculated using the Weibull
215 plotting position (Makkonen, 2006).

216

217 The data in Fig. 5 have been further separated to show how CBP statistics vary with production
218 time. The statistics for the oil fields without water flood are relatively stationary with time (Figure
219 5a). The remainder of the fields exhibit relative stationary statistics for the first 10 to 15 years and
220 then trend towards a reduced production rate, with the exception of the 25 years production for the
221 gas field data (Fig 5b.). However, the latter should not be considered in too much detail as there are
222 only two recorded gas fields that produced for that duration.

223

224 Another way to visualise the data is to consider Figure 6a, which shows plots of CBP against
225 production time for the four categories displayed in Figures 5a-d for PNE of 30%, 50% and 70%.
226 Here it can be seen that the categories in order of decreasing 50% PNE CBP are gas fields, oil fields
227 without water flood and oil fields with water flood. Plotted alongside in Figure 6b are the number of
228 fields active for a given production time, from which it can be seen that there is a moderate
229 correlation between the decline in production rate after 15 years and a decline in the number of
230 fields active after 15 years.

231

232 **Comparison with CO₂ injection data**

233

234 Figure 7a compares the cumulative distributions of CBP, after 10 years of production, for oil fields
235 without water flood, gas fields and oil fields with water flood (net production) with injection rate
236 data from CO₂ storage projects from around the world. The latter data was obtained from Table 4 of
237 Hosa et al. (2011) for 15 projects including Sleipner, Snohvit, Weyburn and In Salah. Hosa et al.
238 (2011) report mass injection rates in tonnes per day. These are converted to MMBBL/yr by
239 assuming a CO₂ density of 629 kg/m³ such that 1 Mt = 10 MMBL, as discussed above. The 50%
240 PNE for net CBP for the oil fields, gas fields and water flood fields are 3.51, 3.38 and 0.416
241 MMBL/yr/well, respectively. The good (high injection rate per well) CO₂ projects are similar to
242 the good gas fields. The more limited CO₂ projects are similar to the oil fields with water flood.

243

244 Hosa et al. (2011) also reports corresponding reservoir transmissivities (i.e.,
245 permeability × formation thickness). Similar data are available for the oil and gas reservoirs from
246 AGH. Figure 7b compares plots of CBP against transmissivity for oil fields without water flood, gas
247 fields and oil fields with water flood alongside the CO₂ injection data from Hosa et al. (2011).
248 Interestingly, gas fields are clustered in the lower right of the plot. This may be largely due to the
249 lower viscosity of gas as compared with oil. However, overall it can be said that there is very little
250 correlation between production/injection rate with transmissivity. Nevertheless, it is interesting to
251 note that distribution of CO₂ injection data shares a similar space to the DECC production data.
252 Overall, Figures 7a and b provide a good basis for using the oil and gas production data to provide
253 additional insights concerning future CO₂ injection rates.

254

255 It should be understood that many of the CO₂ injection rates in the Hosa et al. (2011) study are
256 constrained by factors other than injectivity. Sleipner is constrained to 1 MT/year due to plant
257 design. Weyburn is an EOR (Enhanced Oil Recovery) operation where the amount of CO₂ injected
258 is driven by optimisation of oil recovery and CO₂ price. Furthermore, many of the low-rates are

259 attributed to small-scale test projects where testing of monitoring technologies was a main focus
260 (e.g. Ketzin). Nevertheless, the Hosa et al. (2011) study represents a useful reflection concerning
261 injection rates that have actually been achieved to date.

262

263 **Insights from water flooding**

264

265 The number of injection wells required for a given CO₂ storage site can be reduced by
266 implementing pressure relief via nearby brine production wells (Cavanagh et al., 2010; Neal et al.,
267 2011). However, the effectiveness of pressure relief by brine production is strongly dependent on
268 reservoir connectivity (Neal et al., 2011). Furthermore, Neal et al. (2011) show, through numerical
269 modelling, that brine production only becomes economically beneficial in this context when brine
270 production leads to a greater than 10% reduction in the number of required wells. The water flood
271 data discussed above can be used to explore this issue further.

272

273 Taking the net CBP as a lower bound estimate of the gross CBP that would have occurred in the
274 absence of water flood, an upper bound estimate of productivity improvement factor, as a
275 consequence of water flood, can be obtained by considering the ratio of gross fluid production to
276 net fluid production. This factor can then be used to indicate a possible increase in CO₂ injectivity
277 one would get in the same reservoir when implementing brine production.

278

279 A comparison of gross production with net production for water flood fields after 10 years of
280 production is presented in Figure 8a. This represents data from a total of 57 oil fields. The 50%
281 PNE for net and gross CBP are 0.416 and 1.40 MMBBL/yr/well, respectively, which, in effect,
282 quantifies the improvement in productivity obtained by water flooding. Interestingly, the data also
283 suggests an 8.6% probability of not exceeding zero net CBP. This is because some of the fields
284 have negative net CBP (consider again Figure 4b).

285

286 Figure 8b shows the cumulative distribution for the ratio of gross to net CBP. Note that for ease of
287 interpretation, fields with negative net CBP have been excluded from Figure 8b, which is
288 conservative in this context. The results in Figure 8b indicate a 50% probability of not exceeding
289 (or exceeding) a gross to net CBP ratio of 2.5. Assuming one injection well for every production
290 well, this can be shown to correspond to a predicted reduction in number of wells due to brine
291 production of 20%. Furthermore, a 10% reduction in number of wells corresponds to a gross to net
292 CBP ratio of 2.22, which, according to Figure 8b, corresponds to a PNE of 42.6%. Combining
293 Figure 8b with the analysis of Neal et al. (2011) in turn leads to the idea of a 57.4% probability that
294 brine co-production during CO₂ injection, in the UK offshore region, is likely to be economically
295 beneficial.

296

297 Most of the water flood fields would have yielded higher CBP unaided than their net CBP with
298 water injection. For example at Ninian (recall Figure 4b), net CBP was negative. Obviously, Ninian
299 would have yielded a positive CBP unaided. Therefore it should be realised that the ratio of gross to
300 net CBP is likely to be an overestimate of injectivity improvement (due to water flooding) for many
301 of the fields included. This overestimation has been partially mitigated by the exclusion of fields
302 with negative net CBP. Nevertheless, it would be unwise to interpret the extreme values in Figure
303 8b in this context.

304

305 **Possible performance indicators**

306

307 Figure 7b shows that there is very little correlation between production rate and transmissivity.
308 Other important aspects include the size of the reservoir compartment and connectivity to outer
309 aquifer systems (Zhou et al., 2008; Mathias et al., 2011a; 2013a; Chang et al., 2013). Within the
310 AGH dataset, the various oil and gas reservoirs are designated a structure type. Terms applied for a

311 given reservoir include: structural; stratigraphic/unconformity; four-way dip antiform/anticline;
312 four-way closure over salt diaper, tilted fault block; three-way dip & fault; faulted pericline; faulted
313 rollover; updip pinch-out; combined stratigraphic/structural; combined tilted and inverted fault
314 block and combined anticline and stratigraphic. We have consolidated these further to just four
315 categories: structural; 4-way closure; with a fault seal; and stratigraphic/structural. Figure 9 shows
316 how reservoir productivity partitions out for the four categories. The statistics are almost identical
317 for each category except for stratigraphic/structural, which come out with better production rates.

318

319 Interestingly, the AGH dataset comments on reservoir mechanisms. Mechanism designations
320 include: pressure depletion drive; gas cap expansion drive; aquifer/natural water drive; gravity
321 drive; water flood/water injection; combined aquifer and gas expansion drive; combined aquifer
322 drive and gas injection; combined water injection, gas injection and depressurization; gas recycle;
323 combined full voidage replacement and water injection; combined depletion and water flood;
324 combined aquifer drive and water injection. We have consolidated these further to just three
325 categories: no aquifer; aquifer drive; and water flood. Figure 10 shows how reservoir productivity
326 partitions out for three mechanism designations. Here it can be seen that where there is no water
327 injection, there is little difference between statistics associated with reservoirs with and without
328 aquifer drive.

329

330 Fields selected for water flood exhibited significantly lower net CBP rates compared with fields not
331 employing water injection. In part this is a function of the way in which fields under water flood are
332 managed. Typically, the early phase of production is through depletion drive and consequential
333 pressure drop. The pressure drop is commonly halted just above bubble point through water
334 injection. The field is then managed at just above bubble point. The reason for doing this is to
335 minimise the energy required for injection while avoiding the problems associated with relative
336 permeability loss if gas starts to break-out within the reservoir. Consequently, when we examine old

337 fields with very long injection and production phases, the overall net volume change in the reservoir
338 can be very small (Figure 5d), particularly in instances where late field life has been accompanied
339 by overvoidage (e.g. Figure 4).

340

341 Another interesting indicator is reservoir age. Figure 11 shows how reservoir productivity partitions
342 out for different geological ages. Of note is that the Triassic and, albeit to a lesser extent, the
343 Permian reservoirs have statistically better productivity than the remainder. Both these sets of fields;
344 Permian gas fields of the Southern North Sea and Triassic oil and gas fields of the Central and
345 Southern North Sea respectively have been developed with depletion drive alone. As such the
346 Permian and Triassic data are likely to be a better indicator of long term injectivity potential for
347 CO₂.

348

349 The slight difference between the Jurassic (poorer) and Cretaceous/Tertiary performance may be a
350 reflection of the larger unbroken sandstone bodies of the Cretaceous/Tertiary relative to the older
351 reservoirs.

352

353 **Summary and conclusions**

354

355 The objective of this article was to present a statistical investigation concerning production rates in
356 UK offshore oil and gas reservoirs, with a view to gaining further insight concerning forecasting of
357 likely injection rates for similarly located CO₂ storage projects in the future. Production data was
358 sourced from DECC (2013), which reports field-scale monthly production and injection of oil, gas
359 and water. These data are reported at standard conditions. So as to compare to possible CO₂
360 injection rates, it was necessary to convert these data to reservoir conditions and integrate into a net
361 Cumulative averaged Bulk fluid Production (CBP). This was achieved by virtue of the fluid
362 properties data presented in Abbotts (1991) and Gluyas and Hitchens (2003) (referred to collectively

363 as AGH) in conjunction with correlations presented by Batzle and Wang (1992), Glaso (1980),
364 Peng and Robinson (1977), Spivey et al. (2007) and Standing (1977). Assuming a CO₂ density of
365 629 kg/m³, 1 Mt of CO₂ is equivalent to a CBP of 10 MMBL. Note that the term bulk fluid
366 production is used here to describe the composite volume of oil, gas and water produced at reservoir
367 conditions.

368

369 It was found that CBP statistics became temporally less stable after between 10 and 15 years of
370 production (Figure 5). Furthermore, it was found that the number of active oil and gas fields started
371 to decline significantly after 15 years of production (Figure 6). It was therefore decided to consider
372 CBP after 10 years of production for the remainder of the study. CBP statistics were then compared
373 to existing CO₂ injection data (after Hosa et al., 2011) (Figure 7). It was found that net CBP from
374 water flood fields was significantly less than from gas fields and oil fields without water flood. The
375 largest and smallest CO₂ injection rates were found to be similar to net CBP for the largest gas field
376 and smallest water flooded fields, respectively. The 50% probability of non-exceedance (PNE) for
377 net CBP for the oil fields, gas fields and water flood fields were 3.51, 3.38 and 0.416
378 MMBL/year/well, respectively, which equates to around 0.35, 0.34 and 0.04 Mt/year/well of CO₂
379 equivalent, respectively.

380

381 The 50% PNE for gross CBP in the water flood fields was 1.40 MMBL/year/well. The
382 improvement on productivity due to water flooding was investigated further by studying the
383 statistics of gross to net CBP ratio for the water flood fields. Improved productivity leads to
384 reductions in the number of wells required. In the same way, brine co-production during CO₂
385 injection is thought to lead to reduced numbers of wells for CO₂ storage operations. The 50% PNE
386 gross to net CBP ratio for the water flood fields was 2.5 (Figure 8b). Assuming one injection well
387 for every production well, this corresponds to an equivalent reduction in number of wells of 20%.
388 Numerical work by Neal et al. (2011) suggests that brine co-production becomes economically

389 beneficial for CO₂ storage operations, providing this leads to a reduction in number of wells of
390 more than 10%.

391

392 CBP was found to have very little correlation with reservoir transmissivity. Through a study of
393 alternative variables including reservoir structure, reservoir mechanism and reservoir age, it was
394 found that reservoir mechanism and reservoir age had the strongest control on CBP. In terms of
395 reservoir mechanism, those reservoirs selected for water flood exhibited significantly reduced net
396 and gross CBP as compared to other reservoirs. In terms of reservoir age, the Triassic and Permian
397 reservoirs had the highest CBP. However, this may be largely due to the fact that less reservoirs in
398 the Triassic and Permian were selected for water flood.

399

400 Overall, the following key findings can be asserted: (1) CBP statistics for UK offshore oil and gas
401 fields are similar to those observed for CO₂ injection projects worldwide. (2) The 50% PNE for
402 CBP for oil and gas fields without water flood is around 0.35 Mt/yr/well of CO₂ equivalent. (3)
403 There is negligible correlation between reservoir transmissivity and CBP. (4) Study of net and gross
404 CBP for water flood fields suggest a 50% PNE that brine co-production during CO₂ injection could
405 lead to 20% reduction in the number of wells required.

406

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412

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492 Figure 1: Map of UK showing locations of the oil and gas fields studied. In the legend, “water
 493 flood” refers to oil fields where water injection has been used and “oil fields” refer to oil fields
 494 where water injection has not been used.

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500 Figure 2: Time series plot of monthly production for the Balmoral field. a) Assuming standard
 501 conditions (SC). Note that data here are production data except for “Water Inj.” and “Gas Inj.”,
 502 which are injection data. b) Assuming reservoir conditions (RC). Note that “Cum. Av.” is an
 503 abbreviation for cumulative average and “Net Fluid” involves subtracting the injected water and
 504 gas.

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506

507 Figure 3: Plots of gas expansion factor, gas oil ratio and formation volume factor against pressure,

508 as assumed for the Balmoral field. Assumed associated parameters include $T = 207$ °F, $\gamma_g = 0.79$,

509 $API = 39.9$, $R_{sb} = 352$ SCF/BBL.

510

Figure 4: Same as Figure 2 but for the Ninian field.

516

517 Figure 5: Cumulative distribution plots for net CBP rate (at RC) per well for varying production
 518 times (as indicated in legend). a) Oil fields. b) Gas fields. c) Net production for oil fields with water
 519 flood. d) Gross production for oil fields with water flood.

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521

522 Figure 6: a) Plot of 30, 50 and 70 probability of non-exceedance (PNE) for net CBP rate (at RC) per
 523 well against production time for oil fields, gas fields and oil fields with water flood (both net and
 524 gross production rates), as indicated by the legend in Figure 5b. b) Plot of number of fields active
 525 for a given production time for the three categories: oil fields, gas fields and oil fields with water
 526 flood.

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Figure 7: a) Cumulative distribution plots for net CBP rate (at RC) per well after 10 years of production for the oil fields without water flood, gas fields and oil fields with water flood and the CO₂ injection data reported by Hosa et al (2011) (assuming a CO₂ density of 629 kg/m³ such that 1 Mt/yr = 10 MMBBL/yr). b) The same production data but plotted against the transmissivities of the reservoirs. Transmissivity is calculated using net thickness with the exception of those data provided by Hosa et al. (2011), which used gross thickness.

Figure 8: a) Cumulative distribution plots for CBP rate (at RC) per well after 10 years of production for the oil fields with water flood, both gross and net production rates. b) Cumulative distribution plot for the ratio of gross to net CBP for oil fields with water flood.