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1 2	Determining static reservoir connectivity using noble gases
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15 16	Highlights
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18 19	 Outlines a new methodology to obtain fluid samples for noble gas analysis from PVT cells
20 21	 Provides the first intra-field noble gas study using samples collected directly from individual reservoir units
22	 Demonstrates the application of noble gases for resolving reservoir connectivity
23	Resolved the lateral connectivity of two fluid phases separated by fault
24	
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26	Keywords
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28 29	Noble gas; Fingerprinting; Geochemical tracing; Reservoir connectivity; Tormore; Gas connectivity; Oil connectivity; Vertical connectivity; Lateral connectivity
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31 Abstract

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33 Determining the connectivity of fluids in hydrocarbon reservoirs is a key challenge during the 34 appraisal stage. Such information is critical for assessing the economic viability and planning 35 its development. Although several tools exist to determine static connectivity and the fluid 36 column organisation post-hydrocarbon emplacement, it is extremely difficult to determine the extent of the connectivity between fluids of different phases. Conventional connectivity 37 studies on the Tormore field, West of Shetland Basin, UK have resolved the vertical 38 39 connectivity of one well (T2) but have been unable to resolve further vertical or lateral 40 connectivity. Here, we outline a new tool for assessing hydrocarbon connectivity by 41 completing the first intra-field connectivity study of the noble gas composition (He, Ne, Ar, Kr 42 and Xe) of fluids from individual reservoir units, allowing the resolution of both the vertical and lateral connectivity within the Tormore field. To achieve this, we obtain fluid samples 43 44 from archived PVT vessels rather than from the wellhead or platform separators, allowing sampling of the individual reservoir units obtained during drilling. Our findings corroborate 45 46 previous connectivity studies undertaken on the oil well, T2, confirming that the reservoir unit 47 of T2-A is isolated from the lower reservoir units. We apply the same method to the gas well, 48 T3, finding that unit T3-A is isolated from the lower reservoir units. In addition, we identify a 49 previously unknown connection between the gas and oil phase that is separated by a poorly constrained fault. These findings confirm the effectiveness of using noble gas fingerprints to 50 assess the connectivity of fluids in different phases, providing a new tool for understanding 51 52 connectivity in hydrocarbon and non-hydrocarbon settings (Carbon, Capture and Storage).

54 1 Introduction

55 56

1.1 Introduction to connectivity

57 Determining the connectivity of hydrocarbon fluids within a reservoir is a crucial component of the appraisal stage of a field. Whilst definitive data to quantify fluid connectivity are 58 59 generated once the reservoir enters the production phase, it is extremely difficult to obtain 60 this data during the appraisal phase when critical decisions on the viability of the reservoir need to be taken. Many methods have been developed to assess the connectivity of a 61 62 reservoir prior to production (e.g. Jolley et al., 2010 and papers within; Elshahawi et al., 2008) 63 but only rarely can all potential scenarios be fully resolved. Furthermore, it is currently 64 particularly difficult to assess the connectivity between fluids of different phases.

This study investigates the interaction of fluids (connectivity or continuity) instead of barriers to fluid flow (compartmentalization). Connectivity is defined as the exchange of atoms, molecules or fluids between two bodies. Connectivity within a field varies on timescales ranging from the geological scale (>10,000 years) and production lifetime (<40 years) (Snedden *et al.*, 2007). These are defined as static and dynamic connectivity, respectively.

Static connectivity describes the state of the field prior to production, whereas dynamic connectivity describes the movement of fluids once production has commenced (Snedden *et al.*, 2007). It is also important to define the direction of connectivity in the vertical and lateral sense. Vertical connectivity is the communication of different reservoir units at varying depths within the same panel or fault block. Lateral connectivity is the communication within the same reservoir unit or across a physical discontinuity, e.g. a fault.

Poorly constrained connectivity has a profound and detrimental effect on hydrocarbon recovery; therefore, it is essential to resolve reservoir connectivity as early and as completely as possible during the exploration phase (Smalley & Muggeridge, 2010). 3D seismic, well logs and core analysis provide invaluable data and images over a large area during the exploration phase, allowing the identification of compartmentalization. However, these indirect methods cannot provide direct evidence or predict fluid behaviour.

There are three main conventional tools used to assess fluid connectivity of a hydrocarbon reservoir: drill stem test (DST) and formation testing; organic geochemistry; and thermodynamic modelling (Table 1.1). A DST is the first opportunity to directly investigate the

connectivity of a field during the exploration/appraisal phase. This technique permits analysis
of accumulating pressure in the well and pressure changes in nearby wells (i.e. an interference
test). This can be used to provide an estimate of the reservoir volume and the likely
connectivity can be resolved to a kilometre scale.

Formation testers, e.g. a Wireline Formation Tester (WFT), are downhole tools that sample reservoir fluids and record the pressure from each reservoir unit. If the pressure for each reservoir unit does not follow a common or resolvable pressure gradient, then the units are likely to be disconnected. However, the opposite is not true, i.e. if samples from the same phase follow a gradient, this is not conclusive evidence for a connection between the reservoir units.

95 Several conventional methods exist for the geochemical analysis and comparison of fluids. 96 There are two main fields, qualitative, e.g. comparing and contrasting the organic 97 geochemistry of the hydrocarbon fluid (e.g. Sammons maps) and quantitative, e.g. 98 investigating the statistical significance of differences in hydrocarbon composition (e.g. Inter-99 Quartile Range treatment (IQR treatment)). These methods follow the same logic as many 100 geochemical tools, where selected compounds are used to highlight differences or similarities 101 within samples. However, both methods have their limitations for assessing connectivity as 102 they focus on $C_7 - C_{20}$ molecules. As a result of the wide range of hydrocarbon molecules 103 required this method is only applicable to the liquid phase. When this method is applied to a 104 gas phase there is insufficient liquid fraction available to sample, thus, any analysis is often 105 below the significance threshold and is therefore inconclusive.

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1.2 The rationale for noble gases

The noble gases (He, Ne, Ar, Kr and Xe) are present in trace quantities in all crustal fluids. They do not react with or degrade within hydrocarbon reservoirs in the same manner as organic tracers and hence provide ideal tracers of fluid interaction. Their distribution in crustal fluids is the result of physical interactions between different fluid sources and phases (Ballentine *et al.*, 1991; Pinti & Marty, 1995; Kipfer *et al.*, 2002; Burnard, 2013; Prinzhofer, 2013). Consequently, noble gases can be used to interpret the physical processes that are poorly constrained by reactive tracers.

In the study, we mainly focus on the atmosphere-derived noble gases (²⁰Ne, ³⁶Ar, ⁸⁴Kr and 116 117 ¹³²Xe). These noble gases enter the meteoric water cycle during gas partitioning between the 118 atmosphere and the surface of a large body of water e.g. an ocean. When these waters enter 119 the subsurface either through aquifer recharge, pore trapping and/or wet sediment burial, an 120 atmosphere-derived noble gas signature is imparted in the subsurface. Post-burial there is no 121 other significant source of atmospheric noble gas in the subsurface. The trapped water is no longer able to exchange material with the overlying body of water, and therefore, the 122 groundwater is isolated. Once isolated, the atmosphere-derived noble gas composition is 123 124 unaffected by mixing with other waters or interacting with other fluids. Two other sources of 125 noble gas exist in the subsurface (mantle and crustal), however, these bear no effect as they 126 are devoid of atmosphere-derived isotopes. In petroleum systems, groundwater (e.g. an 127 underlying aquifer) is rarely sampled or not encountered, hence, the groundwater 128 composition is often unknown. Due to the unreactive nature of noble gases, it is possible to 129 calculate the groundwater composition. Gas-specific Henry coefficients are assumed to 130 depend on the temperature and salinity of the water (Fanale et al., 1971; Crovetto et al., 131 1982; Castro et al., 1998; Kipfer et al., 2002). Therefore, the key control of atmosphere-132 derived noble gas signature in the subsurface is the temperature and salinity at the point of equilibrium (Konig, 1963 and Weiss, 1970). Thus, the equilibrium conditions at the point of 133 134 recharge control groundwater composition. This unambiguous origin of atmosphere-derived 135 noble gases provides great utility for understanding subsurface process e.g. assessing 136 hydrocarbon migration, storage and connectivity.

137 Previous noble gas studies have focussed on basin-wide and inter-field scale fluid migration, 138 allowing the source, the degree of mixing between hydrocarbons and aqueous fluids isolation time, be determined (Zwaikowski & Spangler, 1990; Hiyagon & Kennedy, 1992; Ballentine et 139 140 al., 1996, 2002; Torgersen et al., 2004; Barry et al., 2016, 2017, 2018a,; Byrne et al., 2018, 2020). Other work has explored the interaction of natural CO₂ with formation waters (Gilfillan 141 142 et al., 2008, 2009, 2014) along with tracing the fate of CO_2 in response to injection for enhanced oil recovery (Györe et al., 2015, 2017; Barry et al., 2018b; Tyne et al., 2019) and for 143 144 the identification of compartmentalization in ancient fracture networks (Warr et al., 2018). However, to date noble gases have not been specifically applied for the assessment of intra-145 146 field connectivity between individual wells and reservoir compartments.

147 The principle of using noble gases for assessing reservoir connectivity follows the same logic as many conventional industry tools. Given time, a well-connected reservoir will reach a 148 149 steady-state equilibrium with a predictable distribution of noble gases across a reservoir. 150 Therefore, we can assume that spatially varying fluid related properties are good indicators of disconnection (Smalley & Muggeridge, 2010). When results diverge from the predicted 151 152 distribution, this identifies an additional process such as flow retardation along a fault or 153 baffle, or the influence of a recent external processes such as gas leakage (Montel et al., 1993). Such features and mechanisms can delay or perturbing the return to steady-state 154 155 conditions (Kaufman et al., 1990; Elshahawi et al., 2005). When considering reservoir 156 connectivity, a reservoir unit that is disconnected may have a distinctive noble gas fingerprint 157 due to their isolation (Hunt et al., 2012; Darrah et al., 2014, 2015). If the reservoir units are 158 connected and in communication, then a resolvable distribution of noble gases across the 159 field can be observed.

160 In this study, we use noble gas ratios as unique fingerprints of each reservoir unit to assess 161 the source and physical processes that have acted upon the fluids. Which in turn can show evidence of disconnection and connection. We recognise three distinct fingerprints for noble 162 163 gases: 1) Primordial, sourced from the mantle, entrained during the Earth's accretion (Oxburgh et al., 1986; O'Nions and Oxburgh, 1988; Honda et al., 1991; Burnard et al., 1997; 164 Graham, 2002). 2) The crustal component, inherited from the hydrocarbon source rock and 165 the in situ radiogenic and nucleogenic generation in the reservoir (⁴He & ⁴⁰Ar) or from 166 167 migration through an aged aquifer to the trap (Morrison and Pine, 1955; Sarda et al., 1988; 168 Kennedy et al., 1990; Moreira and Allegre, 1988; Ballentine and Burnard 2002). 3) The primordial aquifer component, an atmosphere-derived component which enters the 169 subsurface via aquifer recharge and/or entrained in the original formation water of the 170 171 sediment (Kipfer *et al.*, 2002). Initial fingerprints can be altered by physical processes such as diffusive fractionation (e.g. Prinzhofer and Battani, 2003) related to hydrocarbon migration 172 173 distance, leakage of fluids from or on-going charging of the field (e.g. Battani et al., 2000; Barry *et al.*, 2016) and by equilibration within the reservoir, e.g. the exchange of noble gases 174 175 at the water-oil contact (OWC) (Figure 1Error! Reference source not found.).

Here we present new noble gas isotope and abundance data from the Tormore field, West ofShetland basin. The Tormore field is a diphasic system where conventional methods for

178 assessing reservoir connectivity have failed to confidently resolve the connectivity of the field, 179 particularly between the oil and gas phases, making it an ideal candidate for investigating the 180 role that noble gases can play in assessing connectivity. Fluid samples were collected 181 downhole directly from individual reservoir units, permitting a detailed study of the role that 182 noble gases can play in establishing reservoir connectivity.

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184 2 Geological Background

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2.1 The West of Shetland Basin

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The Faroe-Shetland Basin is situated in the north-eastern part of the North Atlantic margin. Bound by the Wyville-Thomson ridge to the south-west; the Nordland-Silje transfer fault in the north-east; and the Shetland Platform to the south-east. Mesozoic extension created the accommodation space for thick sedimentary sequences within the basin and the majority of the West of Shetland ridges: Shetland Platform, Corona, Rona and Flett Ridge (Naylor *et al.*, 1999).

193 The Early Paleocene c.62 Ma marks the onset of seafloor spreading in the NE Atlantic and the 194 opening of the Faroe-Shetland Basin (White & McKenzie, 1989). Extension continued up to 195 and during the Paleocene. During the Eocene, a basin-wide regional uplift and inversion event 196 is attributed to creating the structural traps for many petroleum plays within the basin. The 197 observed inversion and uplift are interpreted as the result of plume buoyancy, magmatic 198 under-plating or a combination of both (Brodie & White, 1994). This event is well marked in 199 Paleogene stratigraphy through a series of regressive and transgressive depositional 200 sequences across the basin.

201 Dolerite sill complexes and associated dykes were intruded in the Upper Cretaceous-202 Paleocene intervals. Radiometric analysis has dated the intrusions from the Late Cretaceous 203 to Eocene in age (Ritchie & Hitchen, 1987; Naylor *et al.*, 1999). These sill complexes are 204 believed to be a key control of hydrocarbon migration across the Faroe-Shetland Basin (Iliffe 205 *et al.*, 1999).

2062.2 The Tormore field

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208 The Tormore field is located in Quadrant 205 (Figure 2Error! Reference source not found.). 209 Exploration of the basin has occurred for over 40 years but due to its complexity and isolation 210 from infrastructure, appraisal and production from field discoveries has been limited until 211 recently (Austin et al., 2014). The field is a simple monocline structure dipping to the northwest, on-lapping the Flett Ridge. The reservoir comprises of four reservoir units (A, B, C 212 213 & D) of well-sorted Paleocene turbiditic sand exhibiting a high average porosity and 214 permeability of 22 % and 30 - 300 mD respectively. The individual reservoir units are separated by hemipelagic shale layers, with a total reservoir thickness of 50 – 60 m. Seismic 215 216 studies have revealed a series of E-W antithetic normal faults throughout the field. A poorly 217 constrained normal fault with an unknown transmissivity separates T2 and T1 wells (Figure 218 **3Error! Reference source not found.**).

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220 Three wells (T1, T2 and T3) have been drilled and completed since exploration commenced in 221 2006, using a water-based drilling fluid. To date, neither a gas-oil contact (GOC) nor water-oil 222 contact (OWC) has been encountered. Well T2 encountered only oil and T1 and T3 penetrated 223 gas-condensate. Studies by the field operator indicate that the field has been charged by two 224 different fluids: initially, by a low-maturity dense fluid with a vitrinite reflectance equivalent (V_{re}) 0.8 %Ro, followed by a second more mature, low-density fluid (V_{re}~1.2 %Ro). These fluid 225 226 charges are well-mixed across the field and both V_{re} values are observed in both fluid phases. Therefore, the observed phases in the field are a result of Pressure, Volume and Temperature 227 (PVT) conditions and not a reflection of the fields charging history. The field is a closed system 228 229 with no evidence of leakage or spillage.

Conventional connectivity tools have enabled resolution of the vertical connectivity of T2.
This investigation concluded that reservoir unit T2-A is isolated from T2-C and T2-D (Figure 3)
but no other conclusions could confidently be drawn for the vertical and lateral connectivity
of the other wells or the remainder of the field.

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235 3 Sample collection and analytical techniques
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237 3.1 Sampling from PVT vessels
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All reservoir fluids were collected downhole from the individual reservoir units during the drilling process using a Wireline Formation Tester (WFT). A WFT collects 400 cm³ of virgin reservoir fluid under reservoir temperature and pressure (RTP) into a vacuum chamber after flushing the downhole sampling area of drilling fluid. These samples are then brought to the surface and stored onshore at reservoir pressure in conventional PVT sample storage vessels.

244 The specially constructed cells for collecting subsamples for noble gas analysis, comprised of 245 Swagelok stainless steel cells (35 cm³) sealed at each end with all-metal valves. Prior to being 246 transported to the PVT vessel storage facility, each sampling cell was pre-evacuated to below 247 10^{-7} mbar, baked at 60°C for 30 minutes and then helium leak tested. The cells were attached to the PVT vessel with a 0.25 cm³ stainless steel pipe and the system was heated above 50 °C 248 249 to minimise gas condensation. The sample cells were evacuated with a low vacuum pump to 250 10⁻² to 10⁻³ mbar for 15 minutes. The valves on the sampling cell were then closed and the 251 PVT vessel was equilibrated with the fluid in the connecting pipe for one minute. The PVT 252 vessel was then isolated, and the connecting pipe then evacuated for 5 minutes. This process 253 was repeated twice. For sample collection, the was PVT vessel equilibrated with fluid from the PVT vessel for 1 minute then the cell was filled with reservoir fluid at 2 - 3 bar g. 254

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3.2 Major volatile analysis

257 Methane and ethane compositions were determined using extended gas chromatography 258 using a GPA 2286 method utilising a multicolumn gas chromatograph system at Total's 259 laboratory following ISO 140001 and ISO 7000 compliant procedures.

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3.3 Noble gas analysis

Noble gas analysis was conducted at the Scottish Universities Environmental Research Centre
(SUERC) using a MAP 215-50 noble gas mass spectrometer. Helium, neon and argon
concentration and isotopic ratios were obtained using the procedures outlined by Györe *et al.*, (2015) and Kr and Xe were measured following procedures documented in Györe *et al.*,
(2017).

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269 4 Results

271 Nine reservoir units from three wells were sampled, resulting in the collection of 12 samples 272 (including 3 duplicates in T3). The reservoir interval sampled, well depth, natural gas data (C₁, 273 C_2 and $\delta^{13}C_{1-5}$ abundance), noble gas abundance and isotopic composition measurements are 274 documented in Table 2, Table 3 and Table 4. Reservoir units T2-B, T3-B and T1-A were not 275 sampled during the exploration drilling operations.

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4.1 Major volatiles and isotopic data

279 In the gas-condensate wells, T1 and T3, the major gases are dominantly hydrocarbons C₁ (86.6 280 - 87.3%); C₂ (3.8 - 4.0%) (Table 3). C₁/C₂ ratios are similar across both wells (21.8 - 23.2), 281 demonstrating that there is no leakage from the top of the field (Montel *et al.*, 1993). Isotopic values are broadly similar in the gas-condensate wells where, $\delta^{13}CH_4$ (-37.3 to -37.6), $\delta^{13}C_2H_6$ 282 $(-30.9 \text{ to } -31.1), \delta^{13}C_{3}H_{8}(-29.5 \text{ to } -29.7), \delta^{13}C_{4}H_{10}(-28.3 \text{ to } -29.23) \text{ and } \delta^{13}C_{5}H_{12}(-27.4 \text{ to } -28.1)$ 283 284 (Table 3.4). For the oil well, T2, the major gases comprised of hydrocarbons C_1 (62.2 – 62.8%); 285 C_2 (4.0 – 4.4%) (Error! Reference source not found.). For T2, the isotopic values are more negative than those in the gas phase δ^{13} CH₄ (-38.1 to -38.3), δ^{13} C₂H₆ (-30.7 to -31.1), δ^{13} C₃H8 286 $(-29.2 \text{ to } -29.9, \delta^{13}C_4H_{10}(-27.8 \text{ to } -28.0) \text{ and } \delta^{13}C_5H_{12}(-27.5 \text{ to } -27.6)$ (Table 3.4). 287

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4.2 Noble gases

⁴He/²⁰Ne ratios of all reservoir units range from 0.49 to 5525 (Table 3), with all but one sample (T1-B) being significantly above the air ratio of 0.32 and air-saturated seawater (ASSW) ratio of 0.252 (Kipfer *et al.*, 2002). There is a low in situ production of ⁴He due to low U and Th concentrations in the reservoir sandstones due to their low clay content. The elevated ⁴He/²⁰Ne ratios indicate that the atmospheric contributions in all samples are negligible with the exception of T1-B.

Helium (⁴He) concentrations range from 6.08×10^{-6} to 5.21×10^{-5} cm³ STP/cm³. ³He/⁴He values range from 0.051 ± 0.003 to 0.367 ± 0.034 R/R_A, (relative to the air value R_A = 1.384×10^{-6} , where air = 1 R/R_{A} ; Mamyrin *et al.*, 1970). These are resolvable excesses of crustal production and requires a contribution of mantle helium (Ballentine *et al.*, 2002). Using simple twocomponent mixing between sub-continental lithospheric mantle-like (6.1 R_A (Gautheron & Moreira, 2002)) and crustal (0.007 - 0.02 R_A) endmembers (Ballentine and Burnard, 2002; Day *et al.*, 2015) indicates that crustal contribution to the ⁴He concentration varies from 91.2 to
97.6%.

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²⁰Ne concentrations range from 5.81 x 10⁻⁹ to 4.26 x 10⁻⁸ cm³ STP/cm³. There is a clear correlation between ²⁰Ne concentrations and proximity to the predicted oil-water contact, where ²⁰Ne increases with depth (Table 2). ²⁰Ne/²²Ne vary between 9.65 ± 0.036 and 9.86 ± 0.039 indicating little deviation from atmospheric ²⁰Ne /²²Ne (9.80). ²¹Ne/²²Ne ratios vary between 0.0296 ± 0.0005 and 0.0319 ± 0.0004, all in excess of the atmospheric value of 0.0290 (Eberhardt *et al.*, 1965), this excess can be explained by an addition of crustal radiogenic ²¹Ne to air-like neon.

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⁴⁰Ar concentrations range from 2.12 to 4.96 x 10⁻⁵ cm³ STP/cm³. ⁴⁰Ar/³⁶Ar range from 398 ± 2 to 587 ± 4, indicating a significant deviation from the atmospheric ⁴⁰Ar/³⁶Ar value of 298.56 (Lee *et al.*, 2006) due to a resolvable contribution of radiogenic ⁴⁰Ar. ³⁸Ar/³⁶Ar values vary between 0.186 ± 0.007 to 0.190 ± 0.004 which overlap with the air ratio of 0.1885 (Lee *et al.*, 2006).

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⁸⁴Kr and ¹³²Xe concentrations range from 4.15 x 10^{-9} to 9.95 x 10^{-10} cm³ STP/cm³ and 1.98 x 10^{-10} to 4.15 x 10^{-10} cm³ STP/cm³, respectively. ¹³²Xe/⁸⁴Kr ratios range from 0.03 to 0.18, with most samples ranging between 0.10 - 0.18, significantly above both the air (0.03) and ASSW ratios (0.09) (Kipfer *et al.*, 2002).

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4.3 Groundwater noble gas components

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In this study ASSW is defined as a seawater which has equilibrated with air at 4°C (following
Kipfer *et al.*, 2002). Water-derived noble gases for ²⁰Ne/³⁶Ar range from 0.1260 ± 0.007 to
0.3417 ± 0.038, ⁸⁴Kr/³⁶Ar 3.66 x 10⁻³ to 5.32 x 10⁻² and ¹³²Xe/³⁶Ar 3.33 x 10⁻³ to 8.28 x 10⁻³.
Krypton and xenon in the majority of samples correlates with ³⁶Ar and ²⁰Ne showing clear
increase with depth (Table 2 & 3). This confirms that the main source of ⁸⁴Kr and ¹³²Xe in the
Tormore field is from the dissolved air-component present within the groundwater.
5 Discussion

5.1.1 Assessing sample quality and sampling procedure

PVT vessels are widely used in the hydrocarbon industry for preserving fluid at reservoir pressures in excess of 1000 bar for up to 10 years. Hence, the high-pressure sealing valves of PVT vessels can be expected to be sufficiently sealed to preserve the integrity of samples for noble gases over a prolonged period.

The standard method for collecting samples for noble gas analysis is purging stainless steel 341 342 cylinders or refrigeration grade copper tubes at the wellhead (e.g. Holland and Gilfillan, 2013) 343 or from platform gas separators (Ballentine et al., 1996). In this study, we use samples 344 collected from boreholes at depths of 3700 - 4000 m TVDss, directly sampling from the 345 reservoir unit and providing a specific depth. This method allows collection of a sample from 346 each individual reservoir unit, allowing a noble gas fingerprint for each unit to be obtained. 347 Thus, providing a greater depth resolution compared to samples collected at the wellhead. However, only a finite volume of reservoir fluid can be collected on the drill string (typically 348 349 400 cm³ per canister). This means it is not possible to use prolonged purging procedures to 350 ensure there is no contamination. As this is the first study to obtain noble gas samples from 351 such vessels, we investigate the integrity of the samples to atmospheric contamination.

The majority of samples (n = 10), have relatively consistent noble gas concentrations, though we observe two outlier samples (T1-B and T1-D) (Table 3.2 & 3.3). With the exception of T1-B, 4 He/ 20 Ne ratios (108 to 5525), demonstrating that atmospheric neon contributions in all but one of the samples is negligible.

356 In Figure 4, ²⁰Ne/³⁶Ar is plotted against ²¹Ne/²²Ne, highlighting that the samples with the most 357 nucleogenic neon isotope ratios also exhibit the lowest ²⁰Ne/³⁶Ar. We observe a mixing relationship between the most radiogenic sample, T3-D and the least radiogenic T2-A. Two 358 359 samples (T1-B and T1-D) clearly deviate from this trend. For T1-D, the lighter noble gases (He, 360 Ne) are consistent with the majority of samples, once a small addition of atmospheric air is accounted for. However, this is not the case for the Ar and Kr, where we observe a magnitude 361 lower measured ⁸⁴Kr compared to other samples and elevated ³⁶Ar, suggesting an addition of 362 atmospheric air (Table 2). 363

Whilst samples T1-B and T1-D were collected from the same well, there is no trend to the data that indicates the fractionation observed is a geographically distinct feature. It is more 366 likely that it is linked to the storage in PVT vessels for the 8 years prior to sampling for noble367 gas analysis. Hence, we exclude both from further interpretation.

Obtaining a sample at 2 – 3 bar in the sampling cell from a PVT vessel at reservoir pressure can result in mass-dependent fractionation, resulting in a loss of the lighter noble gases during each purge or flush. To assess the reliability of the sampling procedure, we examine the duplicates collected from each PVT vessel for Well T3.

- 372 In Figure 5, we plot ²⁰Ne/²²Ne against ²¹Ne/²²Ne, which illustrates clear repeatability between 373 the first sample collected (solid red marker) and the duplicate sample (red outline marker). 374 Samples from T3-A and T3-C are within 1 σ standard deviation in both ²⁰Ne/²²Ne and 375 ²¹Ne/²²Ne ratios. For T3-D, we observe an agreement in ²⁰Ne/²²Ne between the first sample collected and the duplicate, but not in ²¹Ne/²²Ne. The cause of this is unknown but is 376 potentially related to the smaller volume of fluid (~250 cm³) in the PVT vessel compared to 377 the larger 400 cm³ volume of the other PVT vessel sampled. Given the reproducibility of the 378 results from the duplicate samples, we conclude that we have obtained reliable noble gas 379 samples from PVT vessels and are not fractionating the noble gases during the flushing 380 381 process.
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383 5.1.2. Quantifying the amount of air in the samples

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385 ²⁰Ne is mainly concentrated in the air (typically 3 - 4 orders of magnitude higher in 386 concentration than encountered in the subsurface). Hence, it is an ideal indicator for 387 atmospheric air contamination in samples. In this study, we identify three endmembers 388 within our samples. Two are well-constrained, ASSW and atmospheric air (Ozima & Podosek, 389 2002) and a third, unknown endmember, representing the initial hydrocarbon signature. 390 Though the initial composition is unknown, a theoretical limit for the noble gas composition 391 in the hydrocarbons can be determined based on noble gases partition (Bosch & Mazor, 1988; 392 Barry et al., 2016).

In Figure 6, we plot ²⁰Ne against ²⁰Ne/³⁶Ar. Two mixing lines show the evolution between atmospheric air and ASSW (blue dashed line) and between atmospheric air and the theoretical noble gas composition in the hydrocarbon phase (red dashed line). The air hydrocarbon mixing line is constrained using the measurements from well T3. These samples

are the most recently sampled and the least concentrated in ²⁰Ne, and therefore, the least 397 398 likely to be contaminated. Where the theoretical compositional limit and air-hydrocarbon 399 mixing line intersect, we propose this as the hypothetical initial endmember of the 400 hydrocarbon fluids. From this endmember we can quantify the percentage of atmospheric air 401 contribution in our samples from T3 and allowing constraint of a minimal contribution of 402 atmospheric air of 0.0002 - 0.0015%. When the same method is applied to wells T1 and T2 403 we are unable to resolve these differences solely by atmospheric air addition. Using the initial 404 hydrocarbon endmember, we evoke tertiary mixing between the three endmembers. From 405 this, we constrain that there is a dissolved air component (from the groundwater contained 406 in the water leg in the reservoir) of 0.7 - 1.5% in the ASSW with an extraneous atmospheric 407 air content of 0.0122 – 0.12% in samples from T1 and T2.

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Comparing these extraneous air values with other studies, the samples collected from T3 409 410 contain 1-2 orders of magnitude less air contamination than comparable studies (e.g. Barry 411 et al., 2016, 2017). When this is compared to the older archived samples (T1 and T2), our 412 method of sampling is within the same order of magnitude of previous work of Barry et al., 413 (2016, 2017). Combining these findings with other noble gas ratios of the values of Tormore ${}^{4}\text{He}/{}^{20}\text{Ne}$ (413.94 – 5525.42), ${}^{40}\text{Ar}/{}^{36}\text{Ar}$ (398 – 587), and ${}^{132}\text{Xe}/{}^{84}\text{Kr}$ (0.10 – 0.18) there is a 414 415 significant deviation from air values. We demonstrate that there is a measurable, but very 416 small atmospheric air contribution in our samples. In addition, this confirms that our methods 417 for collecting hydrocarbons samples directly from the reservoir and subsampling are robust 418 for noble gas analysis.

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5.1.3 The source of atmospheric-derived noble gases in samples

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Atmosphere-derived noble gases are transported into the subsurface by water, either through aquifer recharge or within water-saturated pores as sediment is buried (e.g. Kipfer *et al.*, 2002). The initial concentration of noble gases in the ground (or pore) water can be reasonably well constrained from solubility data and accounting for contributions from excess air (Crovetto *et al.*, 1982; Wagner & Pruss, 1993; Harvey, 1996; Ballentine & Hall, 1999; Peeters *et al.*, 2002; Fernández-Prini *et al.*, 2003; Aeschbach-Hertig *et al.*, 2008; Tolstikhin *et al.*, 2017). The solubility of noble gases is controlled by atomic size, with heavier noble gases being considerably more soluble than the lighter elements (He <Ne <Ar <Kr <Xe). Using the solubility of noble gas in hydrocarbons and water, it is possible to model the partitioning behaviour for noble gases between water and hydrocarbons in the subsurface. These models typically assume that all atmospheric-derived noble gases are sourced from buried groundwater and all hydrocarbon fluids are devoid of these noble gases until they interact with the groundwater (Pujol *et al.*, 2018).

The initial model outlined by Bosch & Mazor (1988) uses ratios of atmospheric-derived $^{20}Ne/^{36}Ar$, $^{84}Kr/^{36}Ar$ and $^{132}Xe/^{36}Ar$ to predict partitioning patterns in water-oil and water-gas systems. These models were later expanded and built upon by Battani *et al.*, (2000); Zhou *et al.*, (2005); Gilfillan *et al.*, (2008) and Barry *et al.*, (2016). These models represent a binary mixing between one phase e.g. gas, oil or CO₂ with water. However, the charging history of Tormore is not a simple binary mixing of two fluids and therefore these models are not appropriate models for the processes that have occurred with the field.

442 Hence, we apply Bosch and Mazor's (1988) model to the Tormore field that as this more 443 accurately reflects the known history of double charging of hydrocarbons within the field. 444 Figure 7a shows the evolution of noble gases when an oil or a gas strips an aquifer of noble 445 gases by a batch fractionation process. Noble gases have different solubilities in gas and oil, 446 therefore when the first "droplet" of oil or "bubble" of gas passes through an aquifer, the 447 individual noble gases will partition to different extents based on solubility (Crovetto et al., 448 1982; Wagner and Pruss, 1993; Harvey, 1996; Fernández-Prini et al., 2003). Theoretically, with an infinite hydrocarbon to water ratio within a closed system under ideal conditions, all noble 449 450 gases will eventually partition into the hydrocarbon phase resulting in an ASSW-signature 451 being transferred to the hydrocarbon phase.

452 Tormore was charged by two fluids with a common, the differences in fluid composition with 453 depth i.e. gas condensate and oil are an effect of PVT conditions. The light carbon molecules 454 are $C_1 - C_5$ are unaffected by phase changes, hence, we can directly compare the oil and gas-455 condensate in terms of origin. In Figure 8, we observe a similar trend across the Chung plot, 456 indicating that the sampled fluids have a common origin. Using Kharaka & Specht's (1988) 457 method, the Henry constants of the noble gases dissolving into oil have been calculated by 458 modelling the first charge as an oil-like fluid with an API 25° and methane as a proxy for the lighter drier second charge. These calculations use the average reservoir conditions of 113°C, 459

460 420 bar and salinity of 0.35 M, based on measurements from the three wells drilled and461 assuming that all hydrocarbons are initially devoid of atmosphere-derived noble gases.

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Using these parameters and known charging history, we outline the fractionation of noble gases that will result from a two-stage partitioning model, where an oil partially strips an aquifer of noble gas, followed by a gas stripping an oil. The first hydrocarbon charge of the field can be represented by noble gases partitioning from the aquifer into the oil phase defined by Bosch and Mazor (1988), where

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$$\left(\frac{[i]}{Ar}\right)_{oil} = \left(\frac{[i]}{Ar}\right)_{aquifer} \frac{\left(\frac{V_{oil}}{V_{H20}} + \frac{K_{Ar(oil)}^d}{K_{Ar(H20)}^d}\right)}{\left(\frac{V_{oil}}{V_{H20}} + \frac{K_{i(oil)}^d}{K_{i(H20)}^d}\right)}$$

472 ([i]/[Ar])_{oil} is the ratio of a given noble gas [i] in the oil phase, which is related to the original 473 ratio in the aquifer ([i]/[Ar])_{aquifer}, the oil/water volume ratio V_{oil}/V_{H2O} and K_i^d is the Henry 474 constant of a given noble gas species. The evolution of ²⁰Ne/³⁶Ar and ⁸⁴Kr/³⁶Ar from ASSW in 475 both the oil and gas phase under this scenario is depicted in Figure 7a.

The second phase of the model is a partial partitioning of the aquifer-derived noble gases from the oil phase which had previously interacted with ASSW (([i]/Ar)_{oil}) into a gas phase, representing the second charge of a less dense hydrocarbon fluid. This process is defined using the approach of Bosch and Mazor (1988), where

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$$\left(\frac{[i]}{Ar}\right)_{gas} = \left(\frac{[i]}{Ar}\right)_{oil} \frac{\left(\frac{V_{gas}}{V_{H20}} + \frac{1}{K_{Ar}^d}\right)}{\left(\frac{V_{gas}}{V_{H20}} + \frac{1}{K_i^d}\right)}$$

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484 ([i]/Ar)_{oil} is constrained using the data observed from the Tormore field samples as shown in 485 Figure 7b. The observed 20 Ne/ 36 Ar and 84 Kr/ 36 Ar from well T3 define the upper limit of ([i]/Ar)_{oil} 486 as a V_{oil}/V_{H20} of 0.003 and T2 samples define the lower limit of 0.06. Figure 7b clearly shows 487 that this model exhibits a good fit with the Tormore dataset and hence, we cite that it 488 accurately reflects the charging history of the field. This identification of a likely control on the variation of noble gas composition in the samples, allows resolution that there is a common source of the noble gases throughout the field and explains how noble gas concentrations can vary across the field, but still provide evidence of a fluid connection. In addition, this demonstrates that the distribution of the noble gas is controlled by batch fractionation and therefore we can confidently rule out sample contamination as a cause.

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5.2 Using noble gases to resolve the connectivity of Tormore

The noble gas composition of a fluid is a record of both the origin and the physical parameters that have acted on it. There are four processes that control the distribution of the noble gases within the field (Figure 1). In order to establish connection or disconnection within the field, we examine possible causes of differences in the noble gas compositions. Using the geological history of the field, we can constrain the likely processes that are affecting the noble gas composition.

503 It is assumed that hydrocarbon fluids are fully miscible upon first contact and hence noble gas 504 compositions of the fluids will equilibrate rapidly on contact. Hence, it is valid to rule out a 505 difference in noble gas composition due to the different charging events in different parts of 506 the field. In addition, we account for these differences by fractionation of the noble gases 507 from the double charging of the field. The reservoir is composed of well-sorted turbiditic 508 quartz sands, with a low (< 5%) clay content. The low clay content implies low concentrations 509 of U and Th, meaning that in-situ production of radiogenic noble gases (i.e. ⁴He) in the 510 reservoir will be very low compared that of a U and Th rich shale-dominated source rock. C_1/C_2 ratios in Tormore are constant in all reservoir units in the gas phase (Table 3.3), showing 511 512 no evidence of fractionation from ongoing charging or leakage (Montel et al., 1993). Hence, 513 the main control of the noble gas fingerprints is the equilibrium conditions of the field, in this 514 case at the OWC. Whilst no OWC was directly encountered during the exploration and 515 appraisal phase of the Tormore field, its presence is observed in the noble gas dataset, due 516 to the increasing concentrations with depth of air saturated water-derived noble gases (²⁰Ne, 517 ³⁶Ar, ⁸⁴Kr and ¹³²Xe).

5.2.1 Resolving the vertical connectivity of well T2

521 Organic geochemical analysis from field operator reports indicates that reservoir unit T2-A is 522 isolated from the other sands T2-C and T2-D. This is the only currently known direct fluid 523 connection in the Tormore field, and hence is an ideal proof of concept study for assessing 524 the effectiveness of using noble gases to assess reservoir connectivity.

In a virgin reservoir, the atmospheric-derived noble gas composition within the field can only be controlled by fluid column organisation (Figure 9). In a fully connected reservoir, the noble gases will partition from the aquifer into the hydrocarbons and organise within the accumulation according to the PVT conditions of the field. In the Tormore field, any deviation from this trend is indicative of an absence of connection. In this case, the samples closest to the OWC will have the highest atmosphere-derived component.

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532 In Figure 9, samples from T2 show a clear linear trend between ¹³²Xe/³⁶Ar and 1/³⁶Ar which 533 can be explained by each reservoir unit representing a mix of an atmosphere-derived 534 component, likely a modified atmosphere-derived e.g. ASSW, and an unknown hydrocarbon 535 endmember. This confirms that an underlying aquifer is interacting with all reservoir units in 536 the well. If all reservoir units in well T2 are connected to a common aguifer, this hierarchy 537 would be preserved with depth, where the deepest reservoir unit closest to the OWC will 538 have the highest atmospheric component (Figure 10). However, this predicted hierarchy is 539 not observed. Instead, T2-A has the closest measured value to the predicted ASSW ratio. This 540 deviation from the predicted trend indicates that T2-A is isolated from the T2-C and T2-D 541 horizons and therefore disconnected suggesting that T2-A is connected with a separate 542 aquifer leg.

Hence, the noble gases and conventional geochemical methods for the oil in T2 both illustrate a disconnection, showing that noble gases can be used to determine disconnected reservoir units. However, we cannot confidently draw any conclusions about the connectivity of T2-C and T2-D. We find no definitive evidence to suggest these units are isolated, and no evidence to suggest they are connected. Hence, the noble gas fingerprint method exhibits the same limitation as established static connectivity tools in this scenario (Table 1).

5.2.2 Lateral connectivity across a fault

552 Seismic studies from the field have identified a normal fault with an unknown offset and 553 transmissibility between wells T2 and T1. As the reservoir units on one side of the fault contain 554 oil and the other gas condensate. The degree of fluid communication across the fault is 555 currently unknown. Hence, there is no knowledge of whether it is acting as a barrier to flow 556 (and therefore the likely location of the GOC), or if it is transmissible, where fluids can 557 communicate across the fault zone on geological timescales (statically connected). 558 Conventional connectivity analysis across the fault has proved inconclusive due to the inability 559 to assess the connectivity between the separate oil and gas phases.

560 In order to ascertain whether the noble gases can be used to constraint the connectivity, we 561 now examine all the atmosphere-derived noble gases. If the fault is acting as a barrier to flow, 562 then samples up-dip of the fault will be isolated from the underlying aquifer. Due to its 563 isolation, the up-dip compartment (T1-C) will have lower measured atmospheric noble gases, 564 compared to T2 samples. In a scenario where the fault zone is transmissible, there will be a 565 comparable noble gas fingerprint in the fluids from both wells. Figure 11 shows the atmospheric-derived noble gas isotopes relative to ³⁶Ar and normalised to ASSW from both 566 T2 and the sole reliably sampled reservoir unit of well T1. Firstly, we observe that T2-A (green 567 568 line with square markers) is isolated from the other T2 samples, supporting our interpretation 569 of a disconnection between the reservoir unit T2-A and the other units in T2.

570 The noble gas composition of the samples from either side of the fault, T1-C (orange line) and T2-C (green line, triangle markers) are similar. When normalised to ASSW we observe a 5 -571 7% range in T1-C and T2-C, ²⁰Ne/³⁶Ar, ⁸⁴Kr/³⁶Ar and ¹³²Xe/³⁶Ar ratio. This is despite the samples 572 573 being obtained from two different wells that were drilled 5 years apart, which are located 1.5 574 km away from each other, separated by a fault and sampled from two different phases. These similarities can only be explained if the reservoir units are in direct and ongoing 575 576 communication with each other, providing clear evidence that the two reservoir units are connected. 577

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5.2.3 Lateral connectivity across the Tormore field

582 No conventional method has confidently resolved the lateral connectivity between the gas-583 condensate and oil in the Tormore field. After demonstrating the proof of concept of our new 584 noble gas method in the oil column of well T2 and the lateral connectivity of T1 and T2 we now focus on resolving the connectivity across all three wells. Following the same approach 585 586 used in well T2 we hypothesize that in a fully connected system, in contact with a common 587 aquifer, the distribution of atmosphere-derived noble gases will correlate with depth. We 588 hypothesise that the samples closest to the OWC and aquifer should have higher 589 concentrations of atmosphere-derived noble gases.

590 In Figure 9¹³²Xe/³⁶Ar is plotted against 1/³⁶Ar illustrating that across all samples we observe a 591 linear trend between a modified atmosphere-derived source e.g. an ASSW that has been 592 modified by the drilling mud, and an unknown hydrocarbon endmember. Based on this trend 593 we would predict that the samples closest to the ASSW endmember should exhibit a depth 594 trend linked to the position of the OWC. However, we find that reservoir unit T3-A does not 595 follow the same trend as the other samples. Hence, we can conclude that T3-A is vertically 596 isolated from the other two reservoir units in T3 and must be in contact with a separate 597 aquifer. However, we are unable to draw any further conclusions for regarding the lateral 598 connectivity of T3-A with the other wells using this method.

Two possible scenarios for the lateral connectivity between well T1 and T3 remain; 1) T3-A is in static connection with well T1 or 2) T3-C and T3-D are in connection with T1. From the methods outlined it is difficult to make any further conclusions. However, there is no evidence of faulting between T1 and T3 that could provide a pathway for noble gases. Therefore, the most likely connection between the wells T1 and T3 based on the known geology is reservoir unit C and D.

In Figure 12, we model the proportion of additional ASSW noble gases required for the samples from T3 to match that observed in T1. For T3-A an additional 0.03 % ASSW-derived noble gas contribution is required and 0.02 % for T3-C. Though T3-C requires a smaller addition of atmospheric-derived noble gases than T3-A, to have a similar fingerprint to that observed in T1-C, this is suggestive that T1-C and T3-C are connectivity. However, this is not conclusive evidence for confirming connectivity between the two reservoir units, though the noble gases do provide more information than other static connectivity tools. Hence, this provides useful information on the additional information provided by noble gases in assessing vertical and lateral connectivity between two different phases. The method demonstrates a novel process for assessing static connectivity and readily identifies isolated reservoir units. However, in cases where there is limited data it can be difficult to confirm a definitive connection, especially without dynamic or production data.

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618 3.6 Conclusions

We conclude that noble gases are potentially an effective tool for resolving the connectivity of hydrocarbon reservoirs. In the Tormore field, we find strong evidence that T2-A is isolated from the other reservoir units of T2, supporting the conclusions of Total's conventional connectivity study. In addition, we find that T3-A is vertically isolated from T3-C and T3-D. These findings demonstrate the applicability of noble gases for assessing the vertical connectivity of reservoir units in both phases.

625 In addition to resolving the vertical connectivity, we provide strong evidence for resolving the 626 lateral connectivity within the Tormore field. In T1-C and T2-C we find that two noble gas 627 fingerprints from either side of a fault exhibit extremely similar ratios. This is despite samples being obtained from two different wells that were drilled 5 years apart, located 1.5 km away 628 629 from each other and sampled from two different hydrocarbon phases. The similarities in 630 noble gas fingerprints can only be explained when reservoir units are in direct and ongoing 631 communication, demonstrating noble gases can be used to resolve the static lateral 632 connectivity of fluids in different phases.

It is important to communicate the limitations of this method, which are the same as other 633 634 conventional tools. It is easy to identify samples that are disconnected, but the converse is 635 not true. Unless samples show extremely similar noble gas fingerprints, it is particularly 636 difficult to prove connectivity between two reservoir units, as demonstrated for establishing 637 the lateral connectivity between T1 and T3. Using noble gases on their own are a powerful 638 tool, but by using additional information to add context to our findings allows us to make 639 better informed interpretations. In this case, the lack of evidence of a conduit connecting T3-640 A with T1-C suggests that the two reservoir units are unlikely to be connected, hence, it is

641 more likely that T1-C is connected to T3-C, which are within the same reservoir unit with no642 observed barrier between them.

By sampling fluids directly from each reservoir unit, it is possible to ascertain further 643 information than fluid connectivity. Using the work of Bosch & Mazor (1988) we provide a 644 constraint on the original V_{H20}/V_{oil} ratio. We find a V_{H20}/V_{oil} ratio of 0.003 – 0.06. This suggests 645 646 that the first charge of the denser fluid, had not fully stripped the underlying aquifer of noble 647 gases or was still charging when the second drier, less dense fluid charged the Tormore field. 648 Though there is some degree of uncertainty in these values based on the upper and lower 649 limit, this information is invaluable during the exploration phase of a basin and providing a 650 rough estimate of the water/oil ratio is key parameter for basin modelling.

In summary, we have outlined a new source for collecting noble gases from hydrocarbon reservoirs, subsampling from fluids that have been collected downhole from each reservoir unit. In addition, we have demonstrated the application of noble gases for assessing the static vertical and lateral connectivity of hydrocarbon fluids in both the oil and gas phase.

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Figure 1 Cartoon illustrating the main controls on noble gas fingerprints within a hydrocarbon system. There are three sources of noble gases (red): 1) Primordial, sourced from the mantle, and entrained during the Earth's accretion 2) The crustal component from nucleogenic production and radiogenic decay of U, Th and K. 3) Primordial aquifer component enters the subsurface via aquifer recharge and/or entrained in the original formation water of the sediment. In addition, there are two main physical controls on noble gases within a petroleum system (pink); (i) diffusive fractionation and (ii) the solubility-controlled exchange of noble gases between the aquifer and the trapped hydrocarbon fluids.



Figure 2. Location map of the UK West of Shetland Basin. The Tormore field is located in a water depth of ~600m, 140 km north-west of the Shetland Isles in Quadrant 205. The locations and closure of all petroleum fields in the exploration or appraisal phase are provided along with the bathymetry of the basin (Doré et al., 1999). Also shown are the locations of the completed wells in the WoS basin (taken from the UK Government Oil and Gas Authority, www.ogauthority.co.uk).



Figure 3 Carton cross-section based on interpreted seismic data of the Tormore field. Three wells have been drilled; T1, T2 and T3. This study investigates the connectivity the reservoir units that lie within the Tormore field, namely reservoir units A, B, C & D the lateral extent of unit B is unknown. Separating each unit is a layer of hemipelagic shale (green) with a varying lateral thickness of 2-10m. Wells T1 and T3 encountered gas-condensate, whilst T2 solely encountered oil. During the drilling and appraisal phase of the field, no water-oil contact or gas-oil contact was encountered. Separating T2 and T1 is an antithetic normal fault with an unknown offset and transmissibility. Figure is vertically not to scale.



Figure 4 Plot of 20 Ne/36Ar against 21 Ne/ 22 Ne of all samples from Tormore. Across the Tormore field, there is a clear mixing trend between T3-D and T2- A. Samples (T1-B and T1-D) show a clear deviation from this trend. These samples exhibit low 4 He/ 20 Ne ratios, indicative of a high atmospheric air contribution. Hence, these samples are omitted from further discussion. In the remaining samples, we observe a clear geographical trend. Samples from both of the wells that encountered gas condensate - T1 (orange) and T3 (red), located near the top of the structure show an elevated radiogenic component relative to the oil well T2 (green). This well targets the lower section of the field and exhibits a strong influence from an aquiferderived atmospheric component. Uncertainties are 1 σ .



Figure 5 Neon isotope plot of the Tormore field. Data presented are samples from all three wells. Outlier samples and duplicates (white) have a coloured outline corresponding to the well and the marker type reflects the reservoir unit. We observe a clear difference between samples from the oil phase (T2) and gas phase (T1 and T3). Samples from T2 plot near to the air-value, whereas samples from T3 plot along the air-crust line and exhibit a degree of mass fractionation away from the air-crust line. MFL is the mass fractionation line. Uncertainties are 1 σ .



Figure 6 Neon concentrations vs. ²⁰Ne/³⁶Ar with all samples that passed the initial quality control In the samples from the Tormore field, there are two well-constrained endmembers ASSW (blue marker) and atmospheric air (yellow marker) (Ozima & Podosek, 2002) and a third unknown endmember, the original hydrocarbon signature. A theoretical limit for the noble gas composition in the original hydrocarbon phase is determined for a closed system (Bosch & Mazor, 1982 & Barry et al., 2016). In addition, two binary mixing lines show the mixing between atmospheric air and ASSW (blue dashed line) and between air and the theoretical noble gas composition in the hydrocarbon phase (red dashed line). Where, the compositional limit and air-hydrocarbon mixing line intersect, we propose this as the hypothetical endmember of the hydrocarbon fluids.



Figure 7 Closed-system batch fractionation under the reservoir conditions of Tormore. Figure 7a Noble gas fingerprints will evolve differently when they interact with an oil or a gas. The green line shows the fractionation pattern of an oil and the red line represents a gas. The first droplet/bubble represents an infinitesimally small volume of hydrocarbon fluid passing through an infinite aquifer. Given a large enough volume of hydrocarbons, the noble gases will fully partition in the hydrocarbons and inherit a noble gas fingerprint similar to that of the aquifer. 7b) Applying the known charging history of Tormore, we model a batch fractionation of a gas stripping oil and use the measured samples from Tormore to constrain an upper and lower limit. We find a Voil/Vwater of 0.003 to 0.06 for the Tormore. Uncertainties for measured noble gases are 1 σ . ASSW at 4°C is after Kipfer et al., (2002) and air is after Ozima & Podesk, (2002).



Figure 8 Chung plot of Tormore samples, where the reciprocal of the carbon number is plotted against δ^{13} C. Samples from all three wells show coevolution with carbon number, indicating all fluids are from the same source.



Figure 9 Plot of $1/{^{36}}$ Ar against ${^{132}}$ Xe/ ${^{36}}$ Ar from the Tormore field. Across the field, wells follow the predicted distribution of noble gases, the further from the predicted OWC and ASSW value, the further away each well plot. Uncertainties are 1 σ .



Figure 10 A plot of 132 Xe/ 36 Ar against depth. Plotted at the estimated OWC depth is ASSW. When plotted with depth, T2 samples do not follow the predicted trend. T2-A is much closer to the ASSW signature, though it is the shallowest reservoir unit in T2. As a result of this deviation from the predicted trend, we interpret that T2-A is isolated and disconnected vertically from T2-C and T2-D. This result confirms the conclusions drawn from the conventional study on the vertical connectivity of T2 and provides strong evidence of a second OWC in Tormore for reservoir unit T2. Uncertainties are 1 σ . ASSW at 4°C is after Kipfer et al., (2002).



Figure 11 Spider diagram of atmospheric-derived noble gas isotopes relative to ³⁶Ar and normalised to ASSW. Between wells, T1 and T2 is an antithetic normal fault with an unknown offset and transmissibility. All samples in ²⁰Ne/³⁶Ar space plot between ASSW and air. We propose that the high ²⁰Ne/³⁶Ar is due to the preferential partitioning of ²⁰Ne in the oil system at the OWC. This plot confirms the isolation of T2-A from the other wells in T2 as it significantly deviates from the trend observed in the other samples. Also, it is evident that T1-C and T2-C have very similar noble gas fingerprints. These samples were taken from the same reservoir unit (separated by a fault), taken from different wells (drilled 5 years apart) show the same fingerprints. From this we can confidently conclude that 1) T1-C and T2-C are in static connectivity and 2) that the fault is transmissible between these two units, and therefore proves a lateral connection.



Figure 12 Spider diagram of atmospheric-derived noble gas isotopes plotted relative to ³⁶Ar and normalised to ASSW. Plotted are reservoir units T1-C (orange) T3-A (red line with square markers), T3-C (red line with triangular markers) and air (grey line). The solid black line represents the amount of ASSW derived noble gases needed for the measured samples of T3 to have similar noble gas fingerprint to T1-C, with the percentage required shown in the corner of the plot.

Tables

Table 1.1 Limitations of the conventional methods for assessing reservoir connectivity. During the exploration phase, this is limited to indirect methods for identifying potential compartments or baffles to flow i.e. a fault. Post-drilling, more detailed analysis can be applied using reservoir data and fluids. However, these current methods have their limitations. It is currently difficult to determine the connectivity between the oil and gas phase at a scale of less than 1 km. In addition, we add the application of noble gases (grey).

		Method/Tool	Scale of resolution	Evidence of connection or disconnection	Applicable to a gas phase?	Applicable to an oil phase?	Applicable to a two-phase system?
	Exploration	3D Seismic	Intra-field (limited to ~50m)	Indirectly, identifying possibly physical discontinuities e.g. a fault	°Z	°Z	oz
	phase	Well Logs	Borehole	Indirectly	No	No	No
		Rock Core	Borehole	Indirectly	No	No	No
spou		Drill Stem Test (DST)	>1 km	Estimates connected volume	Yes	Yes	Yes
tən		Pressure test	Intra-field	Disconnection only	Yes	Yes	Yes
ı lsnoitnəvn	Appraisal	Organic Geochemistry	Intra-field	Both	° Z	Yes	o
იე	phase	Thermodynamic modelling (PVT)	Intra-field	Both	No	Yes	No
Our method		Noble gases	Intra-field	Both	Yes	Yes	Yes

Table 2: Concentrations of non-radiogenic noble gas isotopes, reservoir unit and sampling depth in the Tormore field. Noble gas concentrations are given to three significant figures under STP conditions in cm³ STP/cm³. Depth is True Vertical Depth sub-sea (TVDss) in meters. Air values are after Ozima & Podesek, (2002) and ASSW value are after (Kipfer et al., 2002).

Well	Reservoir Unit	Depth (TVDSS m)	²⁰ Ne	1σ	³⁶ Ar	1σ	⁸⁴ Kr	1σ	¹³² Xe	1σ
	В	3755	1.50E-05	6.38E-07	1.79E-05	6.65E-07	7.01E-07	2.91E-08	2.23E-08	1.17E-09
T1	U	3767	1.06E-08	4.51E-10	5.48E-08	2.06E-09	2.38E-09	9.90E-11	3.35E-10	1.75E-11
	D	3777	2.03E-08	8.65E-10	1.61E-07	6.01E-09	5.91E-10	2.46E-11	1.03E-10	5.38E-12
	А	3831	4.26E-08	1.81E-09	1.25E-07	4.64E-09	4.15E-09	1.73E-10	4.15E-10	2.17E-11
T2	U	3878	1.28E-08	5.48E-10	6.21E-08	2.34E-09	2.52E-09	1.05E-10	3.60E-10	1.89E-11
	D	3888	2.07E-08	8.77E-10	7.58E-08	2.86E-09	2.96E-09	1.23E-10	3.64E-10	1.91E-11
	A	3670	5.90E-09	3.54E-10	3.62E-08	1.37E-09	1.70E-09	7.07E-11	3.06E-10	1.04E-11
	Duplicate		8.50E-09	2.47E-10	3.96E-08	1.53E-09	2.00E-09	4.14E-11	3.10E-10	1.60E-11
C F	U	3700	7.69E-09	3.26E-10	4.09E-08	1.53E-09	2.11E-09	8.76E-11	2.74E-10	1.43E-11
2	Duplicate		7.31E-09	3.10E-10	4.29E-08	1.59E-09	2.10E-09	8.73E-11	3.02E-10	1.58E-11
	D	3706	6.78E-09	8.88E-11	4.03E-08	6.81E-10	2.15E-09	9.13E-11	3.34E-10	9.58E-12
	Duplicate		1.15E-08	1.83E-10	4.13E-08	7.03E-10	1.96E-09	8.34E-11	2.75E-10	7.91E-12
Air			1.65E-05		3.14E-05		6.50E-07		3.54E-09	
ASSW at ²	4°C		1.55E-07		1.16E-06		4.74E-08		4.31E-09	

Table 1 Radiogenic noble gas abundances and ratios in the Tormore field. Concentrations are given to three significant figures in standard conditions are after Ozima & Podosek, (2002) in cm³ STP/cm³. Air composition is after Eberhardt et al., 1965; Honda et al., 2015; Mamyrin et al., 1970; Mark et al., 2011; Ozima and Podosek, (2002).

Well	Reservoir Unit	C1 %	C2%	³ He/ ⁴ He (<i>R/R</i> ª)	1σ	⁴ He	1σ	²⁰ Ne/ ²² Ne	1σ	²¹ Ne/ ²² Ne	1σ	⁴⁰ Ar/ ³⁶ Ar	1σ	⁴ He/ ²⁰ Ne	1σ
	В	88.6	3.95	4.45E-01	2.73E-02	7.30E-06	3.73E-07	9.65	0.08	2.87E-02	5.04E-04	300	-	0.49	0.04
11	U	86.7	3.81	1.95E-01	9.54E-03	4.40E-06	4.61E-09	9.67	0.08	3.09E-02	5.20E-04	537.19	ŝ	414	27
	۵	86.8	3.82	2.14E-01	1.32E-02	2.20E-06	1.13E-07	9.81	0.09	2.94E-02	5.49E-04	464.63	2	108	80
	A	62.2	4.05	1.53E-01	9.40E-03	8.20E-06	4.19E-07	9.8	0.08	2.92E-02	5.10E-04	397.88	2	193	14
Т2	U	62.5	4.41	5.09E-02	3.13E-03	1.60E-05	8.17E-07	9.84	0.09	2.99E-02	5.40E-04	509.13	4	1246	93
	۵	62.8	4.36	1.65E-01	1.02E-02	8.40E-06	4.28E-07	9.54	0.08	2.96E-02	4.89E-04	445.99	ŝ	407	30
	А	91.7	3.92	2.70E-01	1.30E-02	3.26E-05	1.20E-06	9.81	0.04	3.14E-02	3.46E-04	586.73	4	4447	276
	Duplicate			2.60E-01	1.20E-02	3.78E-05	1.20E-06	9.83	0.04	3.12E-02	3.78E-04	548.13	9	5525	352
ĥ	U	92.1	3.82	2.56E-01	1.12E-02	3.73E-05	1.91E-06	9.67	0.04	3.11E-02	3.66E-04	566.41	ŝ	4851	295
<u>0</u>	Duplicate			2.57E-01	1.41E-02	3.58E-05	1.83E-06	9.71	0.04	3.12E-02	3.38E-04	573.02	2	4898	339
	D	92.3	3.75	2.69E-01	3.86E-03	3.08E-05	9.10E-07	9.78	0.04	3.14E-02	3.46E-04	555.88	ŝ	4549	88
	Duplicate			2.69E-01	4.12E-03	2.98E-05	8.80E-07	9.86	0.04	3.06E-02	2.57E-04	549.14	3	2603	57
Air				1		5.24E-07		9.81		2.90E-02		298.6		0.31	

Table.2 Carbon isotopic values for C_1 to C_5 from the three wells of Tormore. Values are reported in per mil %

:						
Well	Reservoir	C_1H_4	C_2H_6	C ₃ H ₈	C_4H_{10}	C_5H_{12}
	Unit	(±0.4‰)	(±0.4‰)	(±0.4‰)	(±0.4‰)	(±0.4‰)
T1	U	-37.6	-30.9	-29.4	-28.3	-27.9
	A	-38.3	-30.7	-29.2	-28.0	-27.6
Т2	U	-38.1	-31.1	-28.9	-27.8	-27.5
	D	-38.1	-31.1	-29.2	-27.9	-27.5
	A	-37.3	-31.1	-29.7	-29.7	-28.1
T3	U	-37.3	-31.1	-29.7	-28.3	-28.0
	D	-37.3	-31.3	-29.9	-28.4	-28.0

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