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Offsetting Carbon Capture and Storage costs with methane and geothermal energy production through reuse of a depleted hydrocarbon field coupled with a saline aquifer

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ABSTRACT

Co-production of methane and geothermal energy from produced subsurface brines with onsite power generation and carbon capture has been proposed as a technically feasible means to reduce the costs of offshore carbon storage sites. In such a facility, methane is degassed from produced brine, this brine is then cooled allowing the extraction of heat and then CO_2 is dissolved into it for reinjection into a porous rock formation. Once injected into the porous reservoir formation, this CO_2-loaded brine will sink due to its relatively higher density, providing secure storage. Here, for the first time, we investigate, the economic feasibility and energy balance of such a system within the UK North Sea. We examine the suitability of a depleted hydrocarbon field coupled with a saline formation located in the Inner Moray Firth, Scotland. We find that such a system would be highly likely to have a positive energy balance, and would be an order of magnitude cheaper that decommissioning. Furthermore, as only 10% of the site's storage capacity is needed for disposal of the CO_2 emissions associated with its operation, there is significant potential for additional revenue creation from storing CO_2 from other sources. Whilst the chosen case study site was not ideal, due to its relatively shallow depth, and hence lower than ideal heat potential, it demonstrates that reuse of redundant oil & gas infrastructure that would otherwise be decommissioned could help to offset some of the financial barriers to developing a carbon storage industry in the UK North Sea.

1. Introduction

1.1. Background

Global carbon dioxide emissions from fossil fuel use must be drastically reduced to limit anthropogenic warming to less than 2 °C above pre-industrial levels as agreed by the European Union and the 194 signatory states to the Paris Agreement. Carbon capture and storage (CCS) involves the capture of CO_2 from point sources followed by long-term storage in geological formations. CCS is the only existing technology that can directly reduce emissions from industrial processes such as cement and steel manufacture and many forms of chemical synthesis (Alcalde et al., 2018). Combined with the combustion of bioenergy (BECCS), the technology offers the potential of significant negative emissions and is included in numerous future energy modelling scenarios that meet the 2 °C target of the Paris Agreement (Azar et al., 2013; Scott et al., 2013; IEA, 2014; IPCC, 2014)

Despite the potential emissions reductions offered by CCS, and projections of the long-term cost-effectiveness of it compared with other carbon reduction technologies (e.g. IPCC, 2014), the upfront capital expenditure required for a CCS project are a significant barrier to its industrial scale deployment. The current financial regimes have yet to produce a sufficiently high carbon price to result in widespread implementation of CCS and hence there have been concerted efforts to make it more cost-effective. Using captured CO_2 to enhance oil recovery (EOR) is one method that has proved to be successful at offsetting some of the capital costs of capture and storage (IEA, 2015; Stewart et al., 2018). Recently, methane and geothermal energy co-production has been proposed as an option at storage sites to generate additional revenue in a similar fashion to CO_2-EOR (Bryant and Pope, 2015; Ganjdanesh and Hosseini, 2016).

1.2. co-production of methane, brine, and geothermal energy

Subsurface waters in many sedimentary basins have been found to contain dissolved methane and these have been commercially exploited

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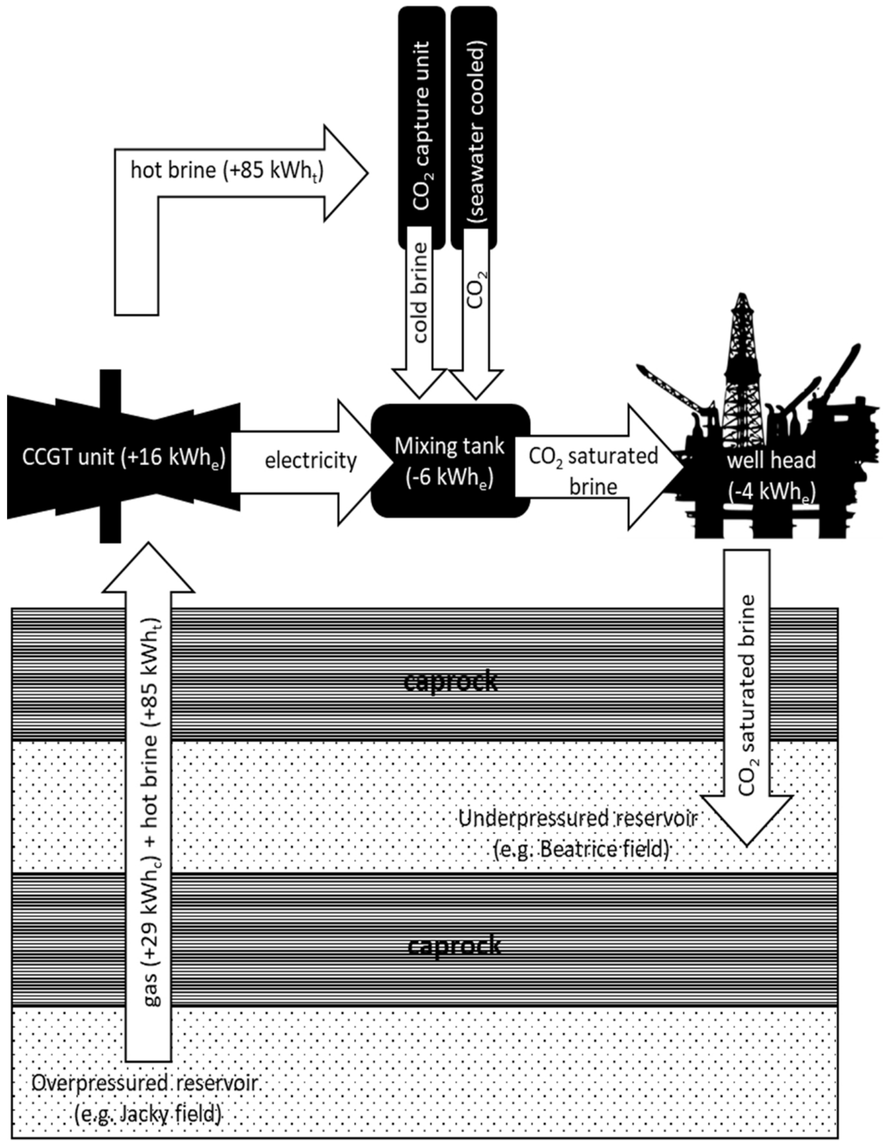

Fig. 1. Schematic overview of the system, illustrating both the above surface capture and separation process and the subsurface underpressured storage aquifer and overpressured production aquifer required for the closed loop system. This also highlights the potential energy produced and required per m^3 brine in the different stages of the process. kWh$_e$ = high grade energy (electricity); kWh$_t$ = low grade energy (heat).

to produce natural gas for decades in several regions (Marsden, 1979; Mankin, 1983; Littke et al., 1999). Building on these existing extraction sites, Bryant (2013) proposed an onshore "closed-loop" system where brine is extracted from deep, hot, overpressured saline aquifers and the methane separated. The methane and hot brine could be sold for power generation and heating respectively. CO_2 captured from the power generation process would be dissolved into the now cold brine before reinjection into the subsurface. This closed-loop model emits very little CO_2 and provides scope for disposal of CO_2 from other external sources. Additionally, as CO_2 saturated brine is denser than native brine and sinks, this technique would remove the risk of leakage through buoyant migration. Pressure management and brine disposal issues associated with supercritical CO_2 storage in saline aquifers are also addressed through the brine reinjection process.

Here, inspired by this concept, we investigate the economic feasibility of a system (Fig. 1) with onsite power generation (gas to electricity) and carbon capture coupled with a depleted hydrocarbon reservoir and saline aquifer in a nearshore depleted hydrocarbon field located in the Inner Moray Firth of the UK North Sea.

In this system, brine would be produced from saline aquifers in the region utilising existing oil & gas infrastructure. We aim to determine if such a scheme will be economically and technically feasible in an area without access to deep, hot, overpressured aquifers and if reusing oil & gas infrastructure can limit its costs, postpone decommissioning and help open up the UK North Sea to a future carbon storage industry.

In this system (based on that originally proposed by Bryant (2013)) methane saturated brine is extracted from an overpressured saline aquifer. The methane is recovered and used to fuel an onsite combined cycle gas turbine (CCGT). CCGTs are common on offshore platforms (Welander, 2000), with the majority achieving efficiencies of between 50 - 60%, with modern units being the most efficient (Aminov et al., 2016). The "gas-to-wire" concept is being explored as an option in the UK and a recent report (Oil & Gas Authority, 2018) suggests that it is both technically and economically feasible to repurpose existing infrastructure and tie-in offshore wind developments to produce electricity from gas. Furthermore the collaboration between gas and offshore wind will help to reduce operating costs and the technology could be applied to offshore hydrogen production as an aid to balancing the intermittency of renewable energy sources (Oil & Gas Authority, 2018).

In our modelled scenario, an onsite carbon capture unit powered by geothermal energy would also be installed to capture the CO_2 produced from the CCGT. In this setup, a post-combustion ammonia capture system will be considered, as this is significantly more energy efficient with lower capital expenditure (CAPEX) and operating expenses (OPEX) than standard amine capture systems (Sutter et al., 2016). The ammonia capture system requires heating and cooling which can be provided by geothermal energy from the extracted brine and seawater, respectively.

The captured CO_2 is then dissolved into the brine and injected into a depleted hydrocarbon field where it sinks due to its relatively higher density. Eventually brine injection will switch to the saline aquifer for pressure management purposes. The injection process is powered by a portion of the electricity produced by the gas turbine with the remainder being sold into the national electricity grid. Fig. 1 shows a schematic of the whole system. This process has the added benefit of generating low carbon electricity while reusing existing platforms, helping to reduce both CAPEX and OPEX.

1.3. Case study site and aquifers

The Beatrice and Jacky oilfields are situated in the Inner Moray Firth (Fig. 2). They contain five platforms between them along with oil pipelines to shore and an electrical connection to the UK national grid. They both produced waxy oil with a low API (38 - 38.9°) and low gas to oil ratio (GOR). The producing formations in both fields were the Beatrice and Mains formations (Fig. 3), though the two fields are separated by a fault. Field production records indicate that this fault maintains a significant pressure difference between the two fields and indicate that the Beatrice oilfield is located within a closed aquifer and the Jacky oilfield is within an open, connected aquifer. A 3D model of the two fields can be seen in Fig. 4). This is supported by the fact that the Beatrice oilfield required artificial lift and downhole pumps from the start of production (Stevens, 1991) and the Jacky oilfield flowed without artificial lift for almost two years (Ithaca Energy, 2009).

Extraction of methane rich brine from an overpressured aquifer (in this case the Jacky oilfield side of the fault) and subsequent CO_2 disposal into an underpressured one (in this case the Beatrice field side of the fault) would reduce the energy and therefore costs required to run the closed loop system. Hence, the existing relationship between the Beatrice and Jacky oilfields is ideal for this concept, particularly as both fields are located relatively near to shore, and with grid electricity and pipeline connections. Once the pressure on the overpressured side drops substantially due to brine production, disposal can be switched from the underpressured side for pressure management purposes. In this study we assume that this occurs after two years, which is how long the Jacky field flowed without artificial lift. After this point, we have accounted

Fig. 2. Location of the Beatrice and Jacky oil fields (in green) in the Moray Firth (see Fig. 4 for zoom in of oil fields). Made using data from OGA (2018).

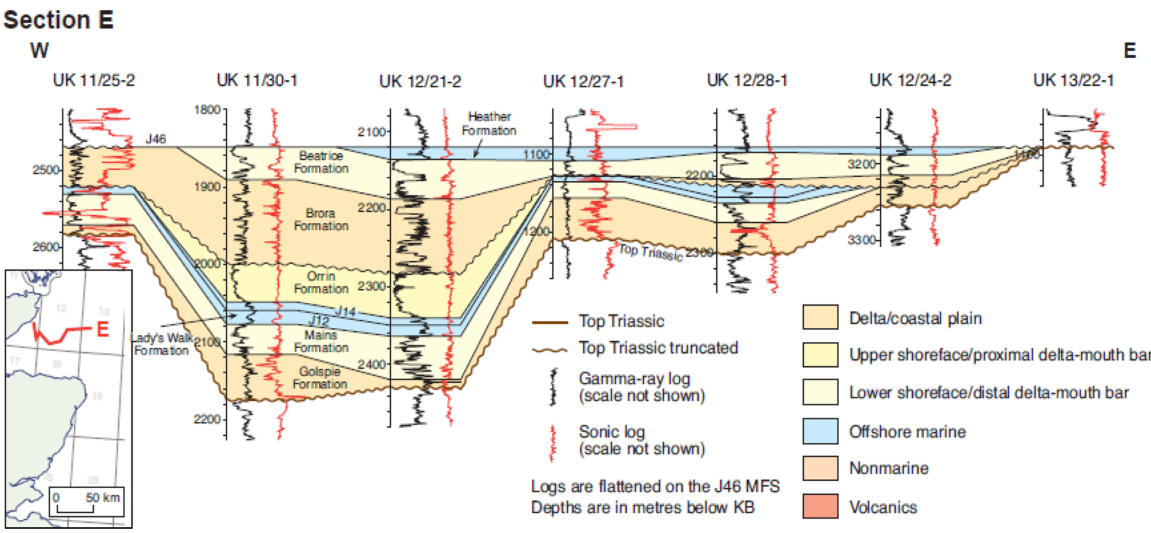

Fig. 3. Well logs showing the extent of the Beatrice and Mains formations in the Moray Firth. Adapted from Evans et al. (2003).

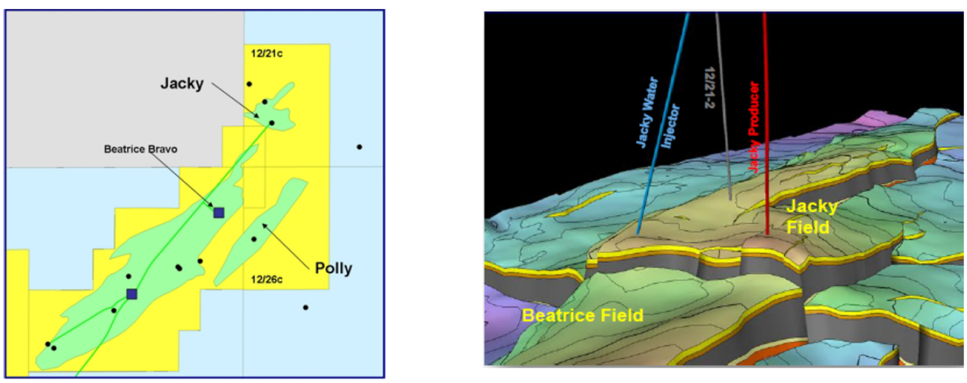

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Fig. 4. Left: Map of the Beatrice and Jacky fields with the nearby Polly prospect. Right: 3D model of the Beatrice and Jacky fields showing the fault that separates them along with the 3 Jacky field wells. Adapted from North Sea Energy Inc. (2013).

for the energy required to undertake brine extraction in our calculations.

2. Evaluating evidence for methane saturation within the oil fields

For this system to be viable, it is imperative that the extracted brine is saturated with methane. A systematic study of well logs from the Beatrice and Jacky oil fields was performed to ascertain if this was the case for the study site. This focused on the identification of gas trips, background gas levels, and identification of the gas effect in well logs (Fig. 5). Alongside this qualitative assessment, saturation calculations using production data were compared with theoretical data from the literature.

2.1. Qualitative assessment

The gas effect (indicating the presence of free gas in pore spaces) was identified in all wells with neutron logs within the oil fields, specifically, six instances in the Mains formation and fifteen in the Beatrice formation. Where neutron logs were not recorded there were a further three gas shows in the Mains formation and three in the Beatrice formation. These gas shows can be accounted by the wells intersecting a portion of the saline formation that are over-saturated with methane.

Wells within the Beatrice field exhibited evidence for small amounts of free gas at the top of individual reservoir sands rather than an overall gas cap, strongly implying gas saturation of the brines. Furthermore, no evidence of a gas/oil contact is present in the resistivity logs from the field.

Background gas levels of 0.1-0.8% occur in many of the wells with a maximum of 3.45% in well 12/21c-6 in the Jacky field. This is also the case for wells outside of the oilfields. A biogenic origin for gas is suggested in the petroleum geochemistry report for well 12/27-1 as it is dry and isotopically light ($\delta^{13}C$ −55‰), a similar situation to the Russian (Littke et al., 1999) and Japanese (Marsden, 1979) methane saturated sedimentary basins.

Gas shows were also recorded in several wells outside the Beatrice and Jacky oilfields. A gas discovery in the Beatrice formation not associated with oil was found in well 12/27-1, and exhibited a flow rate of 9.5 million standard cubic feet (mmscf)/day (~270,000 m^3/day). Wells 11/24a-2 and 11/24a-2z recorded background gas levels up to 1.42%, with wells 11/30-6, 12/20b-1 and 12/24-2 also recording pronounced gas shows.

Unfortunately, the majority of well logs that penetrated the Beatrice Formation did not record bulk density and neutron data. However, those that did (mostly within the oil fields) exhibited a clear gas effect (Fig. 5). Density/neutron logs recorded outside the oil fields also exhibited the gas effect in wells 11/29-1 and 12/26c-5. Evidence for the methane saturation of the Mains Formation is less pronounced, as beyond the oilfields, little attention was paid to the formation in the well logs. However, gas shows were recorded in wells 12/26c-5 and 12/27-1 with large gas effects observed in both wells 12/26c-5 and 11/29-1.

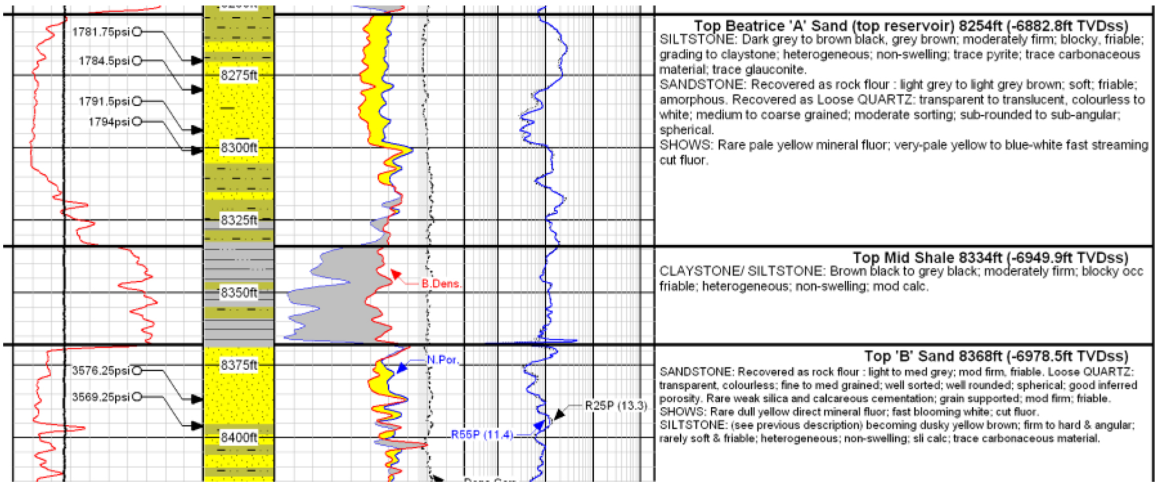

Fig. 5. Reservoir section from composite well log for the Jacky field injection well 12/21c-J2 showing large gas effect between 8310 ft and 8200 ft (area between red and black lines shaded yellow) on the neutron and density logs which are labelled N. Por. and B. Dens. Respectively. Where the gas effect is present the space between the log lines is shaded in yellow. Note the low pressure in A sand after several years of oil production.

Based on the number of positive gas shows, the gas effect, the biogenic origin, and the large gas discovery, we conclude that methane saturation of brine is highly probable throughout both the Mains and Beatrice formations of the Moray Firth basin.

2.2. Methane saturation calculation

To further constrain the methane saturation level of the saline formations within the sedimentary basin, we perform a comparison between the theoretical methane solubility at reservoir conditions and the gas produced during the lifetime of the Beatrice Field, divided by the volume of produced water. Theoretical data from both Duan & Mao (2006) and McGee et al. (1991) imply a methane solubility in brine at the conditions found in the Beatrice and Mains formations of the Moray Firth basin to be ~0.1 mol/kg. The data and calculations for the Beatrice field are outlined in Table A1 in the appendix. As calculated in Table A1, the theoretical solubility of methane under the conditions of the Beatrice field is ~0.1 mol/kg. The calculated solubility using the total volume of produced gas divided by the total volume of produced water is 0.23 mol/kg. This calculated solubility from the field production data is clearly above the theoretical level, but within the same order of magnitude, which is to be expected given the uncertainties surrounding both calculations, such as the variation in temperature across the formation and the accuracy of the produced water volumes. Additionally, the figure of 0.23 mol/kg should be taken as a maximum as some of the gas produced may have been in a free gas state, hence the "gas effect" seen in the well logs. These calculations are clearly indicative of methane saturation or over saturation of the formation waters within the Beatrice field.

The same approach was used to ascertain the theoretical and calculated methane saturation levels within the Jacky field as outlined in Table A2 in the appendix.

Within the Jacky field, the theoretical solubility is ~0.1 mol/kg and the calculated solubility is 0.60 mol/kg. This is three times higher than the Beatrice field but still within the same order of magnitude as both the calculated and theoretical solubilities. It is probable that more gas may have exsolved from the formation water in this part of the reservoir after several years of production due to the drop in reservoir pressure. This would cause free gas to flow towards the well increasing the gas to water ratio, and again implies that there was free gas in the field, meaning that the formation water is almost certainly fully saturated with respect to methane.

3. Analysis Performed and Methods Used

We performed a comparison of three scenarios: gas production only, electricity production from gas only, and a full system with electricity generation and CO_2 dissolution brine storage.

An assessment of the volume of water available was used to calculate the size of both the methane resource and the potential mass of CO_2 that could be stored. Using these estimates, an energy balance for each component of the system was calculated, allowing an estimate of the capital and operating costs over the lifetime of the system to be determined.

A Monte Carlo simulation was used to produce frequency distributions for each of the scenarios. Base values used in all scenarios were determined for the size of the water and methane resources, and expected production. Then the gas production, CO_2 storage, and full system scenarios were calculated.

Probability quantiles were calculated for each scenario where the first quantile represents the value where 75% of results equalled or exceeded that value. The second quantile represents the value where 50% of results equalled or exceeded that value, which is the same as the mean value and referred to as such from here on. The third quantile represents the value where 25% of results equalled or exceeded that value.

3.1. Assessing the size of the resource

Essential components of the scenario calculations are ranges of values for the size of the water and methane resources, and expected production volumes. The volume of water in the Mains formation was calculated by combining data from the literature (Richards et al., 1993) and well logs. The areal extent of the Mains formation was taken from the Scottish Centre for Carbon Storage (2009) report which assessed the volume of the formation using its aerial extent and average thickness. The formation is of variable thickness as observed in well logs but minimum and maximum values are provided by Richards et al. (1993). These values were combined with an assumption of an even distribution across the areal extent of the formation, due to a lack of further data.

The majority of the available porosity data for the Mains formation is from measurement of samples obtained from the Beatrice field, which has an average value of 15%. Outside of the field, well 12/27-1 exhibits a higher average porosity of 23%. The porosity of the Mains formation within the Beatrice oilfield was used with a normal distribution. Based on the findings of Haszeldine et al. (1984), extrapolating reservoir quality outside of the oilfields was justifiable as there was no evidence

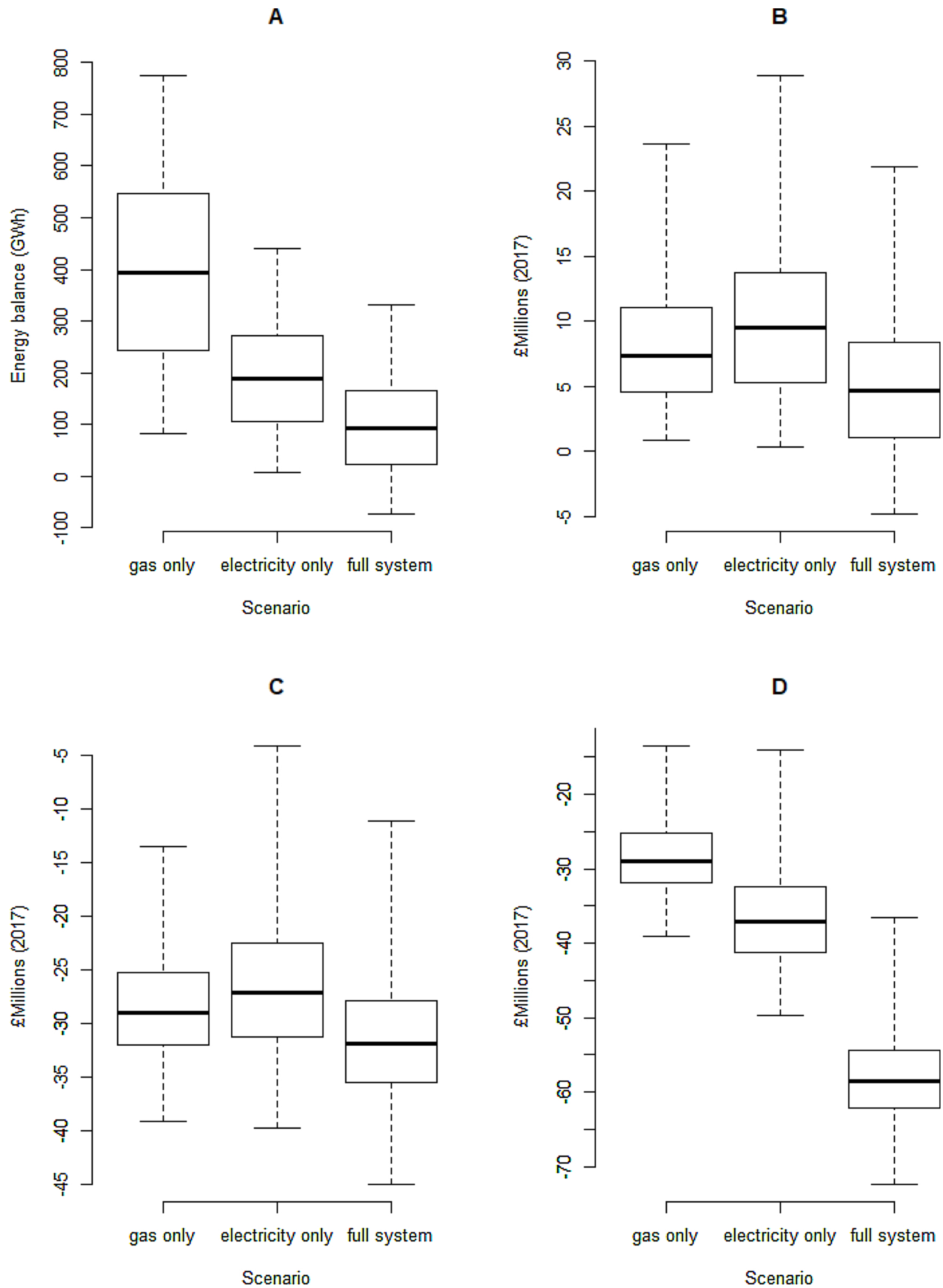

Fig. 6. A - Full 30 year project energy balance for gas, electricity, and full system scenarios; B - Full 30 year project revenue balance; C - Full 30 year project revenue balance including full field exploration and maximum development costs (based on the Jacky field), D - Full 30 year project revenue balance including OPEX costs (based on the Jacky field) plus CAPEX costs for CCGT and carbon capture. White boxes extend to the 25th and 75th percentiles, bold horizontal lines within boxes represent the median value, whiskers extend to the full range of values.

that porosity was related to oil charge.

The net:gross was calculated from well logs and combined with evidence from Richards et al. (1993). A maximum and minimum value with even distribution was used as a model input using this data. This reflects the different proportions of mud and sand in different parts of the formation.

Water density values were used for brine with a salinity of 35000 ppm and temperatures of between 75 °C and 95 °C to account for changes in depth across the formation. The methane solubility in the Beatrice formation and Mains formation brines was calculated using the literature figure from Duan & Mao (2006) of ˜0.1 mol/kg, and the figure calculated from Oil & Gas Authority (2017) data from the Beatrice field of 0.23 mol/kg. The error of methane solubility was calculated to be +/- 0.05 mol/kg.

The Jacky field had a much higher calculated figure (0.60 mol/kg) than that of Beatrice. This could be explained by the fact that the field only produced for a short time compared to Beatrice (causing more degassing per unit of water produced), the field only produced from the top sand of the Beatrice Formation, or that there was a significant gas to oil ratio in that field. However, both the Jacky and Beatrice fields had very low gas to oil ratios, so we can confidently rule out that mechanism as a cause of the higher calculated figure (Stevens, 1991; Ithaca Energy, 2017). Despite ruling out one of the mechanisms, this higher value was not considered for the total methane volume calculation as we cannot rule out the effects of short-term production or isolated production from the reservoir, and it is likely to be higher than the value that would be achieved during longer-term production.

The molar volume of an ideal gas at standard temperature and pressure was used to ascertain the volume of produced gas at the surface. The following equation gives the potential size of the methane resource in the Mains formation:

$$A \times h \times \phi \times NtG \times \rho_{brine} \times sol_{CH4} \times 0.0224\, m^3 \tag{1}$$

Where A is areal extent of the Mains formation, h is the thickness of the Mains formation, ϕ is the porosity of the Mains formation, NtG is the net:gross ratio of sand to mud in the Mains formation, ρ_{brine} is the density of the formation brine, sol_{CH4} is the solubility of methane in brine, and 0.0224 m^3 is the molar volume of ideal gas at STP. We use these water volume and methane solubility calculations to determine a range of values for methane per m^3 formation water produced.

3.2. Daily well production

Production data from the Jacky oilfield (Oil & Gas Authority, 2017) was used to calculate a range of figures for projected daily water production per well. The Jacky field was used for two reasons, firstly, as it produced from an over pressured section of the basin and secondly, as it possessed only one production well, as opposed to more than thirty present in the Beatrice field. The total production of liquids (oil and water) were divided by the number of days of production over the field's lifetime. The Jacky field has produced between 1300 and 1600 m^3 of brine and oil per day in the first two years of its operation (Oil & Gas Authority, 2017). We use these as maximum and minimum figures and assume that the well lifetime is the same as the project lifetime: 30 years. This is in line with the 34 year lifetime of production from the Beatrice field.

3.3. Gas Production Scenario

The well production and dissolved methane concentration values were used to produce values for gas production volumes per m^3 brine that is brought to the surface and degassed. As the solubility of methane is negligible at surface conditions (Ganjdanesh and Hosseini, 2016) we assume a 100% recovery rate from the brine. This is not to say that 100% of the resource present in the formation is recoverable, only that all of the gas contained within the extracted brine is degassed from it. This was then converted into monetary terms via conversion to kWh. Gross monetary value was calculated using the real cost of wholesale gas in the UK corrected to April 2017 prices using data from Ofgem (2017b) and The Office for National Statistics (2017). The maximum and minimum gas prices from the 2010-2017 period were used under the assumption that future gas prices will be similar.

Known per barrel cost of oil production from the Jacky field (Edison Investment Research, 2009) was converted to a per m^3 figure for total produced liquids (both oil and water) of £5.74$_{2017}$ and subtracted to give a net monetary value. Combining this cost with the amount of gas produced per m^3 of water provided the cost per m^3 gas. It is worth noting that this price per barrel figure is for oil and takes into account the exploration, development, and production costs. It is extremely likely that these will be considerably lower for a brine production system using existing infrastructure, but we use the oil production cost figure due to a lack of other available cost estimates.

3.4. Electricity Production Scenario

Assumption of complete combustion of methane in a modern CCGT (combined cycle gas turbine) with an efficiency of 58.3% (Aminov et al., 2016) was used to calculate electricity production:

$$kWh_{gas}\, m^{-3}{}_{brine} \times e_{CCGT} \tag{2}$$

Where $kWh_{gas}\, m^{-3}{}_{brine}$ is the energy equivalent of gas per cubic metre of brine, and e_{CCGT} is the efficiency of a CCGT.

In monetary terms, we can calculate what this power generation is worth using an inflation adjusted average price for electricity from wholesale electricity price data from Ofgem (2017a) and historic consumer price index data from the Office for National Statistics (2017). As previously, the maximum and minimum electricity prices from the 2010-2017 period were used under the assumption that electricity prices over the next decade will not be significantly lower or higher.

3.4.1. CO_2 Volume

The potential storage volume of CO_2 dissolved in brine in the Beatrice oilfield was calculated using the production volumes of oil from the field along with the formation volume factor and CO_2 solubility data from Rochelle & Moore (2002) and Bando et al. (2003). This assumes that the produced oil can be replaced entirely by CO_2 saturated water.

$$\rho_{brine} \times M(CO_2) \times sol_{CO2} \times V \tag{3}$$

Where ρ_{brine} is the brine density, $M(CO_2)$ is the molar mass of CO_2, sol_{CO2} is the CO_2 solubility in brine, and V is the volume of water in the Mains formation.

The storage capacity of the Mains formation is considered to be the amount of CO_2 that can be dissolved in the total volume of formation water. This assumes that as water is produced and reinjected into the formation its pressure does not change.

However, a more realistic scenario is to calculate the amount of CO_2 storage per m^3 of formation water as not all water is likely to be accessible:

$$\rho_{brine} \times M(CO_2) \times sol_{CO2} \tag{4}$$

Where ρ_{brine} is the brine density, $M(CO_2)$ is the molar mass of CO_2, and sol_{CO2} is the CO_2 solubility in brine.

This figure can then be used to ascertain the amount of extra space available for additional CO_2 from outside the system.

3.4.2. Injection/extraction costs

The injection wellhead pressure used was 11.5 MPa as this figure covers the minimum injection pressure required for the Beatrice field and that required for pressure maintenance within the Mains formation.

Assuming a pump efficiency of 0.8 (Ganjdanesh and Hosseini, 2016) the energy requirement can be calculated using equation 5, from Burton & Bryant (2009)

$$W_{inj} = \frac{q_{brine} \times P_{mixing}}{\eta_{pump}} \tag{5}$$

Where q_{brine} is the brine flow rate (equal to production rate), P_{mixing} is the mixing pressure, and η_{pump} is the pump efficiency. As we have taken a pessimistic figure for injection wellhead pressure, we can also assume this equation is the same as the maximum extraction energy.

3.5. Full closed-loop system with Geothermal and Capture Scenario

3.5.1. Carbon capture cost

The mass of brine required to provide enough energy to capture 1 kg of CO_2 can be calculated using the following assumptions: (i) That the ammonia capture process captures 90% of carbon dioxide from methane combustion (Gazzani et al., 2014). (ii) Using the chilled ammonia process as the maximum and the ammonia with organic solvent process as the minimum energy requirement (see Table A3). (iii) The Ammonia regeneration temperature is less than 70 °C and requires cooling water of 20 °C or less (Novek et al., 2016). Bottom water temperatures in the Moray Firth are 6-10 °C year round (Skjoldal, 2007) and so seawater can be used for cooling purposes. As we assume complete combustion of methane, there is a 1:1 ratio of mols methane to mols CO_2 and therefore we can use the methane volume per m^3 brine in the equation, corrected for 90% capture efficiency:

$$V_{gas} m^{-3}{}_{brine} \times \rho_{CO_2} \times E_{amm.} \times \eta_{cap.} \tag{6}$$

Where $V_{gas} m^{-3}{}_{brine}$ is the volume of gas per cubic metre of brine, ρ_{CO_2} is the CO_2 density, $E_{amm.}$ is the ammonia carbon capture cost, and $\eta_{cap.}$ is the capture efficiency.

3.5.2. Mixing tank cost

The energy cost of compression to dissolve the CO_2 into the brine prior to injection is given by the following equation from Burton & Bryant (2009)

$$W_{CO_2} = \frac{SN_{CO_2} nRT_1}{(n-1)} \left[(\frac{p_x}{p_1})^{n-1/n} - 1 \right] \tag{7}$$

Where S is the number of stages, N_{CO2} is the mols per kg of CO_2, n is the polytropic coefficient, R is the gas constant, T_1 is the inlet temperature, p_x is an intermediate stage pressure, and p_1 is the inlet pressure.

3.5.3. Geothermal energy

Using the geothermal gradients calculated by Argent et al. (2002) for wells 21/23-1 and 12/24-2 of 29.7 °C/km and 32.4 °C/km respectively (both +6 °C for average sea bottom temperature) we find that the lowest temperature for the Mains formation is in well 11/30aA18 at 65 °C. The maximum temperature is found in well 11/25-1 where the base of the Mains formation would be 110 °C using the higher gradient. Assuming an error margin of ± 5 °C, the minimum and maximum used are 60 °C and 115 °C respectively. The 115 °C value was extrapolated from a graph of the existing data up to 110 °C from Clarke and Glew (1985). Using the energy calculations in Table A4 in the appendix, we can calculate the geothermal energy that could be produced per unit volume in the brine:

$$kWh_{therm.} kg^{-1}{}_{brine} \times \rho_{brine} \tag{8}$$

Where $kWh_{therm.} kg^{-1}{}_{brine}$ is the geothermal energy per kg of brine, and ρ_{brine} is the brine density.

3.5.4. Calculating Net energy balance

This study assumes a project lifetime of thirty years with a free flowing well for the first two years, as was the case in the Jacky field. The thermal energy extracted from the brine can only be used for the capture process and is assumed to cover that energy requirement. The electrical energy balance for the first two years is given as:

$$(kWh_{gas} m^{-3}{}_{brine} \times e_{CCGT} \times q_{brine}) - q_{brine}(W_{CO_2} \times m_{CO_2} + W_{inj}) \tag{9}$$

And for subsequent years:

$$(kWh_{gas} m^{-3}{}_{brine} \times e_{CCGT} \times q_{brine}) - (W_{CO_2} + 2W_{inj} \times q_{brine}) \tag{10}$$

Where $kWh_{gas} m^{-3}{}_{brine}$ is the energy equivalent of gas per cubic metre of brine, e_{CCGT} is the efficiency of a CCGT, q_{brine} is the brine flow rate, W_{CO2} is the mixing tank energy requirement, and W_{inj} is the injection/extraction energy requirement.

The net energy balance can then be assigned a monetary value (Fig. 6) using the inflation adjusted average price for electricity (Ofgem, 2017a).

3.5.5. CAPEX, OPEX and decommissioning costs

No reliable figures are available for individual wells but the consensus in the literature is that drilling and completing a North Sea oil well costs upwards of £10 million. One 2014 opinion piece stated a cost of between £15 and £40 million (MacDonald, 2014). This considerable cost in drilling and completion makes a strong case for re-use of existing wells for CCS activities where possible.

In this study it is assumed that the per barrel production cost from Edison Investment Research (2009) includes the drilling of the wells at the Jacky site as well as the OPEX of the production platforms. Using the average figure of 40% for production costs per barrel of oil in the UK (The Wall Street Journal, 2016), we calculate an OPEX figure of £2.30 in 2017 money per m^3 brine produced.

CCGT units cost around £10 million for a 17.3 MW model (Welander, 2000). Estimates of the cost of a post combustion capture system for gas range from a low(p80) of 813 $£_{2013}$/kW to a high(p20) 964 $£_{2013}$/kW (DECC and Mott MacDonald, 2012) (£885.45 and £1,049.91 in 2017 money). Hence, CO_2 capture costs from a 17.2 MW CCGT equate to between 15.2 and 17.2 £million (2017 monetary values).

According to Oil & Gas UK (2012), average costs for plugging and abandonment of platform wells is £2.9 million, subsea exploration and appraisal wells are £3.5 million, and over £15 million for a subsea production well. Topsides cost £4200 per tonne and jackets cost £3100 per tonne. This does not include disposal costs or pipeline removal costs.

Using these cost estimates, we calculate that decommissioning of the infrastructure associated with the Jacky field (two platform wells and a subsea exploration well, along with 663 tonnes of topside and 950 tonnes of jacket (Ithaca Energy, 2017)) would cost a minimum of £15 million. In addition, there are also several subsea modules, pipelines, and cuttings piles that would need to be removed which would increase decommissioning costs further. Unfortunately, more detailed estimates of the costs of total decommissioning are not available from the current operator due to commercial sensitivity.

Using the same Oil and Gas UK estimates, decommissioning of the he infrastructure at the Beatrice field (21,773 tonnes of topsides and 13,886 tonnes of jackets across 6 installations, along with 43 platform wells (Repsol Sinopec, 2018)) would cost around £260 million. As with the Jacky field, more specific cost estimates for site specific decommissioning are not available from the current operator due to commercial sensitivity. However, in the case of both fields the significant costs of decommissioning provide a strong case to delay it for as long as possible and invest in re-use of the infrastructure, particularly if it can result in further revenue generation which can be used to assist in offsetting future decommissioning costs.

4. Results

Table of results is in appendix 1 (Table A5).

5. Discussion

The size of the resource is significant when compared to yearly gas consumption in the UK. Our calculations show that the total gas resource ranges from between 3.7 TW h and 1000 TW h. The total UK gas demand for 2017 was ˜875 TW h (Halliwell and Lucking, 2017). The mean resource was calculated as 155 TW h which would cover ˜18 % of this assuming similar levels of demand in future years.

The costs of this system are in the tens of millions, however building a carbon storage site from scratch would cost in the hundreds of millions (Shell UK, 2016). Decommissioning also runs into the hundreds of millions and so reuse of infrastructure in this way provides a cheaper way of getting a large-scale carbon storage industry started.

The storage potential for dissolved CO_2 in the formation is an order of magnitude greater than the amount generated within the system from methane extraction and CO_2 capture. The generated CO_2 only accounts for between ˜3 and ˜10 % of the available storage space. This opens up such a scheme to disposal of externally produced CO_2, which given the EU emissions trading scheme carbon price could also be monetised. Assuming a price of between £10 and £30 (2017 money) per tonne, this could add up to between £7 million and £40 million in revenue. A carbon credit for emissions avoidance of £10 per tonne would also add between £0.3 million and £1.8 million over the lifetime of the project. Given the current desire to reach net-zero in developed nations close to 2050, it is highly probable that these CO_2 reduction incentives will increase and hence these additional revenue estimates can be taken as minimum values.

Whilst this study shows that co-production of methane, brine and geothermal energy is potentially viable at the chosen site, the area selected is not ideal, as it is not the onshore deep, hot (> 100 °C), overpressured aquifers considered by Ganjdanesh et al. (2014). However, as our work shows that such a co-production scheme in a sub-optimal location is a better option than immediate decommissioning, other North Sea locations with higher pressure regimes and hotter aquifers have the potential to generate significant profit. This is especially the case where greater geothermal energy potential could be used to generate electricity, rather than solely be used in the carbon capture process.

This study has shown that the reuse of existing infrastructure for a low carbon CO_2 disposal site is worth serious consideration. The North Sea contains a significant amount of infrastructure earmarked for decommissioning in the near future, but re-use could be the key to helping to overcome the financial barriers currently in place preventing development of a large-scale carbon storage industry.

Whilst the Mains formation capacity estimate is somewhat uncertain as it is based on estimated volumes, the capacity estimate for the depleted Beatrice field is much higher confidence due to accurate production figures. The Beatrice field has the potential to store between 18 and 26 Mt (megatonnes) of CO_2 without the risk of leakage as the CO_2 saturated brine is denser than the native brine and will tend to sink, unlike supercritical CO_2 that remains buoyant in the subsurface.

Recent work has illustrated that production of brine from a North Sea saline formation can significantly increase the potential storage capacity of the Captain sandstone formation and assist in pressure management during the lifetime of the site (Jin et al., 2012). Our study has shown that the addition of gas and geothermal energy production could help to reduce running costs during brine production operations. Economies of scale could be introduced where several platforms could feed gas to a central power generation hub. As the only necessities for this system are a depleted, underpressured field and an overpressured aquifer there are many other potential options available in the North Sea currently accessible through existing infrastructure. If decommissioning is allowed to continue without consideration of such reuse of the existing infrastructure then these opportunities will be lost and CCS in the North Sea will be considerably more expensive.

6. Conclusions

Here we show that the potential methane saturated brine resource in the Mains formation is significant when compared to UK gas demand. However, production of brine gas alone from the Mains formation is unlikely to be commercially viable, even if used to generate and sell electricity.

However, if brine is being produced for pressure management or for dissolution CO_2 storage, then electricity generation can provide some of the energy requirements for running the system. Producing geothermal energy alongside the gas with electricity production can cover the energy costs of a closed loop dissolved carbon storage facility offshore with its own carbon capture unit. Hence, this system has the potential to run off low carbon energy generated on site.

Furthermore, the likely amounts of produced CO_2 by this system would not fully saturate the produced brine. This opens up the potential of importing CO_2 from external sources for storage. This could provide additional income depending on the carbon price and help overcome financial barriers for new carbon storage sites.

Hence, we find that a viable system could build upon existing infrastructure in the UK North Sea, a mature basin with large numbers of platforms and depleted fields. This would be an order of magnitude less expensive than current plans to decommission all UK North Sea infrastructure and could help to open up the UK North Sea to a world leading large-scale carbon storage industry.

Appendix A

Table A1
Calculation of actual solubility of methane in Beatrice oil field

Produced Water Properties	Figure	Unit	Notes
Density of produced water	9.98E+02	kg/m3	Assuming 35000 ppm chlorides and 80 °C using online calculator (CSG Network, University of Michigan and NOAA, 2011)
Volume of produced water	1.27E+08	m3	(Oil & Gas Authority, 2017)
Mass of produced water	1.26E+11	kg	Volume of produced water × density of produced water
Methane Properties			
Volume methane produced	7.20E+08	m3	(Oil and Gas Authority, 2017Oil & Gas Authority, 2017)
Density of methane at 1.013 bar and 25C	6.57E-01	kg/m3	(Air Liquide, 2018)
Mass of methane produced	4.73E+08	kg	Volume methane produced × Density of methane at 1.013 bar and 25C
Molecular weight	1.60E+01	g/mol	(Air Liquide, 2018)
	1.60E-02	kg/mol	
Solubility Calculation			
Mols gas produced	2.95E+10	mol	Mass methane/molecular weight
Methane solubility in Beatrice field	2.33E-01	mol/kg	Mols gas produced/mass of produced water
	0.23	**mol/kg**	**to 2 significant figures**

Table A2
Calculation of actual solubility of methane in Jacky oil field

Produced Water Properties	Figure	Unit	Notes
Density of produced water	9.95E+02	kg/m3	Assuming 35000 ppm chlorides and 85 °C using online calculator (CSG Network, University of Michigan and NOAA, 2011)
Volume of produced water	1.70E+06	m3	(Oil & Gas Authority, 2017)
Mass of produced water	1.69E+09	kg	Volume of produced water* Mass of produced water
Methane Properties			
Volume methane produced	2.48E+07	m3	(Oil & Gas Authority, 2017)
Density of methane at 1.013 bar and 25C	6.57E-01	kg/m3	(Air Liquide, 2018)
Mass of methane produced	1.63E+07	kg	Volume methane produced* Density of methane at 1.013 bar and 25C
Molecular weight	1.60E+01	g/mol	(Air Liquide, 2018)
	1.60E-02	kg/mol	
Solubility Calculation			
Mols gas produced	1.02E+09	mol	mass methane/molecular weight
Methane solubility in Jacky field	6.01E-01	mol/kg	mols gas produced/mass of produced water
	0.60	**mol/kg**	**to 2 significant figures**

Table A3
A comparison of the two chilled ammonia carbon capture processes, their energy requirements, and the equivalent mass of brine required to provide the required geothermal energy at different brine temperatures. Masses were calculated from the data in Table A4.

Process	Energy cost MJ/kg CO_2	kg brine required at 60 °C	kg brine required at 70 °C	kg brine required at 80 °C	kg brine required at 90 °C	Source
Chilled Ammonia	2.43	120.2	100.0	85.6	74.7	(Sutter et al., 2016)
Ammonia + organic solvent	1.39	68.7	57.2	49.0	42.8	(Novek et al., 2016)

Table A4
Energy release from cooling hot brine (35000 ppm) to 10 °C; calculated from Clarke and Glew (1985). The value for 115 °C was extrapolated from the rest of the data.

Molality	Initial temp. (°C)	Specific Heat Capacity (j/kg.k)	Change in Temp (°C)	Mass (kg)	Energy released (j)	Energy released (MJ -2 significant figures)
0.6	60	4044.3	50	1	202217	0.20
0.6	70	4049.1	60	1	242944.2	0.24
0.6	80	4055.4	70	1	283878	0.28
0.6	90	4063.6	80	1	325089.6	0.33
0.6	100	4073.9	90	1	366647.4	0.37
0.6	110	4088.8	100	1	408877	0.41
0.6	115	-	105	1	413900	0.41

Table A5
Results of the Monte Carlo analysis

GAS RESOURCE (TWh)						
TWh gas in Mains formation						
	Min	1 st Quantile	Median	Mean	3rd Quantile	Max
	3.7	68	120	155	210	1000
CO_2 STORAGE CAPACITIES (kg)						
CO_2 storage potential of mains fm.						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	2.23E+10	2.09E+11	3.42E+11	4.03E+11	5.44E+11	2.00E+12
CO_2 storage potential of Beatrice oil field						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	1.83E+09	2.04E+09	2.23E+09	2.23E+09	2.43E+09	2.64E+09
Excess CO_2 capacity per m3 brine						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	1.90E+00	3.80E+00	5.60E+00	5.60E+00	7.50E+00	9.40E+00
ENERGY PRODUCTION (kWh)						
total produced gas						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	1.37E+08	3.02E+08	4.54E+08	4.55E+08	6.05E+08	8.40E+08
total produced electricity						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	6.90E+07	1.66E+08	2.49E+08	2.51E+08	3.32E+08	4.97E+08
total produced thermal energy						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	7.93E+08	1.11E+09	1.35E+09	1.35E+09	1.58E+09	2.00E+09
ENERGY BALANCES (kWh)						

(*continued on next page*)

Table A5 (*continued*)

gas scenario energy balance						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	8.34E+07	2.43E+08	3.95E+08	3.96E+08	5.46E+08	7.75E+08
electricity scenario energy balance						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	6.98E+06	1.07E+08	1.90E+08	1.91E+08	2.73E+08	4.41E+08
full system energy balance						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	−7.52E+07	2.17E+07	9.45E+07	9.61E+07	1.66E+08	3.34E+08
lifetime project energy costs						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	1.20E+08	1.43E+08	1.54E+08	1.55E+08	1.65E+08	1.94E+08
REVENUE BALANCES (£millions, 2017)						
gas scenario revenue						
	Min.	1st Qu.	Median	Mean	3rd Qu.	Max.
	8.48E-01	4.24E+00	7.35E+00	8.11E+00	1.10E+01	2.36E+01
electricity scenario revenue						
	Min.	1st Qu.	Median	Mean	3rd Qu.	Max.
	3.12E-01	5.32E+00	9.46E+00	9.88E+00	1.38E+01	2.89E+01
full system scenario revenue						
	Min.	1st Qu.	Median	Mean	3rd Qu.	Max.
	−4.82E+00	1.09E+00	4.69E+00	4.95E+00	8.35E+00	2.18E+01
REVENUE BALANCES INCLUDING FIELD OPEX (£millions, 2017)						
gas scenario revenue balance						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	−3.91E+01	−3.19E+01	−2.89E+01	−2.84E+01	−2.52E+01	−1.35E+01
electricity scenario revenue balance						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	−3.97E+01	−3.12E+01	−2.71E+01	−2.66E+01	−2.25E+01	−4.12E+00
full system revenue balance						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	−4.50E+01	−3.55E+01	−3.18E+01	−3.16E+01	−2.78E+01	−1.11E+01
REVENUE BALANCES INCLUDING FIELD OPEX & CAPEX (£millions, 2017)						
gas scenario revenue balance						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	−3.91E+01	−3.19E+01	−2.89E+01	−2.84E+01	−2.52E+01	−1.35E+01
electricity scenario revenue balance						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	−4.97E+01	−4.12E+01	−3.71E+01	−3.66E+01	−3.25E+01	−1.41E+01
full system scenario revenue balance						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	−7.24E+01	−6.22E+01	−5.85E+01	−5.82E+01	−5.44E+01	−3.65E+01
EXTRA SPACE SALES AND CARBON AVOIDANCE (£millions, 2017)						
extra space CO_2 sales						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	7.83E+00	1.60E+01	2.13E+01	2.17E+01	2.68E+01	4.30E+01
CO_2 avoidance payments						
	Min.	1 st Qu.	Median	Mean	3rd Qu.	Max.
	2.97E-01	6.59E-01	9.88E-01	9.93E-01	1.32E+00	1.83E+00

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